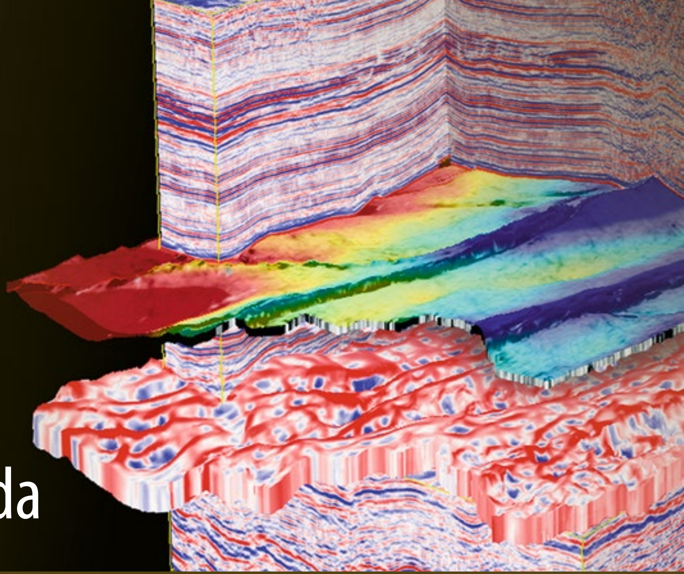

Niranjan C. Nanda

Seismic Data Interpretation and Evaluation for Hydrocarbon Exploration and Production

A Practitioner's Guide

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Cover illustration: A composite display of multiattributes showing a cutaway seismic cube intersected with two strata cubes, the lower one from the most-positive curvature attribute, and the upper one from coherence attribute overlaid with the time horizon in semi-transparent colour (image courtesy: Arcis Seismic Solutions, TGS, Calgary).

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Preface

Young students in universities and freshers in oil companies have asked me on many occasions after my lectures, if I could suggest a reference book on interpretation and evaluation of seismic data. I could not do so because, honestly, I was not aware of any such book. Interpretation, being an aspective art, depends to a large extent on an individual's perception and, perhaps due to this reason, it becomes difficult for one to express abstract things in writing.

Interpretation of any data, especially seismic data in petroleum exploration, needs to be conclusive and logically extended to its geological implications, in evaluating the prospects for techno-economical risk analysis, and consequently in strategizing field development plans for exploration and production of hydrocarbons. There is a difference between interpretation of data and its evaluation, which needs emphasis. For example, detecting and mapping a fault is not an end of an interpretation in itself. It is essential for the interpreter to evaluate its significance in terms of its role in source and reservoir potentials, in trapping and migration mechanisms, and ultimately for accumulation and production of hydrocarbons.

This guide is for practioners, students as well as geoscientists and engineers in the industry in the field of seismic data interpretation and more significantly for data evaluation. It is assumed that the young professionals are well acquainted with the elementary theory, principles and the equations in their respective disciplines of geology and geophysics taught in schools, and as such these preliminaries are mostly kept to the bare minimal. However, as it is essential for a seismic analyst to be familiar with certain relevant geophysical, geological and reservoir engineering principles for a holistic interpretation and evaluation of multidisciplinary data, some of the basics are restated very briefly and in a simple way in the book for expediency.

This guide is principally an expanded and enlarged version of my lecture and training notes to post-graduate students of Petroleum Geology and Geophysics and young professionals in oil companies. A caveat that may appropriately be stated here is that the handbook reflects a flavor of many of my personal perceptions and idealistic thoughts, sieved out of many decades of my practicing experiences in petroleum exploration and development. It is an attempt to encourage and steer young analysts to become more imaginative, logical, and practical in application of their knowledge to achieve the goals.

Ultimately, it aims to motivate and facilitate the practitioners in the art of seismic data interpretation and evaluation and to gain proficiency in a shorter span of time, an objective often sought by E&P companies in the industry. It is hoped that this handbook provides enough stimuli to the inquisitive and sharp minds of the young geoscientists and engineers, compelling them to continue thinking and questioning followed by offering rejoinders, and in the process excel in their profession.

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Acknowledgments

Seismic interpretation is an art or a skill that is acquired with experience, which I happened to attain during my long stint with Oil and Natural Gas Corporation (ONGC), India. On my superannuation from ONGC after 37 years of service, my passion for seismic interpretation encouraged me to take up consulting projects and teaching assignments at Indian Universities, which I have enjoyed very much till the present. A few years ago, my good friend and erstwhile colleague at ONGC, Satinder Chopra of Arcis Seismic Solutions, TGS, Calgary, Canada, suggested that I should condense my long-standing experience in seismic interpretation in the form of a book. His persistent persuasion eventually compelled me to take up this task. From the beginning, Satinder has been extremely supportive and obliging in developing the project, both in mind and matter. His genial and meticulous review of the manuscript has finally brought the book to its present form. I gratefully and profoundly thank Satinder for these acts.

I thankfully acknowledge ONGC, India; Arcis Seismic Solutions, TGS, Canada; Hardy Energy, India; Society of Exploration Geophysicists (SEG); American Association of Petroleum Geologists (AAPG); Earth Magazine; and the individual authors Rob Stewart, Frisco Brower, Paul Groot and Jon Downton who have accorded permission for publication of the many examples included in the book. I also thank my young friend Ravi Kumar of Saturn Energy Solutions, Hyderabad, India, for dispensation of the attractive images and the figures in the book.

I thank Springer publishers for the dexterous handling of the manuscript for print. In particular, I would like to thank Hermine Vloemans and Petra van Steenbergen, who have been very cooperative and patient in ensuring that the book is published well and on time.

And lastly, I owe an enormous gratitude to my wife not only for her ungrudging endurance of my reticence all these years, but also for her love and devotion that continued to encourage and push me to carry on with the endless task of writing this book until its completion. I also wish to place on record my appreciation and thanks to my two loving daughters who very thoughtfully presented me with a laptop to start the typescript and trained me in its intricate operations and eventually succeeded in making me a ‘sesquifingered’ computer ‘semi-literate’.

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Part I
Exploration Seismic

Chapter 1
Seismic Wave Propagation and Rock-Fluid Properties

Abstract Seismic waves propagating through different rock layers in the earth suffer loss of energy. The different types of energy losses and their mechanisms need to be understood for their geologic significance.

The intrinsic properties of a seismic wave, – amplitude and velocity, are influenced by the properties of rocks through which it travels. The elasticity and density of rocks primarily determine the seismic amplitude and velocity, though other properties such as porosity, texture, fractures, fluid saturation and viscosity, pressure and temperature also affect seismic properties.

Focusing on geologic interpretation of seismic data before introducing fundamentals of seismic principles and rock physics can be something like putting the cart before the horse. Therefore, this chapter is a revisit to the basics of seismic wave propagation and related rock physics. It answers briefly some of the important questions, as given below, which ultimately guide interpretation.

- *How do seismic waves propagate through rocks?*
- *How is seismic energy attenuated?*
- *What are fundamental wave properties?*
- *What are rock-fluid properties and how do they affect seismic response?*

Seismic Wave Propagation

A seismic wave is an elastic wave traveling through a solid rock. When a rock is subjected to a pressure wave, its particles get displaced, transferring energy to the adjacent ones causing a seismic wave to propagate onwards in the rock through particle motions. There are two types of seismic body waves that travel in solid rocks; longitudinal (primary or compressional) waves and transverse (secondary or shear) waves. In fluids, however, only the longitudinal waves can travel.

A seismic wave propagating in the earth encounters several discontinuities (boundaries) between rock types of different physical properties and produces wave phenomena such as reflections, diffractions, absorptions, scatterings and transmissions (refractions). At each boundary or interface between two different rocks, a

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part of the incident energy is reflected back to the surface and the rest of energy is transmitted to the underlying rocks. Seismic methods for exploration of hydrocarbons mostly use the reflected energies of primary or compressional waves returning to the surface. Shear waves reflections are also recorded and are used in specific cases, to provide valuable subsurface information. Chapter 9 (Shear Wave Seismic) provides more detailed discussion on shear seismic.

Also as the wave of energy (seismic pulse) travels downwards in solid media, it undergoes gradual loss of energy (attenuation) depending on the rock-fluid properties. Attenuation, a natural phenomenon, comprises of several types of losses and understanding the process behind each loss can be useful in interpreting the rock type.

Energy Losses

Absorption

The seismic source wave, generated at the surface, as stated earlier, propagates through a rock by transferring energy from one particle to another. In the process, a part of the energy is attenuated due to conversion of mechanical energy to heat energy through frictions at grain contacts, cracks and fractures and fluids present in pores of a rock. The frictional loss primarily due to motion between rock particles at the point of grain contacts is known as *absorption*. Frictional loss is also sensitive, though to a lesser extent, to fluid properties like saturation, permeability and viscosity as the wave travels through the rock. Absorption in rocks is believed to be related to the first power of frequency whereas in liquids it is related to square of the frequency (Anstey 1977).

Absorption is anelastic, frequency selective and cuts out higher frequencies progressively from the source pulse. This results in reduced energy with a wavelet of lower frequency and lower amplitude at deeper depths (Fig. 1.1). Absorption effects are severe within shallow weathering zones and decrease with depth. Magnitude of absorption (friction) loss in a hard rock is liable to be much higher than that in a fluid saturated rock as friction in fluid, considered as a slushy medium, is likely to be small (Gregory 1977). Seismic in offshore deep waters hardly shows low- frequency dominance supporting little energy-loss due to absorption in the water column. However, there can be some absorption loss in partially saturated hydrocarbon reservoirs due to viscous motion between the rock and the fluid.

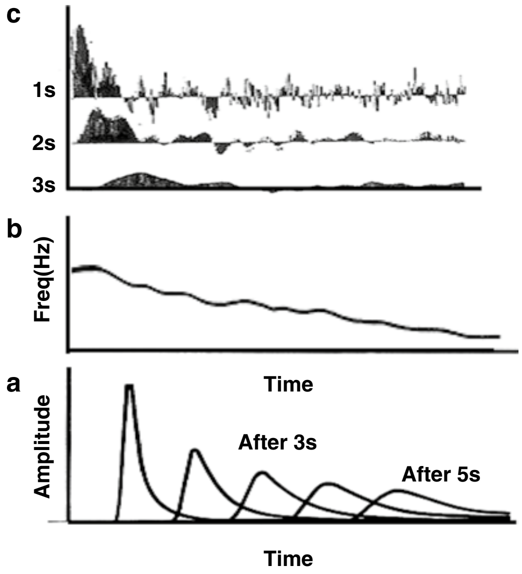

Fig. 1.1 A schematic showing the loss of energy due to absorption during wave propagation. (**a**) Shows a lowering of amplitude with time (**b**) the lowering of frequency with time and (**c**) the overall look of a seismic trace with time (Modified after Anstey 1977)

Scattering

Scattering loss is a frequency dependent *elastic* attenuation linked to dispersion, a phenomenon in which velocities in a rock measure differently with varying frequencies. Scattering losses are irregular dispersions of energy due to heterogeneity in rock sections, usually considered as apparent noise in seismic records. Scattering and absorption losses together are sometimes referred to as attenuation. Geological objects of very small dimensions tend to scatter wave energy and produce diffractions rather than continuous reflections. Highly tectonised shear zones with faults and fractures, very narrow channels, pinnacle mounds etc., are some of the geologic features, most prone to scattering effect.

Transmission

Transmission loss is loss of energy the wave undergoes at every lithologic boundary, as a part of the energy is reflected back to the surface allowing less to go deeper. The loss thus depends on the type and number of reflecting interfaces. It is often believed that a strong reflector like a limestone or an intrusive body reflects most of energy upwards and transmits less in the process, causing poor reflections or shadows below. However, Anstey (1977) has demonstrated that strong reflectors may not be the sole cause for large transmission losses. Instead, such effects may be caused due to large number of thin interfaces, even with small reflectivity, but with alternating signs of contrasts that cause many reflections to account for energy loss.

Transmission losses reduce amplitudes at all frequencies and are not frequency selective as in absorption. One positive spinoff of wave transmission through several thin beds can be the eventual constructive interference of peg-leg multiples from the interfaces of thin beds with reflections at times that aid in recording a reflection amplitude better. But addition of amplitudes tends to lower the frequencies giving an appearance of the pulse similar to the absorption effect. Prima-facie, it may be, hard to distinguish the effects on a seismic pulse due to absorption and transmission losses.

Spherical (Geometrical) Divergence

A seismic wave (usually considered travelling in the form of spherical wave fronts), suffers from reduction of energy as it continually moves away from source and spreads through the subsurface rocks with time (distance). This is also known as geometrical loss as it is linked to the wave-path geometry. The decay is dependent on distance from the source and increases with higher velocities due to greater distance travelled (Fig. 1.2).

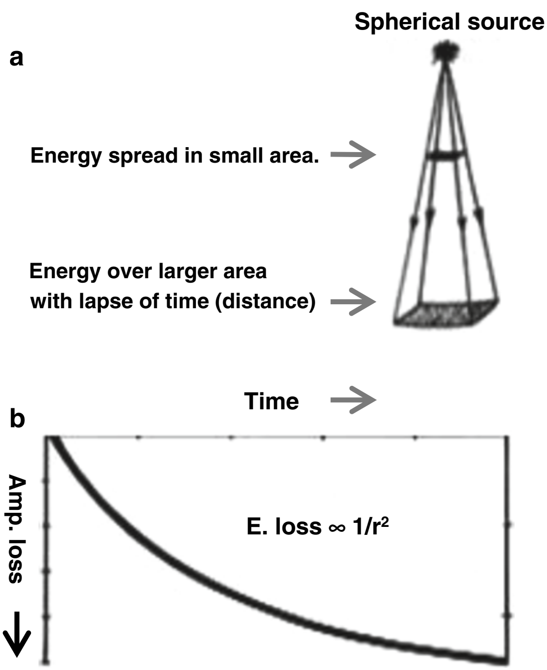

Fig. 1.2 Illustrating loss due to spherical divergence during propagation. (**a**) Spreading of spherical wave causes loss as the energy is distributed over larger area with time and (**b**) is proportional to distance travelled (Modified after Anstey 1977)

Geological Significance of Energy Attenuation

Large attenuation losses in rocks, besides the amplitude, lower the frequencies of seismic wave which lead to lower velocities due to dispersion effect. Measurement of both attenuation and velocity can thus provide complimentary information about the rock and fluid properties. Further, attenuation affecting the frequency and the amplitude content of the wavelet also results in changing the seismic wave shape. Analysis of propagation loss in rocks from the resulting changes in wave shapes can then lead to important geological information about rock and fluid properties. Some significant geological conclusions from analysis of attenuation effect can be as below.

- An indication of high energy loss considered owing to absorption, may give a clue to the type and texture of the reservoir rock. Unconsolidated, fractured, and poorly-sorted rocks having angular grain contacts are likely to have considerable friction (Anstey 1977). A rock, well-sorted and with well-cemented pore spaces, on the other hand, will show negligible loss due to absorption.
- Seismic evidence of high transmission loss can be suggestive of a formation consisting of cyclically alternating impedance contrasts typified by multiple thin sands with intervening shale, the *cyclothems,* in deltaic environment. *Cyclothems* are potentially important geological plays that are commonly sought after by the explorationists.
- Scattering losses due to heterogeneity in strata may provide a clue to the order of irregularities in reservoirs suggesting rapid facies change in a continental depositional environment. Similarly, scattering losses may result in poor to no seismic reflections indicating presence of *mélanges* in highly tectonised zones of subduction which can lead to planning suitable acquisition and processing techniques to achieve better seismic images.

However, energy losses are difficult to identify in real field situations. Can the losses due to absorption be distinguished from those due to transmission, which cause similar effect on a wave pulse? Often the interpreter has little time or access to dig into data processing, which is required to identify and quantify losses. Nevertheless, under certain favorable situations, such as in known geologic areas, relatively shallow targets of exploration, high resolution offshore marine data, it may be possible to detect some of the losses through special processing techniques. This assists in interpreting type and texture of rocks, albeit, qualitatively.

Seismic Properties

The propagating seismic wave has two very important intrinsic elements, which are indispensable to the framework of exploration seismic technology. These are: (1) amplitude of the seismic wave – particle velocity measured by geophones on land or the acoustic pressure measured by hydrophones in marine streamer surveys and (2) velocity of the wave with which it passes through the rocks. Particle velocity conveys the magnitude of the seismic disturbance (micrometers/s) where as wave velocity conveys the speed of the seismic disturbance at which it travels through rocks (km/s). Amplitudes and velocities are the seminal seismic properties and differ over a wide range, depending on rock-fluid properties.

Rock-Fluid Properties (Rock Physics)

Seismic wave propagation with its associated effects brings out vital geological information about different types of subsurface rocks and their fluid contents. The rock-fluid properties, which are many, affect seismic responses and can be intricately complex to decipher. Fortunately, most of the rock-fluid properties affect one way or another the primary properties of a rock, the elasticity and the density, which in turn directly control the seminal properties of a seismic wave, i.e. the velocity and amplitude. Seismic velocity *(V)* is a function of elasticity *(E)* and density *(ρ)*, expressed by the equation

$$V = \sqrt{(E/\rho)},$$

The *amplitude* of a seismic wave, on the other hand is a function of contrasts between two impedances (a product of velocity V and density ρ) of rocks at an interface.

The rock and fluid properties therefore can be determined from seismic properties. Simplistically, a rock is defined in terms of its matrix, pore space and fluid content. All rock-fluid parameters ultimately influence elasticity and density of a rock, and it is expedient to consider the effect of each individual element of the rock and fluid properties separately on elasticity and density separately, to comprehend their seismic responses better. We shall, however, restrict our studies to limited but commonly important rock-fluid properties as below.

Rock Properties

Elasticity

The elasticity of a rock may be defined as the resistance that it offers to stress. The two principal elastic moduli controlling seismic responses are the bulk modulus (k) and the shear modulus (μ). Depending on the type of wave, the elastic moduli play the dominant role in determining the seismic velocity. In the case of compressional waves (P-waves), both bulk modulus and shear modulus control seismic velocity and for shear or transverse waves, the shear modulus plays the dominant role in controlling velocity (S-wave). In an isotropic media, compressional and shear wave velocities are given by the equations

$$Vp = \sqrt{\left[\left(k + 4/3\mu\right)/\rho\right]}, \text{ and}$$
$$Vs = \sqrt{\left[\mu/\rho\right]}.$$

One of the simplest ways to comprehend the elastic moduli of a rock is its incompressibility. A hard rock is difficult to compress because of a high bulk modulus (incompressibility), which ensures high seismic velocity. Likewise, a soft rock with a large compliance has lower elastic modulus and consequently exhibits lower velocity. In a geological sense, elasticity may be likened to a measure of the hardness of a rock, which depends on lithology and commonly increases with depth.

Bulk Density

The bulk density of a sedimentary rock includes the density of the rock matrix and the density of the fluid in the pore spaces. Density of a rock is defined as its mass per unit volume and commonly increases with depth. This is a result of compaction as the rock undergoes burial (Fig. 1.3). Compaction is a diagenesis process that squeezes out water from the pore space of sediments with time (depth) by overburden pressure as they get buried beneath successive layers of sediments. Compact rocks show higher densities whereas under-compacted formations demonstrate lower density values. It may seem paradoxical that compact rocks at depth, though have higher bulk density values, yet show higher velocities. This happens due to relatively increased elasticity of the compacted rock compared to density increase, the elasticity playing the primary role in determining the velocity. It also may be stressed that velocity and bulk density are not directly related, though empirical equations exist which allow an estimation of compressional velocities from bulk densities under certain stipulated conditions as in water-saturated normally pressured sedimentary rocks (Gardener and Greogory 1974). Nonetheless, density determination from seismic remains a difficult task.

Porosity, Pore Size and Shape (Pore Geometry)

Porosity is a measurement of the void space in a given volume of rock. In general, an increase in porosity lowers the density and more so the elasticity of a rock resulting in decreased seismic velocity. Though there is an established relation between porosity and density, no such definitive link exists between porosity and velocity.

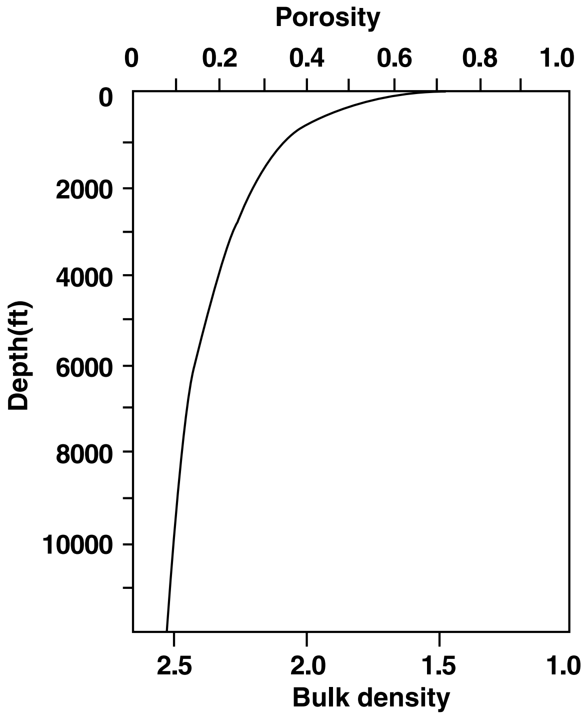

Fig. 1.3 A graph showing an increase in density with depth due to compaction of rock (diagenesis) in normal pressured sections. Compaction leads to the associated reduction in porosity (After Anstey 1977)

Porosity and pore shape varies in different kinds of rock. Unconsolidated sandstones and vuggy carbonates (cavernous porosity) have open, irregular pores whereas partially cemented sedimentary rocks show porosity that occurs between the grains known as intergranular porosity. Cemented sands and tight carbonates, on the other hand, may have dominantly crack-like pore space (fracture porosity). Typically, the seismic velocities depend on both the rock material and the type of porosity controlled by the pore geometry. In general the seismic properties, the velocity and impedance decrease with increasing porosity.

Nevertheless, an empirical time-average equation (Wyllie et al. 1956) provides a basic link between porosity and velocity that is often used by many in interpretation work.

$$1/\mathrm{V_r} = 1-\phi/\mathrm{V_m} + \phi/\mathrm{V_f}$$

V_r, V_m & V_f are velocities of the whole rock, matrix and liquid in pore space, respectively. φ is porosity. It is known as time-average equation as the total time taken for a wave to travel in the rock is assumed to equal the sum of travel times in each rock component (Fig. 1.4).

The time-average equation has, however, several limitations as it is specific to certain types of rock, degree of porosity, type of fluid and normal pressure etc. It can be used to reasonably predict intergranular porosity of highly porous, water and

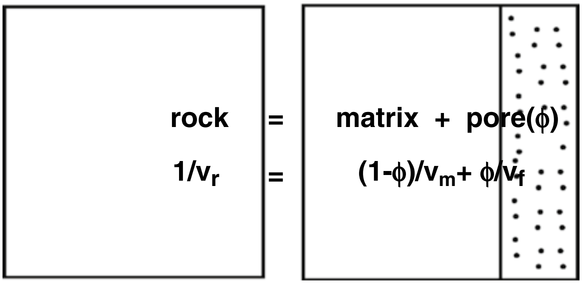

Fig. 1.4 A schematic of 'time average equation' linking velocity and porosity of a rock. The total time taken for a wave to travel in a rock is assumed to be equal to the sum of travel times in the two rock components, i.e. the matrix and the pore space filled with fluid

brine saturated sandstones under normal pressure (Gregory 1977; Anstey 1977) but may not be suitable for highly porous gas saturated unconsolidated sands in overpressured regimes. The equation has since undergone several modifications and changes (e.g., Raymer et al. 1980; Wang and Nur 1992) for modern day applications.

Behavior of velocity, however, is known to be affected more by the shapes of pores than the porosity per se, as the shape plays a major role in determining the compliance of a rock to stress. For example, flat-pore shapes in a relatively low porosity reservoir may indicate lower seismic velocity (more compliance) than that in a high porosity reservoir with spherical pore shapes.

Texture

Grain sizes, roundness, sorting and cementation describe the texture of a rock. Elasticity and density of a rock depend on contacts of grains, their size and angularity though the latter ceases to play a role after the rock is cemented. Large grain sizes and compact sands have generally higher seismic properties due to larger contact areas causing higher velocity (elasticity) and impedance (density), whereas, unconsolidated sands with angular grains are likely to show lower seismic properties (Wang 2001).

Fractures and Cracks, Geometry

Seismic properties are greatly affected by presence of open fractures in a rock. Fractures and cracks facilitate compressibility (compliance) and significantly lower the velocity and impedance. For example, in a given volume of normally fractured carbonate reservoir with a specific bulk density, similar fracture porosity can be expected either by assuming a large number of microfractures or by fewer numbers of bigger fractures, though the lowering of velocity can be much more in the former case compared to that in the latter (Sayers 2007) This can have a significant implication on reservoir evaluation as the micro fractures linked to lower velocity may not be indicative of better reservoir permeability than that having larger fractures.

In case of cemented fractures, seismic velocity may indicate much higher values compared to what is normally expected at a particular depth. Such anomalous velocities for a rock in a known tectonic area can then be used as a clue to corroborate possible presence of fractures that are highly cemented. Similar to pore shapes, geometry of cracks and fractures with varying *aspect ratio* too affect the seismic properties, intricately and significantly, these being generally lower in cases of flat-shaped fractures. The number and shape of fractures also determine the elasticity (compliance) of a rock which primarily decides the seismic properties.

Fractures also create anisotropy in rock sections. Tectonic stress causing fractures, cracks, and vugs may change the texture of a rock to induce seismic anisotropy which can create technological limitations (refer to Chap. 9 for more information).

Fluid Properties

Pore Fluid and Saturation

Most rocks have fluid in pore space. Fluids typically are known to have negligible shear modulus but affect compressional seismic properties depending on its compressibility and density. In a fully water or brine-saturated reservoir rock, water or brine offers resistance to stress and tends to increase velocity though not to the same extent as in a tight rock having little water. Oil in rock pores lowers velocity marginally compared to that with water, as the smaller bulk modulus of oil is offset to some extent by its lower density and makes one velocity hardly distinguishable from the other. In general, rocks saturated fully with liquids exhibit increased seismic properties (Wang 2001). Gas, on the other hand, has the least bulk modulus (highly compressible) and density, and the velocity and impedance of a rock with gas in the pore space thus tend to show significantly lower values than that of rocks saturated with water and/or oil. The lowering of seismic velocity due to presence of gas, even in small quantity, is conspicuously large, especially at shallow depths. Overall, the effect of fluid-saturation on seismic velocities decreases with increasing depth (Fig. 1.5).

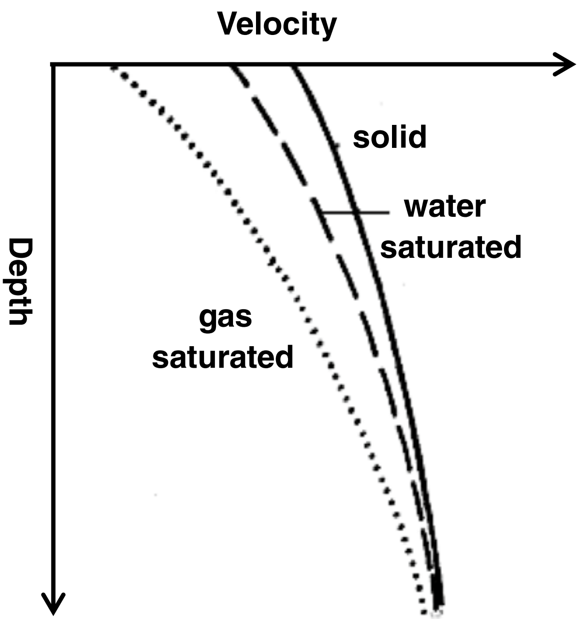

Fig. 1.5 The schematic shows the variation of velocity with depth for solid, water and gas saturated rocks at normal pressure. Velocity variation is significant at shallow depths but tends to be marginal at greater depths (After Anstey 1977)

Viscosity

Rocks tend to exhibit increasing elasticity and density with increase in viscosity of oil. Heavy oil has large bulk modulus and in some cases may tend to act as semisolids in the rock pores (Wang 2001). These rocks obviously exhibit relatively higher seismic properties.

Pressure and Temperature

A rock at depth is primarily under two vertical stresses (ignoring the tectonic stress); the overburden (geostatic or lithostatic) stress and the fluid (formation or pore) pressure. The former is downwards due to gravity and the latter acts upwards due to buoyancy of fluid in the rock pores. The overburden pressure tends to close the pore space, whereas, the fluid pressure tries to retain the voids. The difference between these two pressures, known as the effective pressure or differential pressure (Fig. 1.6) is an important factor in determining seismic properties.

In properly compacted sections where the squeezed water escapes to the surface, the formation shows normal hydrostatic pressure. In normally-pressured sections, effective pressure increases with depth (due to higher overburden pressure) raising elasticity and density of the rock (due to compaction) and resulting in increased seismic properties. The increase in velocity, however, is nonlinear with depth and is

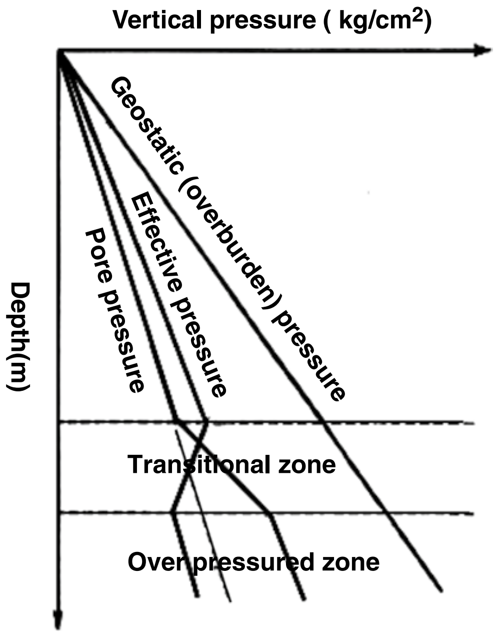

Fig. 1.6 A schematic shows the geostatic, hydrostatic (normal) pore pressure and effective pressure (the difference between the geostatic and pore pressure). Under-compacted rocks withholding water in pores show higher pore pressure than hydrostatic and are known as over-pressured rocks. Over-pressured formations show reduced effective pressure

more pronounced at shallower depths and in lower ranges of effective pressure (Fig. 1.7). The degree of change, however, varies with lithology, depending on hardness; it is maximum in soft unconsolidated sands and minimum in limestone.

In some formations, pore water may be released during compaction but cannot escape due to a non-permeable seal at the top and is thereby forced to stay within the formation with added pore pressure. The formation without undergoing proper compaction remains an under-compacted rock and exhibits higher pressures. The fluid pressure is greater than normal hydrostatic pressure and the formation is termed over-pressured (abnormally pressured). The over-pressured rocks have lower effective pressure, decreased elasticity and density and exhibit lower seismic properties. The decrease in velocity and density, however, typically tends to remain constant with increase in depth of burial of the high-pressured zone (Figs. 1.8 and 1.9). Continued thickening of the overburden does not affect the seismic properties as the high pore-fluid pressure continues to sustain the increasing part of the overburden pressure that occurs with depth.

A rise in temperature leads to changes in pore fluid properties such as viscosity and elasticity. Seismic properties, with increase in temperature, marginally decrease in water and gas saturated rocks but may decrease significantly in oil saturated rocks. Higher temperatures in heavy oil, especially in unconsolidated sands (e.g. tar sands), can result in a remarkable decrease of seismic properties due to more fluid compressibility induced by heat.

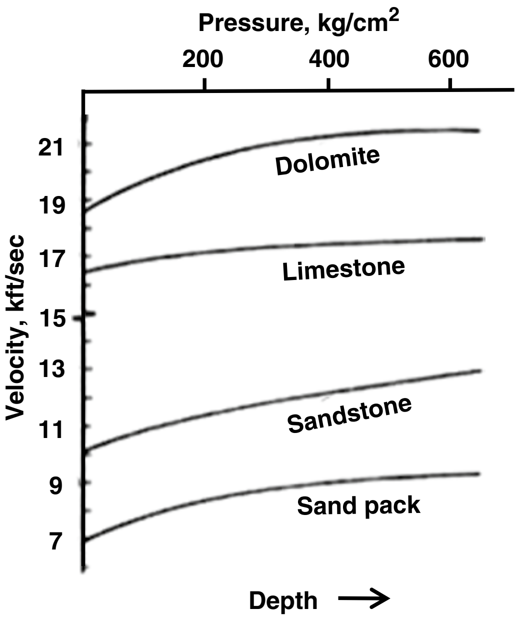

Fig. 1.7 A graph showing increase in P-velocity due to increase in effective pressure for different rocks. Velocity variation is more conspicuous at shallow depths and in lower pressure regimes (Modified after Figure 7 of Gregory 1977)

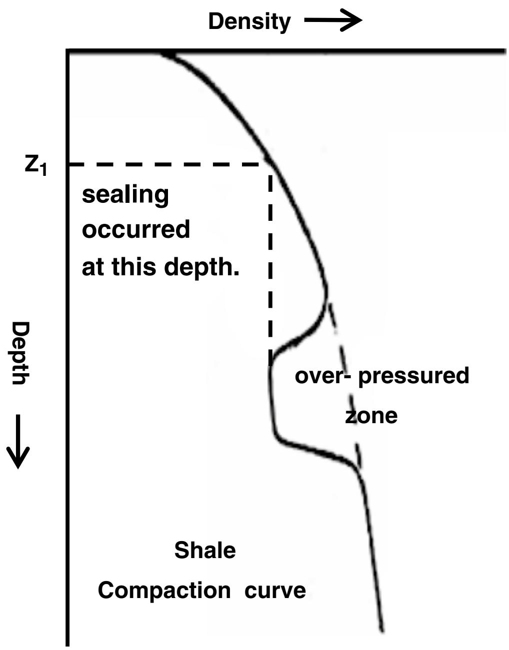

Fig. 1.8 The schematic shows the density variation with depth in normal and over pressured (under-compacted) zones. Note the typical near-vertical curve in the over-pressured zone, showing near constant density without increase with depth. The density shows increase after getting into the normal-pressured zone (After Anstey 1977)

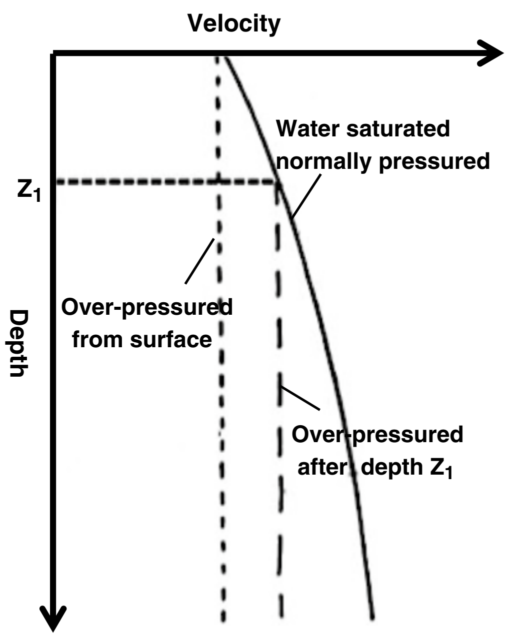

Fig. 1.9 The schematic shows the velocity variation with depth for water saturated formation in normal-pressured and in over-pressured rocks. Over-pressured zones show lower velocity which tends to remain constant with increase in depth. The point where velocity drops (z_1), indicates the depth from where over-pressure started (After Anstey 1977)

Seismic Rock Physics

Seismic rock physics links analysis of rock and seismic properties, the former the causative and the latter the response effect. Properties of rocks and fluids, such as lithology, porosity, fractures, texture, fluid type and saturation, and viscosity etc., and factors like pressure and temperature are all known to affect seismic properties in varying degrees, which can be better understood by realizing their individual roles in influencing the two principal rock properties, the elasticity (incompressibility or compliance) and the density of a rock. The end result depends on the overall effects of each of the individual factors, as many of these interact to reinforce and others to cancel each other.

The most crucial of the rock-fluid properties, permeability, however, remains difficult to be measured or estimated directly from seismic. While estimates of rock properties, such as, lithology and porosity from seismic data has long been a part of routine interpretation; quantitative estimate of the subtler fluid properties like saturation and viscosity remains yet to be fully and effectively realized. This is due to many complicated limitations in seismic manifestation and measurement in routine data, and also perhaps due to lesser understanding in application of rock physics. For example, it is long since reported that some oil/gas saturated reservoirs are associated with low frequency shadow zones below, ostensibly due to much higher absorption in gas as compared to water saturated rocks. However, according to Ebrom (2004) who has extensively researched the phenomena, a convincing good explanation for the observed low-frequency shadow zone below gas reservoir is yet to come up. Ebrom in his paper, on the other hand, has suggested several other possibilities that could be responsible for the phenomena.

Many of the current rock physics studies are, however, theoretical, based on empirical results reported from laboratory tests. Thus, they may need more in-depth investigations for matching the findings with those from real field seismic data. The major limitation, however, remains the critical factor of dimension and scaling, the measured microscopic rock-fluid properties having one-to-one correspondence with properties of macroscopic dimensions imaged by seismic waves. The sensitivity of seismic properties to changes, especially in fluid properties of a rock, seems to be delicate, and its detection and interpretation in a real situation remains a formidable and challenging task for the seismic analyst.

Nevertheless, in some favorable geological and petrophysical setups, such as in highly compliant, shallow unconsolidated gas saturated sands, the effects of individual rock-fluid parameters may be additive so as to result in a seismic response that is discernible in data. 'Bright spot' amplitude anomaly studies may be a case in example which is discussed in Chap. 6. Combined analysis of wave velocity and attenuation losses is another possible approach likely to provide more reliable information about rock and fluid properties.

It may also be noted that the aforesaid discussions are all about compressional seismic properties involving only P waves. Some of the rock-fluid parameters are known to be differently sensitive to compressional and shear waves and a combined analysis of properties of P and S waves is often found to be much more useful. This is dealt in Chap. 9 under the topic of shear seismic.

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Chapter 2
Seismic Reflection Principles: Basics

Abstract Seismic reflection events are caused by the impedance contrasts at layer interfaces having a minimum width (Fresnel Zone). Seismic studies to represent reliably the subsurface geology, require quality data, which depend on signal-to-noise ratio and resolution, the latter being the ability to image thin geologic features separately. This calls for a seismic broad-bandwidth source consisting of both low and high frequencies that can improve resolution limits to layer thicknesses.

Seismic reflections record attributes such as amplitude, phase, polarity, arrival time and velocity that can be measured or estimated. The attributes define the shape and arrival time of reflection waveforms which depend on rock properties. Estimation of rock properties from seismic waveforms and their vertical and lateral changes in time and space is the essence of seismic interpretation.

Appropriate choice of seismic display modes and plotting scales are also important.

When a seismic wave, generated artificially on surface propagates through the earth and meets interfaces between different kinds of rocks, creates phenomena like reflections, refractions, scattering and diffraction. Of these, the reflection is by far the most significant phenomenon, as it forms the basis of the potent seismic reflection method deployed to image the subsurface for finding hydrocarbons. A compressional wave (P-wave) when incident normal to an interface, causes reflection and transmission also normal to it, but when incident at an angle (inclined), it produces two sets of waves, P-reflected and P-transmitted (refracted) and S-reflected and S-transmitted (Fig. 2.1). We shall limit the discussion to the principles of relatively simpler P-wave reflections, used extensively for measuring rock and fluid properties.

A seismic reflection event to be generated needs necessarily two things, an impedance contrast at the interface of two rock types and a minimum width (Fresnel Zone) of the interface. The reflection amplitude and its continuity depend on the degree of contrast across the interface and its extent and nature. The effectiveness of the reflections to reliably represent the subsurface geology is conditional on the quality of seismic reflection signal, which depends on, (1) the amount of noise recorded in the data and (2) the ability of the seismic wavelet to image the different interfaces separately. The reflection signal quality is thus adjudged by the two

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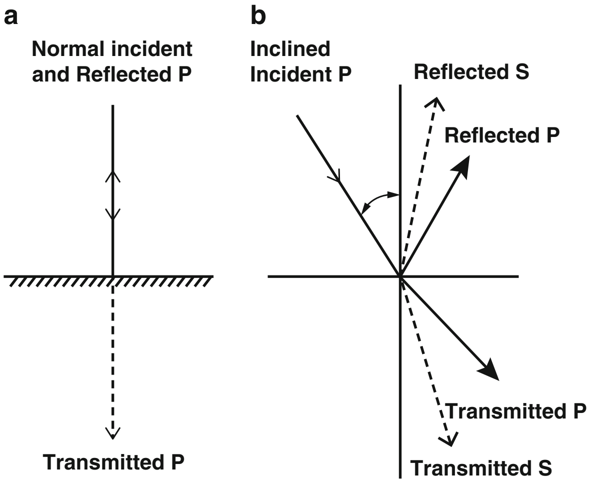

Fig. 2.1 (**a**) A normal incident P-wave on an interface produces one set of waves normal to the interface, the P-reflected and the P-transmitted. (**b**) An inclined incident P-wave, however, produces two sets of waves P-reflected and transmitted and S-reflected and transmitted (refracted)

important factors, the signal-to-noise ratio and the resolving power of the seismic wavelet, briefly discussed below.

Signal-to-Noise Ratio (S/N)

Noise may be defined as all undesired energy, other than the primary reflections from the subsurface strata. It is an inherent part of the seismic recording and processing system present due to ambient (within earth), geological (natural propagation) or geophysical (artifacts during recording and processing) causes. This noise cannot be wished away, but can be effectively reduced by conscious efforts during data acquisition and processing. Noise, though usually unwanted, can be occasionally helpful in interpretation. For example, remnant diffraction noises despite processing may indicate clues to presence of sharp edges, such as faults and other subtle stratigraphic objects. The presence of scattering noise may give an idea about the order of heterogeneity of the reflector, leading to indication of highly tectonised zones, crushed with faults and fractures. Processing of recorded noise as scatters from fractures and fractured zones can also be used as a technique for delineating naturally fractured carbonate and basement fractured reservoirs.

Since noise severely affects seismic clarity in portraying the subsurface image, it is desirable to record good and clean signals with minimum noise. It is a common practice to benchmark the quality of data in terms of a measure of a ratio between signals and noise (S/N). Improved data acquisition techniques including meticulous survey layout plans, field experimentations and strict on-field execution ensure good quality of data. In this context, the common depth point (CDP) seismic data acquisition is a unique technique. A standard technique practiced all over the world, it achieves signal enhancement at the cost of noise, via a summation process of several traces reflected from the same subsurface depth point but with different offsets known as CDP folds. Though summation of higher number of traces in a fixed offset range generally provides better S/N ratio, there may be a limit beyond which it may not be desirable, as adding additional traces (folds) may cost more money without improvement in the seismic images. Also, summation is an integration process, which affects resolution, especially in cases where large far offset traces are included for summing. In areas where the geology promotes good quality seismic reflections, the interpreter may still prefer to look at less-fold CDP data which is likely to offer better resolution and at a lower cost. It may also be noted that data with high S/N ratio does not necessarily assure higher resolution, as the resolution depends on other factors such as source signal frequency, sampling interval and subsurface wave propagation effects, besides noise.

Seismic Resolution

Resolution may be defined as the ability to separate two closely spaced features in depth (time) as well as in space. The resolution we refer to in seismic geophysics is of two types, vertical and horizontal. Vertical (temporal) resolution is the minimum separation in time between two reflections arriving at the surface that allows detection of each reflector separately. Lateral (or spatial) resolution is the minimum lateral distance (spatial) between two close geologic objects that permits each one to be imaged individually. It may be stressed that detection of an event is not the same as resolution which delineates the objects clearly.

Resolution depends on the seismic wavelength with which the subsurface is measured. Wavelength is a fundamental property of a wave which is the distance between successive points of its equal phase (e.g., crest to crest), completing one cycle. It is usually denoted by the symbol λ (see Fig. 2.8) and is defined by the equation $\lambda = v/n$, where 'v' and 'n' stand for the velocity and frequency of the wave passing through a medium. Smaller wavelengths provide better resolution whereas wavelengths too large compared to the dimensions of the object, fail to detect it. Since wavelength is a direct function of velocity and inversely that of frequency, seismic resolution happens to be better at shallow depths where seismic wavelength is smaller due to relatively lower velocity and dominant higher frequencies. On the other hand, resolution deteriorates with depth due to longer wavelengths because of increasing velocity and lowering of frequency.

Vertical Resolution

A short sharp zero phase wavelet (high bandwidth) ideally provides the best resolution, as the arrival times of individual reflections from closely spaced reflectors, being of short wavelet durations, do not overlap during recording at the surface. A zero phase wavelet is symmetrical and has maximum amplitude at time zero, chosen as the origin. A zero phase wavelet is an interpreter's desired wavelet which mathematically speaking is a non-causal wavelet. The commonly used seismic sources like dynamite on land and air-guns in marine produce minimum phase or mixed phase wavelets. However, with a Vibroseis source, a zero-phase wavelet, known as *Klauder* wavelet, is realized by a mathematical treatment (autocorrelation) of the known Vibroseis sweep that makes it a preferred choice.

The seismic short source wavelet, further, while traveling within the earth suffers loss of high frequencies due to absorption and gets changed to a long and cyclic ('leggy') wavelet, practically producing a mixed phase wavelet. The large length of the wavelet does not permit enough separation between the arrival times of reflections coming from closely spaced beds and results in overlapping of the individual events, thus losing the ability to resolve the beds separately (Fig. 2.2). It has been demonstrated by synthetic modeling that *λ/8* is generally the limit of bed thickness, below which thinner beds cannot be seen as resolved (Widess 1973). Widess envisaged a wedge model with impedance contrasts remaining the same at its top and bottom but with the signs of the impedance contrasts reversed (Fig. 2.3). However, in many geological situations the impedance contrasts at top and bottom are likely to be different in values and dissimilar in polarities, in which case, the thin bed resolution limit given by Widess model may be different. Nonetheless, practical experi-

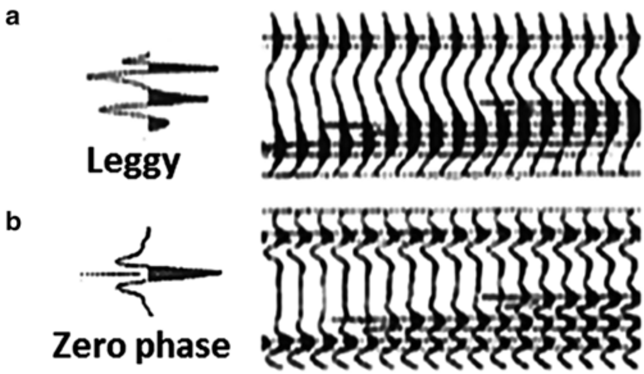

Fig. 2.2 The seismic vertical resolution depends on the type of wavelet embedded in the data. (**a**) A cyclic (leggy) mixed phase wavelet having energy loaded in its later part impedes resolution by causing overlapping of reflections from thin beds. (**b**) The zero phase, short and symmetrical wavelet, has maximum amplitude at zero time with small side lobes and promotes better resolution (Image after Sheriff (1973))

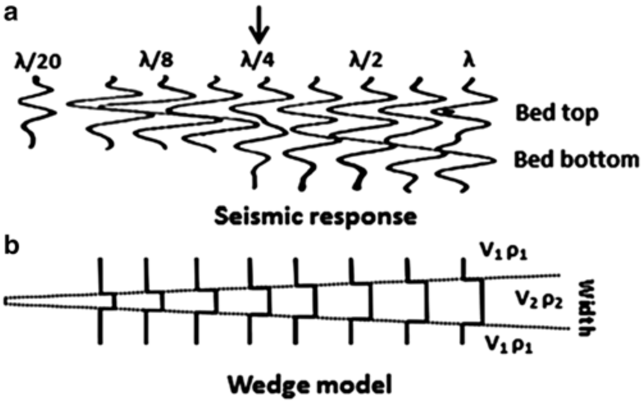

Fig. 2.3 (**a**) The Widess thin-bed wedge model. (**b**) For a bed with thickness greater or equal to the wavelength (λ), the top and bottom reflections are clearly resolvable and this continues till it approaches the quarter wavelength (λ/4). For beds thinner than λ/4, the top and bottom reflections are not seen as distinct, limiting the vertical resolution to quarter wavelength (After Widess 1973)

ence shows that in real-earth situations, where some amount of noise is always present in the data, *λ/4* may be considered a reasonable wavelength as the resolving limit of beds. Broadly, vertical (temporal) resolution varies from 10 to 15 m at shallow depths and from 20 to 30 m at greater depths.

Exploration objectives (reservoirs) are often thin and require improved vertical resolution for proper mapping. Resolution can be enhanced during acquisition by deploying a broad-band wavelet as a source (dynamite) and by recording with smaller sample intervals (temporal, ~2 ms). In addition to the data acquisition efforts, care is taken to retrieve and boost the higher frequencies during processing of the data. The recorded seismic trace is a convolution, a mathematical manner of combining two signals (likened to ~product), of the source wavelet with impedance contrasts present in the subsurface. If the source wavelet can be removed (deconvolved) from the recorded trace through data processing, the impedance contrasts representing geologic rock discontinuities will be left behind. This is the sole aim for seismic investigation, and can be achieved through various data processing techniques known as deconvolution. Deconvolution and zero-phase wavelet are processing steps to increase vertical resolution by suppressing multiples and by compression of the wavelet that is achieved by increasing effective bandwidth.

Lateral (Spatial) Resolution and Fresnel Zone

Huygen's principle stipulates that reflection from a surface consists of a number of diffractions occurring from each point on it and does not come from a single point. Where the reflecting surface is uniform and planar, the diffractions from all points

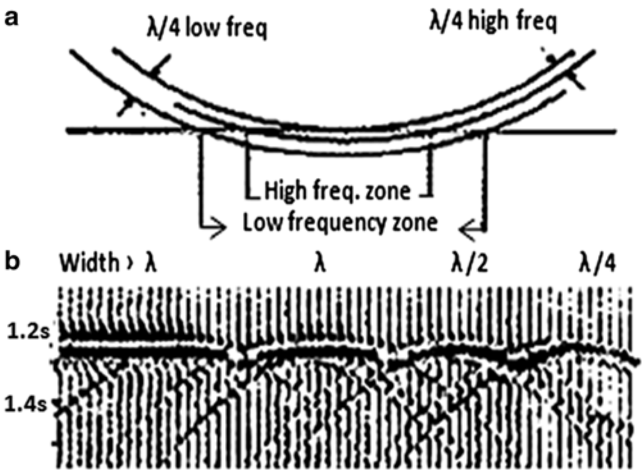

Fig. 2.4 A schematic to illustrate the concept of Fresnel zone. (**a**) Fresnel zone is the effective contact area of a spherical wave with an interface that results in a reflection event. The width of the Fresnel zone is dependent on frequency. (**b**) Synthetic reflection events with variable spatial resolution. Notice the beginning of deterioration in the event at λ/4, which sets it as the limit (After Mickel and Nath 1977)

add constructively to provide a reflection event. If, however, the surface is curved or has less continuity, the diffractions may not add effectively and provide poor reflection.

Seismic waves that originate from a point source are spherical in nature, and when incident on a plane reflector, they sweep through it by producing a succession of contact zones. Nonetheless, the limited planar area, which 'effectively' comes into contact at the interface and collectively contributes to produce a coherent reflection, is called the first *Fresnel zone* (Fig. 2.4a). The seismic wave is a band-limited signal comprising a range of frequencies, and when incident on an interface, each frequency creates its individual area of contact with the interface to cause a reflection. Thus it is important to visualize the phenomenon of reflection as an 'area' concept in two dimensions and as 'volume' concept in three dimensions instead of a single 'point' notion that can have enormous significance in data interpretation and evaluation.

The quality of a reflection depends not only on the area defined by Fresnel zone but also on the type of the reflecting surface. The lateral changes in reflectivity of planar widths less than a Fresnel zone tend to deteriorate the reflection quality. Modeling has demonstrated that interfaces having width less than *λ/4* cannot be viewed clearly and thus defines the limit for spatial resolution (Fig. 2.4b). The Fresnel zone may be considered as a lateral requisite, complimentary to the vertical impedance contrast, responsible for causing a reflection event. Similar to thickness of the bed that determines the temporal resolution, the Fresnel zone width can be considered to serve as a yard stick for defining lateral resolution.

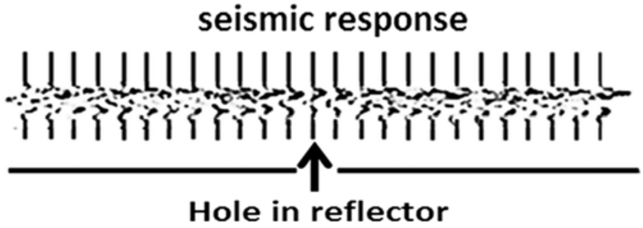

Fig. 2.5 A small discontinuity in the Fresnel zone, such as a small hole in the reflector, has little effect on seismic reflection due to 'wave front healing', a process of diffraction of wave going around the aberration (After Sheriff 1977)

Poor to no reflections, at times, seen associated with fault edges, sharp facies changes, small reefal mounds and erosional unconformities may be examples of inadequate imaging linked to Fresnel's zone width. However, a small discontinuity in the reflecting surface, for instance, a hole cut in the Fresnel zone, will hardly affect the quality of the averaged reflection due to phenomenon of wave front healing (Fig. 2.5), a process by which the waves are diffracted around the discontinuity. This can have important geological implications in that the open fractures and cracks present in rocks may be difficult to be imaged directly by P-wave seismic. Further, Fresnel zones in the subsurface are often not planar but consist of curved surfaces, which is yet another factor that affects quality of reflections. For convex upward surfaces (anticlines), the contact area of the wave with the reflector is small that amounts to loss of amplitudes, where as for concave surfaces (synclines), the contact area being more, provides strong amplitudes. This phenomenon is similar to focusing and defocusing effects of an optical lens.

In reality, it is important to comprehend the Fresnel zone concept through its geometry, the shapes and widths vary greatly depending on several factors, which make it an intricate three-dimensional problem. In a two dimensional case, it may be expressed in terms of a product of seismic wavelength and depth as $R \approx (\lambda \times z/2)^{1/2}$, where R, λ and z represent the Fresnel zone radius, seismic wavelength and depth respectively. The Fresnel zone is small at shallower depths (wave length and distance being small) and increases with depth to the order of hundreds of meters. Since the Fresnel zone width sets the spatial resolution limit, it is important that this be reduced to a minimum to improve spatial resolution and resolve two small geologic objects with clear separation from each other. This is achieved to a large extent by the process of migration that enhances horizontal resolution similar to the role that deconvolution plays in enhancing the vertical resolution.

Migration is a processing technique, which (1) repositions the dipping seismic reflection events to their true geological positions in the subsurface, and (2) collapses the diffractions to improve images and their continuity. Migration eventually preserves true reflection amplitude, creates a more accurate image of the subsurface and more importantly, enhances spatial resolution. For this reason, migration of data is desirable even for data with flat geologic strata. Typically, the Fresnel zone widths, of hundreds of meters in unmigrated data, can be considerably reduced to about 10 m or so by migration. For an effective migration, however, knowledge of proper overburden velocity field and an adequate number of surrounding traces *(aperture)* at the object level is necessary for stacked data. An aperture is the spatial width over which all traces around are considered for migration, and choosing an appropriate aperture is crucial to its effectiveness. Generally, an aperture of twice the Fresnel zone width at the reflection object is adequate (Sun and Bancroft 2001). The migration results suffer gravely near the end of seismic lines as there are no traces recorded and the interpreter should be cautious to consider data in this part.

For better resolution of lateral reflectivity changes of small dimensions, migration may require finer spatial sampling on ground like the temporal sampling used for improving vertical resolution. Take for instance the issue of imaging a small channel of 20 m width, an important geologic object for exploration. Obviously, the channel cannot be resolved with insufficient trace sampling of 25 m though the image with this trace spacing may detect it. The river geometry and more importantly its associated reservoir facies like channel, levee and point bar sands need to be imaged and resolved properly to characterize the reservoir and may necessitate closer trace spacing (subsurface) of no more than 10 m.

Temporal and spatial resolution may be considered somewhat similar in nature and are decided by the wavelength, which is dependent on velocity and frequency of the seismic wave. Both the resolutions depend on velocity but it must be stressed that temporal resolution depends on interval velocity while the spatial resolution is dependent on overburden velocity. As an example, take a limestone bed with an interval velocity of 3200 m/s and an overburden velocity of 2400 m/s for calculating the resolution limits. The vertical and lateral resolution limits for a dominant frequency of 40 Hz, are 20 and 15 m, considering quarter wavelength as the realistic limits of resolution. It is useful for the interpreter to have some idea about resolution limits beforehand; otherwise, he or she may be looking for things that are beyond the capability of the data to offer. It is also interesting to note that the two resolution effects are inter-reliant and improving one tends to better the other (Lindsey 1989).

Interference of Closely Spaced Reflections: Types of Reflectors

We have seen earlier that for beds with thickness, larger than quarter seismic wavelength, reflections from their top and bottom appear as distinct and separate. However, most commonly beds are closely spaced in the subsurface and reflections involving several beds arrive within a time spacing that is less than the length of the seismic pulse. This leads to superposition of the reflections (Fig. 2.6). The ensuing interference can be either constructive or destructive and the resultant composite reflections depend on: (a) number and thickness of the beds (b) magnitude and sign (polarity) of the reflection coefficients and (c) the order of positioning of the individual impedance contrasts. We may consider the behavior of three types of

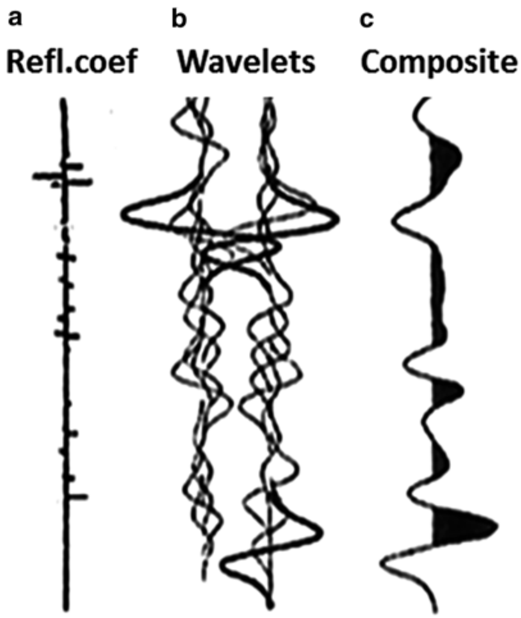

Fig. 2.6 The interference of reflections from closely spaced interfaces. (**a**) Subsurface reflection coefficient series, (**b**) wavelet reflections from the individual beds, and (**c**) the composite reflection caused by superposition of individual reflections from thin beds (Modified after Vail et al. 1977)

reflectors, namely *discrete, transitional* and *complex,* that an interpreter routinely comes across during interpretation (Fig. 2.7).

Discrete Reflectors

Top and bottom of thick beds with sharp impedance contrasts create distinct separate reflections to be recorded and are termed discrete reflectors. The reflections from top and bottom appear well separated with amplitude proportional to reflection coefficients. The onset of the reflection from the interface, either a peak or trough, appears at the right time on record with respect to its subsurface position without any delay.

Transitional Reflectors

A reflector may be termed transitional if there is a gradual gradation of impedance contrasts of one sign, either positive or negative, as in a fining upward channel or coarsening upward bar sand (Anstey 1977). The interference of a succession of reflections of the same signage (polarity) results in a composite reflection of an

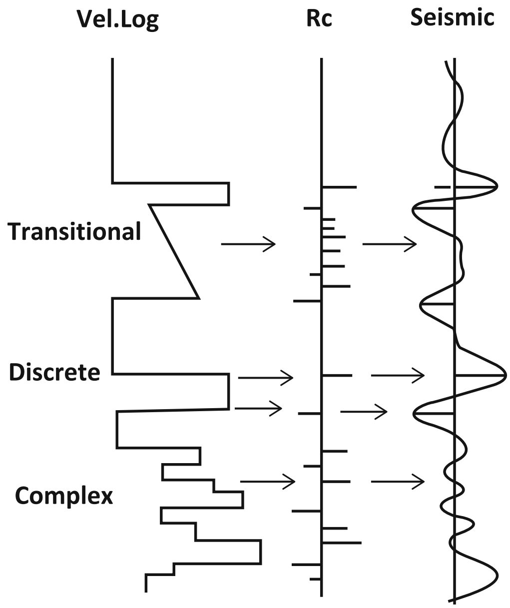

Fig. 2.7 A schematic to show the different types of reflectors. The discrete reflector has thickness that causes top and bottom reflections to be resolvable and with distinctive polarity and exact arrival time. 'Transitional' and 'complex' reflectors are composite events of several closely spaced beds with one or mixed signage respectively. They create reflections with uncertain polarity and delayed arrival time (Modified after Clement 1977)

integrated wave shape. The reflection is generally weak with a low frequency appearance and the event onset is time delayed with respect to the top of the formation.

Complex Reflectors

A complex reflector is a pack of reflectors, spaced closely but with varying magnitudes and polarities of impedance contrasts, which produce a complex reflection. The strength, phase and onset of the reflection are difficult to gauge. Forward seismic modeling may be used as a solution to get an insight to the pattern of a complex reflection.

Innate Attributes of a Reflection Signal

A seismic trace is a log measure of disturbances (particle velocity/ acoustic pressure) of waves reflected from subsurface with time. It records in a waveform the intrinsic attributes of a reflection signal amplitude, phase, frequency, polarity, arrival

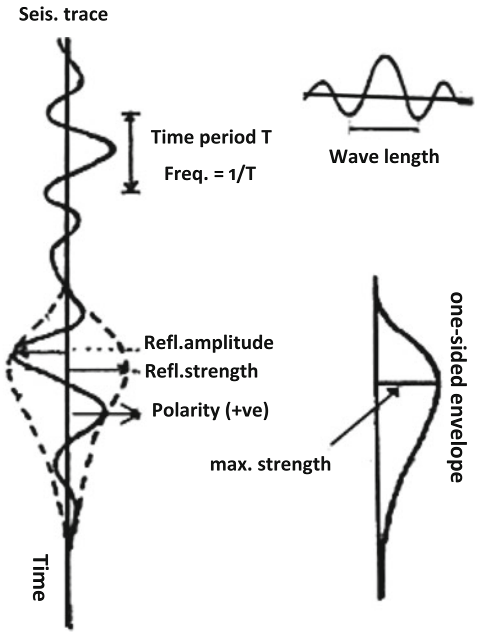

Fig. 2.8 The seismic attributes measurable on a trace, namely the time period, wavelength, reflection amplitude, reflection strength and polarity. Reflection strength is the maximum amplitude of the envelope of a composite reflection, independent of phase (After Anstey 1977)

time and velocity, all of which can be measured or estimated. The reflection attributes (Fig. 2.8) define the shape and arrival time of reflections depending on properties of the rocks. Thus the waveforms carry important geologic information encrypted in them. Estimates of these rock properties from seismic waveforms and their vertical and lateral changes in time and space is the essence of seismic interpretation, which predicts the subsurface structures and stratigraphy required for petroleum exploration. The basic seismic attributes are introduced here; their measurement and application is described in Chap. 10.

Amplitude and Strength

As stated earlier, a seismic wave incident normal to an interface with an impedance contrast produces two waves normal to interface, one reflected back and the other transmitted onward. The amplitude of the reflected wave with respect to that of the incident wave is termed the reflection coefficient (*Rc*) or the reflectivity. Reflectivity depends on the degree of contrast between the impedances on either side and the angle of incidence of the wave. For a normally incident wave, reflectivity *(Rc)* is expressed by the founding equation of seismic reflection method, $Rc = V_2\,\rho_2 - V_1\,\rho_1 / V_2\,\rho_2 + V_1\,\rho_1$, where V_1, ρ_1 and V_2, ρ_2 are the velocities and densities of the upper and lower layers respectively. For non-normal (oblique) incidence, there will be, however, two pairs of *'P'*and *'S'* waves (see Fig. 2.1) and the above equation for the normal reflection coefficient gets relatively complicated and assumes a more general form as in Zoeppritz's equations, discussed in Chap. 10.

Amplitudes are measures of particle velocities or pressures and in an ideal case, the maximum value at peak/trough of a pulse wavelet represents the reflection coefficient of an isolated reflector. Where the wavelet is leggy (lengthy and cyclic) and the reflection is of composite nature, as is often the case in nature, it is difficult to choose the appropriate peak/trough for calculation of amplitude to represent reflectivity. In such cases, it is convenient to make use of the reflection strength, which is specified by the maximum amplitude of one side of a symmetrical envelope, centered about the reflection event (Fig. 2.8). Reflection strength is more meaningful as it is independent of phase and relatively less sensitive to the factors affecting amplitude. Reflection strength may have a maximum at a phase other than at peak/trough and may indicate the nature of the composite reflection. Reflection amplitude and its variations are vital clues to predict lithology of formations and their lateral changes, porosities and sometimes pore fluids as in the case of gas reservoirs. However, a crucial limitation of amplitude is its proneness to wide variance due to several other factors that may not be linked to geology.

Phase

Phase may be expressed simply as the time delay with respect to the instant of start of a reflection. Phase is independent of amplitude, indicates the continuity of an event and provides another useful criterion to interpret reflections. In areas of poor reflectivity, where reflection amplitudes are too weak to be manifested and correlated, phase is likely to be helpful in mapping the continuity of the reflection (reflector). Phase mapping is especially sensitive to detection of discontinuities like pinch outs, faults, fractures and angularities as well as unconformities based on 'out of phase' events.

Frequency (Bandwidth)

A seismic wavelet, usually of one to one-and-a-half cycles in the beginning, changes shape progressively during propagation and becomes long and cyclic (leggy) with passage of time. The pulse width of a wavelet on the seismic record in time (time period) provides an estimate of its dominant lowest frequency, and it grows larger with depth during propagation, indicating lowering of frequencies caused due to attenuation. The bandwidth is a measure of the width of a range of frequencies in the wavelet, measured in hertz and is the key to quality of reflection. Bandwidth decides the time duration of the changing wavelet corresponding to depth intervals, reliant on the velocity and controls vertical and lateral seismic resolution. A broad bandwidth consisting of both low and high frequencies is thus considered essential to provide quality seismic images. The lower frequencies in the spectrum help in deeper penetration of energy where as the higher frequencies direct the thin bed resolution. Unfortunately, during propagation of the wave, the earth attenuates the high frequencies and hampers desired resolution at depths.

Because frequency is affected by propagation phenomena like absorption and transmission in the subsurface, its variance can provide at times valuable information on geologic strata and its geometry. Layered beds at shallower depths generally evince reflections with high frequency contents whereas older and harder rocks (for example, Pre-Tertiary rocks) at deeper depths show relatively low- frequency reflections. The experienced seismic interpreter is familiar with the clearly discernible decrease in bandwidth of reflections from the top to bottom of a typical seismic section. Bandwidth, amplitude and phase create the shape and form of a signal, and the individual components can only be measured and analyzed by detailed spectral analysis, discussed later in Chap. 10.

Polarity

The polarity expresses the sign of a reflection coefficient. It is considered positive if the impedance of the rock below is positive (a hard rock underlying a soft rock) and negative, the other way round. Conventionally, on normal processed data (SEG normal polarity convention), peaks and troughs of reflection events represent positive (black) and negative reflection coefficients (white), though an option for plotting reflections with reverse polarity remains with the interpreter. It is important to define the polarity convention clearly in the processed data so as to avoid making basic mistakes in interpreting the geology. Picking of reflection polarity is simple and straight forward in case of discrete reflectors, but is difficult in transitional and complex reflectors where superposition of reflectors leads to distortion of events and provides a composite reflection. Noise in data also acts as a deterrent for clear determination of polarity. Deconvolution and zero phase processing help to some extent in estimating polarity of composite reflection events. Accurate picking of polarity, wherever possible, helps in locating the disposition and nature of the strata in the subsurface.

Arrival Time

Reflections arriving at different times on a record for discrete reflectors indicate the temporal position of rock boundaries encountered in the subsurface. Since the events are recorded in time, accurate velocity function is required to convert the arrival times and determine the depths of the causative reflectors. Despite deploying true velocity, there can still be inexactness in some cases in matching the actual subsurface depth with depth converted from time. For transitional and complex reflectors, the precise time of onset of a reflection is usually recorded as delayed and can pose a problem, *prima facie*. The system of recording and processing of data also behaves like filters and introduces time lags. If the induced delay is not properly taken care of, it may add to the overall delay, which may vary from a few to several milliseconds, depending on type of seismic data (2D/3D). Seismic analysts often find such time shifts in tying a particular reflection phase in different vintages of seismic, especially in 2D data, due to varying recording and processing parameters used and one must be careful before picking and mapping geologic horizons.

Velocity

Velocity is an important seismic attribute, not only to estimate depths of formations, but also to provide vital information on subsurface rock and fluid properties. Basically, velocities are of two kinds, the *overburden* or vertical average velocity, and the *interval* or formation velocity. Vertical velocity is used for conversion of reflection times to depth and the interval velocity for estimating lithology and other rock properties like porosity and fluid contents. The two velocity functions are interrelated; knowledge of one can lead to calculation of the other. The seismic CDP technique permits the calculation of an apparent overburden velocity from multi-trace data processing and is known as the normal move out (NMO) or stack velocity. Stacking velocity is so named, as it is computed mathematically from the normal move out equation which maximizes the effect of summation of traces in a CDP gather. It is a velocity along the direction of the geophones and is affected by factors such as dips of strata and recording spread lengths. Stacking velocities are usually higher (by about 6–10 %) than true vertical average velocity, which can be measured only in a well. Stacking velocities are also referred to as RMS (root mean square) velocities. Where well velocity is not available, the RMS velocity after appropriate correction is used to predict top, bottom and thickness of geologic formations. The lithology and other rock properties can be also inferred from interval velocities (formation velocity) calculated from stack (RMS) velocities.

The velocity used for migration of seismic data, a process that moves the subsurface reflecting points to their true spatial position below the shot point is known as the migration velocity. It is an overburden velocity and applied appropriately, produces relatively clean and accurate seismic images that help predict rock properties better. Generally, it is lower than stack velocity but tends to equal true overburden velocity where migration of data is perfect to provide reliable depth conversions.

Seismic Display

The visualization of seismic data is an integral part of interpretation and as such, it is important that the processed seismic data be displayed in suitable graphic modes and scales. Nonetheless, it depends to a large extent on the objectivity of the interpretation and the perception and creativity of an individual interpreter. Generally, data are displayed in any one of these modes, wiggle trace, variable area, and variable density or in a combination (Fig. 2.9).

- Wiggle trace is a log of reflection amplitudes with time and makes it handy to interpret geologic information from the variability in the waveform shape.
- Variable area (VA) and wiggle displays are wiggles shaded with bias, and make reflection events appear more consistent and convenient for correlation by reflection character.
- Variable density (VD) shows reflection strength, and displayed with color, provides better relative standout and continuity of reflections. VD sections, though more commonly used, do not show the waveform shapes that embed significant geologic information (Fig. 2.10).
- Combinations of variable area and wiggles may be a preferred display for interpreting stratigraphic details.

Though the work stations provide different modes of display, interpreters generally use Variable density sections due to better apparent continuity of reflections and their amplitude stand-outs that can be conveniently used as an attribute display. But

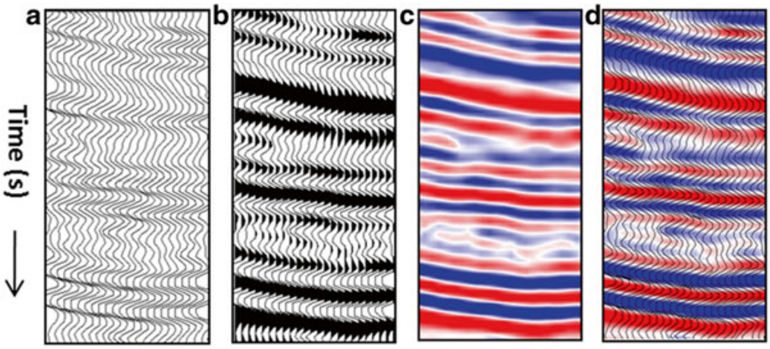

Fig. 2.9 The types of seismic data display modes. (**a**) wiggle, (**b**) wiggle and variable area, (**c**) variable density, (**d**) combination of wiggle and variable density. Note the waveform changes seen clearly in wiggle and variable area display mode (**b**), that carry the crucial geologic information

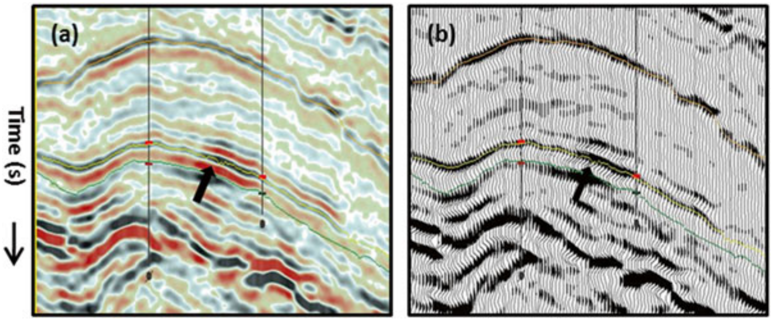

Fig. 2.10 Comparison of seismic (**a**) variable density, and (**b**) wiggle display modes. Reflection stand-outs and continuity seen better in the variable density display, but does not show the changes in waveform that carry important geologic information, whereas wiggle mode clearly shows the variations in waveform shape (trough indicated with an *arrow*) (Image: Courtesy, Hardy Energy, India)

this can be misleading in sedimentary environments of continental to fluvio-deltaic deposits where fast and frequent facies variations are likely to occur causing discontinuous and patchy reflections. Use of Variable density sections for tracking reflection continuity in such cases may be geologically flawed. One may prefer wiggle mode of seismic display that allows inferring geology guided by reflection character relying on the waveform shapes.

Color display is known to increase optical resolution leading to better visual discrimination of features and is used widely. The selection of suitable color and its encoding depends on the artistic attitude of the interpreter but assigning colors in a spectral progression is preferred as it enhances the relative magnitudes well.

Plotting Scales (Vertical and Horizontal)

Plotting scales are extremely important in data display, as reducing or stretching the scales changes visualization of the geologic objectives. The scales are to be suitably chosen depending on the objectivity of the interpretation. Horizontally compressed sections improve perceived continuity of events with gentle dips appearing stronger. Stretched sections, on the other hand, appear to deteriorate reflection continuity with flattening of the dips. Accordingly, faults with small displacement, low dipping progradations, gentle pinch outs and terminations etc., which are subtle but important as exploratory objects, look more conspicuous to be picked on compressed scales. Compressed (squashed) sections are also very useful for interpretation of regional geology for basin evaluation as a long stretch of a profile can be conveniently displayed in one vision frame at a time. Similarly, vertically compressed (half) sections offer the advantage of viewing the entire geological section from the deepest depth to the surface and help in better assessment of geological evolution of a basin. On the other hand, sections stretched in time are often used to magnify details of important targets to be picked for mapping. Each geologic object requires appropriate scales for its clear standout and needs experimenting for choosing the best judicious combination of both the vertical (time) and horizontal (trace) scales along with the mode of display.

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Chapter 3
Seismic Interpretation Methods

Abstract Seismic interpretation conveys the geologic meaning of seismic data by extracting subsurface information from it and can be of different kinds, such as structural, stratigraphic and seismic stratigraphy. It depends on the geologic objectives linked to the phase of exploration and on the type of available data, its grid density and its quality. The workflow for each category is described and the shortcomings highlighted.

Interpreted results must include its geologic and engineering implications on the venture, and address the exploration issues at hand. This may be termed evaluation of data, a process of value addition to interpretation that looks ahead, beyond routine interpretation to help review economic viability of prospects and enable management to strategize exploration policies. Evaluation is emphasized by citing examples and illustration.

Petroleum exploration is a high-cost and high-risk intensive venture, which demands important subsurface geologic information, as precise as possible, with minimal prediction upset. Interpretation of seismic data offers these decisive geologic inputs for exploration undertakings. Providing reliable seismic predictions requires a synergistic approach to analysis of seismic and all other related data by experienced and skilled persons. It is also desirable to have all possible accessible data organized in a multi-disciplinary database prior to the start of a comprehensive seismic interpretation project work flow. Multiplicity of data sets and data types (disciplines), though a challenge to handle, improve the scope for better synthesis and evaluation. It is of course essential that the seismic interpreter has a good understanding of the elementary principles of petroleum geology, petrophysics, and reservoir engineering in addition to in-depth knowledge of seismology and other related geophysical techniques.

Interpretation reveals the geologic meaning of seismic data by extracting subsurface information from it. Seismic interpretation, in the context of petroleum exploration, however, should not be limited to only offering the geophysical results but needs to be geologically inclusive to address the exploration problem at hand. Interpretation thus needs to be logically extended to include the geologic and engineering implications of the seismic inferences on the exploration venture so that it eventually helps in taking a sound management decision. This may be termed evaluation of data, a process of value addition to interpretation that must look ahead,

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beyond routine interpretation, into the success of the entire gamut of exploration. Emphasis therefore must be put on evaluation, as it helps in reviewing the crucial economic viability of prospects that may help strategize exploration policies by the management. For example, detecting and mapping faults in a prospect is not an end in itself of interpretation; it is more important to evaluate the significance of the effects of the fault on the potential of the prospect in terms of its role in accumulation and production of hydrocarbons.

Seismic interpretations can be of different kinds depending on the geologic objectives linked to the particular phase of exploration and on available data type, grid density and quality. The exploration and production (E&P) activity cycle generally starts with analysis of seismic and other geophysical data that leads to drilling of exploratory well(s) in the first phase. In the case of a discovery, exploratory input is followed by a second phase of action, acquiring more and better resolution seismic data to identify suitable locations for drilling delineation/appraisal wells. Depending on the economic viability, appropriate development plans are initiated in the final phase by drilling production/injection wells. Each phase of E and P may be linked, historically in an orthodox way, to a type of interpretation depending on the objective at hand. The interpretation work flows may be categorized as below and each considered in some detail in subsequent sections:

- Category I: Structural Interpretation (on 2D data) – first level regional interpretation, mainly structural in nature, and attempted in the early stage of exploration.
- Category II: Stratigraphic Interpretation (on 2D/3D/4D data) – higher-level synergistic interpretation that provides stratigraphic information including rock and fluid properties during exploration/delineation and production stage.
- Category III: Seismic Stratigraphy Interpretation (on 2D data) – regional geologic interpretation of depositional systems and tectonic styles for basin evolution and evaluation, and is carried out mostly in initial stage of exploration.
- Category IV: Seismic Sequence Stratigraphy Interpretation (2D/3D) – integrated detailed stratigraphic interpretation of log and core data with seismic, in exploration/delineation/development stage.

However, with adequate and appropriate data grid and quality, a comprehensive interpretation, providing details about subsurface structures and stratigraphy may be attempted in the beginning itself of an early exploration phase. Sophisticated softwares are now available and are widely used to facilitate seismic interpretation using advanced workstations and large integrated databases. Nonetheless, it is essential that the principles and methods of interpretation and the linked groundwork be properly understood by the interpreter, the brain behind the machine, so as to extract maximum meaningful geologic information through a man–machine interaction.

Category I: Structural Interpretation (2D)

Structural interpretation of 2D seismic data primarily involves preliminary evaluation by mapping of a number of subsurface reflectors (horizons) and is generally practiced in virgin or less explored areas. The input data package to work with generally consists of a coarse grid (for example 4×8 km spacing between lines), routinely processed seismic with no or sparse well control. The interpretation, in the absence of geologic data from either nearby wells or outcrops, may be more geophysical in nature, but offers useful information about the depth of basement and its configuration, basement paleo-highs and lows and faults. Besides providing an estimate of total sedimentary thickness in the area, the interpretation also infers broadly the individual sedimentary units (formations) in terms of depth, thickness, lithology, and more importantly, their structural forms and attitudes including faults. The major steps involved in the interpretation work flow are: (1) selection of horizons (reflectors) for correlation; (2) picking and posting time values on a location (base) map; (3) contouring the horizons with faults and (4) creating several types of maps for describing the geologic details.

Identification and Correlation of Horizons

Correlation involves interlinking a particular phase (character) of a reflection from one seismic line to another, making sure that the stratigraphic surface followed is the same over the area. It is usually advantageous to identify seismic horizons for correlations first on dip lines where the lateral continuity and dips of events are likely to be seen better. The deepest event (horizon) seen on a seismic section is usually considered as the basement reflection. This reflection is generally characterized by low amplitude and low frequency, and is often discontinuous and may be punctuated by a number of faults. This horizon sometimes is termed a *technical* or *acoustic* basement by the interpreter where the fundamental Precambrian basement (Archaeozoic) is believed to be deeper but not seen in seismic. Reflections, or horizons, that are continuous and present over a wide area and can be easily correlated by their excellent character are known as seismic "markers", analogous to a geologic marker bed.

Identification or picking of reflections for correlation is usually based on some criteria. Picking includes the basement, the markers (if present) and other horizons in the section which show discordant dip attitudes in the area with respect to basement, marker or even with each other. Seismic horizons that are not parallel (nonconformable) to each other are suggestive of unconformities and may need correlation for mapping. The basement, markers and the other nonconformable horizons are preferably picked on a dip-line and extended to all other lines in the area.

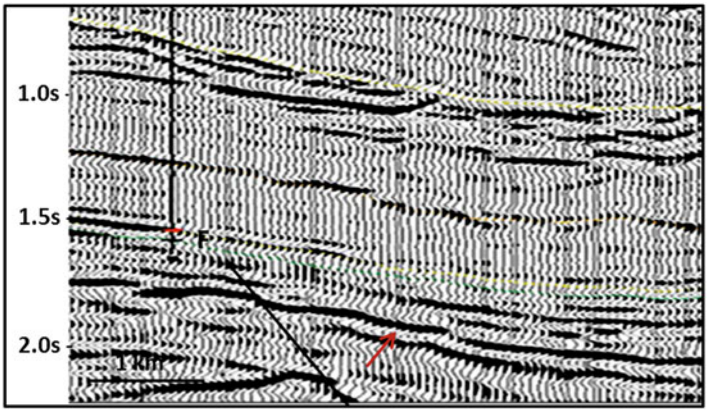

Fig. 3.1 Example of reflection correlation by character as seen on a segment of seismic section. The trough with peaks on either side, the amplitude and frequency characterize the reflection around 2.2s at the bottom right. The correlation should be ideally stopped at the fault but may be tracked up dip beyond the fault by 'phantoming' (Image: courtesy of ONGC, India)

Correlations of events are based on reflection character (Fig. 3.1), which includes amplitude, phase (peak/trough), frequency, waveform and the dip attitude of the horizons. Sometimes problems arise in tracing continuity of a reflection because of change in the reflection character due to noise, lithological variations and faults. This can be conceded, if needed, by resorting to extension of continuity by jumping across ('*jump correlation'*) the poor and no reflection segments or by an intuitive forced picking of the reflector across the section, a method known as '*phantoming*'. The decision to continue correlations beyond the reliable limit and to use *jump correlation* across gaps and faults and/or to force *phantoming,* depends on the exploration goal of the interpretation at hand and the judgment of the interpreter. Such correlations are subjective and the reliability depends greatly on the individual skill and experience of the interpreter. Correlations, now days, are done on the workstations, which save a great deal of time. Correctness of computer automated correlations, however, may be limited to areas of good to excellent quality of seismic images in simple geologic settings. In complex areas where seismic reflection characters are poor and/or patchy and intricate, it may need an interpreter's interaction to guide the computer intermittently for reliable results.

Phantoming and *jump correlations* of horizons can be useful where revealing the structural attitude of the horizon is the prime aim of interpretation. Despite the skill and expertise of the interpreter, the correlations can be highly subjective and arbitrary, influenced by the biased judgment of the interpreter. In such cases, it is advisable to use some kind of a code, qualifying the quality of correlation as fair, poor, questionable, etc., by designated symbols(like '- -', '??' etc.,) which is important.

During correlation, distinction must also be made between steep dips and faults in the horizon, as dips and faults have different geologic significance. Though there may not be difference in time picks of the correlated horizon and its structural configuration, a fault indication may have other consequences linked to prospect potential. (See also Chap. 5, “Seismic stratigraphy and seismo-tectonics in petroleum exploration”). Faults, therefore, need to be identified and carefully picked during correlation for mapping the horizon.

The legitimacy of correlation of a horizon, as from the same stratigraphic level over the entire area is established by validating the reflection times and more importantly, the reflection character for a match at the crossing point of two or more lines. This is accomplished through a process known as ‘*loop tie*’, similar to that used in cartographic surveys, which ensures same time values at the start and end of a loop made through different lines. ‘*Mis-ties’* at the crossing points in 2D data are fairly common due to inefficiency of two dimensional migration that fails to restore the subsurface reflection points to its true subsurface location accurately. The mis-ties may be considerable in cases where different vintages are used because of dissimilarity in recording and processing parameters used at different times including cartographic and navigational errors. It is important that the mis-ties at the cross points in the loops are suitably adjusted to the least-time seen in the vintage for the horizon before proceeding to post the time values on location (base) maps for contouring. Computer softwares, however, automatically take care of the misties in the work station before attempting contouring.

Correlation, though elemental, is the critical input to preparation of the all-important seismic map, which ultimately guides the management in taking major exploratory decisions including drilling of wells. Any lapse in initial step of correlation, will affect the accuracy of the map and unknown to the exploration manager, a flawed decision may be taken accepting the map as otherwise accurate. As stated earlier, qualifying the level of confidence in picking and correlating the horizons including the faults by using coded terms cannot be overemphasized in this context.

Recent techniques allow correlations of horizons by computer in ‘*auto tracking’* mode which are efficient, fast and accurate but may be incorrect due to limitations as stated below:

- Lateral changes of polarity in events due to variations in rock and fluid properties are not recognized in auto mode.
- Thinly interbeded sandstone and shale formations may not be accurately picked by the auto mode.
- In geologically complex areas with poor data quality, splitting of reflection may cause problems to pick the correct phase of the horizon in the auto mode.

Under the circumstances, it may be necessary for an interpreter to intervene and interact with the machine for more reliable results. Lapses in auto tracking may result in faulty maps that depict inaccurate reservoir geometry and volume estimates. It is the seismic interpreter’s responsibility to identify: (1) the type(the phase) of auto tracking that may best assist correlation of the desired object horizon and (2) the limits of an auto tracking approach in a given seismic dataset.

Contouring and Maps

The picked time values are posted with faults on the base map and are contoured to produce time structure maps of horizons. Before contouring, two simple but important parameters, the scale and contour interval, need be appropriately chosen. The map scale is selected based on size of data grids; for example, small scales are preferable for widely spaced data and larger scales for closer grids. Intervals at which contours are to be drawn may have to be decided depending on data reliability linked to degree of scatter observed in the picks at crossing points. A normal practice for choosing contour interval is at least about two times the scatter error. For example, a contour interval of 20 ms may be a good choice for drawing contours if the overall cross-tie errors at the point of intersections are below 10 ms. Smaller contour intervals reveal more structural details but must be commensurably supported by quality of data. Maps prepared with contour intervals smaller than that supportable by data fidelity, ostensibly to exhibit finer details, may indeed be misleading and must be dealt with caution.

Contouring is not just a trivia of mathematically interpolating grid data and mechanically joining the equal values but much more than that. Seismic structure contours represent a particular chronostratigraphic horizon, geologically a stratal surface and are different from surface topographic contours which portray a relief map. Seismic structure contours are to depict structural trends and depositional geometry of geologic bodies and require intelligent handling by skilled and experienced persons. Special efforts may be essential, for example, where the presence of a large number of faults requires appropriate alignment and mapping. This includes careful adjustment of contours across faults to show their correct displacements, a factor that can have serious geologic implications in evaluating hydrocarbon potentials of a prospect. Faults picked on seismic lines, but connected erroneously in maps, especially in geologically difficult cases and widely spaced 2D data, may create pseudo fault-closure trap prospects, leading to unsuccessful drilling.

Contouring by hand is an arduous, time consuming process but importantly represents interpreter's geologic thinking. The reflection time values at grids may not be all that precise due to several snags; often a few values not fitting into the shape of things requires going back to data for a careful check. The values sometimes are modified or discarded by the interpreter for the purpose of contouring. Modern interpretation softwares automatically import the correlated time picks to the base map for contouring. Computers prepare contour maps quickly and efficiently, but cannot perform the task of rechecking/revising of the grid values, an option available in manual mode. Computer generated contours at times may be too mathematical to be realistic as the computer algorithms do not have the kind of intelligence and insight , the interpreter has to analyze and handle the data. As stated earlier, in areas with irregular 2D grid data and complicated geology with several faults of different ages and types, the contouring skill of the machine may be found wanting. An ideal situation may be to get the preliminary contouring done by the machine to save much needed time and then to carry out manual editing to get best results for depicting geologic features.

Contouring provides the all-important structural maps used for deciding drilling locations and volumetric estimation of in-place hydrocarbons. The different kinds of maps delivered are very briefly mentioned below.

Time Structure Maps Time structure maps are horizons contoured in time and are the prime outputs of structural interpretation, which define the geometries and trends of subsurface horizons. Dips, structures and trends in the maps may be ascertained by checking seismic sections to be in harmony with expected or known geology of the area.

Depth Maps or Structure Maps Depth maps are prepared by converting the time values to depth. The vertical average velocities (depth divided by arrival time) for depth conversion are computed either from nearby well velocities or from seismic stacking velocities, after applying suitable corrections.

Relief Maps In the event of uncertainty in chronostratigraphic correlation of a seismic horizon (same stratal surface), and where phantoming is used, it may be appropriate to name the map as a *relief* map. An example can be taken of the commonly annotated 'structure map on top of basement'. Based on usually unclear and dubious correlation of reflection from the top of basement, an unconformity surface, it should be strictly annotated as 'Basement Relief' map.

Isochrons (Time Interval Maps) and Isopachs (Thickness Maps) The maps showing bed intervals in times and depths between two horizons are termed isochrones and isopachs, respectively. Besides the thickness of the different formations, the *interval maps* also reveal the earlier existing paleo slopes and structures at the time of deposition (Fig. 3.2). This provides vital clues for assessment of potential hydrocarbon accumulations, discussed more thoroughly in Chap. 5.

Interval maps may also include faults affecting the horizons with the faults suitably annotated with standard symbols and indexed. The significance of mapping faults on *isopach maps* lies in deciding the optimal drilling locations on ground as it indicates the likely reservoir thickness to be expected in the subsurface. The schematic diagram in Fig. 3.3 illustrates the point. The predicted reservoir thickness varies across a fault zone as a function of fault heave, slip and fault type (normal/reverse). Depending on the ground location, vertical drilling in the fault zone may end up in missing part of reservoir in normal faults or repetition in reverse faults, a criterion commonly used to infer a fault at the well.

Interval maps are more sensitive to data errors because of chances of inaccuracies involved in the two mapped horizons, and require contouring at larger intervals. Interval maps or transects are conveniently prepared on workstations by flattening the upper horizon as a reference and showing the structural attitude of the paleo depositional surface of the older horizon. This is known as 'paleo structural' analysis. However, the analysis represents paleo dips, azimuths and structures appropriately in a "layer-cake" geologic setting where sedimentation is assumed to be horizontal

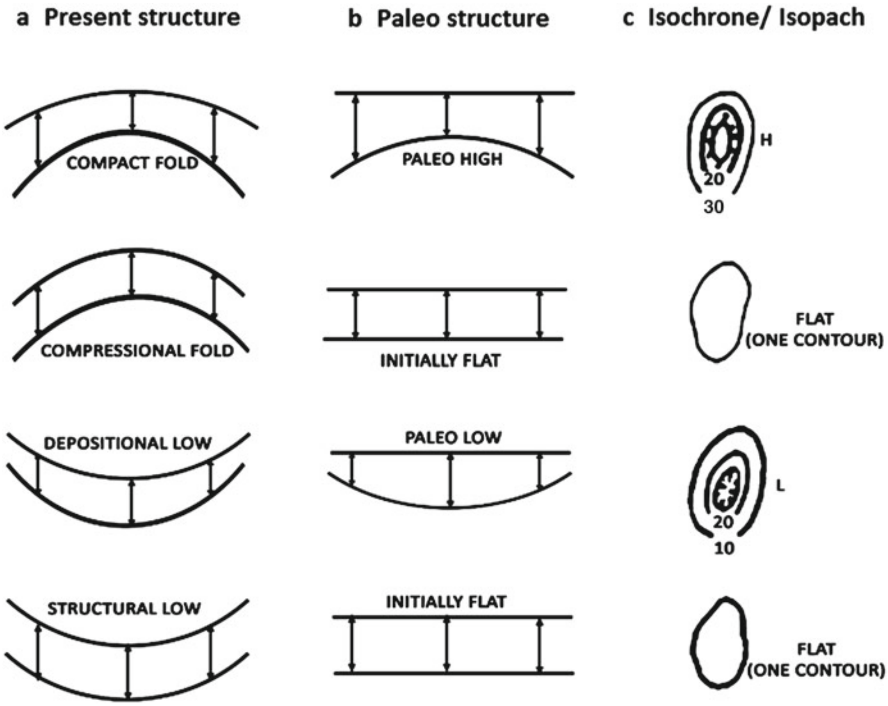

Fig. 3.2 A schematic illustrating paleostructures analysis by flattening the bed top (**a**) Structures as seen at present (**b**) paleostructures existing at the time of deposition of the younger bed and (**c**) paleostructures as seen in plan view in time/depth contour interval maps (Isochron/isopach)

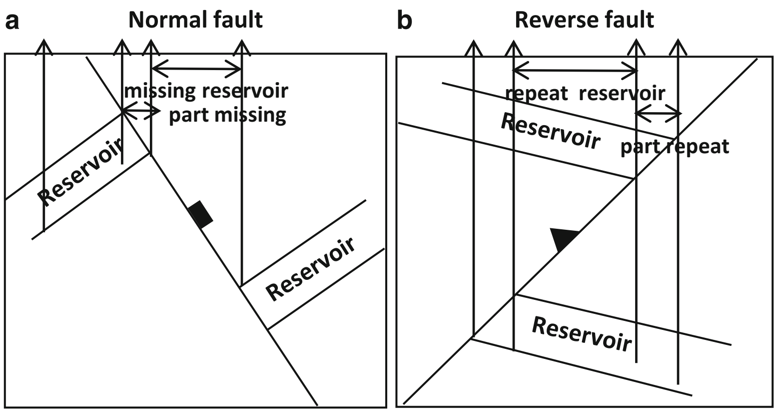

Fig. 3.3 Effect of fault on thickness of bed varying with drilling placed in the fault slip zone. Drilling misses or repeats the bed thickness partly or entirely in case of normal fault (**a**) and reverse fault (**b**), depending on surface drilling location

at the reference horizon. The method may not offer meaningful paleo-structural information in case of depositional features like carbonate/clastic mounds, prograding sequences and erosional unconformities.

Structural interpretation, besides offering structural attitude and thickness of formations, also provides the lithology of the rocks. The interval velocity (formation velocity) between two horizons is derived from seismic stack (RMS) velocities and used to predict lithology of the formation.

Category II: Stratigraphic Interpretation (2D)

Stratigraphic interpretation is a high level synergistic technique to evaluate structural and stratigraphic details of the subsurface with attempts to estimate rock properties, though qualitatively. It begins with the calibration of seismic response to geologic information at the well, and extends prediction from known geology at the borehole to areas away from it, based on seismic data.

Seismic horizons picked for correlation in workstations also automatically provide amplitudes, which can be mapped. Since the amplitude depends on properties of the rocks on either side of the interface, vertical and lateral variability in amplitudes can often be a good indicator of structural and stratigraphic details. Analysis of reflection continuity and amplitudes of a horizon reveals information related to lithology and porosity variations laterally. Stratigraphic interpretation becomes more important and exhaustive in appraisal and development phases for reservoir delineation and characterization. The interpretation of high-resolution and high density seismic (3D/4D) constrained with well data is discussed in Chap. 8 "Evaluation of high resolution 3D and 4D seismic data".

Seismic Calibration

The essence of stratigraphic interpretation lies in the art of obtaining successful ties of seismic with well log data, specifically for the target objectives (reservoirs). The process is known as seismic or well calibration/tie. Modern workstations allow converting log curves from depth to time domain using the well velocity function and overlay them on seismic section for convenient display of log and seismic correlations. Log correlations often are based on lithostratigraphic correlation and may vary from the seismic chronostratigraphic correlation, at times the trends crossing each other. The display provides an opportunity to cross check log and seismic correlations for correspondence and to modify one or the other if found differing. Reliable seismic correlation often leads to alter suitably the log correlations. For instance, the log characteristics of sand units in two wells may be extremely similar yet may not be continuous as the sands may belong to different ages having alike log responses linked to similar genesis of geologic setting. The log markers may not match seismic markers but the correspondence is usually considered satisfactory if the trends are parallel.

Seismic reflection waveforms carry subsurface information and their correlation with the stratigraphic horizons at the well permits benchmarking the seismic response of geologic features at that point. Changes in geologic parameters away from the well can then be inferred from related changes in seismic wave forms. Seismic calibration at the well is commonly attempted using methods, such as synthetic seismograms, vertical seismic profiling (VSP) and continuous velocity logs (CVL).

Synthetic Seismogram

This is a simple forward modeling technique, most commonly used in calibration. As illustrated in Fig. 3.4, a synthetic seismogram is a seismic trace computed by convolving an appropriate wavelet with the reflection coefficient series determined

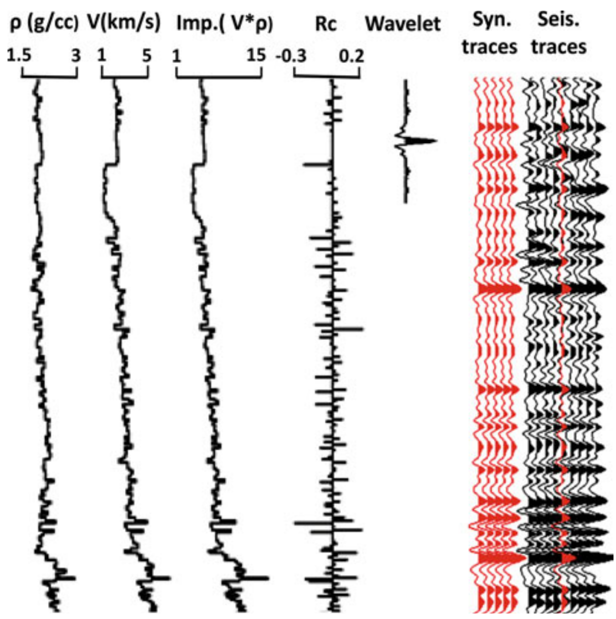

Fig. 3.4 A synthetic seismogram workflow. Reflection coefficients computed from impedance log is convolved with a wavelet to create synthetic seismogram which is compared with seismic for a match (Image: courtesy of Arcis Seismic Solutions, TGS, Calgary)

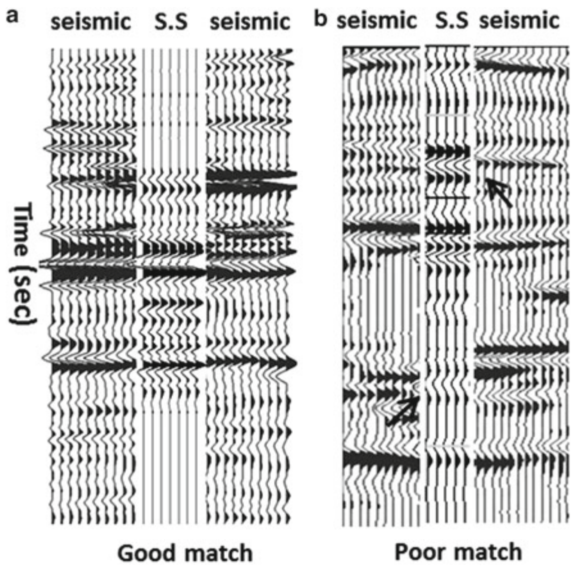

Fig. 3.5 Calibration of seismic with a synthetic seismogram (S.S) showing (**a**) good match and (**b**) poor match. Note the marked mismatch in amplitude and phase of reflections in synthetic and seismic in (**b**) in the upper and bottom part that suggests reprocessing of seismic (Image: courtesy of ONGC, India)

from sonic and density logs at a well and matched with seismic trace at that point. Logs are sensitive to mud invasion and poor borehole conditions, and the density log is particularly susceptible to error. Suitable corrections should be applied before use in creating a synthetic seismogram. Sonic tools similarly may require corrections for drift with respect to true velocity measured in a well (see Chap. 7).

Despite corrections applied and precautions taken in preparing synthetic seismograms, it may still result in mismatches with seismic (Fig. 3.5). This is due to the presumption of conditions in computing a synthetic that differs from actual. Possible causes of mismatch can be listed as below.

- Computation of reflection coefficients is for normal incidence only.
- 1D array of vertical reflector points is in contrast to Fresnel zone.
- Assumption is made of horizontal and plane reflecting layers.
- Wave propagation effects and noise are not considered.
- The precise shape of the wavelet for computing response is unknown.

Occasionally, the interpreter may find a poor match of synthetic seismogram due to inconsistency in positioning of the subsurface seismic image vertically below the well position. The first suspect is of course the ground location of the well, which needs checking. However, this can also be because of limitations in the positioning of seismic imaging due to the layers not being flat and planar and having high dips. In such cases, the mis-ties can be investigated by shifting of the synthetic seismogram, by a few traces, in the vicinity of the well to provide the desired match. The positioning problems are, however, more difficult to deal in strongly deviated wells and highly dipping horizons, especially with unmigrated/poorly migrated 2D seismic data of early vintages. Migration, then, was considered an expensive and time consuming special processing and often avoided as a trade-off between data quality and financial convenience.

Poor well ties can also be due to seismic imaging problems because of the complicated nature of the subsurface geology. In areas of strong subsurface heterogeneity, for example, in the proximity of a fault, rapid facies changes in a fluvio-deltaic deposits and stratigraphic pinch out, the ties in general can be more troublesome. The primary reflection arrivals at the CDP may be noisy, impeding NMO velocity analysis and eventually ending up in poor stacked seismic images.

A synthetic seismogram tie at the well, besides giving ideas about positioning of well on ground and kind of reflections expected from the subsurface strata, it sheds light on the quality of the processed seismic data. A good example of this is illustrated in Fig. 3.6. A thick shale section sandwiched between limestone units, indicated by a flat sonic (CVL) and a weak reflection zone in the synthetic, however, is evidenced by strong continuous reflection horizons in seismic. Clearly, this is a spurious anomaly where the reflections are not primary but possibly multiples that need reprocessing of data.

Vertical Seismic Profiling (VSP)

The VSP is generally the preferred tool for seismic calibration. VSP survey records seismic waves with a geophone in the well (see Chap. 7) and provides accurate measurement of true vertical velocity. It records reflections from subsurface beds at and/or near the borehole and provides better match with field seismic (Fig. 3.7). The survey, however, increases drilling downtime and is sometimes skipped to minimize exploration cost.

Continuous Velocity Logs (CVL)

The CVL is a plot of interval velocity computed from sonic log transit time, which is transformed from the depth to time domain for match with seismic. It is a simple process and often provides useful correlation of seismic with geology at the well where VSP data is not available (Fig. 3.6).

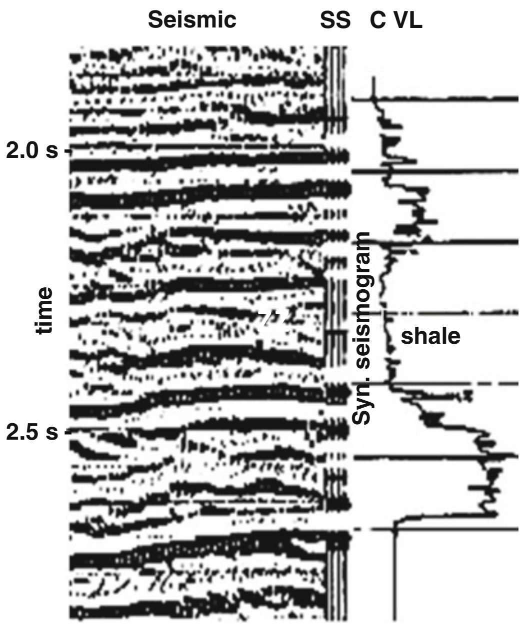

Fig. 3.6 Seismic calibration with CVL and synthetic seismogram. The seismic matches well except for the strong events at the centre against the shale section represented by flat CVL zone and no events in synthetic. Strong seismic events are suspected multiples and entail reprocessing (Image: courtesy of ONGC, India)

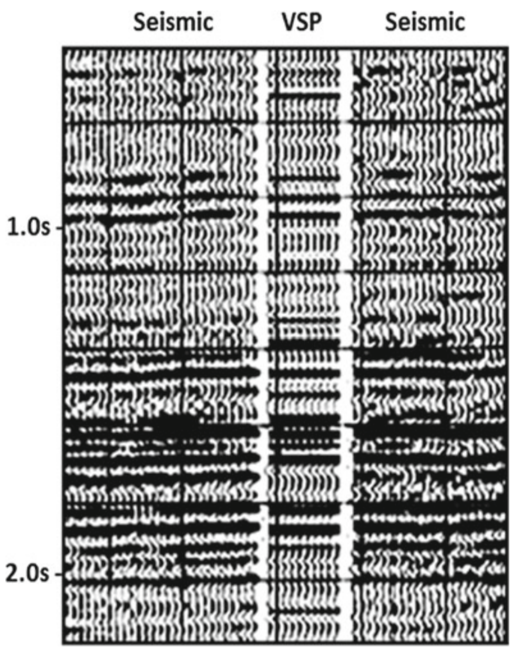

Fig. 3.7 Calibration of seismic with VSP corridor stack spliced in a segment of seismic section. Note the excellent match between the two (After Balch et al. 1981)

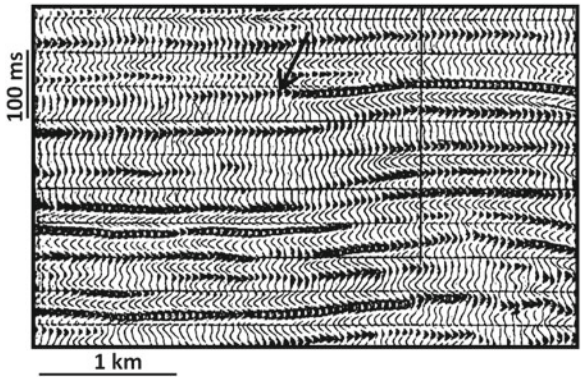

Fig. 3.8 Change in reflection character indicates lateral changes in facies. Note the clear changes in amplitude and frequency (*arrow*) of the reflection event which decide the limit of the horizon continuity (Image: courtesy of ONGC, India)

With a proper seismic tie, stratigraphic interpretation permits delineation of potential prospects and prediction of structural and stratigraphic details, including depth, geometry and rock properties of reservoirs. Seismic data at this stage may need reprocessing or special processing with object-specific parameters to enhance resolution and clarity at target zones in relevant time windows. Phantoming and jump correlations are, in general, avoided. Sometimes, aiming for better continuity of a reflector by reprocessing may not justify the geologic goal, as in fluvial and deltaic deposits where, variations in reflection character and/or discontinuities are sought after as prime information. Variations in reflection character of traces from the one calibrated at well and the geologic setting of the area, strongly indicate changes in reservoir facies and/or properties that help delineate the limit of the reservoir (Fig. 3.8). Importance of a stringent well tie to provide a benchmark should be stressed in this context.

Velocity Estimation

Accurate *average velocity* estimation, though usually a hard task, is essential for reliable prediction of reservoir facies, depths, thickness, porosities and fluid contents. Several techniques for velocity estimation in 2D seismic are available and the proper choice depends on the type of data and an interpreter's expertise and experience. Where wells are available, but with no/meager well velocity or sonic data (as in old, underexplored blocks), a cross plot of datum corrected log depths of a horizon against corresponding seismic times can provide an average velocity (overburden velocity) for that horizon in the area. Strong deviations from the regressive straight line fit in the cross plot may be indicative of lateral velocity variation (Fig. 3.9). However, it should be ensured that the correlations of horizon in the logs and the corresponding times in seismic are unambiguous and error free. In cases where velocity data from several wells, spread over the area, exist, the values can be contoured to yield a fairly reliable velocity field over the prospect. Yet another way to get a velocity function is from preparing a contour map of close grid seismic

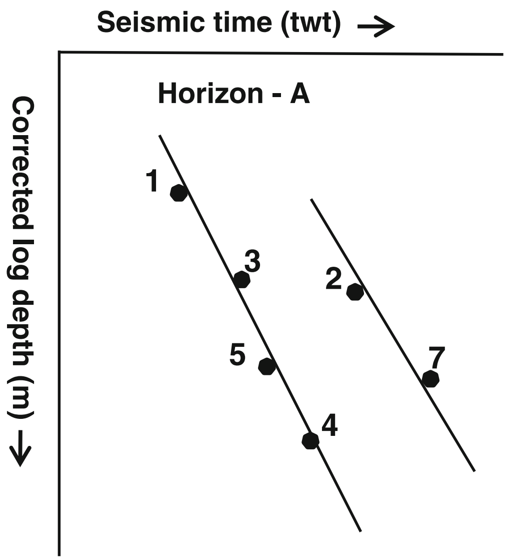

Fig. 3.9 Estimating velocity by cross-plot method in an area with several wells but without velocities measured. Datum corrected log depths of a horizon (*A*) and the corresponding seismic times at the wells are plotted and the best straight line fitted. The line provides the average velocity of the horizon with depth. Shift in the gradient (*right side*) indicates a lateral change in velocity

stack velocities that are suitably edited and modified constrained by well or sonic velocity data.

A workstation based technique known as 'stripping method' is often employed to estimate velocity function. The first shallow seismic horizon is converted to match the tied log depth at the well and the interval velocities are then used iteratively to compute isopachs that match with the next horizon. The process is progressively continued till a satisfactory match is found at subsequent deeper horizons. The process may be repeated at other wells to extend the estimated velocity field over the area. However, in relatively low resolution and low density seismic 2D data, the technique may suffer varying orders of inaccuracies depending on data quality. It may also not account properly for lateral velocity variations due to poor control on data extrapolation in the area between the wells.

Interval velocity computed from seismic RMS velocity, and duly constrained by sonic velocity, is useful to predict changes in the reservoir facies, porosity and fluid contents. A lowering of velocity is usually considered as an indication of higher porosity and a severe velocity lowering may indicate gas in reservoir, considering there are no changes in lithology involved. However, interval velocities can be highly sensitive to deficiencies in stacking velocities, especially in smaller order of intervals and can be erroneous in case of thin reservoirs.

A simple but an excellent clue to presence of lateral velocity variation is realized by simply displaying the drilled depth values of a horizon at the wells on the time map (Fig. 3.10a). Discrepancy in relative variance of depths with corresponding seismic times at the wells grossly reveals presence of lateral velocity variation in the area. For instance, a study of the three pairs of depth and time values, 1340 ms,

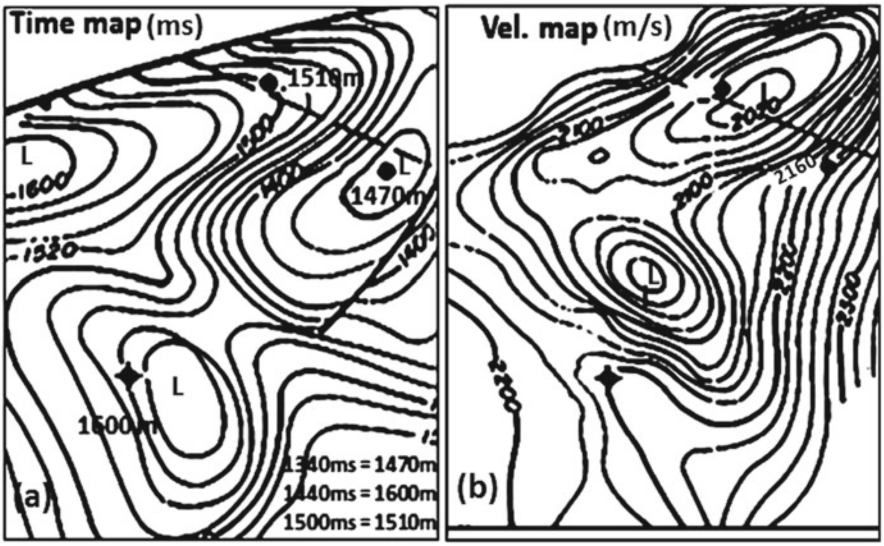

Fig. 3.10 Simply plotting the drilled depths on the time map of a horizon indicates lateral velocity variation if any. Inconsistency in gradients of time and depth pairs (as shown in the *bottom left* panel) clearly indicates lateral velocity variation. Ensuing velocity mapping derived from seismic confirmed the velocity as varying, slower on the *top* and *central* part (Image: courtesy of ONGC, India)

1470 m, 1440 ms, 1600 m and 1500 ms, 1510 m in Fig. 3.10a clearly shows the contradiction in variance of the last pair with respect to the other two, suggesting presence of a lower velocity. A velocity map prepared from 2D stack velocities, corroborated the existence of the low velocity in this part (Fig. 3.10b).

In such extreme cases, where the drilled depth gradient is opposite to that of time gradient, it exposes the presence of severe velocity variation in the area, a forewarning of a grave concern for the interpreter. Computation of velocity fields in such cases requires rigorous analysis for reliable depth prediction for deciding optimal locations for drilling. Also, analyses of the anomalous velocity trends may be corroborated by establishing the geologic causes that effect such variations for better confidence. The velocity problems, however, are much better mitigated in 3D seismic because of higher density of sampling and better resolution of data.

Seismic (Structure) Maps

Structure maps, besides being a key decision point for drilling successful wells, are also the prime inputs for volumetric estimate of in-place hydrocarbons. As such, accurate seismic depth maps play a vital role in exploration and development of fields and pose a challenge to the skill and experience of an interpreter. The precision of the map depends on initial meticulous picking and correlation of the appropriate seismic phase and an accurate velocity function at that level. It is also to be ensured that the contouring, including that of the faults, be geologically appropriate, especially for stratigraphic features and traps. As stated earlier, precise velocity estimation is the most crucial factor for creating accurate maps. Errors in prediction of depths to reservoir (pay) and its thickness can lead to disappointing drilling results with consequences of severe downgrading of in-place hydrocarbon estimates. Economic viability of a field can change significantly if an appraisal well meets the actual pay deeper and ends up in a dry well. Empirically, a departure up to 5 % in 3D and 10 % in 2D data between predicted and actual depths may be considered tolerable at moderate depths (~2000 m). The prediction accuracy decreases with depth, as errors in seismic derived velocity usually shows larger deviations at deeper depths.

Hydrocarbon discovery in a well shifts the project from the exploration phase to the phase for delineation of the reservoir. Invariably, the old seismic data is revisited for fresh interpretation and often suggested for reprocessing or special processing of data. New data sometimes is necessary and may have to be acquired. With better quality new data and geologic information gained from the drilled well(s), reinterpretation produces a set of new, more precise structure maps to predict depths and geometry of the reservoir. Contouring, depending on geologic leads from wells, may require explicit representation of stratigraphic features such as channel sands, delta lobes, bar sands etc. It calls for special contouring skill to properly portray the stratigraphic features and needs human intervention in computer-made contouring. An example of hand-made contour map of sand thickness map for a geologic depositional model and the contour prepared by computer cokriging method for the same data set is shown in Fig. 3.11. The repetition of the 20 m contour in the manually prepared contour map (Fig. 3.11b) truthfully implies thinning of sands as expected in the swampy lagoonal area to the north. In contrast, the computer-generated map indicates thickening of sands to north (Fig. 3.11c), contrary to the geologic realities in the model (Fig. 3.11a). Human imagination incorporates prior information on structural and stratigraphic analogs, while cokriging only interpolates the current data mechanically.

Detailed reservoir maps are normally prepared with small contour intervals (10 ms) and small scales (1:10,000–20,000) to signify the details better. It is also important that all cartographic details are correctly displayed to avoid any uncertainty in location (ground-position) of wells and seismic for ties. The revised seismic maps also need to be validated by the known hydrocarbon distribution and fluid contacts at wells for better confidence. For example, a structure map prepared at the top of an oil-pay is normally not supposed to indicate structural disposition lower than the established oil–water contact. If, however, this apparently anomalous situation is confirmed after due checks, it will have major implication on the significant aspect of distribution of oil in the prospect; it then becomes a separate isolated oil pool, which can have severe repercussion in the development of the prospect. Faults are an important component of structural maps, and play a crucial role in the distribution and accumulation of hydrocarbons. They should be carefully mapped and cautiously evaluated (see Chap. 5).

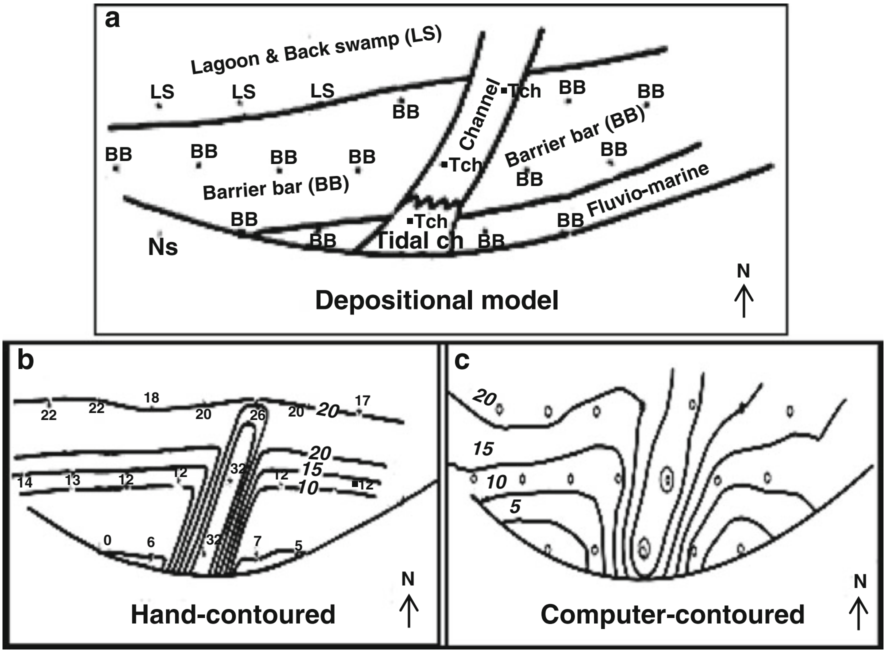

Fig. 3.11 Comparison of hand-contoured and machine-contoured maps of a stratigraphic model (**a**) depositional model (**b**) hand contoured map of sand isolith and (**c**) computer generated isolith map for the same data set. The computer contouring is mathematical and lacks imagination of the human brain. Note the repetition of the 20′ contour in hand drawn map that indicates thinning of sands to north in the swampy lagoon area contrary to computer contours that suggest increase of sands in this part

Seismogeological Section

The seismogeological transect is an effective composite display of well-log correlations superimposed on seismic correlation (Fig. 3.12). These are convenient and preferred ways of presentation to understand and assimilate the stratigraphic details across the profile with its log and related seismic response.

Analysis of lateral changes in seismic waveform, constrained by well log data, allows better assessment and prediction of stratigraphic details. Variations in interval velocities combined with reflection amplitudes, frequencies, and wave shapes, can be useful to predict qualitative changes in reservoir properties, and heterogeneity. Quantitative estimates of rock-fluid properties can be made reliably with high density, high-resolution seismic data, addressed in 3D/4D interpretation (Chap. 8).

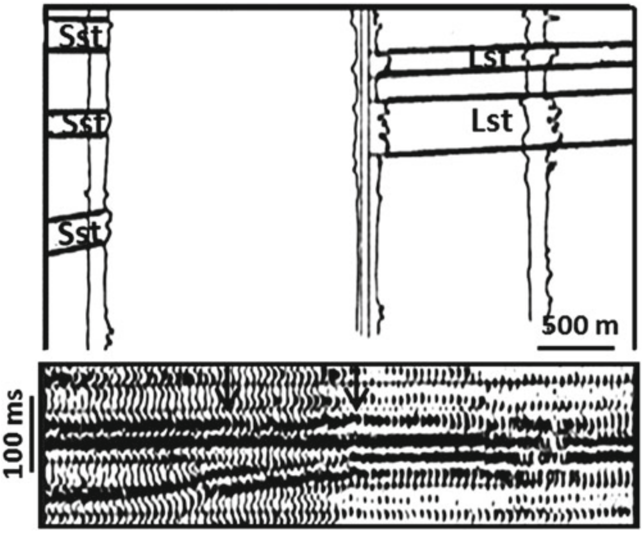

Fig. 3.12 A composite section display of seismic and logs helps understand better the changes in lateral facies. Note the change in reflection character of shelfal limestone to that of sandstone at shelf break(indicated by *arrows*) (Modified after Galloway et al. 1977)

Category III: Seismic Stratigraphy Interpretation

Seismic stratigraphy is a geologic approach to interpret regional stratigraphy from seismic. It is a powerful technique, especially suitable for less explored or virgin basins with no or sparse well data. Even a few long routinely processed regional seismic lines can help to capture information on the evolutionary history of the basin and evaluate hydrocarbon habitats. Generation, migration, and accumulation potentials of hydrocarbons in the basin in general and in selective structural and stratigraphic plays in particular, can be assessed and resources prognosticated for deciding future exploration strategy in the basin.

The seismic stratigraphy method is based on analysis of reflection patterns of stratal surfaces. Stratal surfaces signify a period of no deposition or a change in depositional regime, forming time-lines through the process (Mitchum 1977). The reflections from impedance contrasts at interfaces tend to parallel the stratal surfaces, so seismic horizon correlations are generally considered chronostratigraphic. Chronostratigraphic correlation helps study of sequences deposited during a given span of geologic time.

Commonly, the seismic image portrays the subsurface geology adequately. The reflections and their patterns can thus be taken as fair representatives of geometry of the stratal surfaces and their depositional morphology. However, seismic chronostratigraphic correlations often are at variance with other types of correlation and can cut across lithostratigraphic or biostratigraphic correlation of facies which do not belong to same geologic time. Facies deposited during different interval of geologic time are known as diachronous and their correlation is termed time transgressive.

The technique essentially involves study of lateral termination and patterns of reflection to identify depositional sequences, analysis of seismic facies to interpret depositional environment and lithofacies associated with sea level changes. We shall briefly state the standard terminologies used in seismic stratigraphy framework (Mitchum and Vail 1977) that consists of three parts: (i) Seismic sequence analysis; (ii) Seismic facies analysis; and (iii) Relative sea level change analysis.

Seismic Sequence Analysis

A depositional sequence is defined by unconformities or correlative conformities at top and bottom and is recognized in seismic from four types of lateral termination of reflections (Fig. 3.13). An unconformity separates the older from younger rock sections. Younger horizons terminating against older ones at the base (Baselap) are termed onlaps and downlaps. Older horizons seen as terminating against younger ones at top (Toplap) are called toplaps and truncations.

Onlap Onlap has discordant relation at the base and can be coastal or marine depending on landward building of nonmarine coastal sediments on shelf or of aggrading marine sediments on basin slope (Fig. 3.14). Onlaps generally are indicative of relative sea level rise.

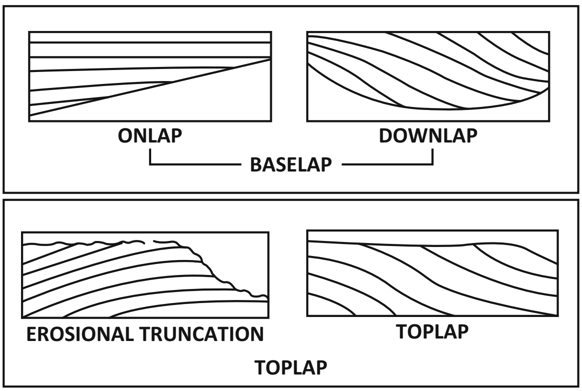

Fig. 3.13 Schematics showing types of seismic reflection termination patterns used for identifying depositional sequences (After Mitchum et al. 1977)

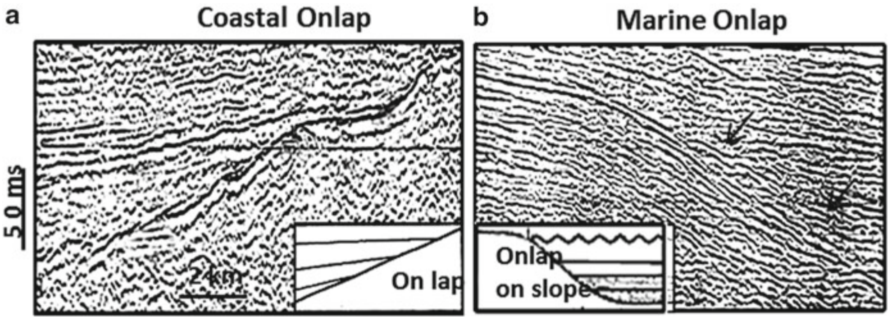

Fig. 3.14 Seismic onlap, a base discordant relation with the schematics shown in inset (**a**) Coastal onlaps are nonmarine back-stepping build ups on the coast and (**b**) marine onlaps, the deep water marine sediments deposited on the shelf slope (Image: courtesy of ONGC, India)

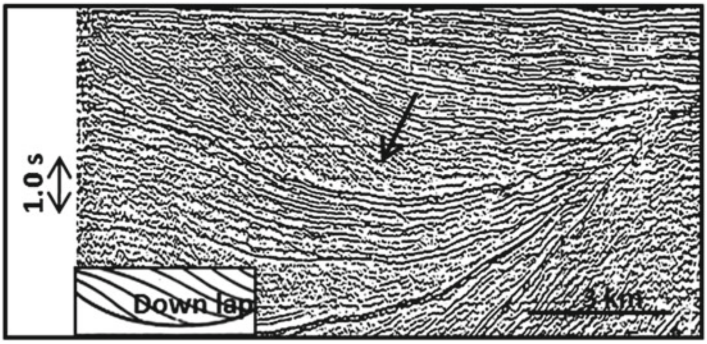

Fig. 3.15 Seismic example of down lap (*arrow*), a base discordant relation with the schematic shown (*inset*) (Image: courtesy of ONGC, India)

Downlap Downlap, like onlap, is also a base discordant relation and indicate lateral extent of stratal deposition basin ward (Fig. 3.15). The down dip and gradient of the strata indicate the transport direction and rate of sediment supply. Large and fast sediment dumps are likely to show steep gradients.

Toplap Toplap is a top discordant relation and is the termination of strata at the top against younger units (Fig. 3.16). Coastal top laps represent non-deposition and/or mild erosion above wave base in still-stand sea level. Toplaps also can be seen in deep marine depositions.

Truncation Truncation is another top discordant relation, which shows strong angularity with overlying younger strata and is indicative of erosional unconformity (Fig. 3.17).

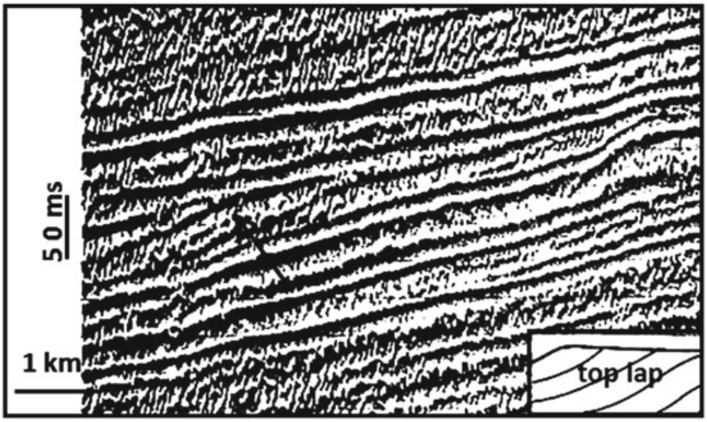

Fig. 3.16 Seismic example of top lap, a top discordant relation with the schematic shown (*inset*) (Modified after Taner and Sheriff 1977)

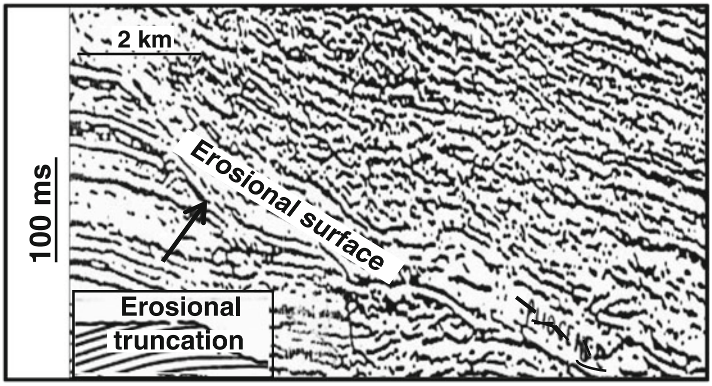

Fig. 3.17 A segment of seismic section showing a top discordant relation – an erosional truncation by canyon cut with schematic (*inset*) (Image: courtesy of ONGC, India)

Seismic Facies Analysis

Geologic facies vary in lithology and rock properties depending on depositional environment and sedimentary process and have individual characteristic signatures embedded in seismic images. Seismic facies analysis deals with the study of internal seismic reflection patterns within a sequence and its other associated parameters to interpret depositional environments and related lithofacies. The sequence facies analysis includes reflection continuity, amplitude and frequency, the internal reflection configurations, interval velocity and the external form of the sequence.

Reflection Continuity and Amplitude Reflection continuity over large areas with consistent amplitude is an indication of wide spread uniform depositional environment implying marine facies. Discontinuous reflections with variable amplitudes over an area, on the other hand, imply frequent lateral changes in facies indicating continental environment. High amplitude continuous reflections are usually suggestive of sandstone or limestone and extensively spread thick section of poor amplitude reflections indicates monotonous lithology, mostly inferred marine shales though it could occasionally the massive continental sands deposited in certain type of geologic basin.

Frequency Frequencies are often suggestive of thickness of stratigraphic units and their facies change (see Chap. 2). Low-frequency reflections at the lower and high frequencies at the upper part of seismic records are common observations that clearly give clues to relative geologic age of rocks and often make it convenient for an experienced interpreter to distinguish older Mesozoic rocks from younger Cenozoic rocks, for example.

Internal Reflection Configuration Reflection patterns within a sequence, considered as a replica of internal geologic stratal configuration, are important for evaluation as these indicate the depositional energy of environment. Low-energy is related to deposition of finer clastics like clay and high energy linked to coarser clastics like sands. Depositional patterns are controlled essentially by two factors: (1) the energy of the agent transporting the sediments, and (2) the accommodation space available, controlled by a balance between rate of supply and rate of basin subsidence. Some of the common seismic internal configurations with their geologic significance are briefly discussed.

Parallel and Divergent Reflection Patterns Parallel to sub-parallel pattern suggests a balance between uniform rates of sediment deposition on a uniformly subsiding or nearly stable basin shelf. Reflections with divergent patterns, on the other hand, imply lateral variation in rate of deposition on a progressively tilting surface (Fig. 3.18).

Prograding Clinoforms Patterns Progradation is an out building of sediment deposition, due to relatively higher rate of sediment supply and less accommodation space with comparatively lower rate of subsidence (Fig. 3.19). Prograding clinoforms are sloping depositional strata with their shapes influenced by transporting agencies and are excellent indicators of unconformities, relative sea level changes, bathymetry at the time of deposition and depositional energy. The tops and bases of clinoforms offer clues to paleo-bathymetry and are helpful in distinguishing deltaic deposits in shallow waters from those in deep waters. The three most significant and common clinoforms are the sigmoidal, oblique and shingled.

- Sigmoidal Clinoforms are recognized by vertical building (aggradations) of depositional surfaces (Fig. 3.20). Aggradations suggest high rate of sediment supply with rapid rise of relative sea level providing large accommodation space and depicts a low-energy deep-water depositional environment.

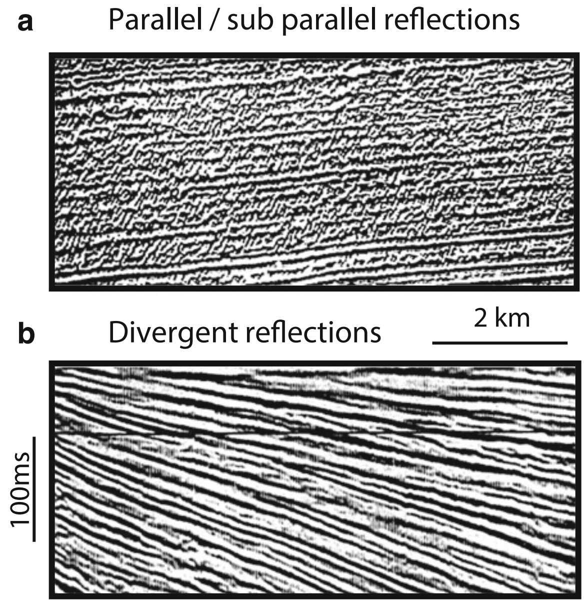

Fig. 3.18 Internal reflection configurations of a seismic sequence (**a**) parallel reflections – indicate uniform rates of deposition on a uniformly subsiding or near stable basin shelf (**b**) divergent reflections represent lateral variation in rate of deposition on a progressively tilting surface (Image: courtesy ONGC, India)

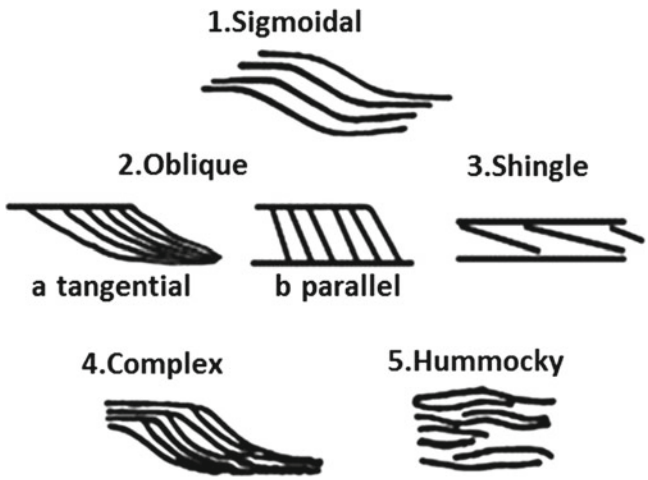

Fig. 3.19 A schematic showing examples of different types of progradational clinoforms characterizing varied depositional energy and environment (After Mitchum et al. 1977a, b)

- Oblique Clinoforms are characterized by distinct toplap and downlap terminations. The progradation is called tangential oblique (Fig. 3.20) or parallel oblique (Fig. 3.21) depending on the steepness of the angle made at the lower boundary. The patterns suggest high sediment supply with slow to no basin subsidence in a relative still- stand sea level and a high energy depositional environment.
- Shingled clinoforms are similar to parallel oblique (Fig. 3.22) patterns except that the clinoforms are much gentler and with a hint of an apparent toplap and

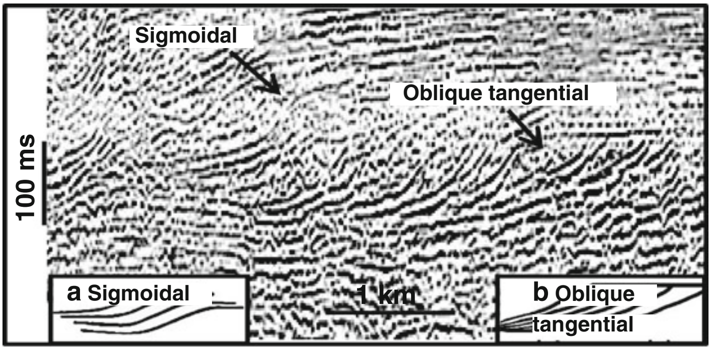

Fig. 3.20 A segment of seismic showing examples of (*a*) sigmoidal and (*b*) oblique tangential progradations with schematics (*inset*) (*a*) Sigmoidal progradations characterized by vertical build ups suggest high influx, low energy and deep-water environment, and (*b*) Oblique tangential clinoforms with toplap suggest high influx, high energy deposits in still-stand sea level

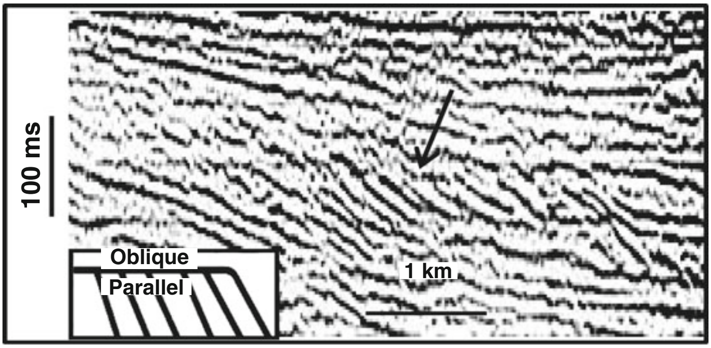

Fig. 3.21 A segment of seismic section showing example of 'oblique parallel' clinoforms with schematic (*inset*). The pattern with toplap indicates relatively higher influx and higher energy deposited in still-stand sea level. Note the relatively steeper stratal dips (Image: courtesy, ONGC, India)

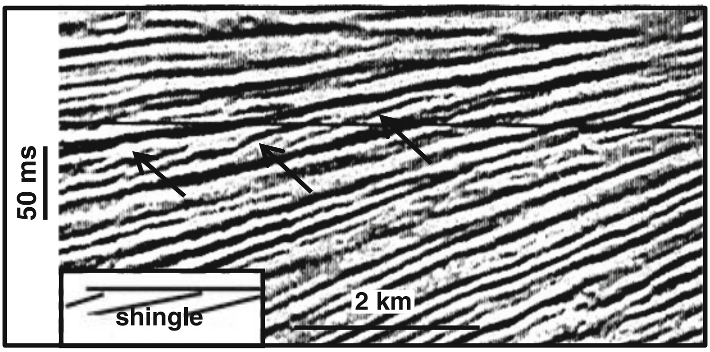

Fig. 3.22 A segment of seismic section showing example of Shingled progradation. It suggests low influx, high energy, deltaic to shallow marine environment. Note the subtle suggestions of toplap (*arrow*) (Image: courtesy, ONGC, India)

downlap at the base. The prograding surfaces are suggestive of relatively less supply of sediment, deposited on shallow stable platforms in shallow marine to deltaic, high-energy environment.

Hummocky, Chaotic and Reflection-Free Patterns Hummocky patterns are often associated with low energy facies such as interdeltaic and prodelta shale whereas chaotic pattern of reflection is usually linked to high energy deposits such as channel fills, fans, reefs, turbidites, etc, Reflection free zones may be related to complex tectonised zones, salt or mud diapirs, or over-pressured sections.

Interval Velocity As stated earlier, interval velocity is an important indicator of rock properties that can be calculated from sonic or average velocity measured in a well or estimated from seismic stacking velocity. Stacking velocities, despite their limitations, can still be extremely useful, if analyzed cautiously by the interpreter for prediction of lithology (Chap. 2). However, difficulty arises as more than one type of lithology often have a velocity range, overlapping others. An analysis of depositional environment by seismic stratigraphy approach combined with velocity can lead to reliable prediction of lithology and its changes within a sequence.

External Forms External form is the study of geometry of a seismic sequence in a map view and is extremely helpful for validating geologically the inferred depositional feature. For example, a channel system interpreted and mapped from amplitude time-slice must not trend parallel to the paleo coast. The reflection discordance patterns, internal configurations, formation velocity of a sequence, and the external form, analyzed together, offers dependable information on depositional energy and associated facies of the geologic object. Some common occurring external forms of sequences easy to figure out on seismic sections and maps include wedges, fans, lenses, mounds and trough-fills. Wedges are commonly associated with fluvial to shallow marine shelf facies and the internal configuration of reflections in terms of amplitude and continuity provide clues to type of depositional energy and associated lithology. Fans, lenses and mounds with discontinuous and weak to fair amplitudes, are usually linked to high energy facies. Nevertheless, it may be mentioned that the seismic responses can vary greatly under different geologic settings, and the observed patterns may be restricted to a specific area only.

Troughs, canyons and channels with their varied types of fills, offer interesting studies of reflection patterns and are good indicators of basin subsidence, depositional energy and facies (Fig. 3.23). Parallel and divergent reflection fills in a trough with good continuity and amplitude (Figs. 3.24 and 3.25) denote low energy marine facies with little or no subsidence. Mounded and chaotic trough fills having discontinuous and random reflections (Fig. 3.26) signify high energy deposits, e.g., turbi-

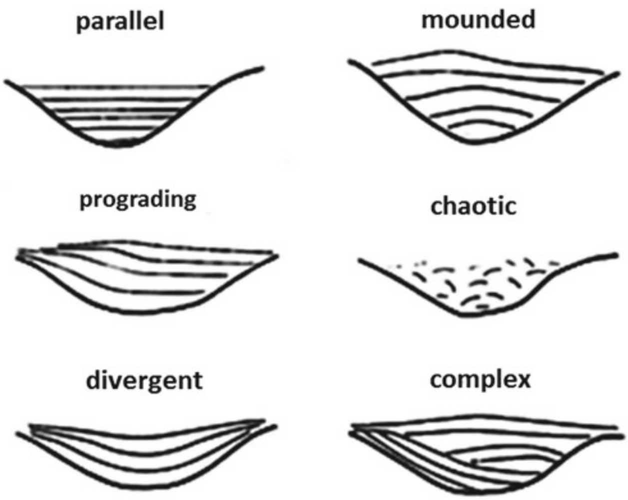

Fig. 3.23 Schematic examples of some external forms of troughs and their pattern of fills, common in seismic facies analysis. The internal reflection configurations of the fills serve as good indicators of basin subsidence, depositional energy and facies (After Mitchum et al. 1977)

dites, channel cut and fill sand complexes. Prograding and irregular fills may indicate depositional facies of variable energy like debris flows and gravity slumps, whereas, reflection-free trough fills are suggestive of low energy, fine clay deposits (Fig. 3.27).

Relative Sea Level Change (RSL) Analysis

One of the key components of a depositional environment is the sea level and its change with time, which controls the shoreline and consequently the depositional systems. Sea level changes on a global scale are known as eustatic changes and used for glacial and global geochronology studies. An apparent rise or fall of sea level with respect to land surface in a regional way is known as relative change of sea level (Mitchum 1977). Relative changes in sea level (*RSL*), amount of sediment influx and shifting of shoreline control the accommodation space, facies type, depositional process, thickness and sedimentary patterns, the key to understanding hydrocarbon habitats for exploration.

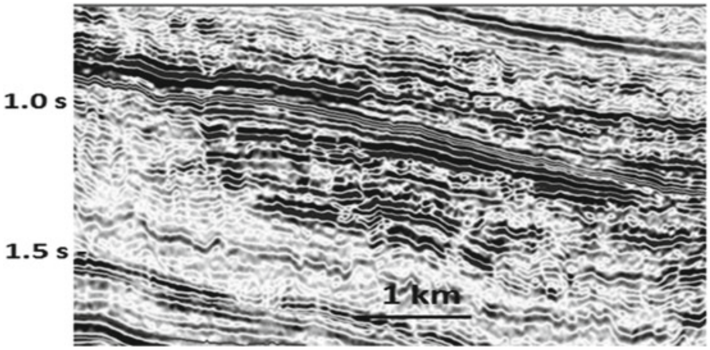

Fig. 3.24 Seismic example of a trough-fill (a cut and fill channel complex) with near-parallel internal reflection configuration. The layered and flat fills indicate low energy deposition (finer clastics) in a stable trough without subsidence (Image: courtesy ONGC, India)

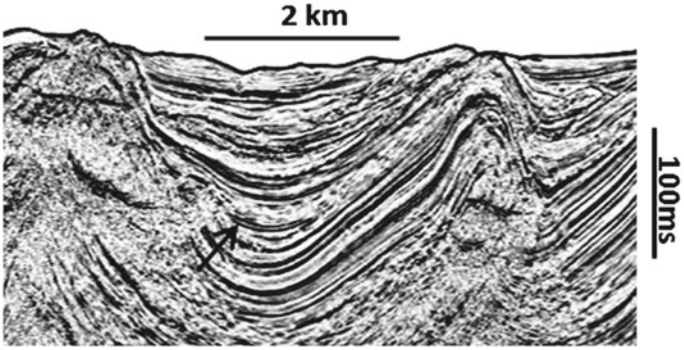

Fig. 3.25 A segment of a seismic section showing an example of 'divergent' trough- fill suggesting continuing sedimentation with a gradual sinking of trough due to rising intrusive bodies on the flanks (Image: courtesy ONGC, India)

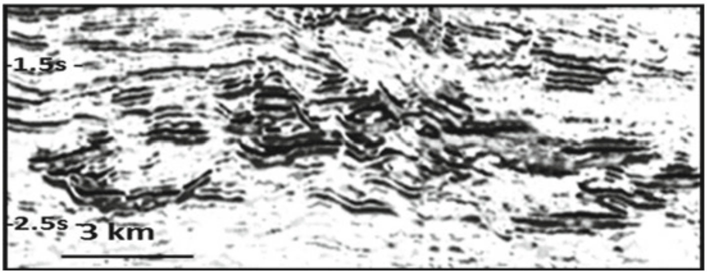

Fig. 3.26 Seismic example of a trough fill with chaotic and mounded reflection configuration. The high amplitude, discontinuous and random reflection patterns suggest high energy deposits (coarser clastics)

Fig. 3.27 A segment of seismic section showing an example of a trough with 'reflection free' fills. It suggests low energy finer clastics facies (Image: courtesy of ONGC, India)

Important inferences of relative sea level changes can be made from seismic sequence analysis. A rise in relative sea level is indicated by progressively shifting coastal onlaps landward, whereas a fall in sea level is indicated by shifting of onlaps seaward *(forced regression or offlap*). Fall in sea level can be distinctly inferred from seismic where prograding clinoforms are seen shifting progressively downward towards basin (Fig. 3.28).

A rise or a fall in sea level does not always determine the associated facies as transgressive or regressive. The marine transgression and regression is defined by shifting of shoreline, landward or basinward and not by transgressing or regressing of sea, confusing terms used at times, instead of stating sea level rise or fall. Shoreline is defined as the divide between marine and nonmarine facies, and the shore facies are characterized by littoral sediments deposited between high and low tides. Mapping shoreline is thus an important aspect for locating potential targets as several kinds of high-energy reservoir facies of great exploration interest occur on or close to shores. But unfortunately it is difficult to map paleo shoreline from seismic without well information.

It may be emphasized that shoreline shifts are not only dependent on rise and fall of sea level but also importantly on rate of sedimentary influx during that period. For example, during a sea level rise, a transgressive, regressive or stationary shoreline facies can occur (Fig. 3.29) , depending on the balance between relative sea level changes (including subsidence) and amount of influx supply. A seaward shoreline shift with regressive facies during a rise in sea level is known as normal regression and the regressive facies during fall in sea level is known as *forced regression*.

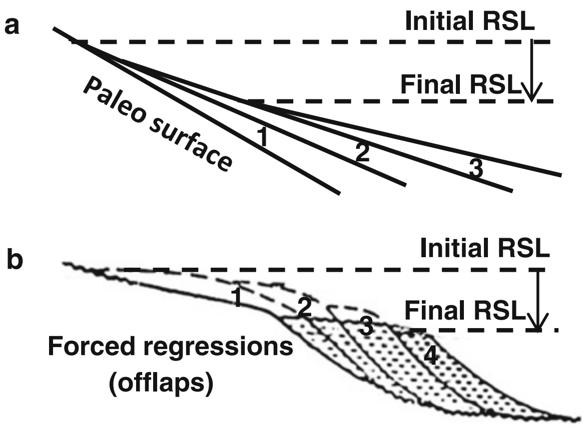

Fig. 3.28 Sketches illustrating regressive facies associated with fall in relative sea level (**a**) seaward shift of onlaps (offlap) and (**b**) downward shift of clinoforms. Regressive facies shifting basin ward during sea level fall, is known as 'forced regression' (Modified Fig. 3.28b after Vail et al. 1997)

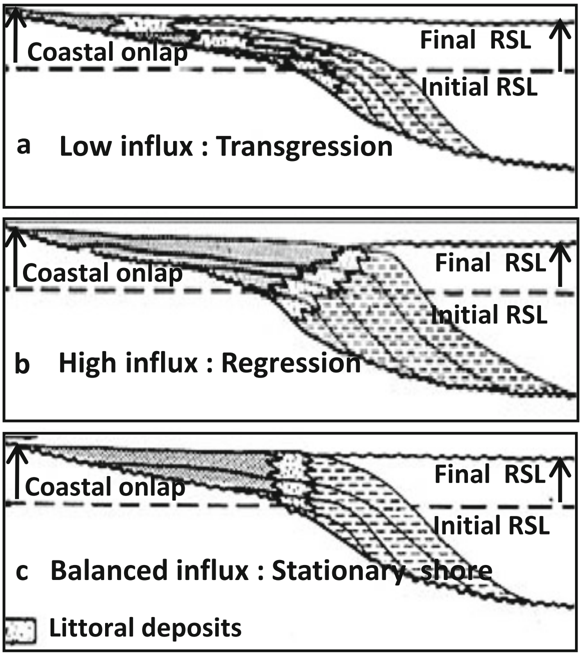

Fig. 3.29 Sketches illustrating shore line shifts during rise in relative sea level change. The shore line shifting land and basin ward or remaining stationary depends on amount of sediment supply (**a**) Shifting is landward (transgressive) when influx is low (**b**) basinward (regressive) when influx is high and (**c**) stationary if the rate of influx is balanced with rise in sea level (After Vail et al. 1977a, b)

Category IV: Seismic Sequence Stratigraphy Interpretation

Sequence stratigraphy is an evolved and refined version of seismic stratigraphy, which reveals depositional process and architecture of a sequence in minute detail. A depositional sequence is bounded by unconformities and deposited during one cycle of sea level change; a cycle is defined by the time interval starting from low sea level, rising to a high, and followed by a fall to low level again. A cycle may vary from millions of years to a few thousands, depending on the order of sea level changes: mega or minuscule. Seismic stratigraphy studies deal generally with third order sequences of 1–5 my duration and lower (Mulholland 1998). Sequence stratigraphy studies, on the other hand, deal with analysis of small cycles of sea level changes of higher order sequences with cycle duration periods of as little as hundreds of years. The analysis is mostly done from study of outcrops or from an integrated correlation of macro- and micro-scale well log and core data. The duration of deposition being small, the sequences are generally much thinner than lower order seismic stratigraphic sequences and may be difficult to detect on seismic due to limited bandwidth resolution. Nonetheless, help from meso-scale seismic data is used wherever found relevant. Analysis of stratigraphy of higher order sequences from well log, core and sedimentological data with some help from seismic data may be termed as *seismic sequence stratigraphy.*

Sequence stratigraphy has somewhat different terminologies and nomenclatures compared to those in seismic stratigraphy. The principal focus of sequence stratigraphy is the *systems tract*. A depositional sequence is collectively composed of a succession of strata termed as systems tracts deposited during one cycle of sea level change. The systems tracts are mostly divided into three groups depending on position of sea level with respect to shelf edge and can be individually recognized in well log, core, and sometimes in high resolution seismic data. A highly simplified sequence stratigraphy model is described below.

Low Stand Systems Tract (LST)

The sea level is called low stand when it is below a shelf edge. The bottom part of the sequence deposited over the base unconformity during low stand is termed a *low stand systems tract (LST).* The *LST* may include varied depositional systems like slope and basin floor fans, fan deltas, and submarine channels, prograding wedge complexes with outbuilding deltas albeit depending on the rate of sediment supply (Neal et al 1993). *LST*s may be inferred in seismic by external forms of deposits such as mounds, fans, wedges, and by their reflection configurations such as chaotic, hummocky and prograding clinoforms patterns.

Transgressive Systems Tract (TST)

With the rapid rise of sea level, and with little or no sediment supply envisaged, the shoreline transgresses landward. During this period, the basin may according to one model, accumulate sediments eroded from the low stand systems tract wedge and deposited backwards as a *transgressive systems tract* (Neal et al. 1993). Ideally, the depositional pattern may be recognized by progressive units of retrostepping seismic onlaps sequences bounded by marine flooding surfaces, which are called *parasequences*. However, *TST*s are commonly thin and below seismic resolution to be perceptible. Top of *TST* denotes the maximum limit of the encroachment of sea and is termed as maximum flooding surface *(MFS)*, during which a thin section of pelagic shale, known as *condensed section*, is regionally deposited. The *condensed section (MFS),* is considered a good source rock and can be sometimes recognized in seismic as a continuous downlapping event, distinguishing refection patterns and characters, above and below it.

High Stand Systems Tract (HST)

As the sea level begins to gradually fall, vast areas of land emerge and large amount of sediment supply is resumed to form *HST* deposits. The resulting parasequences migrate seaward and the high stand deepwater deposits can be easily identified in seismic by sigmoid progradational clinoforms, downlapping onto the condensed section. Finally, the sea level falls below the level of deposition and *HST* is exposed to surface erosion and the depositional cycle is completed with the unconformity at the top and a complete sequence is established.

The Baum and Vail (1998) growth model of a sequence is shown schematically in (Fig. 3.30) and the diagnostic patterns of system tracts in seismic are summed up in Table 3.1. A representative interpretation of system tracts from seismic based on reflection patterns and external forms is also exemplified in Fig. 3.31. Geologic features like channel and canyon cut and fills, slope/basin floor fans, prograding clinoforms, downlaps etc., can be handily inferred from their seismic signatures to interpret linked depositional system tracts.

The seminal growth model of a sequence is based, however, essentially on three important assumptions of depositional environment factors: (1) a typical shelf and slope configuration of a passive margin basin, (2) deposition of cyclic marine clastic sediments, and (3) amount of sediment supply varying appropriately with changes in relative sea level. Variations in any of the geologic elements like tectonics, depositional regimes (fluvial), rate of sediment supply, and slope of the depositional surface etc., in a basin may be an impediment to comprehend the above described

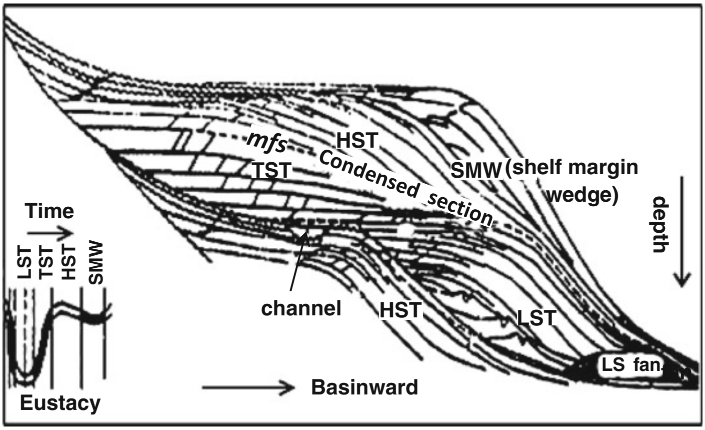

Fig. 3.30 A schematic growth model of a sequence. Depositional process and architecture of sequences of small cycles of sea level changes (higher order sequences) with cycle duration periods of as little as hundreds of year is detailed. Seismic stratigraphy studies, on the other hand, deal with third or lower order sequences of 1–5 *my* duration (Modified after Baum and Vail 1998)

Table 3.1 Growth model of a sequence; depositional features and seismic diagnosis

	System tracts	Depositional features	Reflection patterns, external form
Growth of a Depositional Sequence	UNCONFORMITY		
	HST: Sea level above shelf edge and high sediment supply	Wedge of progradational stacks with aggradations	Sigmoidal clinoforms downlapping to a weak, continuous reflection (mfs)
	TST: Transgressing sea level and little or no sediment supply	Thin retrograde onlaps, topped by a veneer of pelagic shale, the condensed section (mfs)	Weak/no downlaps pattern, usually below seismic resolution
	LST: Sea level below shelf edge and high sediment supply	Prograding sediments; typical wedge complex with deltas overlying slope/basin floor fans, fan deltas, submarine channel cut and fill features, etc.	Shingled/oblique progradational clinoforms, External forms of fans/mounds with chaotic, hummocky reflections
	UNCONFORMITY		

Higher order sequences have small depositional durations, are relatively thin and often hard to identify in seismic. Nevertheless, certain depositional characteristics can be traced to typical seismic signatures based on study of reflection patterns and external form of geological features which is exemplified in Fig. 3.31.

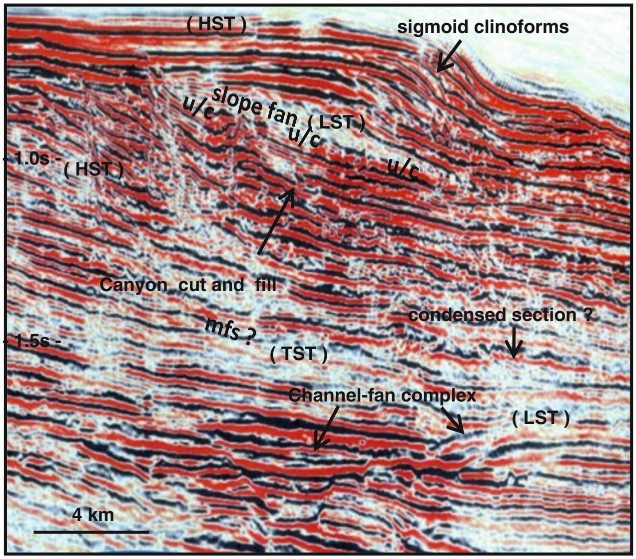

Fig. 3.31 A representative example of interpretation of seismic sequence stratigraphy system tracts based on seismic reflection patterns and external forms linked to geologic features like channel/canyon cut and fills, slope/basin floor fans, prograding clinoforms and downlaps, etc. (Image: courtesy ONGC, India)

classical growth model of sequence stratigraphy. Such geologic changes are likely to result in drastic modifications of the patterns of the depositional sequence and its geometry shown in Table 3.1. Sequence stratigraphy analysis generally appears to work well for passive margin basins with high clastic sediment supply though it is said to be applicable to carbonate deposits also. The technique may not be useful in all types of geologic basins.

Application of Seismic Sequence Stratigraphy

Seismic sequence stratigraphy being a synergistic analysis of well logs, core (biostratigraphic & sedimentological) and high resolution, high density seismic (3D) data, is likely to improve definition of prospects, especially the subtle stratigraphic traps. The finer details of stratal geometry and related changes in their patterns can also be extremely important for reservoir delineation and characterization, especially with reference to study for presence of small intra-formational paraconformities within the reservoir. *Paraconformity* is a nondepositional unconformity with parallel strata in which the unconformity surface resembles a simple bedding plane. Paraconformity interfaces may act as horizontal permeable paths but inhibit vertical connectivity within a reservoir sequence, which can influence flow of fluid during production and/ or water injection.

Seismic Stratigraphy and Stratigraphic Interpretation

Seismic stratigraphy and stratigraphic interpretation are two widely used terms, which sound similar, but may not be synonymous. There are, in our opinion, philosophical differences between the two approaches; nevertheless they are complementary to each other in achieving the common goal of seismic data interpretation and evaluation. The differences in their core objectives are summarizes in Table 3.2.

Table 3.2 Comparison between seismic stratigraphy and stratigraphic interpretation

	Seismic stratigraphy	Stratigraphic interpretation
1.	Preliminary level of regional interpretation with no/sparse well data; usually made in first phase of exploration	High level synergistic interpretation after calibration with well data; made in later stage of exploration, usually in delineation and development phase
2.	Usually on routinely processed, long regional, wide-grid 2D data	Usually better processed, better resolution, close- grid seismic data (2D/3D)
3.	Typically interpretation of entire vertical time section to comprehend basin evolution and evaluation for prospectivity	Detailed analysis of prioritized area limited to prospect and specified time-window of interest
4.	For understanding depositional environment and tectonic history	Estimating rock-fluid properties as inputs for estimate of hydrocarbon volumes
5.	Regional mapping of structures commonly at lesser resolution	Detailed mapping of pays/reservoir with precision and high resolution
6.	A powerful tool for evaluating basins and prospects for hydrocarbon potential to prognosticate resources in the basin	For delineation and development of hydrocarbon prospects; reservoir delineation and characterization for reservoir modeling

Though the two expressions, the seismic stratigraphy and stratigraphic interpretation sound alike they are not synonymous. The two techniques differ greatly from each other in several aspects as showcased here

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Chapter 4
Tectonics and Seismic Interpretation

Abstract Tectonics deals with deformation of the earth and its evolution in time in response to geologic stress and plays a major role in hydrocarbon exploration. An assortment of structures and deformations associated with different stress regimes, show typical manifestations in seismic data that can be conveniently picked. A brief description of such common geologic structures resulting from each of the stress regimes and their easy recognition on seismic data are outlined, exemplified by seismic images and graphic illustrations.

Study of tectonics – the stress regimes, resultant deformations and their chronological history inferred from seismic, may be termed seismo-tectonics, analogous to the term seismic stratigraphy.

Tectonics deals with deformation of the earth and its evolution in time in response to stress. Studies of tectonics help understand earthquakes, volcanoes, major erosions and depositions linked to geomorphology. In petroleum exploration tectonics plays a major role in hydrocarbon generation, expulsion and accumulation. Analysis of tectonic stress regimes and their stages with chronological history is thus extremely useful in understanding the evolution and evaluation of geologic basins for hydrocarbon exploration. Applied to seismic interpretation, knowledge of tectonics helps in evaluating potential prospects for hydrocarbon, beginning with guiding the preliminary step of correlation of seismic horizon. For instance, subjectivity in correlations forced by 'phantoming' and 'jump correlations' in areas of poor quality data can be greatly reduced if an interpreter is familiar with tectonic styles in the area.

Tectonic stress also alters physical properties of rocks like elasticity and density influencing seismic responses. In orogenic belts of mountainous areas under substantial tectonic stress, the effective pressures can affect rock and seismic properties. Flanks of over thrusts may sometimes indicate higher density and velocity than expected for these rocks present elsewhere under no such horizontal stress. However, in geologic basins, where the horizontal stress, compared to the overburden vertical stress is small, it may hardly alter the rock properties.

Analysis of tectonic stress regimes, the resultant deformations and their chronological history can be conveniently inferred from seismic. The study of tectonics from seismic data therefore may be termed *seismo-tectonics*, analogous to the term seismic stratigraphy – which is about the study of stratigraphy from seismic data.

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Stress at any point below earth's surface is a resultant of the geostatic (vertical) stress or overburden pressure, the pore pressure, and the tectonic (horizontal) stress. However, only the tectonic stress and its effects which can be easily analysed from seismic data are presently considered. Tectonic stress, which is due to external geologic forces, are categorised as (1) extensional; (2) compressional; (3) shear (or wrench); and (4) diapiric (shale and salt diapirs) depending on major stress direction. The fourth category, diapiric, though strictly belongs to extensional stress regime, is considered separately here due to its typical vertical nature having unique manifestation in seismic.

Each of the stress regimes has an assortment of associated deformations or structures, most of which leave distinct footprints on seismic data for clear diagnosis. Analysis of tectonics and related deformations can be made from both seismic sections as well as from the maps. Some common geologic structures that are associated with each stress regime and are easily recognized on seismic data are briefly outlined for the interpreter, with seismic and schematic illustrations, for elementary and convenient grasping.

Structures Associated with Extensional Stress Regimes

Compaction/Drape Folds

Compaction or drape folds are formed due to differential compaction of sediments deposited on pre-existing paleo-highs. These are inferred from seismic by the thinning of time intervals (considered as bed thickness) of horizons seen on the crests of structural highs, compared to that on flanks of structures (Fig. 4.1).

Horsts and Grabens Accompanied by Normal Faults

Horsts and grabens are structural features associated with normal faults (Fig. 4.2). These are structural highs and lows between two adjacent faults, caused due to relative movement along the faults and are usually oriented parallel to paleo depositional trend which can be clearly seen in plan view seismic maps.

Compaction Faults and Gravity Faults

The compaction faults are low-angle rootless faults with decreasing dips and throws that do not extend roots deeper into older sections (Fig. 4.3). These mostly occur in thick finer clastics formations due to the large amount of compaction taking place. As a corollary, faults which do not show such decrease in dip with depth can be inferred as occurring post-compaction.

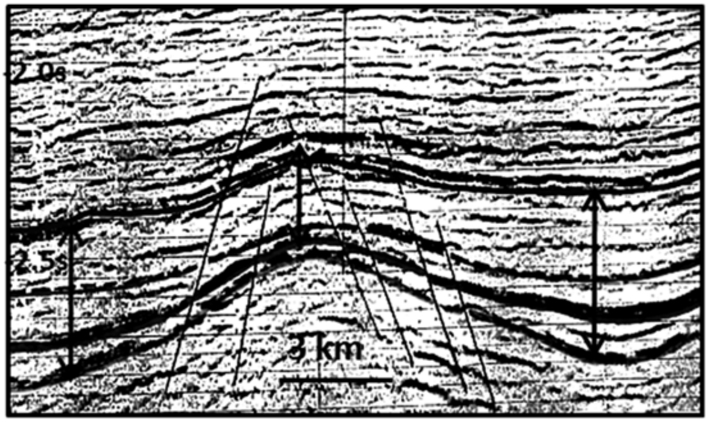

Fig. 4.1 A segment of seismic section showing an example of drape (compaction) fold. Drape folds are caused by compaction of sediments deposited on paleo highs in extensional stress regimes and are typified by crestal-thins compared to thickening on flanks of structures. Note the gradual flattening of structural relief upwards at shallower levels (Image: courtesy ONGC, India)

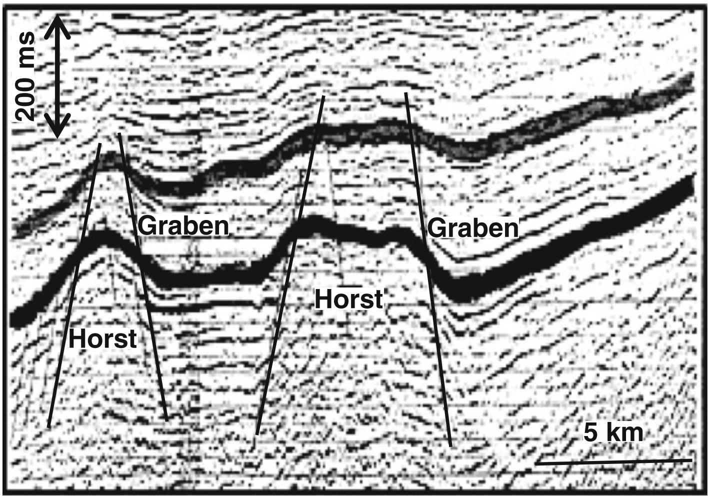

Fig. 4.2 A segment of seismic section showing examples of horsts & grabens features associated with normal faults in extensional stress regime. The horst is the up thrown and the graben is the down thrown block caused by relative movement between two normal faults (Image: courtesy of ONGC, India)

The gravity faults, in contrast, are due to deep-seated tectonic stress. Gravity faults can be categorised as synsedimentary, reactivated or post-depositional (younger) faults. The age, history and type of the faults can be easily studied in seismic from the pattern of fault throws and bed thickness variations seen in either side of a fault, the foot wall and hanging wall (Fig. 4.4).

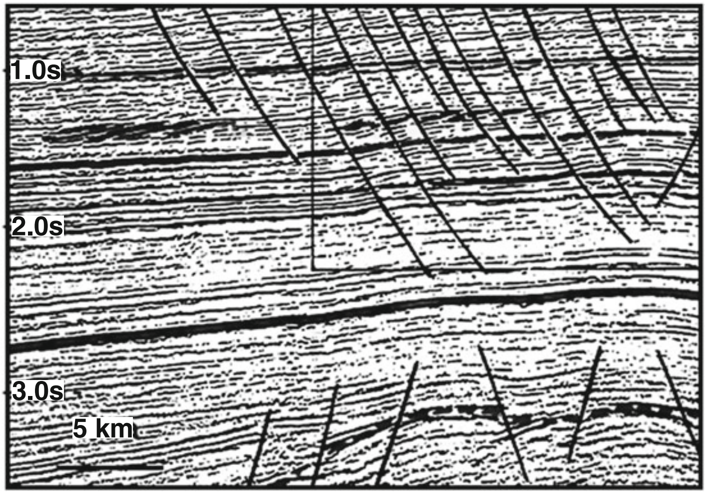

Fig. 4.3 A segment of seismic section showing an example of compaction faults. The compaction faults are rootless, post- deposition faults associated with extensional stress and are discernible in thick clastic sections. The faults originate in the shallow younger clastic sediments and die out downwards gradually without extending to deeper depths and hence called rootless (Image: courtesy ONGC, India)

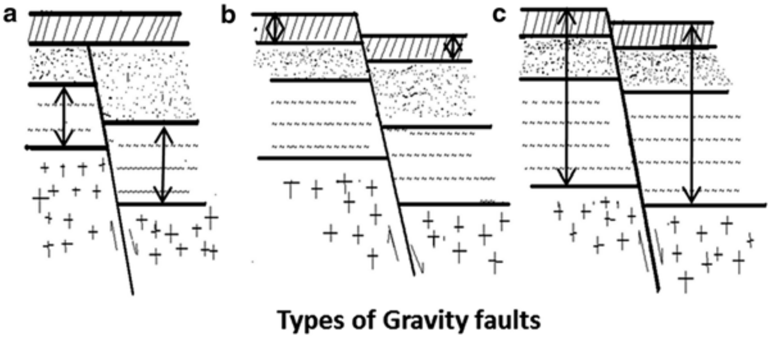

Fig. 4.4 A sketch illustrating types of gravity faults that are deep seated. (**a**) A syn-sedimentary fault is active concomitantly with deposition and shows greater sedimentary thickness on hanging wall compared to foot wall. (**b**) A reactivated fault is an earlier existing fault rejuvenated later affecting younger beds(hatched) that shows greater throw for the deeper beds (existing plus recent) than at the shallower level. (**c**) A post deposition fault occurs after deposition affecting all the beds and typified by similar throw (displacement) at all affected beds

Listric Faults, Growth Faults and Roll-Over Structures

The listric faults are rootless normal faults, discernible on seismic sections by their concave upward geometry and by a gradual decrease of dip with depth until they merge with the bedding plane. Growth faults are syn-sedimentary listric faults and are characterised by thicker sedimentary sections (growth) observed on the hanging wall (Figs. 4.5 and 4.6). It may be stressed that all listric faults are not growth faults. At times, intensive depositional load on the hanging wall of a growth fault leads to instability and subsequent gravitational sliding of sediments along the fault plane that results in roll-over structures, imaged as an antiform in seismic (Fig. 4.7). All growth faults, however, do not end up creating associated roll-over structures.

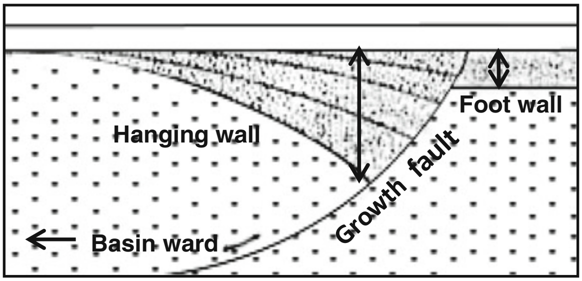

Fig. 4.5 A schematic illustrating growth fault which occurs in extensional regime. The growth faults are rootless syn-sedimentary listric faults with an upward concave geometry and progressively decrease in dip with depth until merging with bedding plane. The concave plane of growth faults face basin ward allowing sediments to pile more (growth) on the hanging wall block

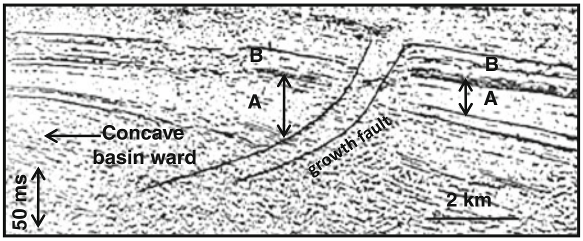

Fig. 4.6 A segment of seismic section as an example of a growth fault, characterized by increased thickness (growth) of bed 'A' on the hanging-wall with the concave plane facing basin ward. In contrast, note the near-similar thickness for bed 'B' on either side of fault suggesting reactivation of the fault after deposition of 'B'

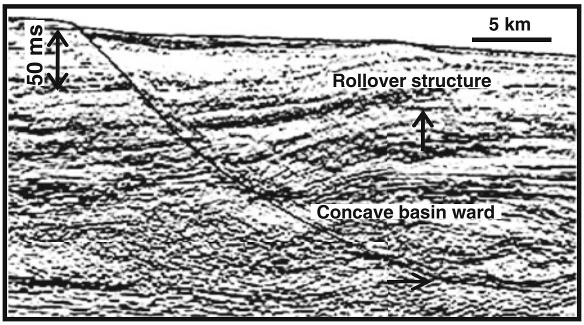

Fig. 4.7 A seismic segment showing an example of a 'roll over' structure associated with growth fault. Overloading on the hanging wall block leads to instability and sliding of sediments along the fault plane that causes the roll-over structure (Image: courtesy ONGC, India)

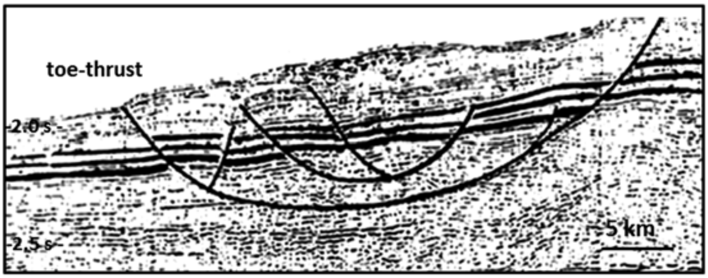

Fig. 4.8 A seismic segment showing an expression of a cylindrical fault which often occurs at slope margin. The fault is caused by excessive loading of finer clastics resulting in slope failure and attendent gravitational sliding of the sediments along the fault plane. The fault is often typified by small thrusts at the distal end (toe thrust) caused by resistance offered by the mobile shale mass (Image: courtesy ONGC, India)

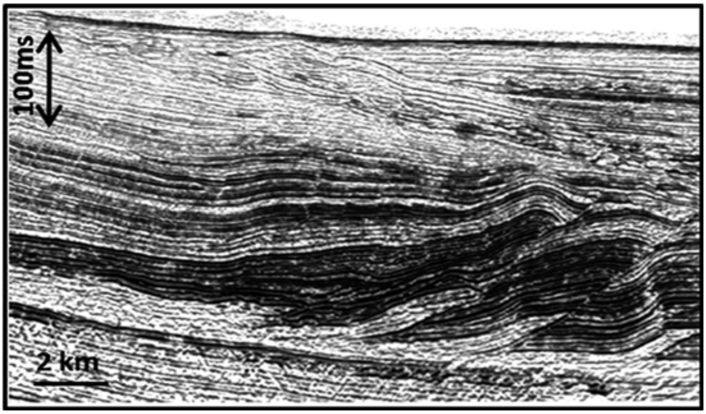

Fig. 4.9 A seismic segment showing an example of imbricate structures formed in extension regime. Gravity sliding of huge mass of mobile shale due to slope failure causes a buttressing force (compression) within the shale that results in forming imbricate structures. Also called “gravity tectonics” it must be distinguished from imbricates formed in compressional tectonics regimes (Image: courtesy ONGC, India)

Cylindrical Faults and Associated Toe Thrusts, Imbricates

The cylindrical faults appear commonly at basin slope margins and are caused by excessive loading of finer clastics on the slope (Fig. 4.8). This leads to slope failure with attendent gravitational sliding of mobile sediments along the fault plane, known as gravity tectonics. Often a common feature associated with this kind of fault is a thrust at the distal end of the fault. These kind of faults are known as *toe thrusts* which are caused due to the resistance created within the mobile shale mass. Intense gravity tectonics may also cause huge slides that can create *imbricates* clearly discernible in seismic dip sections (Fig. 4.9). It is important to differentiate these structures from imbricates that are formed in compressional regimes.

Structures Associated with Compressional Stress Regimes

Folds/Duplexes

The compressional folds are inferred from seismic by equal or larger time-intervals (thickness) seen at the crest compared to the flanks of structures (Fig. 4.10). This is in stark contrast to the expression of drape folds seen in seismic.

Reverse Faults, Thrusts and Overthrusts

The reverse faults and thrusts (low angle reverse faults) are deformations which may occur with or without involving basement. Low angle reverse faults are referred as thrusts and very low-angle thrusts are known as overthrusts. Where the thrust planes do not extend deeper and disappear in a basal bedding plane known as *decollement*. The term 'thin-skinned' tectonics is often used to describe such regimes (Fig. 4.11).

An important aspect regarding reverse faults and thrusts is the understanding of the phenomenon of relative upward movement of the block due to compression, which is called the *'vergence'*. The determining factors for *vergence* are the paleo-topography and pre-existing faults and weak zones in the rocks under stress (Fig. 4.12). For instance, it is difficult to determine the *vergence* in case of a flat sedimentary unit without existing fault when subjected to compression; where as, in the presence of a pre existing fault, it will result in an upward movement of the hanging wall block. *Vergence* can be easily inferred from the seismic sections that can help characterize the tectonic history to recreate the paleo structural configura-

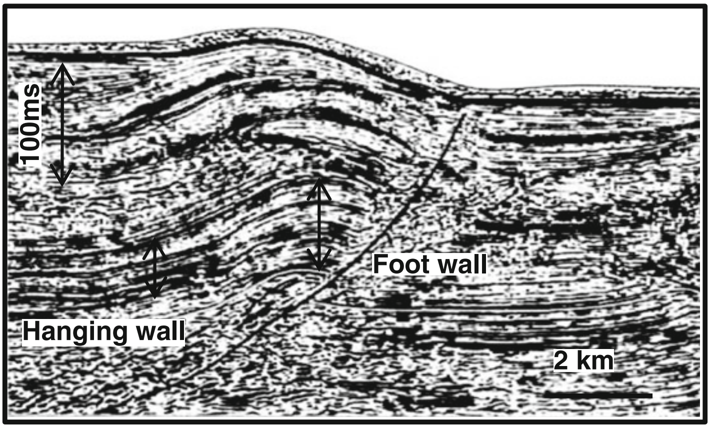

Fig. 4.10 A seismic expression of a fold and reverse fault associated with compression. The fold is characterized by greater thickness at crest of the fold than at the flanks (shown by *arrows*), in contrast to drape folds

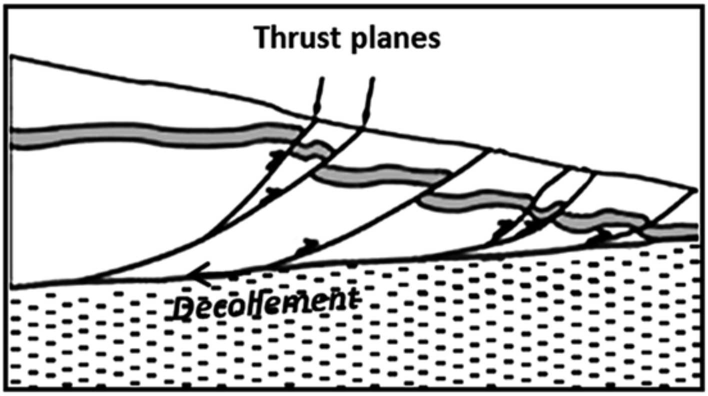

Fig. 4.11 A schematic diagram illustrating 'skin tectonics' in compressional regime. The thrust plane dips gradually lessen till they disappear in a basal plane, called the '*decollement*' and do not extend to depths (Adapted from Wikipedia)

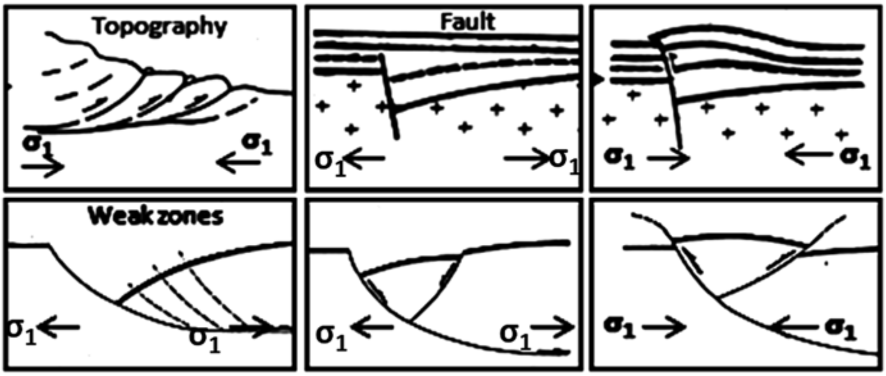

Fig. 4.12 A schematic illustrating '*vergence*' which is about relative movement of block under compressional stress. The displacement is linked to existing fault/weak zones of the rock or topography; the hanging wall always gets pushed up. The *arrows* and *symbol* σ_1 denote the principal horizontal stress axis

tion, an important factor in evaluation of hydrocarbon prospect. Understanding vergence also explains sometimes an apparently baffling situation for a beginner where seismic shows a fault as normal at deeper level but continues upwards as reverse fault at shallower levels. This is because the pre-existing normal gravity fault, reactivated under compressional stress, caused the hanging wall block to move up creating a reverse faults at younger levels but not as much moving up as to compensate for the throw of the normal fault at depth (Fig. 4.13).

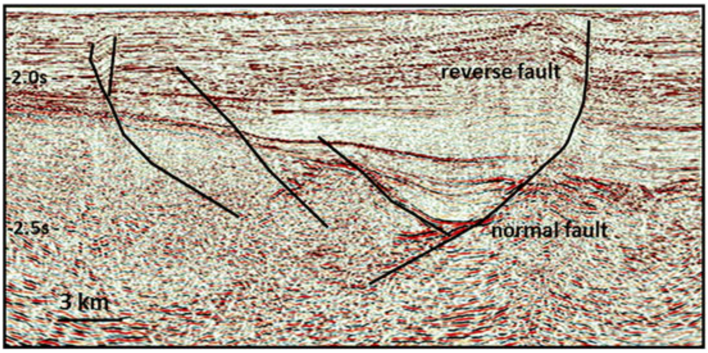

Fig. 4.13 A seismic expression of an existing normal fault which on reactivation in a compressional regime creates reverse fault at younger level. Under compression, the hanging wall moves upwards but not enough to negate fully the existing displacement of the normal fault (Image :courtesy ONGC, India)

Structures Associated with Shear Stress (Wrench) Regime

Wrench tectonics is caused by horizontal shear stress couples due to differential movement of deep crustal blocks. Stress couples can be divergent or convergent depending on the dominant stress component of extension or compression. The resulting structures may accordingly vary between the two extreme cases of wrench, the dominant extensional (transtensional) and compressional (transpressional) stress.

En Echelon Conical Folds

Compressional folds created at an inclined angle to stress orientation are known as conical folds, typical of wrench tectonics. The folds are often associated with high angle vertical faults that can be easily discernible in seismic sections (Fig. 4.14). On a seismic map the folds may be seen as a number of separate fold culminations, off-shifted spatially, in a pattern known as *en echelon* folds. The pattern of spatially off-shifted folds indicates the stress direction of the shear couple; called left lateral or sinstral (anticlockwise) if the folds shift progressively to right and dextral or right lateral (clockwise), where the shift is to the left (Fig. 4.15).

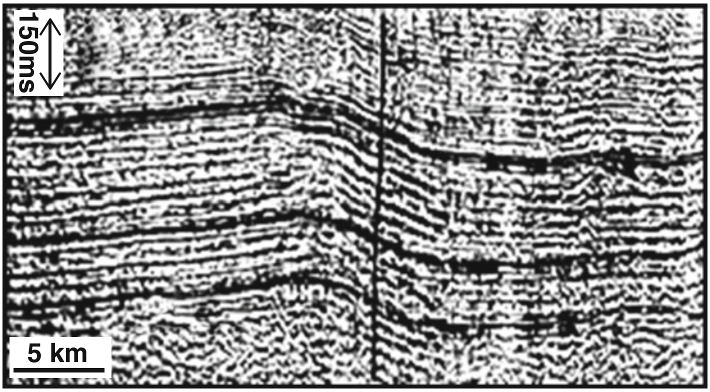

Fig. 4.14 A seismic expression of a fold structure with high angle fault associated with wrench tectonics (Image: courtesy ONGC, India)

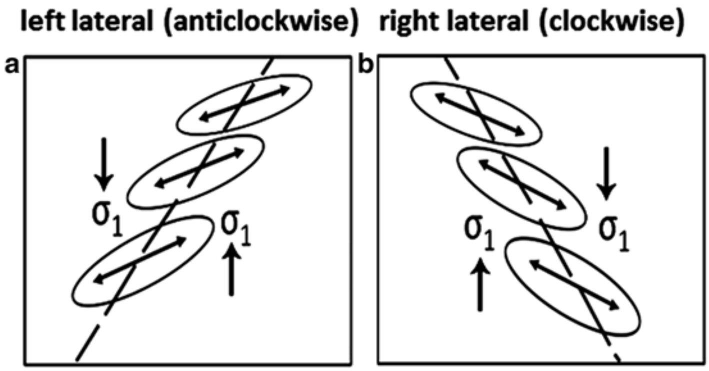

Fig. 4.15 A schematic illustrating wrench associated enechelon conical folds, evinced as off-shifted features in plan view. The pattern of lateral shifts indicate direction of wrench stress. (**a**) Folds shifted progressively to right indicate left lateral wrench and (**b**) shift to left indicate right lateral wrench

High-Angle Faults and Half Grabens

The high-angle faults with associated half grabens are often linked to divergent wrenching (Fig. 4.16). A half graben is a sag feature that forms against a major fault present only on one side unlike two faults on either side of a graben.

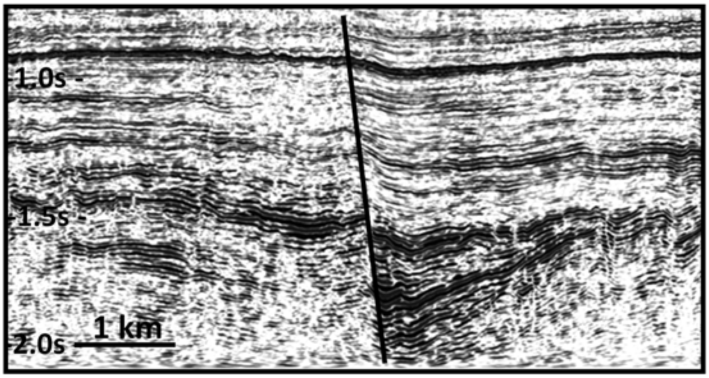

Fig. 4.16 A seismic expression of high angle near-vertical fault and half graben associated with wrench (Image: courtesy ONGC, India)

Flower Structures and Inversions

Flower structures are typically related to wrench tectonics and can be clearly seen in seismic sections. A positive flower is associated with reverse faults and a negative flower with normal faults depending on type of wrench, convergent (transpressional) or divergent stress (transtensional). Schematics for positive and negative flower structures (Fig. 4.17) and a seismic expression of a negative flower sometimes referred as 'inversion structure' are shown in Fig. 4.18.

Strike-Slip Faults

Strike-slip faults have considerable horizontal displacements compared to vertical, which often make them difficult to identify on conventional seismic sections. Nevertheless, strike-slip faults can be recognised in a plan view by the typical '*dog-leg*' pattern of mapped faults, which is characterized by a trend of spatially offset *en echelon* faults with cross faults joining them. The pattern also offers clues to shear stress direction as dextral (right lateral, clockwise) or sinstral (left lateral, anti-clockwise) depending on the direction of shifts of the faults (Fig. 4.19). In 3D high resolution volume seismic data, the strike-slip fault patterns and trends can be mapped precisely from seismic attributes through horizontal slices (see Chap. 10).

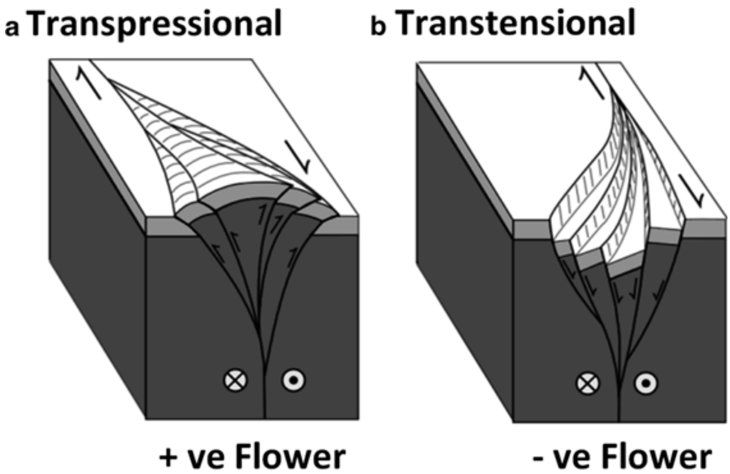

Fig. 4.17 Schematic illustration of Flower structures related to wrench. (**a**) Positive flowers are created with reverse faults associated with transpressional stress and (**b**) Negative flowers with near-vertical normal faults under transtensional stress (Adapted from Wikipedia)

Fig. 4.18 A seismic segment showing an 'Inversion' structure associated with wrench typified by a synform vertically overlain by antiform (Image: courtesy ONGC, India)

More seismic indications of wrench can be found in seismic maps from discordances seen in trends of features and contours (Fig. 4.20). Convergence of a high trend into low and vice-versa, anomalous juxtaposition of a high/low against a low/high feature across a fault, and sudden change in trends of contours are some of the distinctive evidences of a wrench stress. Sudden change or drastic deterioration of reflection events and/or their characters in the same or adjoining seismic sections can also be a strong clue to existence of strike-slip faults.

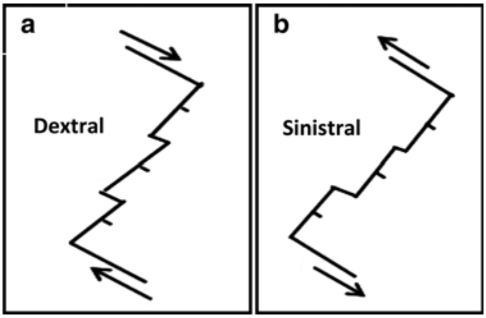

Fig. 4.19 A sketch illustrating the enechelon, strike-slip faults seen in plan view as laterally off-shifted faults (dog-leg). The lateral shift pattern indicates the shear stress direction (**a**) left shift implies the clockwise (dextral) and (**b**) right shift the anti clockwise (sinistral) stress

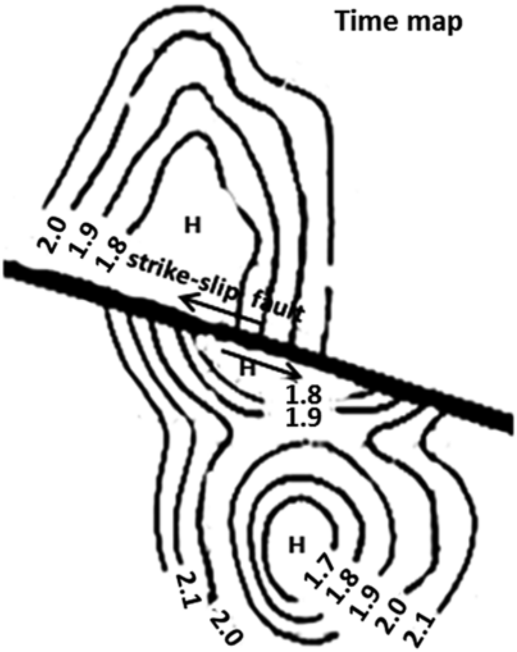

Fig. 4.20 An example of strike-slip fault as evinced in seismic map, plan view. Note the change in shape and shift in the position of the high across the fault due to strike slip fault. The *arrows* signify the wrench stress direction (dextral) (Modified after Moody 1973)

Salt/Shale Diapirs

As stated earlier, the diapirs (growth structures) are classically grouped under structures of extensional stress regime but are categorized here separately because of their typical manifestation in seismic, that of vertically piercing bodies within sediments. Explained simply, wide spread thick salts in a basin undergo plastic flow due to over burden load during sedimentation and forms diapirs. Mobile shales can also exhibit diapirism which makes shale and salt tectonics similar, the latter being characteristically more intensive in nature. Although shale and salt diapir geometries may sometimes look alike, they can be differentiated on the basis of seismic velocity, salt having a much higher velocity relative to the surrounding sediments than that of shale. The shale and salt diapirs are also linked to distinct geological environments, which can distinguish them by seismic stratigraphy studies and understanding of regional geology. The study of salt tectonics, which includes the process of salt flow and the resultant deformations creating salt structures, is known as *halokinesis.*

Salt Diapirs - Types

The salt diapirs can be categorised as syn-sedimentary or post-depositional like the faults, depending on the history of the growth. Syn-sedimentary diapirs grow concurrently with the process of sedimentation similar to that of a syn-sedimentary fault. If movement of salt occurs after deposition of sediments, the diapir is post-depositional.

Syn-sedimentary diapirs can be further categorised as intrusive when the growth remains below depositional level or extrusive when gets exposed at surface. Seismic manifestations in images of salt structures provide excellent clues to unravel the chronological history of these developments. Syn-sedimentary intrusive growths may be inferred from seismic by presence of associated drapes in younger formations (time interval thinning) of overlying strata (Fig. 4.21a). Extrusive growths, on

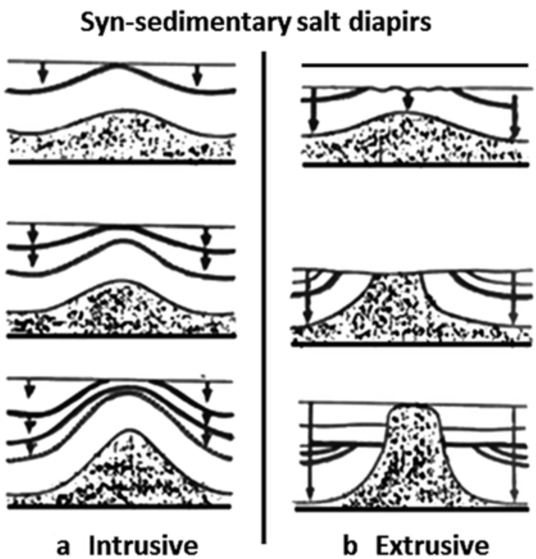

Fig. 4.21 A schematic illustrating syn-sedimentary growth of salt mass with continuing deposition of overburden sediments. (**a**) The intrusive diapir typified by drapes in overlying beds and (**b**) the extrusive diapir by presence of erosional unconformity with the near-flat younger strata terminating against the vertical diapir

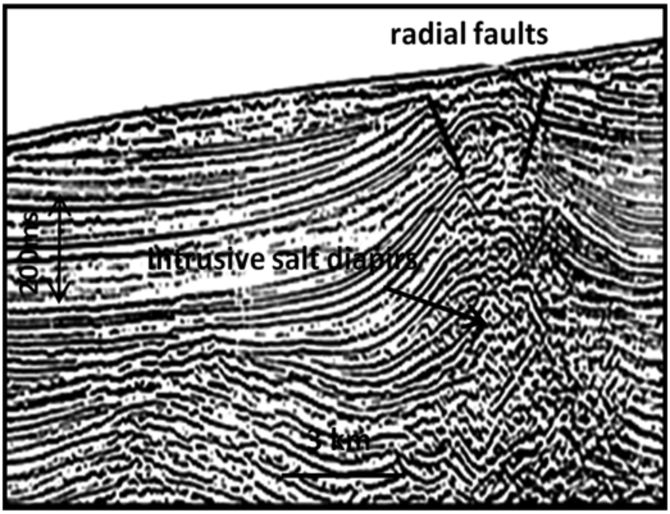

Fig. 4.22 A seismic expression of an intrusive salt diapir. The concurrently growing diapir without getting exposed to surface, builds up the stress which gets released by creating faults. Note the typical radial faults at top of diapirs

the other hand, are indicated by prominence of an erosional unconformity with near-flat younger strata terminating against the vertical growth (Fig. 4.21b). Often the most reliable diagnostic of an intrusive growth in seismic, is the presence of radial faults ('adjustment faults') at the top of the structure, which are caused due to release of accumulated stress stored during the growth (Fig. 4.22). In case of extrusive diapirs, no such faults may exist as the stress gets released due to erosion during its exposure at the surface.

Post-depositional diapirs, on the other hand, can be characterised by sharp upward drag of overlying strata caused by an upward piercing of the salt growth (Fig. 4.23), that occurs after the deposition of younger beds. Sometimes, '*flank synclines*' and '*turtle back*' features are also formed associated with salt diapirs (Fig. 4.24). These deformations are caused due to withdrawal of salt from the flanks that feed continuing growth of salt vertically. Two adjacent salt growths, fed by salt from their flanks, can cause a residual salt hump in the centre resembling a 'turtle back' (Fig. 4.25).

Synopsis of Significance of Seismo-Tectonics Studies in Seismic Data Evaluation

Analysis of tectonic stress regimes and their styles from seismic provides important insights into the genesis and chronological history of the associated structures, letting these to be correctly mapped and evaluated for hydrocarbon potential.

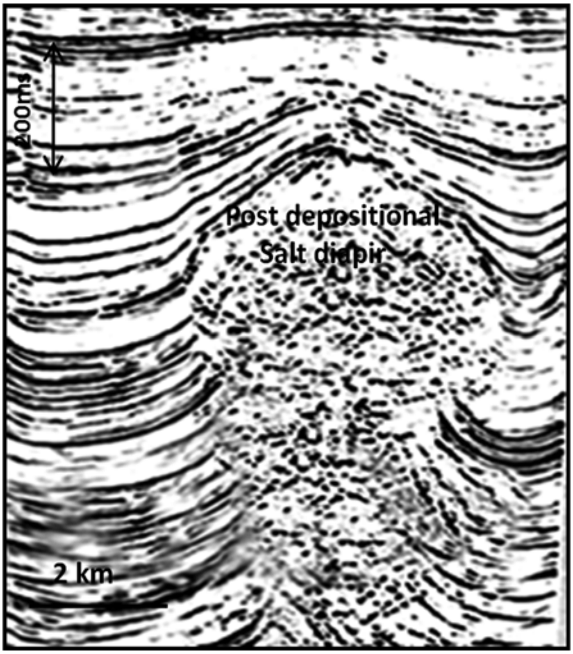

Fig. 4.23 A seismic expression of a post depositional salt growth triggered by overburden loading. Note the upward drag of the beds due to piercing of the salt diapir

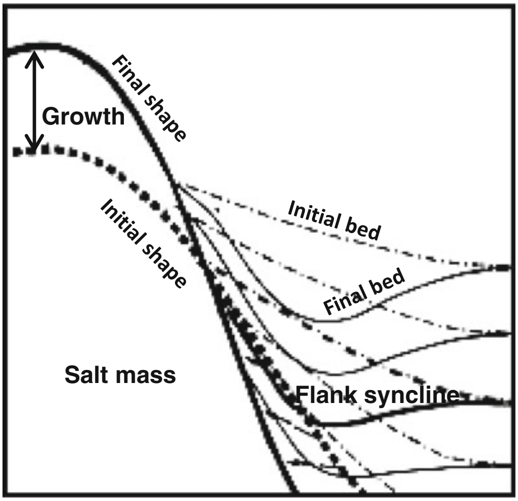

Fig. 4.24 A schematic illustrating continuing growth of salt causing related flank synclines. The growth (*arrow*) is fed by withdrawal of salt from flanks triggered by overburden pressure. Removal of salt from the basal part causes the overlying beds to collapse resulting in flank synclines

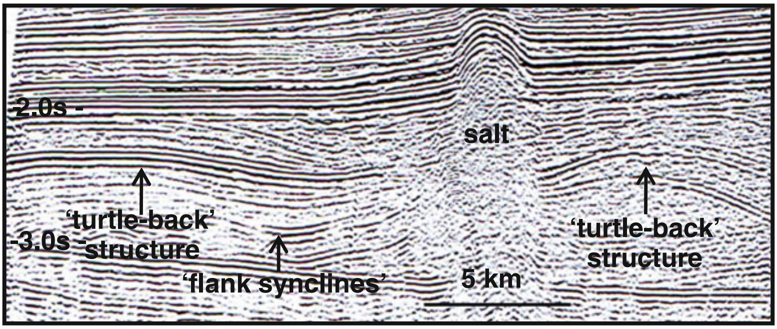

Fig. 4.25 A seismic segment showing salt diapirs and attendant structural deformations – the 'flank synclines' and the associated 'turtle-back' structures. Adjacent salt diapirs (not seen here) fed from their flanks, cause sags creating a residual salt hump in between resembling a 'turtle back' (After Anstey 1977)

Understanding tectonic history of faults is especially important in this context (see Chap. 5). Knowledge of types of faults, their hades and throws can provide valuable guidance for dependable correlation of seismic events across faults with apt sedimentary thicknesses inferred on both foot wall and hanging walls. Correlation though is the initial step in data interpretation, it is crucial to preparation of accurate seismic maps, which are the key inputs for estimating hydrocarbon volumes and deciding drilling locales. Understanding fault vergence from seismic also guides in reconstruction and balancing of sedimentary sections in complicated geologic regions.

Assimilation of tectonic styles and their architecture in an area, like depositional styles, can be also advantageous for comparisons with similar known basins elsewhere in the world and to facilitate better evaluation by drawing analogies. For example, recognising wrench tectonics in an area, can by itself, be a precursor to certain favourable aspects of petroleum geology associated with wrench. For example, long period, active basement fault systems in a wrench regime tend to provide conditions for differential block movements of varying degree with related sinking, tilting and rotation. This may create conducive situations for a petroleum habitat by providing connectivity between source and reservoir either laterally by juxtaposition or vertically through faults. Further, wrench related deformations are also likely to offer an assortment of interesting structural and stratigraphic trap plays suitable for hydrocarbon accumulation, enhancing hydrocarbon potential of a basin.

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Chapter 5
Seismic Stratigraphy and Seismo-Tectonics in Petroleum Exploration

Abstract Mutually integrated, the seismic stratigraphy and seismo-tectonics studies provide a highly effective technique, which may be considered indispensable in petroleum exploration. The conjoined analysis enables the building up of the basic tectono-stratigraphic framework for petroleum system modeling. Modeling helps evaluate potential of source generation, reservoir facies, and migration, trapping mechanism, accumulation and preservation for estimating hydrocarbon resource base for the basin. It also leads to the generation of hydrocarbon prospects that are evaluated for technical and financial risks before being drilled.

The synergistic analysis of seismic stratigraphy and seismo-tectonics for hydrocarbon accumulation, complimenting each other, is highlighted. As faults play major roles as conduits, seals, and leaks in hydrocarbon migration and accumulation, fault attributes analysis and its trap integrity is stressed.

Seismic stratigraphy and seismo-tectonics are highly effectual interpretation techniques, indispensible in the quest of discovering hydrocarbons. Mutually integrated, the techniques support understanding the evolution of geologic basins. They help in reliable evaluation of hydrocarbon potentials of plays and prospects for exploratory ventures. The studies are especially useful in virgin or least-explored areas, where well data do not exist or are fragmentary and inadequate. The degree of success, however, depends on the experience and skill of the interpreter in comprehensive understanding of fundamentals of tectonic styles and depositional systems. The entwined link played by seismic stratigraphy and seismo-tectonics in analysing the process of hydrocarbon accumulation is outlined.

Basin Evaluation

The seismic investigation through synergy of seismic stratigraphy and seismo-tectonics reveals the depositional and tectonic history of the sedimentary fill of the basin, allowing recognition and mapping of potential geological plays (leads) and their assessment for hydrocarbon exploration. Evaluation of a basin for hydrocarbon potential requires identification of its petroleum systems – a term used for the geologic elements and processes responsible for hydrocarbon accumulation. Four

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crucial elements define the petroleum system: (1) source and generation; (2) reservoir; (3) migration (pathways); and (4) entrapment and preservation. Each element is briefly discussed examining the role of seismic stratigraphy and seismo-tectonics in application.

Source and Generation Potential

The potential for hydrocarbon generation in a basin is assessed based on knowledge of amount of organic-rich fine clastics (shale), its organic content, kerogen type, burial history and thermal maturity. The geological environments linked to deposition of source rocks are known to include fluvial/lacustrine, deltaic, shallow marine and deep-marine settings. Seismic stratigraphy studies can identify the distribution and extent of these varied depositional environments and associated lithofacies, which indicate not only the presence of source rocks but also the type of organic matter (kerogen). The source potential can be assessed as oil or gas prone, depending on kerogen type linked to depositional environment as fluvial, deltaic or marine. Kerogen which comprises most of organic matter in sediments, characteristically exhibits low velocity and density and high porosity and kerogen- rich shales may be detected directly from seismic reflections like that of coal under favourable situations.

Tectonic analysis unravels clues to burial history of source rocks, useful in assessing thermal maturity to produce oil and gas at depths and also its expulsion. Consider, for instance, the geological implications of a syn-sedimentary normal gravity fault in the shelf margin, episodically active and for a long time. The seismo-tectonic analysis of the fault not only provides information on the increasing thickness of source rock (shale) on the basin side under anaerobic conditions, but also on its maturation history. The seismic can point out the details of the individual episodes of recurring subsidence with time that helps infer rate of subsidence and the depth attained during a geologic age. These are generally considered as factors favourable for potential source generation and maturation. Inferences of severely tectonised zones and volcanic activities from seismo-tectonic analysis can also offer valuable clues to geothermal gradients in the area in analysis for source maturation.

However, it may be noted that it is not the generation but the quantity of expulsion that is important as it decides the amount of hydrocarbon eventually captured in traps. The expulsion from source rock known as primary migration is believed by many to be a process triggered by high pore fluid pressure within it. As hydrocarbons are generated by thermal cracking of kerogen, the generated fluid tries to occupy larger volume than that of the original rocks. Rise in temperature with subsidence further increases the fluid volumes resulting in high pore pressures within the source and at some point of time the continuing increase in pressure causes micro fractures that facilitate expulsion of hydrocarbon. Each episode of subsidence, linked to seismic evidence, thus can be a clue to a new expulsion phase of hydrocarbons as the source continues to get buried under more and more layers of strata.

Reservoir Facies

Reservoir rocks with good primary porosity and permeability are commonly deposited on shelf and slopes associated with high energy fluvial/lacustrine, deltaic and shallow marine depositional environments. Reefal mounds also offer excellent porosities. Seismic sequence and seismic facies analysis of external forms and internal reflection configurations can identify reefs and potential high energy clastic reservoir facies as in delta lobes, fans, channel cut and fills. Tectonic stresses leading to uplifts, faults and unconformities often induce secondary porosities in the form of leaching, channelling, vugs and fractures, which enhance permeability and facilitate production. Seismic stratigraphy and seismo-tectonic analysis help identify the depositional and tectonic elements to evaluate reservoir facies and types and more importantly their distribution in the basin.

Migration

Hydrocarbon migration process deals with generation and expulsion from source rock to transmission through carriers and eventually to traps for accumulation. Thus, source-reservoir connectivity is required for hydrocarbons to migrate from source to trap. After expulsion (primary migration), the hydrocarbon continues to move up-dip in the porous and permeable rocks until it reaches the structurally highest part of a reservoir, where it gets accumulated in the trap (secondary migration), formed by surrounding nonpermeable rocks, called the seal. Expulsions from source may be upward or downward which determine the migration pathways and charging of traps located in the corridor (England and Fleet 1991).

The charging of hydrocarbon into a reservoir is facilitated by unconformities, faults and permeable beds, which are considered critical elements for migration. Comprehending migration pathways for charging of traps requires knowledge of carrier bed geometries with vertical and lateral permeability characters and paleodips in the subsurface at the time of hydrocarbon expulsion. Migration paths are not simple two dimensional paths as is often assumed by interpreters such as a fault connecting the source to reservoir above. Migration is a more intricate three dimensional process which is challenging to envisage precisely and can be dealt better by '3D basin modelling' (discussed later in the chapter).

Nonetheless, broad pathways can be conveniently predicted from seismic sequence and tectonic studies and paleostructural analysis. In simple systems, such as in a delta sequence where the delta-front sands are in contact with the pro-delta marine source rocks, migration and charging process is rather simple and straight forward as hydrocarbon expulsion charges the juxtaposed trap directly. Vertically stacked delta sequences, often with growth faults and roll-over structures, are considered highly potential exploration plays that can be recognized and evaluated from seismic stratigraphy and seismo-tectonics studies.

Timing of migration with respect to the presence of a trap is a key factor in the accumulation process. Hydrocarbon migration misses accumulation if the mapped trap was not present at the time of migration but formed later. Similarly a mapped paleo structure (trap) may have no accumulation if it has undergone distortions before time of migration. Since hydrocarbon moves up dip, it is also important to analyse the paleodips at the time of migration, together with presence of traps, to analyse migration pathways and accumulation. Seismo-tectonic studies comprehend chronological history and make it convenient to evaluate the 'timing' factor.

Entrapment and Preservation

Reservoirs need seals to trap hydrocarbons for accumulation. Impervious rocks such as shale or evaporites (salt), as well as some faults, commonly act as seals to form 'traps'. An assessment of the trapping mechanism includes evaluation of lateral and up dip seals for reservoirs, to act as effective traps for accumulation of hydrocarbons. While structural closures are generally considered as safe traps, stratigraphic and combination traps can be of varied types and need careful analysis of the trapping processes for their integrity to hold hydrocarbons. In this context, fault related and associated traps which are usually common can be risky and may demand rigorous attention. Faults play a very significant role in migration, sealing, accumulation and distribution of oil and gas and are briefly discussed later.

Preservation includes remigration, biological degradations and possible escape of accumulated hydrocarbons from the trap that are caused by diagenesis, faults, basinal tilts, and erosions. Particularly, post-accumulation rejuvenated and new young faults can play major roles in hydrocarbon redistribution and obscure understanding the mode of occurrence in the prospect with different hydrocarbon phases and fluid contacts. Hydrocarbon escaping to younger and shallower reservoirs from the main accumulation can sometimes be misleading as the explorationists may consider it as new found geologic target for pursuing future exploration and development. Seismo-tectonic studies provide the useful clues to evaluate properly the accumulation and preservation phase in a petroleum system.

Basin and Petroleum System Modeling

Basin evolution and evaluation for hydrocarbon potential is commonly carried out in an exploration stage to understand the hydrocarbon locales in a basin. With the advent of sophisticated softwares and fast computers, a unified geological modeling of petroleum systems and the tectono-sedimentary framework of a basin, known as basin and petroleum system modelling (BPSM) is in practice as the comprehensive model helps understand and predict hydrocarbon habitats better. Essentially, the model reconstructs the dynamic process of the hydrocarbon sequence chronologically – from generation to preservation. The geological and thermal evolution of elements like trap evolution, temperature and pressure history, and timings of generation, migration, accumulation and preservation of hydrocarbon in the basin/prospect are recreated through geologic time to reveal the hydrocarbon accumulation episode. The integrated basin model makes use of geological, geophysical and geochemical data and can be prepared in 2D or 3D mode. However, the migration process is a complex three dimensional problem and cannot be handled efficiently in 2D basin modelling.

The key geological parameters include crucial input from interpretation of stratigraphy and tectonics from seismic data- the tectono-stratigraphic frame work. Highly sophisticated recent 3D basin modeling softwares are capable of addressing the complicacies of modelling petroleum systems including simulation of hydrocarbon expulsion and accumulation. Nevertheless, the model predictions can sometimes be flawed as it depends on the exactness of data input to the model and is expected to be as good as the geological and seismic input- the basic tectono-stratigraphic framework, which to a large extent is the interpreted version with subjectivity. For instance, 3D modelling of an area may suggest a significant quantity of hydrocarbon generation and expulsion with abundance of reservoir and seal rocks, yet subsequent drilling of several wells may establish no sizable accumulation. The drilling results may prove the elements of the petroleum system that went into modelling as legitimate except for the key one, the timing; that is, the lack of harmonization between timing of the peak expulsion and that of the deposition of an effective cap rock to form traps in place, standing by, and awaiting accumulation.

Fault Attributes Analysis and Trap Integrity

Faults are known to play important roles as conduits, seals, and leaks in the migration, accumulation and (re)distribution of hydrocarbons and become an integral part of basin petroleum system modeling work flow. Critical analysis of fault attributes like type (stress genesis), throws, age and history from seismo-tectonic studies, allows their proper definition and mapping. This assists in investigating the likely role(s) played by faults in hydrocarbon accumulation, which can have significant influence on exploration and development of prospects. Fault properties have been exhaustively studied and modelled by several authors in different types of geologic settings to understand their role in hydrocarbon accumulation.

A fault, per-se, has no sealing properties, is neither an open conduit nor a leaky one. It is emphasized that the fault shown in a map may be considered as just a mere line of discontinuity indicating probable changes in the rock properties and in structural dips of the strata across it (Downey 1990). The migration and trapping at a fault depends upon the type of strata juxtaposed at the fault which needs analysis. For example, impermeable beds juxtaposed against permeable beds makes the fault act as lateral seal, whereas permeable beds coming in contact by juxtaposition, let the fault leak hydrocarbons (Allan 1989).

Tensional fault planes are often considered as pathways for hydrocarbon migration. The growth fault planes are mostly regarded as conduits at shallow depths, where they behave as open fractures and at greater depths, where buoyancy driven fluid enhances up-dip hydrocarbon movement. The co-joined permeable zones, present along the fault planes, facilitate migration from source to reservoirs (Downey 1990) as shown in Fig. 5.1. Buoyancy driven fluid in overpressures also enhances hydrocarbon movement along a fault. On the other hand, for a reverse fault in compressional regime, the fault plane may hardly act as open fracture and facilitate migration.

A fault acts as an effective up-dip seal of a trap where the throw is more than reservoir thickness so that nonpermeable rocks rest laterally against the reservoir (Fig. 5.2). However, faults commonly change throws along their length which can complicate the effective sealing process, especially in thin and multi-pay reservoirs. It is for this reason that the throws across faults need to be correctly estimated and represented by contours in the structure map (see Chap. 3). An elaborate approach to understand hydrocarbon migration and accumulation in fault-associated traps is by using an analytical technique known as 'fault-plane-mapping' analysis (Allan 1989). The analysis consists of mapping of strata juxtaposed across the faults three-dimensionally with appropriate structural dips to bring out the contact zones of permeable and nonpermeable rocks to judge the role of the fault.

Faults may be considered as seals where the fault planes comprise of impermeable rocks such as clays or cemented materials at the walls in the throw interval. Fault zones, especially of growth faults developed in clastic sequences of predominantly shales can cause smearing of the fault walls, isolating the permeable strata on

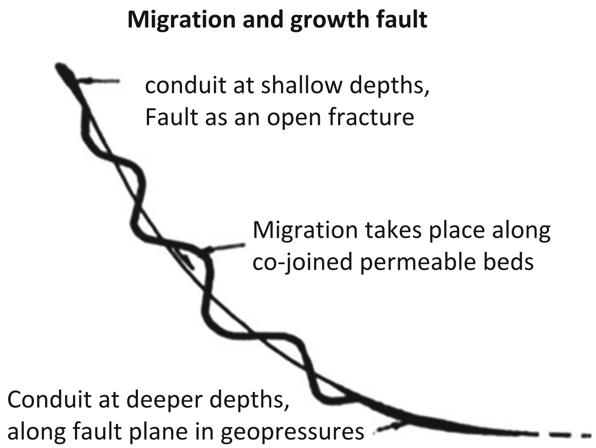

Fig. 5.1 A sketch illustrating hydrocarbon migration pathway along growth- fault. At shallow depths the fault plane behaves as open fractures and acts as conduit. At greater depths, growth fault augments upward movement of hydrocarbon due to buoyancy driven fluid under geopressures. Elsewhere, the co-joined permeable zones present along the fault plane facilitates migration (After Downey 1990)

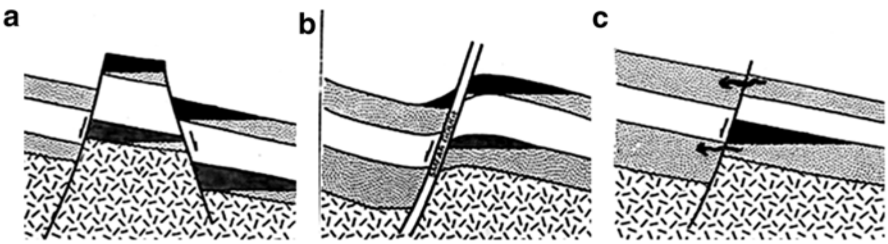

Fig. 5.2 Sketches illustrating fault properties. (**a**) Faults act as seal when the impermeable rock is juxtaposed to the reservoir, (**b**) faults occurring post entrapment may cause separate contacts in the faulted blocks when the fault plane gouge acts as lateral seal and (**c**) faults may cause hydrocarbons to leak partly or completely depending on occurrence of partial or no trapping due to permeable rocks set against reservoir (Modified after Harding and Tuminas 1989)

either side and termed "clay smear potential" of a fault (Doughty 2003). The behaviour of clay smears during the growth of a fault has important implications for fault seal analysis as its discontinuity over the prospect area can cause leaks. This may be hard to comprehend from seismic and quantitative fault seal prediction in the subsurface becomes a difficult task (Doughty 2003).

Similarly, granulations created along the fault surface during the tectonic stress can be cemented during diagenesis over a period of time to act as a nonpermeable plane. Big granules along a fault plane are known as 'fault breccias' where as the smaller ones are known as gouges. Quantitative analysis to estimate net shale content in a fault plane is useful in determining the efficacy of fault seal and is termed "Shale Gouge Ratio" (Freeman et al. 2008). Softwares are available to analyse sealing efficacy of clay smear potential (CSP) and shale gouge ratio (SGR) of faults but the results need calibration with subsurface data such as formation pressures and fluid contacts for successful predictions (Doughty 2003).

Occurrence of new faults or reactivation of old faults post oil and gas accumulations, may cause redistribution of trapped hydrocarbons differently in the reservoir, and in worst case scenarios, cause leaking of the entire volume of hydrocarbon, as in 'breached structure' (Figs. 5.3 and 5.4). Fault attributes revealed from seismotectonic evaluation further assist in proper reconstruction of the episodic stress and deformation history to assess precisely the timing of hydrocarbon charge and accumulation. For instance, a cursory interpretation of a growth fault affecting the entire sequence, on close examination of seismic stratal reflections, may unravel its episodic history as that of a cyclic growth punctuated by intermittent reactivations. It is vital to understand the genesis and age of faults affecting a prospect, with respect to the moments of expulsion, migration and accumulation of hydrocarbon, and as well to its status in the trap as pre-existing, concurrent or post-charge. This understanding is vital. Without it, one may be led to flawed evaluations of hydrocarbon prospectivity ending in an exploration debacle.

Fault analysis can also be important during development phase as its presence may impede flow continuity within the reservoir, leading to compartmentalisation of the field. Separate fault blocks may have separate fluid contacts that require more

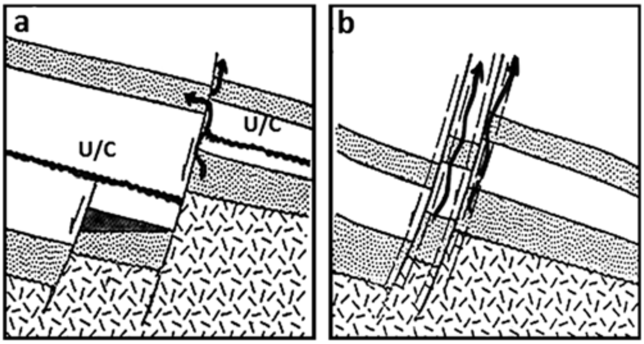

Fig. 5.3 Sketches illustrating role of faults occurring after hydrocarbon accumulation. Reactivation or generation of new faults (**a**) redistribute the trapped oil/gas in the shallower reservoirs or (**b**) facilitate escape of accumulated hydrocarbon (Modified after Harding and Tuminas 1989)

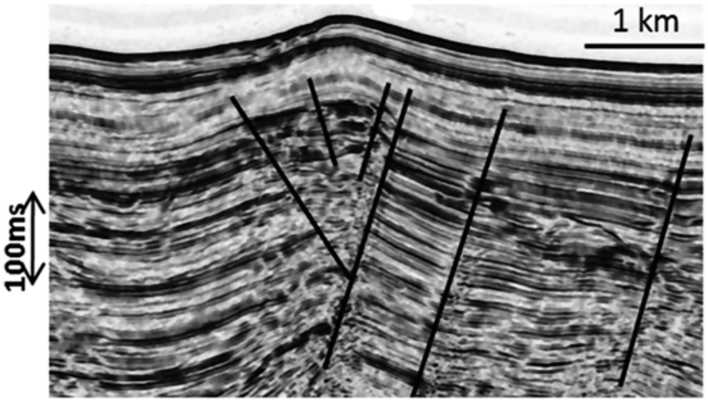

Fig. 5.4 A seismic segment showing an example of a 'breached' structure. Young faults occurring after accumulation facilitate escape of trapped hydrocarbon (Image: courtesy ONGC, India)

production wells to be drilled, increasing the operational cost. Stresses causing faults sometimes also induce fractures, which can augment porosity and permeability, and introduce elements of anisotropy in the reservoir, affecting production and water injection strategies.

Prospect Generation and Evaluation, Techno-Economics

After basin evaluation, detailed interpretation upgrades the identified geological leads and plays to firm up prospects for drilling. This is sometimes achieved through fresh evaluation of the existing data in the light of new geological findings from near by well in the area. Frequently, new and better close-grid seismic data in the area are acquired to support improved interpretation for prospects that have definitive hydrocarbon potential. The prospects are invariably assessed first for their probable commercial values before making a decision to drill. Prospect evaluation deals with technical and financial risk analysis – an exercise which proffers an estimate of profitability of the exploration venture in case of a hydrocarbon find. Clearly, the results depend to a large extent on reliability and probability of the geological parameters input from seismic analyses, as well as on other important factors like commercial, political, logistical and environmental. We shall, however, restrict discussions to technical (geological) risk assessment.

Vital evaluation parameters for a technical evaluation of a prospect include essentially aerial extent and amplitude (thickness) of the structure, the source type and reservoir facies, the seals and the entrapment mechanism to form an effective trap. However, a more significant point in the exercise, as discussed earlier, may be the assessment of the moment of trap formation with respect to the timing of hydrocarbon charge as well as post migration tectonics affecting accumulation. It may be stressed that comprehending the tectonics and its chronological history from seismic is extremely crucial for justifiable assessment of all prospective traps, like four-way anticlinal closures, fault-closures, wedges, primary stratigraphic and unconformity traps, for their disposition to charging, effectiveness of entrapment mechanism, and redistribution of hydrocarbon to establish the ultimate habitat.

Some of the critical geological parameters which play major part in risk evaluation linked intimately to financial consequences and drilling decisions are outlined. A few of these may be pertinent to later phases like appraisal (described briefly at the end) and production and may not be of immediate concern at this stage of exploration. Yet the evaluation of these factors to assess attendent risks may be made as it helps management to be aware of likely financial implications. Nonetheless, these points are touched to underscore technical risk evaluation in a wider perspective that is relevant to decision making process on future commercial and strategic plans in case of a discovery achieved. This is particularly applicable in situations where acreages and assets, offered on contract for exploration and development license, are to be geologically evaluated before taking important decisions to bid for entering into exploration agreements.

Type of Source

Forecasting the expected type of hydrocarbon find in the prospect is important as economics for gas and oil differ greatly depending on market, price and mode of transport etc. For a given prospect size, generally oil fields may need drilling of more production wells than that needed for a gas field. The capital and operational costs on engineering and infrastructures for developing a field varies with type of hydrocarbon and the future strategy may be guided by decisions depending on resources of a company.

Migration-Timing and Pathways

Source-reservoir connectivity and existence of trap at the time of migration is a prerequisite for accumulation which needs careful evaluation. In this context, presence of carrier beds, unconformity surfaces and faults acting as migration pathways, need to be carefully assessed for their uncertainty.

Reservoir Lithology (Clastic/Carbonate)

Clastic and carbonate reservoirs may have different development and production plans. The productivity and recovery varies with the type of reservoir, e.g. sand reservoirs generally have higher primary recovery of reserves in-place. Carbonate reservoirs, on the other hand, are more complex and heterogeneous in nature, often fractured and offer relatively lower primary recovery. Enhanced oil recovery (EOR) processes and their efficiencies vary greatly for the two types of reservoirs with sand reservoirs being generally more amenable to enhanced secondary recovery through water injections. Enhanced recovery in carbonates may also have the added risk of producing the dissolved H_2S gas in hydrocarbon (sour oil/gas) and being corrosive may need special processing that increase expenditures considerably.

Type of Traps

Traps can be structural, stratigraphic or a combination of the two and implicitly may be risked accordingly. For example, in a typical single-pay structural prospect, the hydrocarbon rock volume estimate may be relatively straightforward but may not be so easy in a multi-pay stratigraphic prospect due to uncertainty in disposition of number of reservoirs and varying thicknesses. Stratigraphic traps may also require stricter assessment of trapping mechanism and may be considered more risk prone. Structural prospect with several criss-cross faults may also need to be appropriately risked. As stated earlier, faults may compartmentalize the field needing more production wells and may also exhibit anomalous pattern of fluid flow during production, seeking new solutions that involve more expenditure.

Estimate of Hydrocarbon Volume

Estimate of hydrocarbon volume is the most important outcome, eagerly awaited, to be followed by financial calculations to assess cash flow for the company. Hydrocarbon pore volume is estimated by multiplying the likely hydrocarbon bearing area of the prospect with thickness, the porosity, and the hydrocarbon saturation. In structural traps, the hydrocarbon accrual depends on the spill point, controlled by top, bottom and vertical closure of the structure and on the hydrocarbon water contact. The volume of hydrocarbon-in-place (*volumetric*) gives estimate of hydrocarbon at surface by multiplying it with an appropriate factor. For oil it is known as the *shrinkage* factor as oil volume is reduced due to gas coming out of the solution when produced. For gas, it is the reverse; it expands in volume at surface and the factor is known as gas formation volume factor.

Since the estimates are based on reservoir parameters assessed from interpreted seismic maps and geologic prediction of petrophysical parameters and all of these have inherent uncertainties, it is likely to be highly influenced by technical subjectivity and the analyst's bias. Skill and experience of an interpreter only helps come out with a judicious realistic estimate of hydrocarbon volume in place.

After a discovery well, the work enters the appraisal phase, in which additional data are acquired – usually including drilling more wells – and analyses are conducted to manage and reduce the risks before making an investment decision to develop the prospect as a field. Synergistic study of seismic stratigraphy and seismotectonics, however, provides information at all phases, which is the key to assess hydrocarbon prospectivity sensibly. Seismic studies reduce uncertainties and help minimise exploration and production risk.

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Chapter 6
Direct Hydrocarbon Indicators (DHI)

Abstract The presence of gas in highly porous young sands significantly lowers the bulk modulus and typically creates high amplitude anomalies (bright spots) in seismic stack sections that make them direct hydrocarbon indicators (DHI). Though high amplitudes are more commonly a characteristic of gas, light and normal grade oil can also manifest high seismic amplitude responses. However, all bright anomalies may not be due to hydrocarbons and may need proper validation before drilling. Other related characteristics of gas reservoirs such as velocity and polarity, and associated phenomena such as 'flat spots', 'shadow zones' and time 'sags', manifested in seismic, can also act as indicators and may be considered for validating DHI amplitude anomalies for hydrocarbons. The genesis of high amplitudes is analyzed and DHI limitations outlined.

Seismic reflection amplitudes are produced as a result of contrasts in impedances that seismic waves experience at the subsurface rock interfaces A sedimentary rock may be defined by its composition, matrix, porosity and pore fluid, each of which influences elasticity property, which is a measure of rock compressibility. Gas is highly compressible and when present in rock pores appreciably lowers its bulk modulus, making it more compressible (compliant) than rocks saturated with fluids. This property is used as a good discriminator which often makes it convenient for detection of gas. Compliance of gas-saturated rock which considerably reduces the "P" wave velocity, under certain favourable geologic situations, causes significantly high amplitude seismic anomalies in clastic reservoirs. Because these high amplitudes indicate the presence of hydrocarbons in clastic reservoirs, they are termed 'direct hydrocarbon indicators' *(DHI)*. However, it may be stressed that all high amplitude anomalies may not be due to the presence of gas in the reservoir. As stated earlier, it depends on specific conditions and geologic settings. Other seismic attributes and phenomena related to gas reservoirs, such as velocity, polarity, '*flat spots*', '*shadow zones'* and time *'sags'*, can also be crucial indicators and must be considered when validating DHI amplitude anomalies for the presence of hydrocarbons.

High amplitude anomalies (DHI) mostly refer to gas saturated sands, and are characterized by distinctive seismic properties described later. Typically, the high amplitudes are due to reduction in impedance, caused by substantial lowering of bulk modulus of pore-fluid, as free gas is highly compressible compared to oil and

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water. Nevertheless, the presence of light oil in rock pores, may also manifest as high seismic amplitude responses similar to that of gas (Whang and Lellis 1988; Clark 1992; Bulloch 1999). This is believed to have been caused by lowering of compressibility due to the large quantity of gas dissolved in light oil, notwithstanding the reports that no such effect were established for gas dissolved in water (Gregory 1977; Wang 2001). Osif (1988) reported little to no effect of gas in solution on compressibility of water or brine. Experimental measurements by Liu (1998) showed a reverse trend, a slight increase in acoustic velocity of dissolved gas in water. Interestingly, Anstey (1977) stated very categorically that only free gas in pores can cause the lowering of compressibility resulting in high amplitudes and not dissolved gas.

But bright amplitude anomalies in conventional seismic stack sections linked to normal grade oil saturation have been observed and must be due to reasons other than solely due to pore fluid compressibility. A bright amplitude anomaly for a Pliocene sand at moderate depth located offshore India, tested normal grade oil which did not show any lowering of P-wave velocity (Nanda and Wason 2013). The oil sand P-velocity, in fact, was higher than the overlying shale, though the impedance computed was marginally lower due to a significant decrease in density of the sand reservoir.

As discussed in Chap. 1, rock and fluid properties such as texture, porosity, pore shape, fluid saturation, viscosity, pressure and temperature, all affect the elasticity and density of a rock in one way or the other, which consequently influence the seismic response. A change in property of any of the rock constituents, the matrix, the pore space or the pore fluid, will influence the seismic response. The DHI responses are influenced by bulk modulus of the rock, the pore fluids and its saturation, albeit to a much lesser degree by saturation. For example, a fully saturated oil sand may have a different response from that of the fully saturated water sand or from partially saturated oil sand. However, the effects due to changes of individual rock constituents are often interrelated and their interaction can alter the ensuing resultant seismic response. Some of the effects may be individually too small to be perceived in seismic, but a few of them added together can create a discernible change in seismic. Predictably, the seismic responses can vary widely depending on the geology of the area which fundamentally controls the rock and fluid properties. Varied depositional scenarios can have a dramatic effect on the compressional velocities of rocks and eventually on the seismic response for the DHI signature to differ greatly. Such responses are modelled by Wandler et al. (2007).

Another interesting phenomenon that merits mention is the seismic response influenced by impedance contrast between fluids at the contact, such as gas-water, gas-oil and oil-water, that provides DHI clues. Such responses usually exhibit flat spots and are primarily linked to contrasts in density and modulus of the fluids present in reservoir. Expectedly, ‘flat spots’ corresponding to the gas-water interfaces, having significant fluid density contrast, are noticed more prominently than the oil-water interfaces, especially in thick reservoirs as demonstrated by Schroot and Schüttenhelm (2003). Though oil and water, often exhibit near similar acoustic impedance, an oil-water contact may be imaged by seismic under favourable conditions. For instance, light oils can have large quantities of gas absorbed under pressure in insitu reservoir condition that can affect their moduli and densities and cause adequate contrasts at oil-brine contacts for producing flat spots.

DHI Amplitude Anomalies

Three types of amplitude anomalies are generally known to manifest in normal stack seismic sections, associated with gas saturation in a reservoir – the bright, dim and the flat spots.

Bright Spots

Bright spots are strong amplitude anomalies with negative reflection coefficient (−ve R_C), and are mostly linked to gas in sand reservoirs, capped by shale. In geologic scenarios where water-saturated rocks have velocities and densities, (e.g. 2300 m/s, 2.2 g/cm^3) close to that of overlying shale (e.g. 2100 m/s, 2.3 g/cm^3), reflections will show weak amplitude due to the marginal positive impedance contrast (+R_C). When the sand is saturated with gas, the velocity is considerably reduced (e.g., to 1600 m/s), causing a significant negative contrast at the interface (Fig. 6.1). This results in creating bright amplitude at the top of the gas-sand. Following the schematic example further, in the presence of a gas water contact, the shale and water sand interface on flanks will be represented by a weak reflection with positive polarity (+R_C), where as, in contrast, the gas reservoir at the crestal part, above the contact, will provide bright reflection with reverse polarity (−ve R_C). A seismic expression of a bright spot for an oil sand is shown in Fig. 6.2.

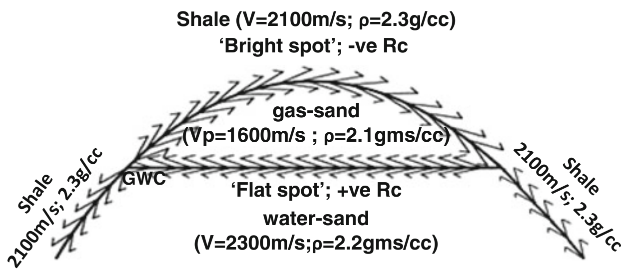

Fig. 6.1 A model illustration of DHI 'Bright spot'. Gas sands due to −ve impedance contrast with respect to the overlying shale are indicated by high amplitude and negative polarity at the crestal part. On flanks of the structure it changes to weak amplitude, positive reflectivity caused from contact of shale and water sand. The *arrows* to *left* indicate trough (negative Rc) and *right* as peak (positive Rc)

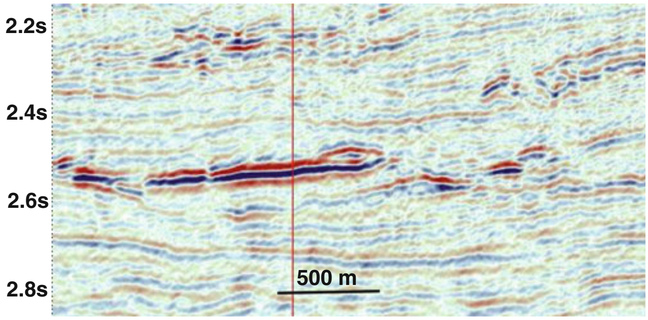

Fig. 6.2 A segment of a seismic section showing an expression of 'Bright Spot'. Bright amplitudes and negative polarity of the reflection from top of gas sand characterize the DHI. Base of gas sand is imaged as high amplitude but with +ve polarity (Image: courtesy ONGC, India)

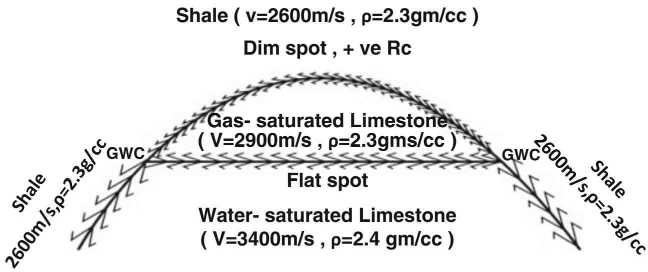

Fig. 6.3 A model illustration of 'Dim spot' in limestone and a 'Flat spot'. Gas in limestone lowers the positive impedance contrast and causes 'dim spot', an anomaly with weak amplitude and positive polarity at the crest. Reflections from contact of shale and water saturated limestone, on flanks, indicate positive polarity and much higher amplitudes compared to the crestal part. 'Flat spot' is a reflection at the fluid contact due to density contrasts between gas and water and has positive polarity

Dim Spots

Dim spots are weak amplitudes with a positive reflection coefficient, linked to mostly gas in carbonate reservoirs. Water saturated limestone generally demonstrates much higher velocity (~3400 m/s) than that of the capping shale (~2600 m/s) and shows high reflection amplitudes with positive polarity (+ve R_C). Impregnated with gas, the velocity of the carbonate rocks is greatly reduced (e.g. 2900 m/s), which decreases impedance contrast and creates reflections at carbonate reservoir top with weak amplitudes, as illustrated in the diagram (Fig. 6.3). The reflection coefficient, however, remains positive. The seismic image for a dim spot is exemplified in Fig. 6.4. Dim spots though are commonly associated with gas saturated carbonate rocks, can also be associated with sandstone reservoirs. High-impedance older

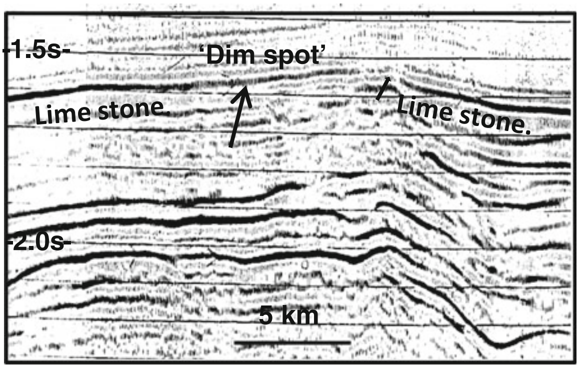

Fig. 6.4 A segment of seismic section showing an example of a 'Dim spot'. Gas in limestone lowers the positive impedance contrast with overlying shale and causes weaker amplitudes with positive polarity. Note the high reflection amplitudes from shale and brine-filled limestone contact on flanks (Image: courtesy ONGC, India)

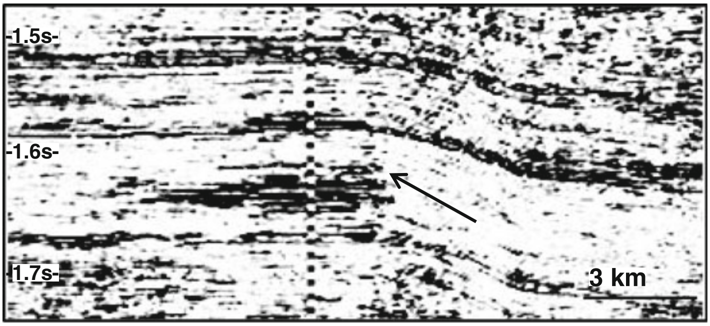

Fig. 6.5 A segment of seismic section showing n example of 'flat spot'. Flat spot is typified as a horizontal reflection event caused by density contrasts between gas/oil and water at the contact in a reservoir. OWC is imaged as positive polarity event and the amplitude depends on degree of contrast in fluid density. Note the contact, aptly located at the crest of the structure (Image: courtesy ONGC, India)

sandstones having higher velocity (e.g. 3400 m/s) and capped by shale, of lower velocity (~2800 m/s), when saturated with gas cause dim spots.

Flat Spots

Flat spots are moderate to high amplitude, horizontal reflections that are associated with gas water contacts and show reflections with positive polarity (Figs. 6.3 and 6.5). This is a unique case where the reflection is not related to lithology but to fluid contacts, and the impedance contrast being influenced by fluid density of gas and

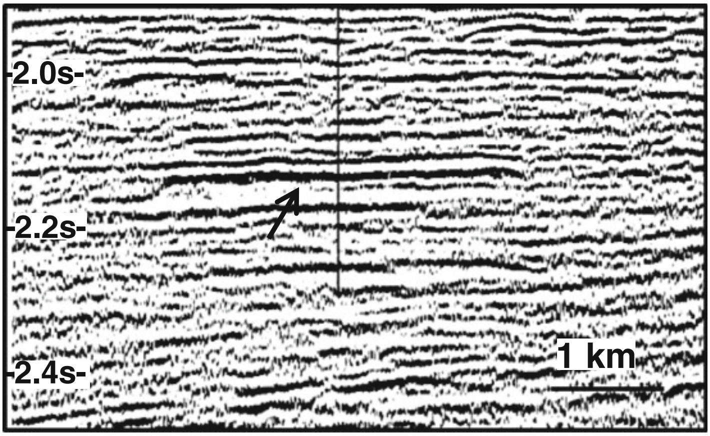

Fig. 6.6 A segment of seismic section showing an example of a pseudo 'flat spot'. The high amplitude, flat reflection with positive (peak, *black*) polarity, on drilling, turned out to a near-horizontal brine saturated Oligocene sand (Image: courtesy ONGC, India)

water. However, a localised, near horizontal, water saturated sand may sometimes also show flat spots. One such flat positive reflection with bright amplitudes, inferred as a flat spot, on drilling turned out to be spurious, as water saturated sand (Fig. 6.6). Fluid contacts, however, need not always necessarily be horizontal being dependent on hydrodynamic conditions; consequently, a genuine contact seen as a slant but positive reflection within a trap may be overlooked.

Amplitude anomalies are known to occur due to several other reasons such as lithology changes, reflector geometry, thin-bed tuning effects, propagation effects, interference of reflections, and noises. Consequently, amplitude alone cannot always be considered a decisive criterion to indicate hydrocarbon. Other supportive criteria are therefore necessary to authenticate the DHI anomalies before drilling for gas.

Validation of DHI Amplitude Anomalies

Velocity

Significant lowering of interval velocity due to gas in a reservoir may be detected from analysis of seismic NMO (normal move out) velocities. Lowering of P-velocities combined with high amplitude anomaly studies, acts as better criteria for detection of gas. However, conventional interval velocity computations require reflections from top and bottom of the reservoir. The top or bottom reflection in many instances may fail to be resolved if the reservoir is not thick enough or the impedance contrasts with rocks above and below are weak. For example, for fining upward channel sands, the top contrast may be gradual and may not evince a reflection, even though the discrete bottom may show the reflection well. Similarly, for a bar sand, the top may be imaged well but not the bottom as the contrast is gradual. Also, the computation of interval velocity from NMO is highly sensitive to interval thickness and can be often flawed in case of thin reservoirs. Further, the velocity lowering can also be due to other reasons; e.g., change in lithology (shale) and presence of fractures.

Polarity

DHI anomalies, as stated earlier, are explicitly associated with distinct reflection coefficient criteria: 'bright spots' with negative polarity and 'dim' and 'flat spots' with positive polarity. The polarities thus are reliable indicators of reservoir lithology, fluid and contacts. A high amplitude reflection of negative polarity abruptly reversing to positive can be a strong evidence of up-dip gas sand watering out down-dip (Fig. 6.7). Though, determining polarities of DHI amplitude anomalies is extremely crucial, in practice it is often difficult to precisely estimate the true polarity. Limited seismic band-width, interference of reflections and presence of noises affect estimation of true polarity.

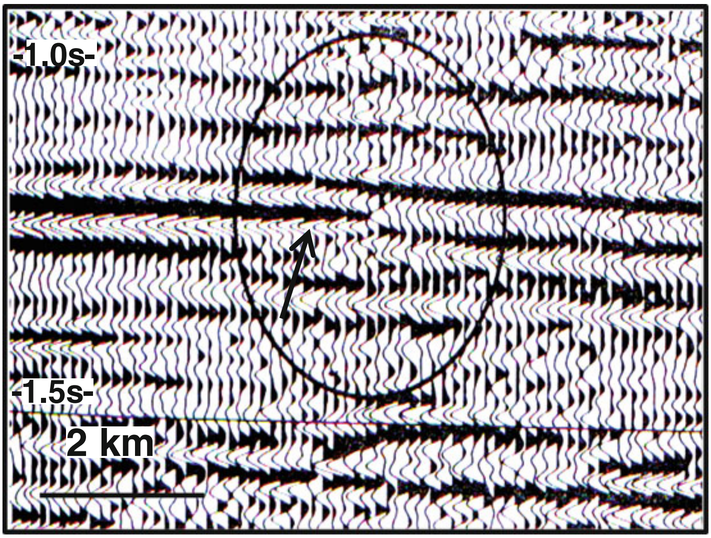

Fig. 6.7 A segment of seismic section showing an example of DHI validation by polarity. Reflection from top of gas-sand (trough, negative Rc, high amplitude) reversing to positive polarity (peak, weak amplitude), due to gas sand changing to brine saturated sand down dip causing high impedance contrast with shale. (After Anstey 1977)

'Sag' Effect

Velocity lowering due to gas in a reservoir can create artefacts below it. In case of a thick gas reservoir, arrival times of reflectors below will be delayed and may indicate a local depression, vertically below the gas zone. This is called '*sag*' or '*pull-down*' effect which is exemplified by synthetic response and actual field seismic (Fig. 6.8).

Shadows

Low-frequency shadow zones below 'bright spots' are at times observed and believed by some due to absorption of energy by gas in the reservoir. The absorption phenomenon in gas has led to significant and wider geologic connotations in exploration applications. Techniques are developed based on energy attenuation studies for direct detection of hydrocarbons by studying amplitude spectra for decay of higher frequencies. This is known as "sweet spot" analysis, where the absorption is mathematically determined as the amplitude divided by square of frequency (see

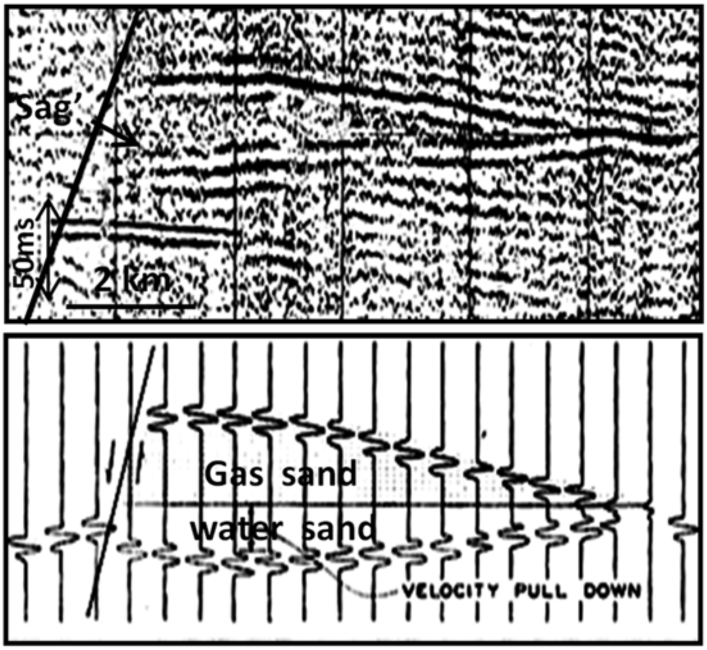

Fig. 6.8 A DHI validation by modeling. The 'pull-down' or 'sag' seen below the gas sand reservoir (*top frame*) is inferred as caused by low velocity due to gas. Validation is done by modeling (*bottom*) the gas sand which supports the inference. (After Anstey 1977)

Chap. 1). Another application of this technique is for the differentiation of faults as open or closed, as reported by Strecker et al. (2004). High energy absorption along fault planes, studied from amplitude-frequency spectra in successive time windows, as a function of travel time, signifies open fractures that help hydrocarbon migration and accumulation and improved permeability. Low energy attenuation, on the other hand, would imply cemented fault planes indicating sealing faults.

But gas is considered a slushy material and is unlikely to cause substantial friction for loss of energy that can be perceptible in seismic (Gregory 1977; Anstey 1977). However, partially saturated hydrocarbon reservoirs are reported to show some degree of absorption loss. Nevertheless, substantial absorption of energy in gas to form shadows below remains a contentious issue. Despite several explanations, none seems good enough to explain reasonably the low-frequency shadow zones (Ebrom 2004). Extensive studies by Ebrom, nonetheless, have identified the likely mechanisms for such phenomena based on numerical forward modelling. This includes the study of type of reservoir rock matrix with high absorption factors and CDP stack-related problems during data processing that leads to loss of high frequencies. Improper stacking, inappropriate deconvolution and velocity picking (Anstey 1977) and inefficient migration can result in low frequency reflections. Low frequencies can also be caused due to transitional nature of the reservoir reflector and also due to transmission losses in a thick formation consisting of multiple thin gas reservoirs with alternating signs of impedance contrasts (see Chap. 1). According to Anstey (1977), the low-frequency tail by itself may not be a hydrocarbon indicator.

However, since many gas reservoirs do not demonstrate low-frequency shadow phenomenon, it may be surmised that gas-linked absorption cannot be the sole reason. Other factors such as the reservoir rock type, presence of multiple thin gas units, vertical heterogeneity in facies and interference of multiples from thin beds may account for the shadow phenomenon.

Limitations of DHI

Though the DHI attributes appear simple, they are often not easy to estimate from seismic, due to inherent limitations. Volcanic sills, streaks of calcareous sands, coal beds, over pressured sands and shales, thin-bed tuning and digenetic rocks are all potential creators of bright and flat spots. The key validation factor is the polarity which is unfortunately often hard to determine correctly. An interpreter may have to consider all available seismic evidence for an integrated analysis to authenticate the DHI anomaly as a justifiable hydrocarbon prospect for drilling. It is also equally important to evaluate the prospect in the context of the overall geological perspective in the area for reduction of exploration risk. The seismic validation and the geological play assessments must be mutually compatible before taking a drilling decision. A DHI anomaly, duly validated by geophysical means, but without any geological likelihood of its association with a trap may have to be cautiously cast off. For instance, high amplitudes (bright spot) at the flanks instead of at crest of a structure or flat reflections (flat spot) seen in a trough can be considered as suspects, unless a geological case can be made for the type of stratigraphic trapping.

Even though the high amplitude 'bright spot' anomalies, are accepted as the most common yardstick for gas indication, they cannot be generalised. The high amplitude anomalies may only appear under certain favourable geological conditions, specific to an area. For an eligible classical 'bright spot' anomaly to materialize in seismic, a typical clastic depositional environment is a prerequisite where preferably the reservoir sand is highly porous and unconsolidated, capped by shale to create a significant negative impedance contrast. Mio-Pliocene and younger sands occurring at relatively shallow depths and exhibiting low impedances commonly qualify the best to meet the ideal geological conditions to create DHI anomalies. Nevertheless, different geological settings may have varied lithofacies and diverse impedance contrasts, which will eventually determine the nature of amplitude anomaly. In this context, it may also be stressed that the rock properties of the shale overlying the reservoir (usually the crux of the study) needs to be closely investigated as it can have a wide range of varying properties in different basins, capable of causing varying types of DHI anomalies. Shales, especially at shallow depths, are also known to exhibit significant anisotropy at times, which can further complicate the issue.

To offset the problem of false amplitude anomalies misleading as an indicator of gas, more sophisticated techniques such as, AVO (amplitude versus offset), shear wave analysis and inversion techniques are developed to substantiate the prospects and reduce risk. These techniques are briefly discussed in Chaps. 9, 10 and 11.

One of the major shortcomings of exploration by DHI approach is the estimation of gas saturation in a reservoir from seismic response, as a gas saturation of as low as ~10 % tends to show similar responses as increasing saturations up to 100 %. This is because in general, the rock compressibility does not perceptibly change with higher gas saturation. Consequently many wells drilled based on amplitude anomalies though resulted in gas finds, were of too low saturations to be commercial.

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Chapter 7
Borehole Seismic Techniques

Abstract When seismic waves are recorded using geophone(s) in a well with the energy source at the surface, the survey is referred to as a well seismic survey and when the seismic waves are recorded using geophones in one well and the energy source in another nearby well, it is referred to as a cross-well survey. The well seismics include surveys known as check-shot and VSP and provide the all important measured true velocity, essential for time- to -depth conversion and seismic calibration. Cross well survey based on tomography, mostly used in monitoring EOR sweeps is very briefly touched.

Different types of VSP and their benefits are outlined with stress on seismic calibration through corridor stack. The difference between the check-shot and VSP surveys and distinction between VSP well (seismic) velocity and sonic velocity are pointed out. Shortcomings of check-shot and VSP velocity surveys and ways to check these are suggested.

Borehole seismic deals with the recording of seismic waves using geophone(s) in a well and the energy source either at the surface or in the well. The former layout of source and detector is commonly known as *well seismic survey* and the latter as *cross-well survey*, which is discussed briefly at the end of this chapter. In well seismics, there are two types of surveys, *check-shot* and *vertical seismic profile* (VSP).

Check-Shot Survey

The check-shot survey, also known as well velocity shooting, is conducted to measure the true average velocity needed for converting recorded reflection times to depths of geologic formations. With a source firing at the surface, it records the first arrivals of direct waves (the first breaks) by deploying geophones in the well, placed at different depths, usually at irregular and at large intervals. The energy source is placed as close as possible to the well-head of a vertical well (without any risk to the well), so that the ray path travels straight down to geophones measuring the true vertical velocity. In the case of a deviated well, the source to receiver travel path becomes slant and needs a simple correction of cosine factor for conversion of

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drilled depth to true vertical depth to provide the true velocity. The receiver depth spacing in the well is chosen with the geophones placed preferably close to the major litho-boundaries to provide the formation velocities accurately. The spacing is commonly irregular and random, typically 75–150 m (Brewer 2002), depending on a trade-off between precise velocity measurements at more depth points and the additional cost incurred because of required increase in rig-time.

Direct travel times of seismic waves from the surface (source) to the geophones in the well provide accurate measurement of true average velocities at the receiver depth points. A graph, plotted with first arrival time recorded at the geophone versus its depth (T-D curve), provides the true average velocity function, which is the key requisite for crucial conversion of seismic times to geologic depths. The check-shot data, besides being useful for time-depth conversion, also plays a significant role in correcting sonic velocities which are used for preparing synthetic seismograms or continuous velocity logs (CVLs) to calibrate seismic. Constrained by check-shot, the corrected sonic velocities offer accurate estimation of interval velocities for thin formations which is not doable in check-shot survey due to time and cost constraints. Sonic velocities need correction as these are generally found different, from seismic velocity due to several reasons, some of which are briefly outlined later in the chapter.

Vertical Seismic Profiling (VSP)

Vertical seismic profiling is similar to a check-shot survey but is a more evolved and advanced technique meant to offer solutions to diverse problems in hydrocarbon exploration and production. The VSP records all seismic arrivals, the direct, the reflected and the multiples by geophones in a well, placed in a vertical array of short regular interval. A simple VSP geometry in a vertical well is shown in Fig. 7.1. However, several other types of VSP geometries can be designed for use in both vertical as well as in deviated and horizontal wells depending on the objective. The types of VSPs commonly used in vertical wells are relatively simple and are briefly described below.

In contrast to check-shot recording of first arrival data arbitrarily with relatively large and irregular spacing, the VSP technique samples all arrivals at a uniform and shorter spacing (~15–30 m, Brewer 2002), for better accuracy. The VSP geometry allows the recording and processing of not only the down-going direct arrivals (first breaks as recorded in a check-shot survey) but also the useful later arrivals of upcoming reflections from all the subsurface rock interfaces below the recording geophone depth in the well (Fig. 7.2). The down going waves directly recorded at the geophone, in addition to providing the true overburden (average) velocity, gives valuable information about the initial wave shape of the source wavelet and its progressive change with depth during propagation (due to attenuation). Analysis of the changes in shape of the down going source wavelet captured at each depth point leads to an understanding of attenuation and anisotropy present in the subsurface at

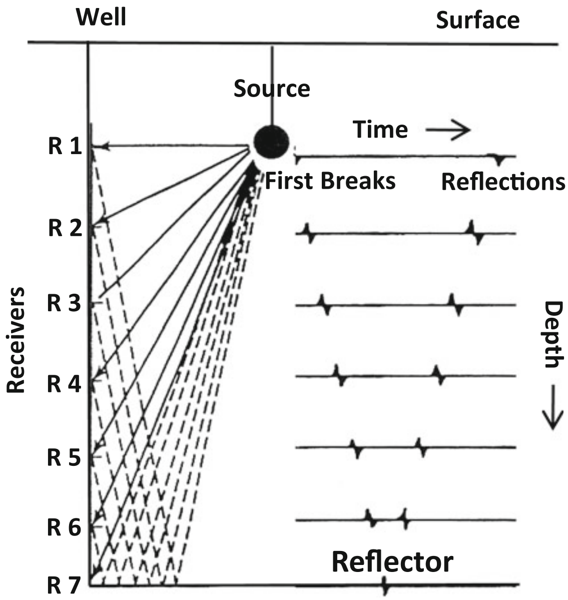

Fig. 7.1 Diagram illustrating VSP survey lay-out. Geophones (R1, R2, …) are placed in the well with regular and close spacing. The *solid lines* stand for 'first break' direct arrivals and the *dashed lines* for up-coming reflections from a horizon. Panel in the *right* shows the arrivals as recorded (Modified after Fig. 5 of Balch et al. 1981)

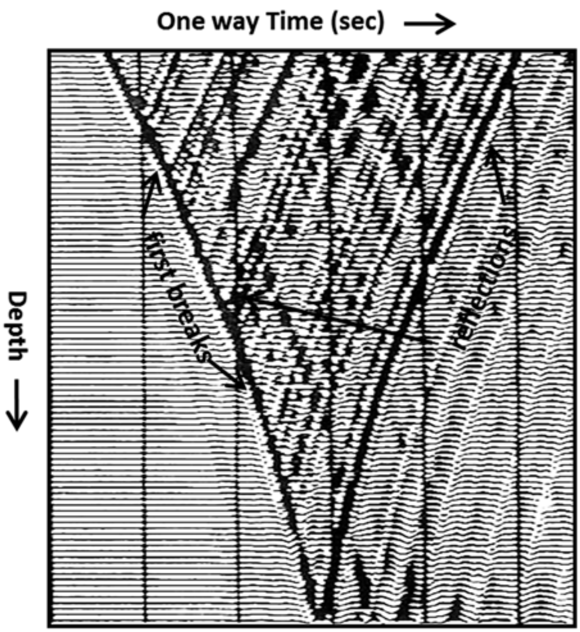

Fig. 7.2 A VSP raw record showing down-going (first breaks) and up-coming (reflections) waves (Image courtesy of ONGC, India)

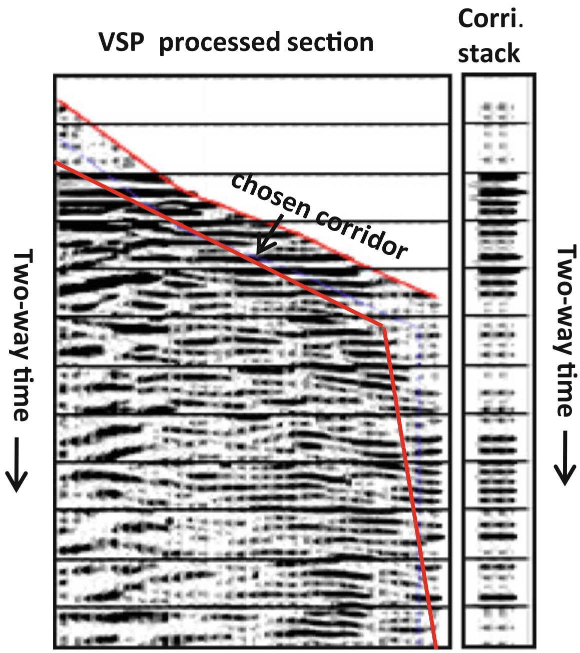

Fig. 7.3 VSP processed section (*left*) and corridor stack (*right panel*). Poor quality reflection at deeper depths may be due to weak signal and bore hole noise. Corridor stack is a partial summation of events in a subjectively selected corridor (*red*) in two-way-time for seismic calibration (Image courtesy of ONGC, India)

different levels. This information can be used effectively and gainfully to optimise the crucial processing parameters in seismic data for obtaining better resolution. Some of the benefits offered by VSP for optimising seismic processing are:

(a) Designing an appropriate wavelet for deterministic deconvolution,
(b) Identifying multiples and their genesis for effective removal,
(c) Determining attenuation spectrum of subsurface for 'Q' compensation,
(d) Estimating the interval velocity and zero-phase reflectivity, and
(e) Determining optimal filter bands for signal enhancement.

The up going waves recorded in a VSP contain reflections arriving from all the reflectors including those present beyond the well depth. The reflection recorded at the geophone close to a horizon, undergoes one-way propagation in the medium unlike the two-way passage, in conventional surface seismic. The reduced (one-time) absorption in the medium together with no near-surface complexities and transmitted multiples, the VSP in effect offers better seismic resolution. The VSP data, processed meticulously, eventually represents a single fold reflection section. The signal-to-noise ratio is enhanced by a partial summation of events in a selected corridor, often subjectively, and is known as a corridor stack (Fig. 7.3). The corridor stack is then conveniently spliced into a seismic section to calibrate the geologic events at the well.

A corridor stack is considered multiple-free, zero phase seismic response of earth's reflectivity and for this reason, a VSP is considered as a preferred tool for reliable calibration of surface seismic with well data. However, the time values of

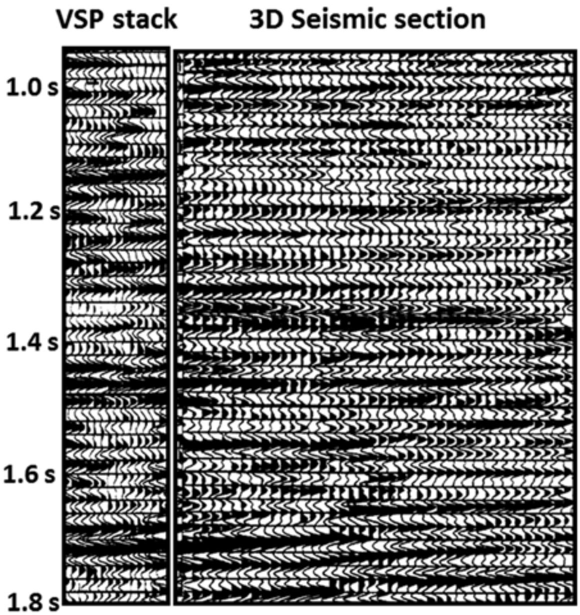

Fig. 7.4 VSP calibration with seismic. Note the good phase match of VSP with 3D seismic events after correcting time by 18 ms (Adapted from PetroWiki)

the stratigraphic units as seen on the VSP image at the well may be different from the surface recorded seismic time due to several reasons. These may include among others, difference in response of the recording instruments and detectors, disparity in processing related issues, improper statics and datum corrections and the ambient noise present in the data sets. The VSP corridor stack may therefore, in such cases, need appropriate correction (time shifts) for a proper phase (peak and trough) match with seismic. An example, where reportedly a time correction of 18 ms was applied to the VSP image time for a proper match with 3D seismic, is shown in Fig. 7.4. Nevertheless, the relatively noise-free, high resolution, zero-phase data, make the VSP technique extremely useful in reservoir delineation and characterisation where conventional seismic resolution fails.

However, the most unique feature of VSP is perhaps having the capability of ‘predicting ahead of drill bit’ as an aid to drilling engineers and exploration managers. Since reflections from all discontinuities present in the subsurface are captured, a VSP can help predict the geology of yet to be drilled formations within the planned target depth and even below. Under circumstances, where further drilling to deeper depth is contentious, futile or dangerous, it may be prudent to conduct a VSP survey to help decide appropriate future strategy including that of drilling. One such example may be running into an unexpected high-pressured zone during drilling before the target depth is reached. To continue further drilling blindly without knowing the scale and extent of the high-pressured zone could be a difficult and risky decision to take. Yet another case in point may be where the geologic object is not met even after drilling the planned target depth. This may require the management to take a decision to either close down drilling operations or continue further. Abandoning

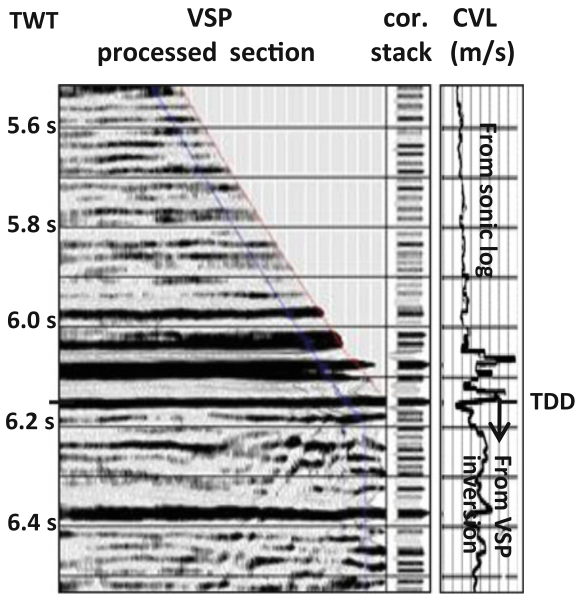

Fig. 7.5 VSP prediction 'ahead of drill bit' in a deep water well. Sonic was logged up to drilled depth (TDD), with no geologic information of layers below. Velocities extracted by inversion from VSP are used for predicting geology of formations yet to be drilled in the well (Image courtesy of ONGC, India)

the well without meeting the exploratory objective may be tremendously frustrating considering the time and money expended. On the other hand, if a decision to continue drilling is to be taken it would require that all the geologic information about the subsurface formations is estimated properly to plan afresh a suitable drilling strategy with a revised target depth.

VSP surveys provide the solution by using seismic inversion technique that quantitatively estimates interval velocities from the VSP recorded reflections, similar to a CVL computed from sonic log (Fig. 7.5). Constrained with the sonic curve, it can predict subsurface geology such as lithology, thickness, porosity and more importantly the pressure of formations to help engineers ahead of the drill bit.

Types of VSP

The commonly deployed survey geometries in a vertical well are the *zero- offset*, *non-zero offset* and *walk-away* VSPs, the design depending on the exploration objective at hand. The zero offset VSP is recorded with the source placed close to well-head similar to that in a check-shot survey and provides a real 1D seismic response at the well like a synthetic seismogram. A non-zero offset or an offset VSP with an energy source placed several hundreds of meters away from the well-head, on the other hand, provides a 2D seismic image of limited areal extent of subsurface coverage, close to the well (Fig. 7.6). The lateral extent of the imaged subsurface is sparse, limited to less than half the source- well offset, and depends on factors like structural dip, source offset, the depth of the reflector and the placement of shallowest and deepest geophones in the well.

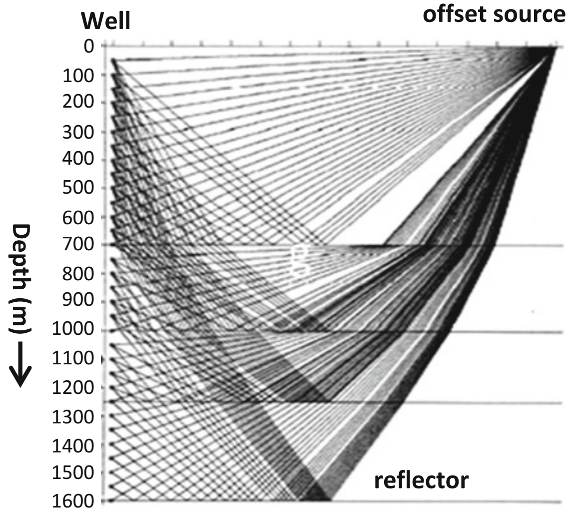

Fig. 7.6 Ray tracing for an offset VSP model configuration showing the down going as well as the upcoming rays from an offset source and reaching the detectors in the well. Notice, the sparse subsurface coverage and becoming sparser with depth as indicated by the reflections from different interfaces

Yet another type, the walk-away VSP, is a more elaborate technique in which seismic signals are recorded at each geophone in the well with a number of shots fired at the surface with varying offsets and along one or several azimuths around the well. The walk away survey generates a stacked seismic section similar to conventional CDP and provides high resolution multi-trace coverage around the borehole for reservoir characterisation.

A VSP survey planned and executed properly has several applications to help solve exploratory problems which are:

(a) Obtaining vertical velocity function for time-depth conversion,
(b) Optimising processing parameters for seismic data enhancement,
(c) Calibrating sonic log,
(d) Seismic calibration with well data,
(e) Geologic prediction "ahead of bit" during drilling and
(f) Reservoir delineation and characterisation.

However, its application for delineating lateral extension of a pay beyond the well bore, may be a little debatable. Imaging a mere 500 m extent of a reservoir requires a wide source-well head offset of one kilometre and can be a large constraint both technically and operationally. Reserves swept from a well are usually expected from an area of 400–500 m surrounding the well bore and conducting a VSP, under the circumstances, may not be prudent.

Check-shot and VSP Survey Comparison

Though both the surveys, the check-shot and VSP measure velocity in a well, there are several differences between the two surveys. These are shown in Table 7.1.

Table 7.1 Comparison of check shot and VSP surveys

Sl.no	Check-shot	VSP
1.	Source close to wellbore	Source placement variable depending on objectives of survey
2.	Geophone spacing large (~50–100 m) and irregular	Geophone spacing close (~10–20 m) and regular
3.	Records first breaks only	Records first breaks plus subsurface reflections
4.	Source signal not recorded and does not offer information about absorption (Q) loss	Source signal recorded at each geophone and its variation with depth provides absorption (Q) information
5.	1D recording of first break; no information on subsurface	2D/3D recording of reflection, subsurface imaged close to well
6.	Processing trivial- picking first breaks and static-corrected to datum	Elaborate processing of down-going and up-coming waves with static corrections, decon, NMO etc., as in conventional seismic
7.	Measures true average velocity at depths in a well and delivers 1D T-D curve	Measures true average, velocity more accurately and delivers a seismic section or volume, depending on whether the recording is 2D or 3D
8.	Used for tying well events to seismic time, sonic drift corrections and sonic surface integrated time	Used for precise well-seismic calibration, reservoir delineation, prediction ahead of drill bit, and optimizing seismic processing
9.	Survey simple – entails less time and money	Relatively more involved – takes more time and is expensive

Well (Seismic) Velocity and Sonic Velocity

Generally, the average velocity measured at a well is found to be different from the sonic-derived average velocity due to several reasons. Firstly, the seismic and sonic waves greatly vary in their source frequencies. The seismic uses a frequency range of ~5–125 Hz, which is much lower than that used in sonic of ~2–20 kHz (Bulant and Klimes 2008). Since higher frequencies exhibit greater velocities due to dispersion effect, sonic is likely to indicate higher velocities than seismic. Secondly the propagation principles and depth of investigations are highly dissimilar; the volume of rocks through which seismic waves propagate, are much greater and may have different facies and propagation characteristics (Thomas 1978; Stewart et al. 1984) than the very small volume of rocks through which sonic waves travel through. Seismic velocities are averaged over the horizontal distance through which the seismic energy travels and phenomena like absorption and short-path multiples, involved in a volume of rock but missing in sonic measurements, tend to make seismic velocity lower. Further, fractures (open) present in a medium, tend to lower seismic velocity due to lowering of bulk modulus while the sonic velocity may remain unaffected as it travels fastest through the matrix avoiding the voids. Incidentally, this trait of sonic being insensitive to fractures is used to calculate

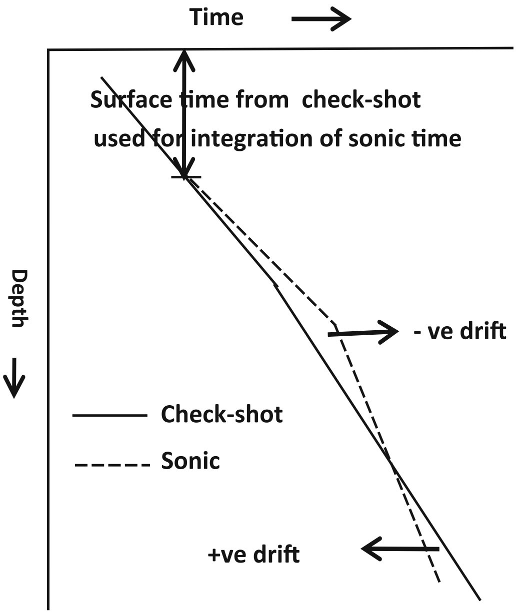

Fig. 7.7 Illustrating drift corrections for sonic. Drift is the difference between check-shot and sonic time. Drift can be nonlinearly variable. The correction is positive if sonic time is slower and negative if higher with respect to true times measured by check-shot

fracture porosity, computed by the difference between the neutron logs derived total porosity and the sonic derived intergranular porosity.

Though the sonic velocities can be expected in general to be faster than seismic, sometimes the sonic velocities can be slower as in cases of poor well conditions with mud-invaded and altered zones. Sonic velocities can also be affected by errors due to tool sticking, washed-out zones and cycle-skips (Brewer 2002). Cycle-skipping in a sonic log occurs when the first arrivals (cycle) at one or both the receivers are misread (skipped) due to noise and, depending on the cycle skipped, the computed velocity may be faster or slower.

The differences observed between check-shot/VSP travel time and sonic integrated time is known as drift. The drift is dynamic and may vary nonlinearly in order and degree over the range of well depths. It can be positive in some intervals and negative at other levels of the well (Fig. 7.7). This necessitates proper corrections to sonic velocities prior to its use for computing the earth reflectivity series to prepare synthetic seismogram. Further, sonic logs are seldom recorded from the surface, and the sonic integrated time for the logged depth interval would need the initial time from surface to be added for arriving at the velocity function from the datum. VSP/check-shot survey supplies this critical missing information required to calibrate sonic log (Stewart and Disiena 1989) for preparation of a synthetic seismogram.

Finally, it may be stressed that well survey and sonic measure fundamentally two different kinds of velocities. VSP or check shot measures the true vertical (average) velocity in the vicinity of the well where as sonic measures the variations in interval velocity of rocks immediately adjacent to the borehole.

Limitations of Well Velocity Surveys

The velocities measured in a well, although generally reliable, may however suffer from inaccuracies due to poor quality recording, picking and processing of the first breaks. The recording quality can be affected by bad geophone-wellbore coupling, inadequate source strength, adverse borehole conditions and ambient noises in and around the well. Often the source strength may be insufficient to impart enough energy into the subsurface for propagation but unfortunately it cannot be helped as enhancing source strength may jeopardize the well. Especially in onshore wells, the seismic velocity measurement may be contaminated due to the locally present near-surface anomalous velocity zones, shallow anisotropic strata, improper datum corrections, and propagation delays. Velocity dispersions and short-path multiples can also significantly delay seismic arrival times. As a reliability check, it is advisable that well velocities be used by the interpreter to check ties of all levels of seismic markers with the geologic boundaries at the well rather than just the one at the target level.

Before attempting a customary match of the corridor stack with seismic, it is important the interpreter take a look at the VSP processed final section that shows the upcoming waves. This provides an insight into the quality of recorded and processed data to show the reliability of the reflection events in the VSP section vis-a-vis the corridor chosen subjectively (by someone) to output the final corridor stack. Scrutiny of VSP final processed section thus should work out as a quality check (QC) for the VSP and the corridor stack output that is crucial for seismic calibration. It is best achieved by preparing a composite panel displaying the VSP processed section, the corridor stack and the seismic section spliced with the stack to rationalize the VSP calibration process with seismic (Fig. 7.8). The mode of display of seismic and VSP corridor stack sections is also important. It is preferable to use wiggle display rather than the often used variable density mode to justify proper character correlation of object reflections.

VSP surveys, although are likely to offer more reliable and accurate information, seem to have been under-utilised in real practice. In addition to earlier-stated natural constraints in VSP acquisition, the other reasons may be due to lack of definition of the exact survey objective and inadequate planning (Hardage 1988). Nevertheless, a properly executed survey for achieving effective solutions may require a lot of rig down-time which can be prohibitively expensive. It is also possible that the relatively high cost and low benefit of acquiring VSP may be the reason for its less usage. Many companies seem to be content with recording a relatively simple and cheaper check-shot survey as a cost- benefit trade-off.

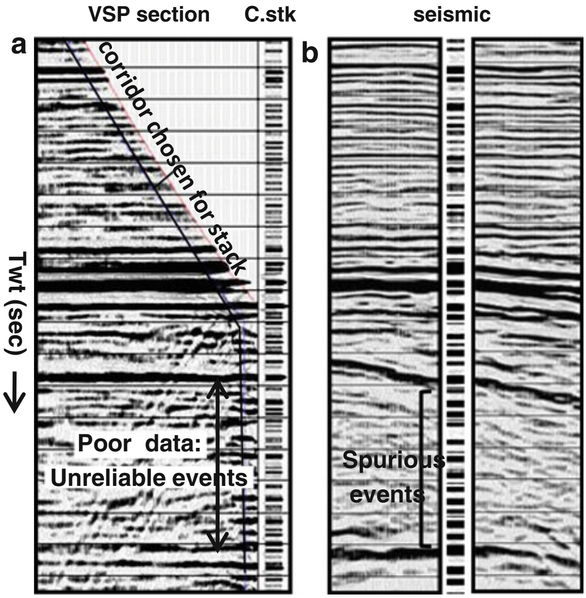

Fig. 7.8 Composite display of VSP, corridor stack and seismic for quality check. Note the noisy and unreliable data recorded in the lower part which gives a plethora of strong events in the corridor stack (**a**). Absence of these events in seismic corroborates the corridor stack events as spurious (**b**). Note also the VSP-seismic time mismatch needing corrections and the difficulty in phase match of events due to variable density mode of display (Image courtesy of ONGC, India)

Cross-Well Seismic

The cross-well or cross-borehole seismic technique deals with imaging of interwell areas through travel time tomography. Innovations and improvements in acquisition and processing systems have made it possible to measure accurate travel times with non-destructive, high frequency (kHz) sources and sensitive geophones, both lowered inside the wells. Since both the source and receiver are placed down hole, the cross well data does not suffer the distressing problems due to the near and shallow surface effects, as in borehole (one-way) and surface seismic (both ways) and thus offers the desired high resolution data. Powerful imaging of a geologic object is achieved through tomography, a technique of reconstructing a velocity model through travel time inversions. Though limited to a small area between the wells, cross-well seismic data holds great potential for providing solutions in reservoir studies including engineering problems during production stage. Some of the important and interesting applications can be in reservoir characterisation and analysis of fractures and linked anisotropy that control the permeability and fluid flow. In enhanced oil recovery (EOR) processes, the technique is used to monitor fluid flow in the reservoir by detecting anomalous high permeable and impermeable (barriers) paths, responsible for early water-cuts or blocking energy drives during production. In particular, cross-well seismic technique is extremely helpful in production of low viscosity heavy oil from reservoirs. Production of heavy oil necessitates injection of steam in a well to mobilize oil through another well, a few meters away and the efficiency of the heat front and sweep process affecting well productivity is monitored by the cross-well seismic technique.

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Part II
Reservoir and Production Seismic

Chapter 8
Evaluation of High-Resolution 3D and 4D Seismic Data

Abstract 3D data have several advantages that include creation of seismic sections in any desired azimuth for display and extraction of multiple seismic attributes. Horizontal viewing of 3D seismic is another advantage that resolves small-scale depositional features better in plan view. Stratal attribute slices are extensively used as a tool to map channel/fan complexes with their associated diverse facies. Horizontal-view seismic is also useful for sequence stratigraphy interpretation (SSSI) to build tectono-stratigraphic frameworks for petroleum system modeling.

Higher resolution and closer spatial sampling of 3D data ensure better delineation of reservoir geometry and characterization of reservoir properties that are the key inputs (static characterization) to initial reservoir modeling for estimating reserves and formulating production profile.

4D seismic is a time-lapse repeat of 3D surveys which evaluates the reservoir parameters (dynamic characterization) altered due to depletion .4D seismic can be useful in studying fluid flow during production, referred as seismic reservoir monitoring (SRM) and can help identify areas of by-pass oil, flow barriers and EOR sweep efficiencies. 4D limitations and in particular, its application restricted to only certain type of reservoirs responding to DHI anomalies with associated conditions are highlighted.

High resolution, high-density 3D and 4D seismic data offer scopes for precise estimation of rock and fluid parameters, which is crucial for reservoir characterization and reservoir monitoring during development and production of a field. The interpretation and evaluation techniques remain essentially similar to those of 2D seismic but require a multi-disciplinary synergetic approach, involving all types of data like seismic, geological, well logs, cores, drilling, reservoir and production data. Obviously, the evaluator is required to have knowledge, expertise and experience, and more importantly, an attitude to work in a team of persons from diverse disciplines, to produce the desired results. Since 3D data is increasingly used for reservoir characterization and 4D for monitoring fluid flow during production, the former may be considered synonymous to '*Reservoir seismic*' and the latter, '*Production seismic*'.

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3D (Reservoir Seismic)

3D seismic is recorded over an area in which data is sampled densely along a regular grid and the processed output is available in a volume. On land, 3D acquisition is done with closely spaced grid of shot and receiver points spread over an area called a 'swath'. Along the swath, receivers are placed on parallel lines and shot points positioned on parallel lines orthogonal to receiver lines (Fig. 8.1). However, there can be several alternate lay outs that can be modelled and designed depending on the geological objective.

Essentially, the survey geometry allows each receiver to record reflected waves coming from several azimuthal directions in contrast to 2D data that records limited reflections coming only from the plane of the source-receiver defined by a single profile of source and receiver. The close spacing of traces in 3D is defined by the "bin" size, which is the minimum area containing the cluster of common depth points (CDP) for stacking and typically varies between grid sizes of 12.5×12.5 and 25×25 m, depending on the dimension of geologic objective to be imaged. In marine 3D surveys, data however, is mostly recorded in a set of closely spaced lines with multistreamer and multisource (air guns) arrays, towed by the recording seismic vessel for operational efficiency.

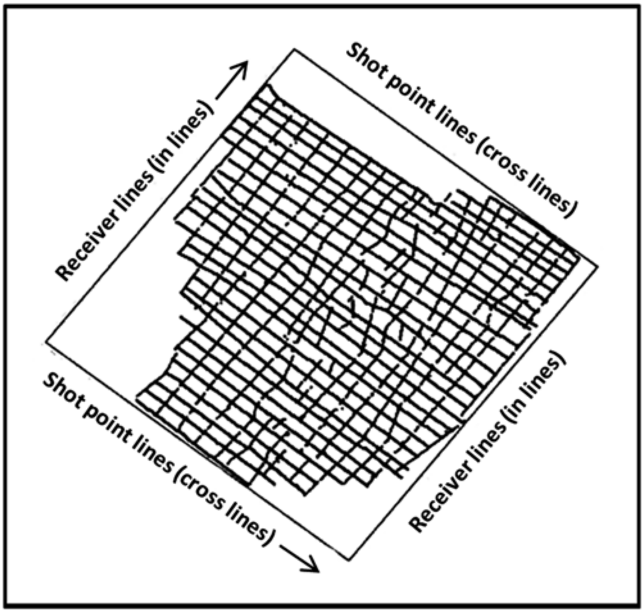

Fig. 8.1 A typical 3D swath survey lay out showing parallel receiver and source lines, orthogonal to each other. Receiver lines are called inlines and the shot point lines the cross lines. Breaks in the grid are due to ground logistic problems

The closely sampled regular-gridded 3D data permit volume-based processing techniques like surface-consistent static and deconvolution, improved velocity analysis and migration that yield much improved seismic resolution**,** both temporal and spatial. Seismic data recorded with multiple azimuths (*MAZ*) help collapse diffractions and out-of-plane events most efficiently and create a more accurate three dimensional image of the subsurface compared with 2D images. Multiple azimuth (*MAZ*) data also permits detecting azimuth-dependent anisotropic and fractured formations present in the subsurface. Specifically, the 3D prestack migration process plays a very important role in enhancing the sharpness and resolution of the images (Fig. 8.2).

The higher resolution and densely sampled 3D volume data proffer an excellent opportunity for volume based interpretation utilising 3D visualization softwares. The volume based interpretation is often convenient and permits to comprehend better the stratigraphic and structural styles that are less evident on conventional section-based display of 2D data that requires line to line interpretation. Interpretation of 3D data results in a superior definition of the reservoir geometry and quantification of rock parameters needed for development of the field. This, however, requires unambiguous seismic horizon correlations to start with after a meticulous well calibration and to be followed by detailed seismic mapping and evaluation of rock properties.

The 3D interactive interpretation is accomplished fast and accurate by use of powerful and sophisticated softwares. Several important 3D techniques like creation of arbitrary and reconstructed seismic sections in any desired azimuth, display of time/depth slices in plain view , extraction of geometric attributes like dip, azimuth, curvature, and coherency and fault-plane mapping (See Chap. 10) can be conveniently used that are not achievable with 2D data. Subtle sedimentary features, such as gentle delta progradations or channel cut and fills, often are seen only on dip or strike lines and may be altogether missed on 2D seismic if the lines are not shot

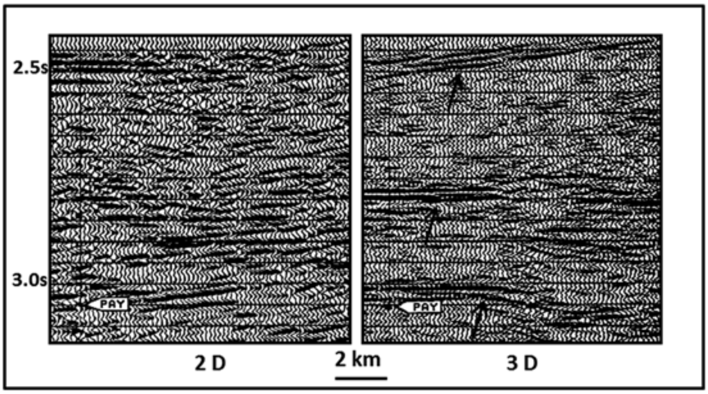

Fig. 8.2 Comparison of 2D and 3D seismic images. Note the improvement in clarity and continuity of events in 3D data (shown by *arrow*) notably by the process of migration, that reduces noise and improves spatial resolution (Image courtesy of ONGC, India)

in those specific azimuths. 3D seismic is free of these constraints as an arbitrary line can be generated from the volume data in any direction the interpreter desires to perceive the geological features. Reconstructed and arbitrary seismic lines connecting wells are simple but extremely useful in analyzing seismic responses in relation to known reservoir properties at the wells. These created profiles passing through hydrocarbon and dry wells, help calibrate seismic and set bench marks to guide prediction of lateral variations of geologic properties in areas between the wells and beyond.

One of the most straightforward and particularly effective means of 3D interpretation is horizontal viewing of seismic as against the traditional 2D vertical viewing. Depositional bodies mostly have horizontal dimensions greater than their vertical dimensions and horizontal-view seismic interpretation is therefore likely to resolve small-scale depositional features better in plan view (Zeng 2006). Though horizontal viewing by cutting slices through the 3D data volume is widely used for all types of attributes only the amplitude slices are described here. Other attribute slices are discussed in Chap. 10 (“Analysing seismic attributes”).

Horizontal-View Seismic: Horizontal Amplitude Slices

Horizontal slices cut across the 3D volume at constant time (known as horizontal or time slices) or along a flattened correlated seismic horizon (known horizon slices), conveniently show the variations in seismic amplitude along a constant time or along a horizon, facilitating fast and precise mapping of the two-dimensional extent of geologic features in plan-view in the entire area. Time slices are also called ‘*seiscrop*’, a term analogous to geologic term outcrops where surface rocks are studied on a traverse and the horizon slices, the ‘*horizon seiscrop*’.

The slicing technique makes it possible to reveal subtle subsurface depositional features like channels, deltas, barrier bars, fan complexes etc., in plan- view, somewhat similar to surface geomorphologic features observed in satellite images (Zeng 2006). Conventional interpretation of vertical sections may detect these features but the smaller and interesting exploratory objects like point bars, levees, crevasse splays etc., may not be resolved due to limited seismic resolution. An illustration of a channel, a common exploration play, mapped clearly by horizon slice but not quite comprehensible on a vertical section, is shown in Fig. 8.3.

Horizon seiscrop being a slice along a bedding plane (horizon) essentially represents the depositional surface of a feature and works well mostly in conformable sequences that assume beds deposited flat, as in ‘layer-cake’ geology. Horizons along which the slices are generated are flattened so that slicing is along the bedding surface and does not include feature belonging to different geological age. Scanning through horizon slices at close intervals reveals the vertical and lateral changes in a depositional sequence and works fine when it is of uniform thickness. Where the sequences change thickness, as are often found in nature, horizon slices may sample diachronous events of different geologic age. In such cases, to limit slicing along the

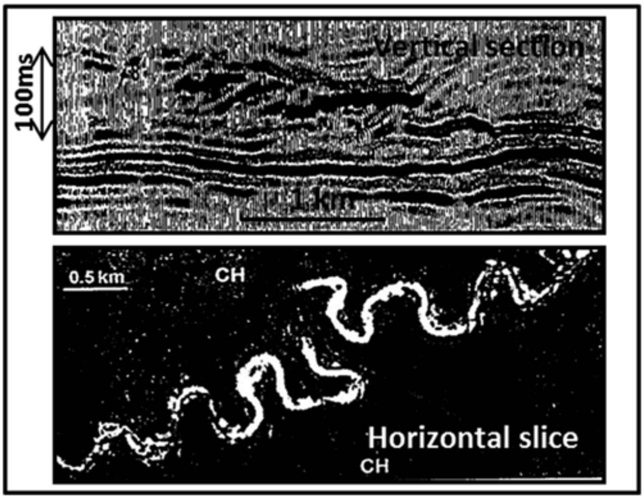

Fig. 8.3 Example of a channel geometry clearly revealed in seismic *horizontal* section (seiscrop), but not intelligible in the *vertical* section (Modified after Figs. 4 and 12 of Kolla et al. 2001)

bedding surfaces, geologic time surfaces (stratal surfaces) are constructed from the seismic volume by dividing the variable time interval between two seismic reference events into a number of uniformly spaced subintervals. Slicing along these surfaces is known as *stratal slicing or proportional slicing* and is likely to provide more details on variability of facies within the sequence. Seismic attributes mapped from the stratal slices can then be analyzed in terms of depositional systems (Zeng 2006).

Another commonly used technique is display of amplitude values in a specified window of stack data. These windowed versions include Average, Maximum, and RMS (root mean square) amplitudes in a specified time window. Essentially the amplitudes for all samples in a selected window are considered for estimating amplitudes to be displayed in a plan view. The average amplitude computes the mean of amplitudes, whereas, the maximum computes the maximum of the absolute value of peak and trough amplitudes in the window. The most commonly used, RMS amplitude computes the square root of the sum of squared amplitude values divided by the number of samples within the specified window. Squaring offers the opportunity for the high amplitudes to stand out best though it is highly sensitive to noise. The windowed amplitudes are basically used as a simple and quick means to identify interesting zones of hydrocarbons for resource estimates in reconnaissance stage. The window selection is critical as different windows will provide varying amplitude patterns having diverse geological implications and requires careful choice of window for the purpose.

Often the horizontal slices of the seismic images are shown riveted to their corresponding position in the vertical sections and are called ‘chair displays’. Chair displays make it convenient to cross-refer both vertical and horizontal slices to bring out clarity in interpretation of geologic bodies (as in Fig. 8.4). Stratigraphic resolu-

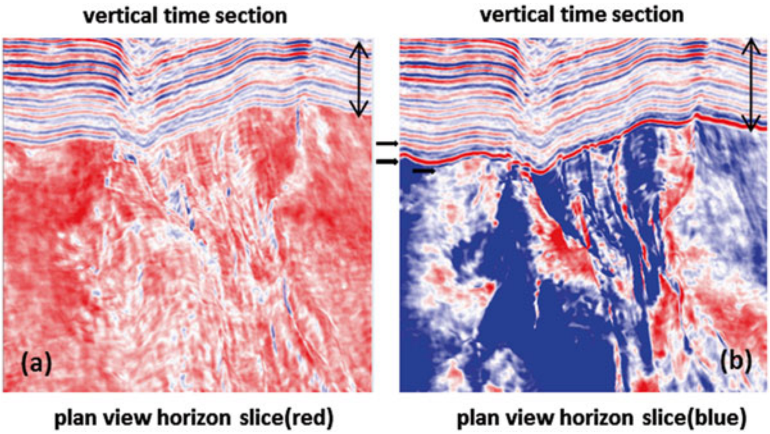

Fig. 8.4 Chair displays of horizon amplitude slices with vertical section. Plan view maps of amplitudes for the reflections (**a**) *red horizon* and (**b**) *blue horizon* shown by *arrows* in the vertical section. Note the differences in amplitude slices displayed in the horizontal views, despite the two reflections looking similar in the vertical view section (Images courtesy of Arcis Seismic Solutions, TGS, Calgary)

tions are best achieved by using both vertical and plan sections and in this context chair displays are extremely useful.

Horizontal-View Volume Seismic: Sequence Stratigraphy Interpretation

Traditionally, conventional interpretations are carried out on vertical seismic sections as the image is expected to replicate the subsurface geology in depth. But with emerging advantages of seismic 'horizontal-view', it has evolved as a powerful and fast technique for seismic sequence stratigraphy interpretation (*SSSI*) of 3-D volume data and the work flow is briefly outlined as below.

SSSI Framework: Horizon Cube

The seismic sequence stratigraphy interpretation of plan view seismic is essentially based on creation of a Horizon Cube and its transformation to Wheeler domain. Horizon cube is a dense set of correlated stratal surfaces each interpreted to represent a relative geological age. Major sequences boundaries are mapped and all possible reflection events within it are auto tracked to create a large number of horizons. Auto tracking is either model based or data driven. In the former mode, tracking is done interactively with a geologic model by calculating or interpolating horizons parallel to upper/lower boundaries (Brouwer et al. 2008). In the data-driven mode it

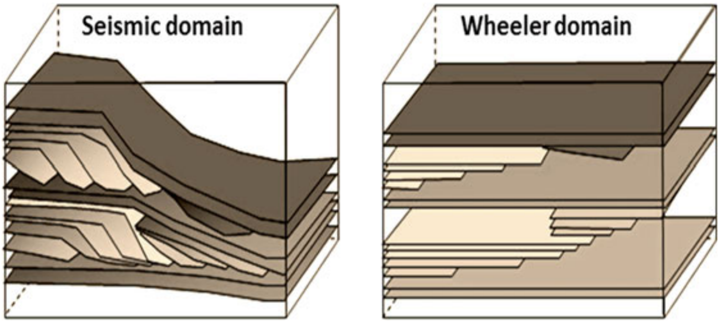

Fig. 8.5 Sketch illustrating transformation of events from seismic to Wheeler domain. Wheeler domain time slices are the horizon slices of seismic domain. Wheeler domain color display facilitates better interpretation of spatial distribution and timing of sediment deposition and environment (After Fig. 2 of Brouwer et al. 2008)

deploys auto-tracking by following dip of the events. Essentially, each created horizon corresponds to a stratal surface and assigned a geologic time, the stratal surfaces effectively represent chronostratigraphic events.

SSSI Framework: Wheeler Domain

The stratal surfaces of the Horizon Cube may be flattened and the data transformed into the Wheeler domain. Time slices in the Wheeler domain are the equivalent of horizon slices in the seismic domain. The Wheeler transformation is an extremely convenient graphic display (Fig. 8.5) for better comprehension of chronostratigraphic study. The Wheeler time slices make it easier to interpret spatial distribution and timing of sediment deposition.

Because of its accuracy and speed in evaluating geologic basins, volume based *SSSI* interpretation techniques have become part of the workflow in many companies. However, the techniques work well in geologic set-ups where sediments are not much distorted by tectonics. It also requires good quality data without noise, suitable for auto tracking which though accurate, may not be correct in many instances.

Prediction of Shallow Drilling Hazards in Offshore

Another important utility of 3D seismic worth mentioning is prediction of shallow drilling hazards in offshore areas. Locations of upcoming drilling wells based on seismic maps are checked for the presence of shallow hazardous zones that could imperil offshore operations. Presence of soft, loose and mobile strata at or near the sea bottom and shallow high pressured pockets can endanger drilling operations. It is mandatory that the sea floor and the sub strata around the prospect area are assessed for their strength and stability for safe drilling and related operational activities. Several surveys like sea bottom sampling, shallow soil coring and high resolution acoustic profiling like *'sparker',* are carried out to locate the hazardous zones.

Marine 3D seismic images of the sea bottom and the sub-bottom zones, often exhibit adequate resolution that allows detecting and mapping features linked to potential drilling hazards. Buried river channels, clay 'dumps', localised gas pockets and seepages in the sub bottom constitute a few of these hazards and are avoided for safe location of drilling rigs and ships to operate. Mobile clay dumps and channel-fills (Fig. 8.6) are highly unstable and can collapse putting erection and operation of jack-up rigs in risk. Gas seepages through sea bottom, phenomena often observed especially in deep water offshore areas may reduce buoyancy of water and can impede deployment of semi-submersible floaters at the site for drilling. Isolated, high-pressured shallow pockets of gas/water sand (Figs. 8.7 and 8.8) and shale can also cause blow-outs or shale flow into well, posing drilling hazards and difficulties.

By far the most significant interpretive advantage of high density-high resolution 3D volume data is the accessibility of quick and accurate analysis of a multitude of seismic attributes. This leads to better estimates of rock and fluid properties to evaluate

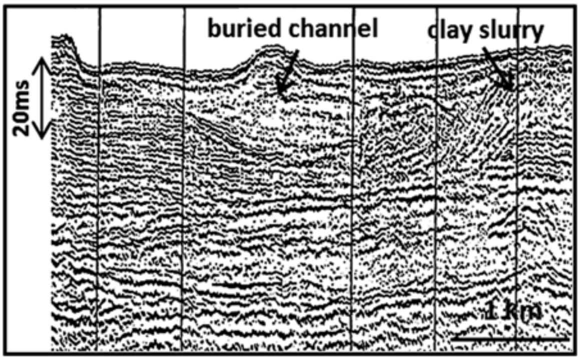

Fig. 8.6 Example of 3D seismic in prediction of shallow drilling hazards in offshore. Buried channel and clay slurry are extremely pliable and mobile which pose potent threats to installation and stability of jack-up rigs for safe operation (Image courtesy of ONGC, India)

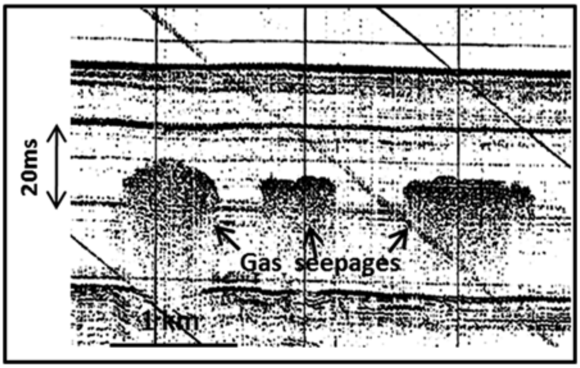

Fig. 8.7 Seismic image of shallow offshore gas seepages, used for prediction of drilling hazards. Gas leaking through sea bottom reduces buoyancy of water, endangering operation of semi-submersible floaters deployed for drilling (Image courtesy of ONGC, India)

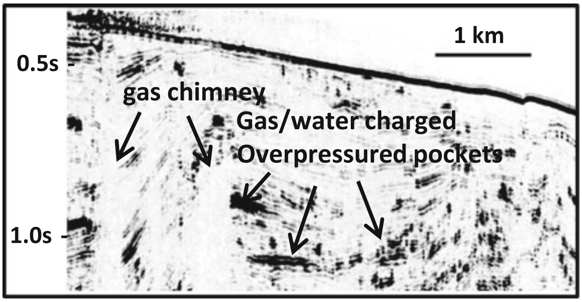

Fig. 8.8 Offshore seismic image of shallow gas/water charged high-pressured pockets (high amplitudes) and gas chimneys (transparent), that Indicate potential drilling hazards (Image courtesy of ONGC, India)

potential prospects for assessing all-important in-place reserves in exploration stage and for reservoir delineation and characterization during development stage. Some of these attributes are discussed later in Chap. 10 (Analysing seismic attributes).

Reservoir Delineation and Characterisation

3D seismic data has become indispensable as based on its evaluation the hydrocarbon reservoirs are defined and assessed for field development. Reservoir delineation and characterization parameters estimated from seismic contribute the prime inputs for initial static reservoir modeling to plan production profile. A hydrocarbon reservoir may be defined by the basic parameters:

A. Reservoir geometry (shape, size and thickness)
B. Depth to reservoir top
C. Fluids and contacts (GOC, OWC, OSC, GWC, etc.)
D. Rock and fluid properties (porosity, permeability, fluid saturation etc.)
E. Reservoir heterogeneity (facies change, barriers, faults and fractures)

The first three parameters may be subsumed under the term 'reservoir delineation' to differentiate from the latter two, termed as 'reservoir characterisation'.

Reservoir Delineation

Hydrocarbon discovery in a well requires as a follow up, proper delineation of the reservoir for appraisal of production potential of the prospect. This is achieved through a set of fresh structural and facies maps prepared in the prospect area after a seismic tie with the well. Emphasis is put on stringent calibration for picking the exact reflection phase (peak/trough/zero inflection) correlated to the reservoir top and bottom and its lateral continuity is strictly decided on the basis of reflection character to map the reservoir limit (Fig. 8.9). Reservoir delineation is a crucial step

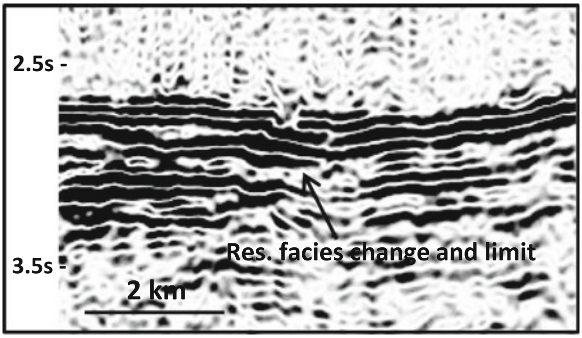

Fig. 8.9 3D seismic image offers better resolution that helps delineate the reservoir facies and its limit precisely (Image courtesy of ONGC, India)

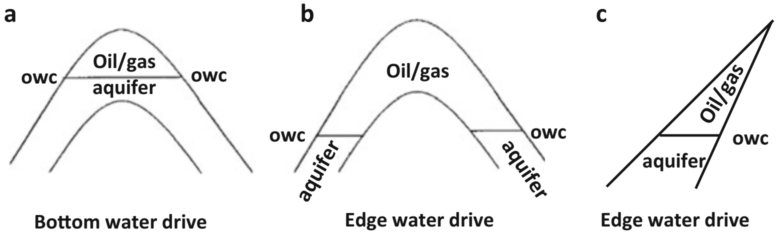

Fig. 8.10 Diagram illustrating common types of hydrocarbon-water contacts in structural (**a**) and (**b**) stratigraphic traps (**c**)

as it leads to estimate of hydrocarbon rock volume for establishing reserves. It may be stressed that though the log curves overlain on seismic are converted to time by velocity measured in the well, there can be a possibility of phase and polarity mismatch due to limitations of well velocity surveys. Several ways to verify the velocity functions may include plotting of velocity curves of all nearby wells and of the sonic velocities for trend-matching. Ensuring precise chronostratigraphic log correlations to certify seismic calibration is essential before proceeding to map the limits of reservoir and predict the changes within it from seismic.

The precise structural and stratigraphic interpretation of higher resolution 3D data provides accurate information about depths to top and bottom and thickness of the reservoir with lateral extent. The seismic structure maps are used for estimating rock volume for in-place reserve calculation and it is necessary to take note of the hydrocarbon contact and its type. For structural traps with bottom water contact (OWC/OGC), the effective rock volume is calculated by the difference between the top of pay and the hydrocarbon contact (Fig. 8.10a). This necessitates the structure map at the top reservoir to be accurate in details. Whereas, for edge water (Fig. 8.10b), it is the volume between the reservoir top and the hydrocarbon contact minus the volume between the reservoir bottom and the contact which requires the structure maps to be accurate both at top and bottom of the reservoir. However, a map for the bottom reservoir may not be required, when the reservoir thickness is greater than the vertical closure of the structure or the reservoir thickness remains same. In cases where the gross pay thickness is greater than the vertical closure mapped, it would signify multiple reservoirs that may need another set of maps to delineate them. For shale contacts (OSC/GSC), where the reservoir is underlain by shale, it is difficult to estimate the exact rock volume unless a down dip well establishes the water contact.

In clastic set ups amplitudes are often helpful in delineating thin hydrocarbon sands for which appropriate slice must be chosen for use. The relative advantages and limitations of each slicing technique must be weighed based on the specific geologic issue on hand. For example, delineation by RMS windowed amplitude may show more amplitude stand outs leading to overestimate of the hydrocarbon rock volume. RMS amplitude may work well for a single reservoir but not for multiple reservoirs occurring at different levels within the specified window especially if it is chosen arbitrarily and wide. Horizon or stratal amplitude slices, on the other hand suffer lesser contamination and are preferred for delineating single reservoirs provided the horizon phase is correctly identified and tracked for correlation.

The newly prepared precise structure maps are also vital guides for deciding appropriate locations for drilling delineation/appraisal wells. For example, in fault-bounded, steeply dipping structure, especially saturated with low viscous oil, it is important that the early production wells are located suitably at the structurally highest part to have the benefit of active gravity drainage drive for maximum primary recovery from high relief areas first. Starting earlier production from wells, located structurally lower, runs the risk of leaving behind oil at the highest part of the crest, known as *attic oil* that is difficult to produce economically later on. However, velocity estimation for depth conversions for an accurate structure map at this stage poses a stiff challenge as prediction errors can result in the well being unproductive – ending up as water well if the actual reservoir top happens to be met deeper than predicted.

Reservoir Characterisation

Characterisation of a reservoir deals with quantifying its rock and fluid properties, such as the porosity, permeability and hydrocarbon saturation. Reservoir heterogeneity is another important factor that also needs addressing. These are briefly discussed.

Porosity Porous sedimentary rocks are known to have lesser density and bulk modulus and exhibit lower seismic properties such as velocities and impedances. Lowering of velocity is generally considered an indication of a porous rock provided the lithology remaining unchanged. The amplitudes of reservoir top reflection may be weak or strong depending on impedance contrast with the overlying rock. Thus, porosities can be estimated quantitatively from analysis of attributes like amplitude, velocity and impedance studied from seismic data.

However, as stressed earlier, the seismic calibration needs to be precise to provide proper benchmarking set by the measured porosity values at the wells, so as to ensure reliability of seismic prediction away from the wells. Sometimes the measured porosity values at the wells, duly constrained by seismic and the geology of the area, are geostatistically mapped to indicate porosity variations over the prospect using techniques like cokriging. More commonly with good quality data, spatial distribution of porosity values at inter-well regions and beyond are precisely estimated from inversion of seismic data. Seismic inversion has evolved as a sophisticated process which transforms seismic reflectivity to reservoir rock and fluid properties. More about inversion is discussed later in Chap. 11.

Permeability Permeability is the property of a porous rock which describes the ease with which a fluid passes through the interconnected pore spaces. Permeability depends on effective porosity (interconnected pores) but is not the same and is controlled by the pore network geometry. It is calculated from well log data or by laboratory measurement of core. Permeability is the most important parameter in reservoir characterization, but unfortunately it does not directly influence seismic properties; seismic may be linked to porosity but not to effective porosity and permeability.

Fluid Saturation Fluid saturation affects seismic properties variously depending on type of fluid and its volume fraction in the pore space (For more discussion, please see Chap. 1). In general, sedimentary rocks saturated fully with liquid tend to show increase in compressional velocities but a decrease in shear velocities. Permeability and saturation are usually difficult to determine from 3D seismic, but may be qualitatively assessed by an experienced interpreter from a synergetic analysis of seismic, geological and well data (See for more discussions in Chaps. 9 and 11).

The areal extent of the reservoir, the hydrocarbon thickness (pay), porosity and saturation provide the volumetric estimate of in-place hydrocarbon reserves and constitute the key inputs from seismic to initial reservoir modelling (static). Reservoir simulation for fluid flow patterns, however, need other properties like viscosity, permeability, bubble point, capillary pressure, and pore pressure as inputs, which are commonly derived from analysis of log and engineering data obtained at the well.

Reservoir Heterogeneity Heterogeneity in a reservoir can be attributed to facies changes, fractures and faults present that cause anisotropy and cause complications in hydrocarbon flow during production. Evidences of reservoir facies variations in inter-well areas can be clearly picked from seismic by dissimilarities in their reflection character. Seismic display in wiggle mode is better suited for study of reflection character based on amplitude and waveform shapes (Fig. 8.11).Locally present high permeable paths, vertical and lateral barriers often cause separate *flow units* – the portions of the reservoir that have similar properties for consistent fluid flow. A reservoir is likely to have several flow units depending on degree of heterogeneity and the flow units may or may not be in communication with each other. Reservoir continuity and reservoir connectivity are two different aspects of fluid

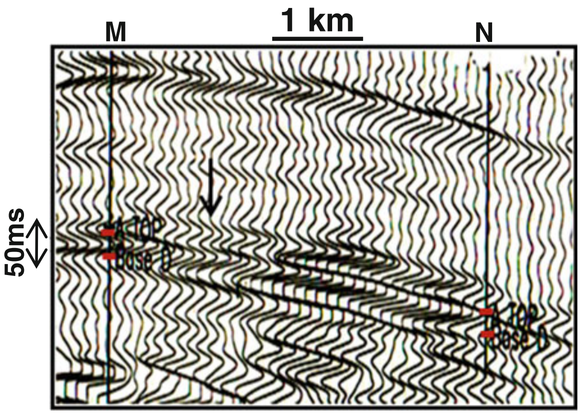

Fig. 8.11 Seismic evidence of reservoir heterogeneity. Note the big dissimilarity seen in reflection waveform and amplitude (indicated by *arrow*) between the wells M and N, indicating facies change and co-linked heterogeneity in the reservoir. Reservoir *top* and *bottom* identified from log is marked on seismic (Image courtesy of ONGC, India)

flow and if excluded in initial reservoir simulation model, it can lead to unforeseen anomalous fluid-flow patterns during production.

Volume-based seismic facies and multi-attribute analysis with structural maps are useful to identify these problematic elements, which can then be modelled to take care of heterogeneity and anisotropy in the reservoir.

Initially, the high cost of 3D seismic technology restricted its use for delineation and development of fields. But growing cost-effectiveness of 3D survey over the years has allowed the technology to be deployed even in initial stages of exploration, increasingly so for mapping subtle stratigraphic prospects.

4D (Production Seismic)

4D seismic is a time-lapse 3D survey, repeated after a period of time following production from a field and is considered a useful tool for reservoir monitoring. During production, the initial virgin fluid saturation and pore pressure in the reservvoir decrease due to depletion. This results in altering some of the rock and fluid properties, which may manifest changes in seismic responses. Simply stated, the differences in seismic attributes of two 3D surveys, one before production (baseline) and the other after a period of production (monitor), is skillfully exploited to address the crucial changed rock-fluid parameters for better reservoir management.

Because the differences in the two observed seismic properties are considered linked directly to the altered rock-fluid parameters in the reservoir, it is essential that the data acquisition and processing parameters of the repeat seismic campaign be ideally the same as that of the initial one. Since it is usually difficult to achieve this in real practice due to several reasons, including ground logistics, special softwares are used to normalise amplitude, frequency, and phase and the bin locations in the two data sets to bring them to a common platform for comparison. Interpretation and evaluation of 4D data is mostly based on attributes like amplitudes, P- and

S-impedances and *Vp/Vs* ratios derived from seismic elastic inversion. Powerful and efficient image display graphic softwares are generally used for detecting the subtle differences in seismic properties for analysis of reservoir parameters and fluid flow changes during production. This is why 4D seismic is considered synonymous to *production seismic*.

Seismic Reservoir Monitoring (SRM)

Reservoir characterization providing the initial distribution of properties over the prospect needed for reservoir modeling is referred as static characterization. Dynamic reservoir characterisation, on the other hand, simulates fluid flow through the reservoir model over time, for an optimal production profile with planned injection and production wells. A field under production requires reservoir monitoring which is basically about observing the fluid flow patterns over a period of time to evaluate performance of the planned field development profile. In case of discrepancy noticed in the actual production behaviour from that predicted, the production plan may need tweaking by mid-course corrections through adjusting or altering the reservoir parameters, used in the static and dynamic models, and/or by modifying subsequent drilling plans suitably.

The modifications in rock and fluid properties are commonly constrained by information received from newly drilled well or reinterpretation of existing well and production data with passage of time. Yet, there can be uncertainties about the reservoir parameters in the regions between and away from the wells. Calibrated 4D seismic attributes, constrained with log, core analysis and engineering data can fill in with the newly estimated reservoir parameters in the inter-well areas. Nonetheless, the inputs from seismic need to be authenticated by reservoir simulation which must honor all other information from multiple data sets like geological, well logs and engineering data. Because a time-lapse 3D (4D) seismic can be used as a tool for reservoir monitoring, it is often referred to as seismic reservoir monitoring *(SRM)* which is essentially a more involved and intricate inverse modelling problem. *SRM,* however, can be complicated at times to interpret and evaluate depending on type of reservoir and the drive mechanism, discussed later under ‘limitations’.

Amplitude attributes happen to be the simplest and are relatively straight forward in analysis of 4D data for *SRM*. In favourable geologic situations, amplitudes lead to identification of zones of anomalous fluid movement and have immense capability to provide vital leads to help improve reservoir management by providing clues such as:

- Corroborating the drive mechanisms and its imminent effect
- Impending water/gas coning / formation of gas phase
- Areas of bypassed oil
- Permeability barriers and high permeable pathways
- Dynamic reservoir characterisation (porosity, saturation and relative permeability)
- Enhanced oil recovery (EOR) sweep efficiency

Each of these is briefly outlined later.

Primary hydrocarbon recovery from a reservoir exploits the pressure drop from production. It depends on the type of reservoir and fluids and the mechanical energy (drive) stored in each. Types of drive mechanism can be enumerated as:

1. Gas cap drive – energy of compressed free gas cap overlying oil in reservoir
2. Water drive (aquifer) – energy from surrounding water in oil reservoir
3. Solution drive (depletion) – energy of dissolved gas in oil in oil reservoir
4. Gravity drainage drive – energy due to gravity in oil reservoir
5. Gas expansion drive – energy from compressed gas in gas reservoirs.
6. Compaction drive – energy derived from compaction of reservoir rock.

Aquifer driven reservoirs are fairly common and can be by bottom water drive or edge water drive (see Fig. 8.10) which needs a little elaboration as they affect production profile differently and needing different well completion strategies. In bottom water drive, the aquifer underlies the reservoir and drives from beneath by moving vertically upward into the pay zone. In edge water drive, the aquifer is located on the flank(s) and moves upward along the reservoir dip with flank wells cutting water earlier than the crestal wells. In stratigraphic traps, however, the aquifer drive is mostly edge water and from the single flank.

While the first five drives are fairly familiar, the last one, the compaction drive, needs a mention. Compaction drive is caused due to geomechanical effects on a reservoir under production. Over a period of a time, as hydrocarbon is being produced, reservoir pressure continues to deplete in the absence of external energy prop, thereby increasing the effective vertical stress. This induces deformation in the reservoir and in clastic reservoirs it creates compaction of rocks which triggers an energy drive. Compaction can be considerable in large soft reservoirs with the associated reduction in porosity.

Corroborating Drive Mechanism and Its Impending Potential

Appropriate drive mechanisms for optimal recovery from the reservoir are decided by the geological, petrophysical and reservoir engineering data, analysed by modelling and simulation studies. Nonetheless, seismic clues can be useful in supplementing/supporting information on the active drive mechanisms and also help simulating several scenarios as sensitivity studies for recovery under different drives. 4D amplitudes calibrated with well and production data may allow seismic identification and mapping of the altered fluid contacts observed initially at the wells. These maps can then be used to re-estimate volumes of fluids, for instance, the overlying gas and the underlying water for an oil reservoir. Re-estimation of the fluid volume(s) is likely to help predict/ corroborate the degree of its potential in future of such gas cap drive or aquifer support, or both, fully or partially, during rest of the primary recovery period.

Impending Water/Gas Coning and Gas Phase Formation

Comparison of 4D monitor and baseline 3D amplitudes can provide evidence of fluid movements linked to the drive mechanism, which can serve as an indicator of impending effects that may warrant immediate corrective action. In fields where hydrocarbon is manifested by seismic expression of high amplitude anomalies, changes in amplitude and sizes of anomalies can be symptomatic of type of drives operating in a reservoir and linked to fluid flow (Staples et al. 2006; Bousaka and O'Donovan 2000; Xu et al. 1997; He et al. 1997). The 4D amplitude precursors can offer vital clues for initiating suitable steps immediately to improve reservoir management. These are briefly discussed below.

Gas-cap drive – An increase in size of bright amplitude anomaly in 4D, compared to 3D, can be indicative of expanding gas cap due to active gas-cap drive in an oil reservoir.

Aquifer drive – A decrease in dimension of high amplitude anomaly in 4D may indicate gas production linked to oil depletion with water encroachment, suggesting an aquifer drive.

Solution drive – An increase in amplitude can be suggestive of gas phase formation during solution drive due to release of gas from oil within the reservoir.

Gas expansion drive – Sustained bright amplitudes in 4D monitor with no change from that in baseline may imply de-pressurization of gas due to expansion drive in a gas saturated reservoir.

Gas fields at shallower depths and with aquifer drives manifest best the changes in seismic responses in 4D and can be extremely effective in seismic reservoir monitoring *(SRM)*. Nonetheless, varied nature of amplitude changes in oil reservoirs during production are reported which may not be strictly linked to drive mechanisms alone. The amplitude changes depend on the reservoir (rock texture), nature of fluid and saturation, fluid contacts (water/brine varying in density) and the drive mechanism in operation. For example, the oil depletion indicated by dimming of amplitude in one case may be manifested by brightening of amplitude in another case (Anderson et al. 1997). Water encroachment into the reservoir is likely noticed by dimming of amplitude and up-dip movement of oil-water contact in 4D. Changes in seismic amplitudes are good indicators to understand and differentiate confined local incidents like gas and water coning. Water coning is a phenomenon due to upward movement of water around the completed zone of well locally and can be different from a field-scale movement of the hydrocarbon water contact or of water flooding during secondary recovery.

Bypassed Oil, Permeability Barriers and High Permeable Paths

As an obvious corollary to what has been discussed above, no change in the amplitude observed in portion of a producing reservoir may signify little or no production of hydrocarbon from that part. These can be the interesting areas of unswept and bypassed hydrocarbon that remains to be produced, and may warrant drilling in-fill wells. Permeability barriers such as shale and faults leading to creation of such isolated zones of unswept hydrocarbon, can also be identified by 4D seismic corroborated by other geological, reservoir and production data. Similar integrated analysis of amplitude and other seismic attributes in league with multidisciplinary data can also identify anomalously high permeable pathways, responsible for nagging problems like early water/gas cuts and coning at the wells, impeding production.

Dynamic Reservoir Characterisation (Porosity, Saturation and Relative Permeability)

Seismic impedance is related to lithology, porosity and fluid saturation in a reservoir. Over a period of production, the reservoir under depletion suffers from reduced fluid saturation and lower pore pressure with attendant increase in effective pressure leading to compaction of reservoir. Compaction linked porosity reduction in unconsolidated sands creates changes in seismic impedance. Simply stated, the differences in impedances estimated from 3D and 4D seismic can then be related to saturation if the other factors like the lithology and porosity are assumed to remain same. In a more realistic case, however, the dynamic reservoir characterization may demand renewed estimates of initial static parameters like saturation, porosity and permeability for a fresh reservoir simulation. Nonetheless, the most crucial parameter controlling flow simulation is the relative permeability and its spatial distribution in the field, which is difficult to estimate from seismic. Relative permeability is the ratio of effective permeability of a fluid at a particular saturation to its absolute permeability at total saturation. Obviously, relative permeability varies as saturation decreases with production and is a key factor that needs attention in dynamic characterization. Comprehending fluid flow pattern in the reservoir, co-linking rock and fluid properties and other engineering and production data clearly stresses the importance of an experienced and skilled seismic analyst in effecting a meaningful evaluation of 4D seismic in *SRM*.

As stated earlier, production from a field results in decrease of fluid saturation and a drop in pore pressure (increase in effective pressure) with resultant water intrusion into the reservoir. Both the factors i.e. increased effective pressure and water intrusion, may add to raise appreciably the elasticity of the rock and the seismic impedance. Estimates of higher impedances of reservoirs from the monitor volume compared to that in the baseline, is therefore normally expected during hydrocarbon production. On the other hand, areas indicating no change in impedances would suggest a status-quo, that is, no drop in pressure and saturation, and thereby identifying the areas of untapped or by-passed hydrocarbon under virgin pressure. Impedance derived from 4D through techniques like inversion of seismic waveforms can also offer information on reservoir continuity and fluid movements. Seismic reservoir monitoring deals with quantitative solution through techniques which include analysis of compressional and shear velocities *(Vp/Vs)* and *P-* & *S*-impedances (discussed in Chaps. 9 and 11). Where deterministic approach is not feasible, as in cases of multiple thin-pay reservoirs or of inadequacy in data quality, estimation of rock parameters can be attempted by extending the measured parameters at wells to interwell regions and beyond, constrained by seismic, through geostatistical techniques like cokriging.

Enhanced Oil Recovery and Sweep Mechanisms

Secondary recovery (EOR) involves providing energy externally to the reservoir. Several artificial drives like water injection, gas injection and steam flooding are commonly used to boost the depleting reservoir pressure. Success of such drives in enhanced recovery of hydrocarbon clearly depends on the efficacy of the sweeps following the planned desired scheme of pathways. In case of drive suspected of deficiency, it may be necessary to check the sweep performance to identify and rectify the problem. Seismic 4D analysis can be used in some cases to provide the necessary information by tracking the flooding fronts. Seismic 4D monitoring is likely to be most effective in shallow young, unconsolidated sand reservoirs under water and gas flooding, for obvious reasons of detectability of amplitudes. In-situ combustion for enhanced oil recovery increases the temperature and perceptibly lowers the seismic properties, especially in soft sand reservoirs and may be monitored by 4D. 4D utility in carbonate reservoirs also for monitoring steam floods successfully is reported (Xu et al. 1997). Heavy oil in pore spaces of rocks behaving as semisolids are good candidates for such monitor studies as it exhibits higher seismic properties (Wang 2001). 4D seismic in monitoring thermal fronts in in-situ combustion in such cases can be indeed very effective.

3D and 4D Seismic Roles in Exploration and Production

3D and 4D technologies are proven highly cost-effective and are extensively used in petroleum exploration and production. Some of the utilities are summarized below:

(a) Allows mapping of subtle stratigraphic prospects.
(b) Defines accurately reservoir parameters for estimating hydrocarbon reserves and planning production profiles for field development schemes.
(c) Minimises uncertainties in exploration and production, saving drilling costs of redundant/dry wells.
(d) Helps in reservoir monitoring of fluid movements and flow performances for better reservoir management.
(e) Identifies zones of by-passed hydrocarbon for increased production.
(f) Helps optimize reservoir characterisation by providing information about heterogeneity such as highly permeable and impermeable pathways, faults/fracture zones.
(g) Decides optimal drilling locations for production, in-fill and injection wells.

4D Seismic: Limitations

4D seismic studies can be applicable to only specific type of fields and not to all fields. Its effectiveness in reservoir monitoring greatly depends on type of reservoir and the drive mechanisms. For instance, seismic amplitudes for monitoring fluid flow requires DHI as a prerequisite and therefore cannot be applied if there are no hydrocarbon indicators (DHI) seen in seismic for the reservoir. Studies are likely to be most effective in soft, unconsolidated, thick hydrocarbon saturated sands at shallow depths as the seismic response of DHI is likely to be excellent (Chap. 6). Production under depletion or water drive in these types of reservoirs creates fluid flow-linked changes in rock-fluid properties (geomechanics), as discussed earlier which cause perceptible changes in seismic response in 4D.

Another problem in 4D data is the stiff requirement to acquire identical data sets for baseline and monitor surveys. This is usually difficult to achieve as seismic acquisition and processing parameters are seldom same due to several technical, logistical and environmental problems. Especially in marine 4D survey, the sea conditions may not be same as was during 3D acquisition resulting in subsurface reflection points different from those in 3D. This may seriously affect data quality and analyses in terms of ascribing the recorded anomalies to related reservoir parameter changes. Despite rigorous data conditioning for bringing the two sets of data to one working platform, it may still not be good enough to detect subtle changes in seismic response that can be attributed to only rock and fluid property or pressure and temperature changes in the reservoir.

In an active reservoir, several rock-fluid parameters such as elasticity, density, porosity, permeability, pore pressure and temperature undergo changes during production. Each parameter contributes to changing the seismic property. The seismic responses due to individual rock and fluid parameters vary in different ways and may not interact to add favourably to provide a perceptible change in seismic response. Considering the limitations in clear understanding of rock physics and attendant seismic imaging response and resolution, it may pose a formidable challenge for the seismic analyst, especially in the context of myriad geological diversities especially found onland.

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Chapter 9
Shear Wave Seismic, AVO and Vp/Vs Analysis

Abstract The shear wave properties and their propagation mechanism are relatively complicated, their acquisition with shear source (S-S) is expensive and often impracticable. Land shear surveys are therefore rare, though multicomponent surveys (3C and 4C) in offshore are occasionally acquired with OBC mode to record shear waves (P-S) with P-source by deploying horizontal geophones on sea bottom.

Conventional P-surveys also generate mode-converted waves (P-Sv) that are recorded along P-reflections on land and offshore. This offers an excellent and convenient opportunity to analyze the combined P-and S-wave data. The benefits of joint studies provide more reliable prediction of rock-fluid properties and specifically help authenticate DHI anomalies for hydrocarbons through effective techniques such as AVO and Vp/Vs. Different classes of AVOs, their attributes and limitations are highlighted with examples and illustrations.

Vp/Vs (or Poisson's ratio), an important hydrocarbon discriminant and 'birefringence', the unique S-wave property in anisotropic medium used for fracture detection, are outlined.

P-wave reflection technology is the mainstay of petroleum exploration and continues to be so, to date, because the mechanics of compressional waves are better understood and simpler to realize compared to that of transverse (shear) waves. P-waves with faster velocity, arrive earlier than S-waves, and more importantly, with much better signal-to-noise ratio. Moreover, compressional waves can be conveniently generated and recorded both on land and offshore and are easily adaptable for processing.

The propagation mechanism for shear waves, on the other hand, is more complex. In horizontally layered isotropic medium, the S-wave displacement can be in two modes *SV* and *SH;* the particle motions of *SV* are in the incident vertical plane and that of *SH* in the orthogonal horizontal plane. Particle motions of both the S-waves are perpendicular to direction of propagation. This is in contrast to that of P-waves propagating in isotropic medium where the particle motion is orthogonal to the wave front, along the path of propagation.

Shear wave recording needs appropriate horizontal source and detectors that are different from vertical detectors used in P-wave recording. Shear wave reflection surveys (S-S) on land are relatively more expensive and are not feasible in marine

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environment due to lack of a suitable shear source. The processing and interpretation of data is also relatively more complicated compared to that of P-waves. Nonetheless, the shear wave data, if made available, can be extremely useful for more accurate evaluation of seismic data.

Shear Wave Properties: Basics

In isotropic media, the equation $V = \sqrt{E/\rho}$ states the relation between velocity and the elasticity and density of a rock. For P- velocity, it is

$$V_p = \sqrt{\frac{k + \frac{4}{3}\mu}{\rho}},$$

and for the S-velocity, it is

$$V_s = \sqrt{\frac{\mu}{\rho}},$$

where, ρ is the density of the rock, and the modulus *'E'* is represented by the relevant moduli, the bulk modulus *'k'* and the shear modulus *'μ'*. As noticed from the above equations, while the P-velocity depends on the bulk modulus, the shear modulus and the density, the S-velocity is dependent only on the shear modulus and the density. The shear wave velocity is much slower and as a rule of thumb, is considered about half of P-wave velocity.

Polarization and Polarization Vectors

Polarization is the direction of particle motion for a certain wave as that of an elastic wave passing through a solid medium. In an isotropic medium shear waves are polarized in the plane orthogonal to direction of propagation in contrast to the particle motion of *P*-waves, which is parallel to the direction of propagation.

A wave is described by a vector which has a magnitude and direction. *Polarization vector* is the single orientation for a given plane wave. For *P*-wave, the *polarization vector* generally deviates from the direction of *phase velocity* which is normal to the wave front. It may be noted that this is usually different from the direction of wave propagation (the direction of energy flow), defined by the *group velocity*. Only in a homogeneous isotropic medium with no attenuation loss, the orientation of the P-wave vector is in the direction of wave propagation. However, when an elastic wave travels through an anisotropic medium, such as fractured rocks, the polarization vector of P-wave generally deviates from both the phase and group directions.

An important property of shear wave is its lack of ability to travel in a fluid medium, which has little rigidity. Consequently, fluids in a rock hardly influence *Vs*, whereas they affect considerably the *Vp.* The *Vs* for fluid saturated rocks may, however, exhibit marginal changes due to bulk density changes linked to fluids. Another major property of shear wave is its splitting into two orthogonally polarized waves while passing through an anisotropic medium, such as in fractured rocks and in some types of shale. The two split waves travel with different velocities and the phenomenon is known as *shear wave splitting* or *birefringence*. The phenomenon of birefringence and its utility in data evaluation is briefly discussed later.

Shear Wave Recording

Shear wave excitation on land is done by deploying a shear Vibroseis source which generates waves by oscillating horizontally. Shear waves can be excited by vertical vibrators also, but their recording requires large source-receiver offsets. In horizontally layered isotropic media, the generation of shear waves, *SH* and *SV,* depends on the orientation of the source with respect to the receiver line. When the source is broad side to a receiver spread, *SH* waves are recorded with particle motions in X-Y plane. If the source is parallel to the detector spread, *SV* waves are recorded, the particle motions being in X-Z plane (Fig. 9.1). For a down- going shear wave at oblique incidence, the *SH* and *SV* waves have particle motions orthogonal to the P-wave vectors, the *SH* having particle motions in a horizontal plane whereas the *SV* displacement is in a vertical plane. The propagating *SV* waves also create *P*-waves at interfaces, similar to *P*-wave generating shear wave *(SV)* at interfaces, and can cause complications by interfering with recording of P-reflections. *SH* waves, on the other hand, are polarized parallel to layered strata and provide relatively simpler records.

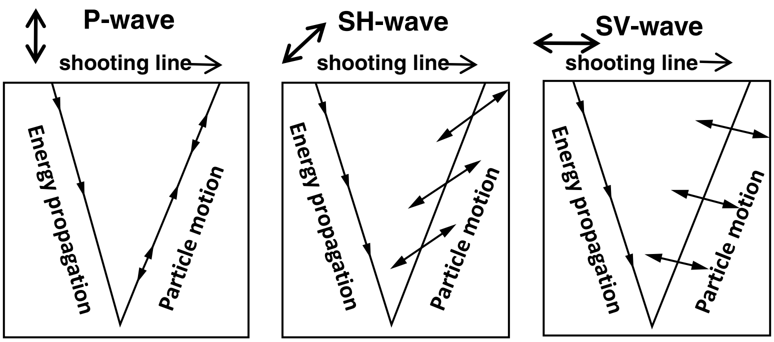

Fig. 9.1 Sketches showing compressional (P) and shear (SH and SV) wave particle motions with the source-receiver recording geometry. Shear wave source and receivers are in a *horizontal plane* in contrast to the *vertical plane* for P-wave. SH is recorded by the broad side receiver while SV by in line with the source (After Ensley 1984)

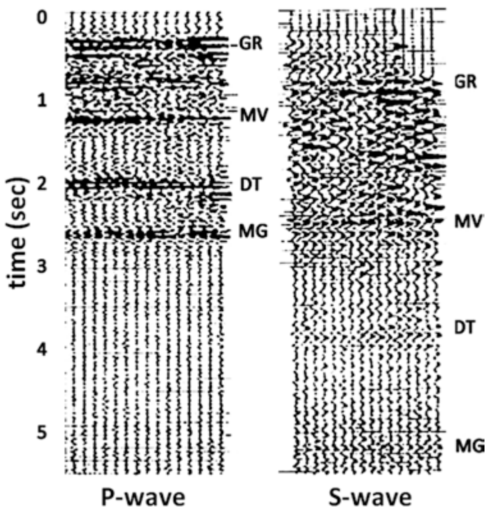

Fig. 9.2 An example showing more noise and less continuity for S-reflections compared to P. Note the nonlinear delay in S-arrival times of the geologic units with respect to P-reflection. Dissimilarity in reflection characters and arrival times of P- and S- images make it hard to correlate the P- and S- events for combined analysis (Modified after Robertson and Pritchett 1985)

The deployment of Vibroseis on land, particularly in rugged terrains, can be logistically problematic and expensive. Further, appropriate horizontal geophones, different from the vertical geophones used for P-waves, are required to record the shear waves. Thus, two sets of survey equipments will be required to record compressional reflection (*P-P)* and shear reflection (*S-S)* data which can be time consuming and cost intensive. Further, poor signal-to-noise ratio and low-velocity near surface statics, combined with problems of wave splitting as in anisotropic medium, make processing of *S*-wave data more complicated. Moreover, due to large differences in propagation velocities (arrival times of events) and ample variations in shapes of the wave forms, it becomes difficult to identify and correlate, time-wise or character-wise, the *P-P* and *S-S* reflection events coming from the same interface (Fig. 9.2). Without a satisfactory correlation of an event, a joint analysis of *P*- and *S*- amplitude and velocity for better interpretation becomes meaningless. Due to the drawbacks in acquisition, processing and interpretation (API) of data, shear-wave surveys are yet not too common in practice.

Mode Converted Shear Waves

As mentioned earlier, when a P-wave strikes a reflecting boundary at oblique incidence, in addition to the reflected and transmitted P-waves, it generates reflected and transmitted shear waves. These are known as mode converted waves. The converted waves can be recorded on the surface by horizontal geophones *(P-SV)* or by vertical geophones *(P-SV-P)* as *SV* waves gets reconverted to P-waves at boundaries. For normally incident P-waves in isotropic media, there is no mode conversion into S-waves. Mode conversion occurs every time an inclined P-wave encounters an interface and the ensuing SV waves in turn generate P-waves at rock boundaries, which are recorded along with P-wave reflections. The degree of mode conversion is dependent on the angle of incidence and the velocity contrast (usually specified as *Vp/Vs* or *Poisson's ratio*) as well as on the *anisotropy coefficients* that cause birefringence in anisotropic medium. The balance between reflected and transmitted P and S energy changes with angle of incidence. For small angles of incidence, most of the energy is carried by the reflected and transmitted P-waves and as the angle of incidence increases, the mode conversion becomes more prominent. Its amplitude is governed by the conversion coefficient, which is a non-monotonic function of the incident angle. At larger angles of incidence, approaching 90°, the mode conversion decreases and becomes negligible at angle of incidence reaching 90°.

On land, especially in older geologic basins, where rocks with large velocities are present, the mode conversion can be expected to be more pronounced. Moreover, the shift of the conversion point from the reflection point of P-wave and the asymmetry of the *P*-incident and the *S*-reflection (Fig. 9.3) pose difficulties. Combined with other problems as stated earlier, the asymmetry makes the converted wave data processing complicated. An interface with very high impedance contrast like that of an intrusive body within a sedimentary section can generate strong mode-converted waves which may interfere with primaries and cause problems in smooth processing of conventional P-wave data. Processing of converted wave data is a separate operation and requires special efforts other than for *P-P* processing.

P-seismic surveys, fortunately, allow natural generation and recording of shear waves, on land as well as in offshore. *PS*-waves are indeed a welcome spin-off of

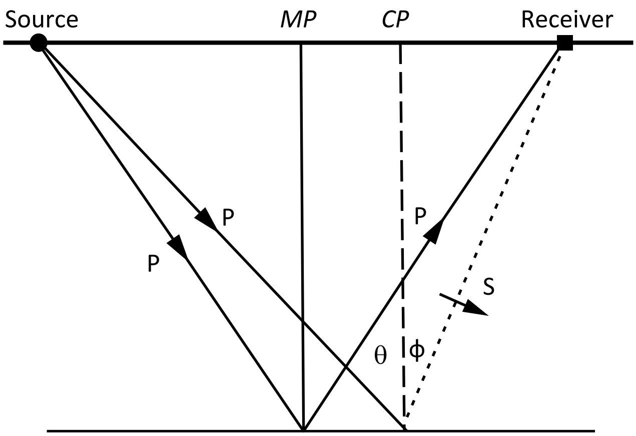

Fig. 9.3 A line diagram showing recording of mode converted (P-S) waves on land. Note the asymmetrical ray trajectory for S-wave that calls for separate and extra processing efforts than the conventional P-P processing (After Stewart et al. 1999)

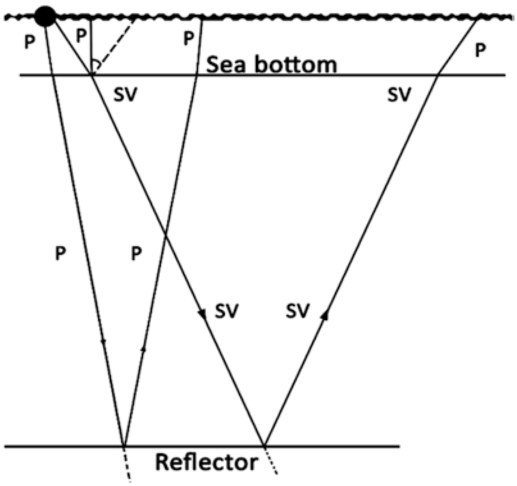

Fig. 9.4 A line diagram showing recording of converted waves in offshore (P-S-P). P-wave is converted to shear (SV) wave at the sea bottom and on travelling upward is reconverted to P-wave at the sea bottom and recorded (After Tatham and Stoffa 1976)

P-surveys though they have to be recorded with horizontal geophones requiring special processing. In conventional marine surveys, the first mode conversion occurs when the P-wave gets converted to S-wave at the sea bottom as this offers the first velocity contrast boundary. The mode converted wave travelling downwards gets reflected at interfaces and during its upward travel, is converted back to *P*-wave and recorded by the conventional streamer geophones *(P-S-P)* (Fig. 9.4). The mode conversion is likely to be most efficient when the velocity contrast is large at sea bottom. In areas where the sea bottom is soft and loose, as is often the case in offshore deep waters, the mode conversion efficiency may be hampered.

P-seismic containing shear information as a byproduct without additional cost and efforts (as converted waves are not processed), has thus found much favor with explorationists for combined analysis of *P*- and *S*- wave attributes.

Multicomponent Surveys (3C and 4C)

Multicomponent seismic surveys on land record *P*- and *S*- waves *(P, SH, SV)* by deploying *P*- and *S*- sources with three orthogonally oriented detectors, two horizontal and one vertical and is known as *3C* survey. In offshore areas, with conventional air gun as *P*-source, *P*-waves and mode converted *S*-waves are recorded (*P, P-SH and P-SV*) by planting three component geophones on sea bottom. A streamer hydrophone is also added as a fourth component to record conventional *P*-waves and the survey is referred to as *4C* acquisition. *P*-waves are detected by the Z-component geophone and the hydrophone while S-waves are detected by the X- and Y-component, horizontal geophones. Because the geophones and the connecting cables are laid on the ocean bottom the recording is known as ocean bottom cables *(OBC)* acquisition. Multi-component *P-S* recording, however, is relatively expensive, especially in offshore environment. Also formidable problems like asymmetric binning, shear statics and shear wave splitting due to azimuthal anisotropy make data processing more complex for regular data processing centers.

Benefits of Shear Wave Studies

P-wave reflection data alone may not be able to predict rock-fluid properties decisively as rocks with varied properties may show near-similar effects in *P*-response. Since the *S*-wave characteristics and their seismic responses are different from that of *P*-waves, it provides supplementary means to assess and validate the interpretation from *P*-data. For example, in presence of near-surface gas chimneys and diffusions, *P*-imaging of an underlying reservoir may suffer but the *S*-waves, being insensitive to fluid saturation, may be effective in mapping the reservoir. Similarly, the presence of shallow anisotropic sections such as thick layered shale (vertical transverse isotropy) and fractured rocks (horizontal transverse isotropy), overlying a potential prospect could impede *P*- imaging but not the *S*-images, that may delineate the reservoir better. Further, in cases, where *P*-impedance contrast for an interface is too small to cause a reflection, the *S*-impedance contrast may be adequate to offer a perceptible image (Fig. 9.5). Reservoir properties are mostly analyzed from the three essential seismic properties, the amplitude, the velocity and the impedance contrast seen by the P- and S-waves. Ideally, both the *P* wave and *S* wave data, wherever possible, need to be jointly studied for better prediction of rock-fluid

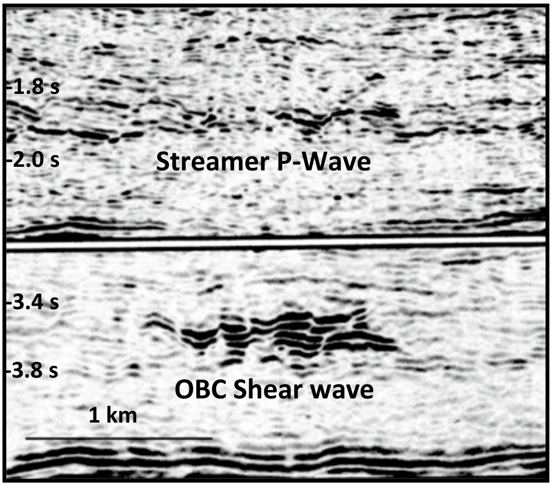

Fig. 9.5 Comparison of P-(streamer) and S-wave (OBC) seismic in offshore shows the benefits of S-wave recording over P-wave. The geological features, imaged clearly by shear waves in central and bottom part in OBC could not be imaged by P-waves in conventional streamer mode (After Stewart et al. 1999)

properties in a reservoir. Shear wave studies though are known to be useful in a wide range of geologic problems, only a few common but important applications are described below.

Validating Bright Spots (P-wave Amplitude Anomalies)

Bright spots are amplitude anomalies associated with hydrocarbon reservoirs and more commonly with gas sands and are considered as direct hydrocarbon indicators (Chap. 6). However, many bright spots, on drilling, were found to have no hydrocarbons, which necessitated validation of bright spots prior to drilling to avoid dry wells. This can be accomplished by the joint study of *P*- and *S*-wave data. In early years, from conventional *P* records, the far offsets containing converted S-waves were picked and separately processed to provide the supplementary *S*-stack section (Tatham and Stoffa 1976). Once the *P*-and *S*-stack sections are created from the prestack gathers of recorded *P*-data, amplitude and velocity of a DHI anomaly can be easily compared for its authentication. Bright amplitudes present in P-stack but absent in the S-stack data would qualify the anomaly as hydrocarbon bearing (Fig. 9.6), whereas, presence of amplitude anomalies in both sections would indicate it due to rock lithology. Similarly, a dim-spot anomaly in *P*-data with no such corresponding anomaly in *S*-data can be suggestive of the presence of gas in a carbonate reservoir. Likewise, analysis of *P*-and *S*-velocities for hydrocarbon

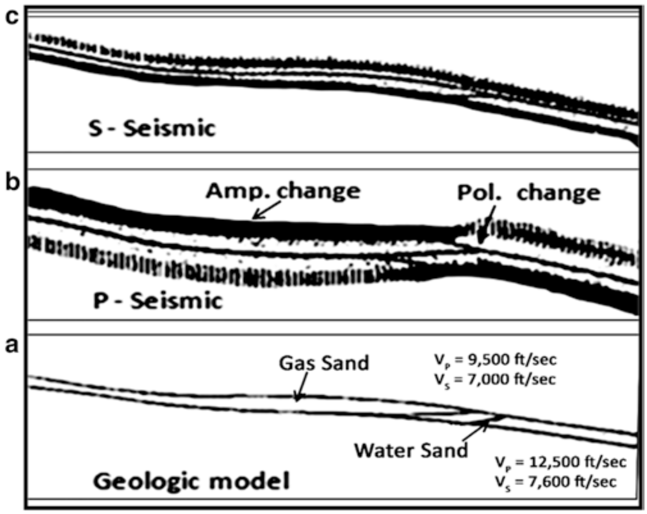

Fig. 9.6 Seismic modeling of P-and S-waves validate P-amplitude 'Bright spot' for a gas-sand with help of S-amplitude study. (**a**) geologic model, (**b**) P-seismic, (**c**) S-seismic. Note the high amplitude and polarity change in P-seismic due to gas but absent (**b**) in S-seismic as shear waves are insensitive to fluid (Modified after Ensley 1984)

indication can be done which is discussed later. However, extraction of shear wave information from normal P-data for building an *S*- stack section at the processing center can be painstaking and cumbersome and highly subjective depending on data quality and survey geometry. A more convenient approach to utilizing *P* and *S* amplitudes is by analysis of trends of amplitude variations with offset (AVO) from P- wave pre-stack data, a technique set as current industry practice.

AVO Analysis, Near and Far Stack Amplitude Studies – Prediction of Hydrocarbon Sands

Though AVO is primarily a study of *P*-amplitudes with offset, it is included in the chapter for shear wave, as AVO phenomenon involves shear waves and its velocity. In a prestack gather, the *P*-amplitude response is dominated by *P*-impedance at small angles of incidence (near offsets) but at larger angles (far offsets) by Poisson's ratio *(σ)*. More about Poisson's ratio *(~Vp/Vs)* is discussed later in the chapter. The *P*-reflectivity for inclined incident waves varies with angle of incidence due to mode conversion of energy generating shear waves and predominantly so at larger offsets. The *P*-amplitude variations with offset (angle) due to shear wave generation are influenced by the contrasts in each of the physical properties, the *Vp*, the *Vs* and the density of rocks across the interface. The relationship is mathematically expressed by the Zoeppritz's equations, which provide a linkage between the variations of *P*-reflection coefficient with angle of incidence *(θ)* for a given primary and shear velocity ratio *Vp/Vs*. The *Vp/Vs* ratio is considered as one of the deciding parameters that controls the variations in P-amplitude patterns with angle of incidence (offset) in presence of hydrocarbon.

AVO is mostly applicable to siliclastic sand hydrocarbon reservoirs though more commonly to ones saturated with gas where the effect of amplitude anomaly is more pronounced. Geologic models are usually defined by a set of values of *Vp, Vs*, and ρ of gas sand reservoirs and of shale/tight rocks acting as seals. Depending on the variations in contrast of these properties at the interface, AVO anomalies for the reflection from the gas sand top are categorized as Class 1, 2, 3 and 4, and variation of amplitude attribute with offset is illustrated schematically in a plot of reflectivity *versus* angle of incidence in Fig. 9.7. The figure also shows intercepts and gradients for different classes of AVO, these attributes are discussed later in this chapter. Though the following description highlights gas for AVO effects, oil, too, shows similar AVO behavior, may be with relatively reduced effect.

Class 1 AVO (High-Impedance Gas Sand) Model The class 1 AVO anomalies are caused by high impedance gas sand, a compacted and relatively less porous rock with substantial compressional velocity and density contrast with overlying shale cap. The gas-sand and shale interface thus presents positive contrast for *Vp* and ρ (density) but negative contrast for Poisson's ratio 'σ' due to presence of gas. Referring to Fig. 9.7, the amplitude shows a maximum positive value at normal incidence after which it decreases to zero at the crossing of x-axis at a certain angle of incidence. Beyond this angle

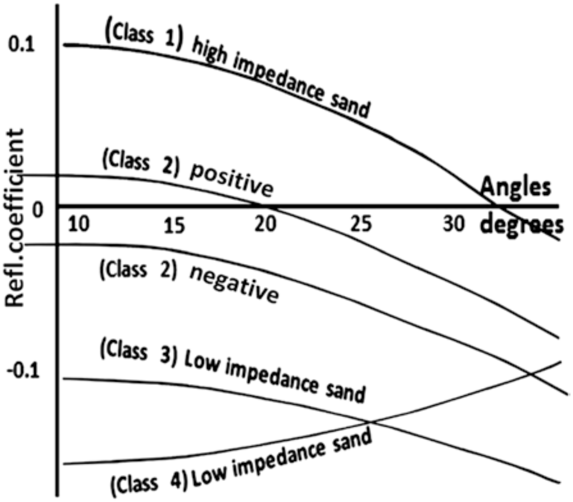

Fig. 9.7 An AVO schematic illustrating the four classified P-amplitude variation with offset (incident angle) for the reflection from *top* of gas-saturated sand. The curves give the reflection coefficient at zero offset and show the amplitude changes with incident angles (offset)

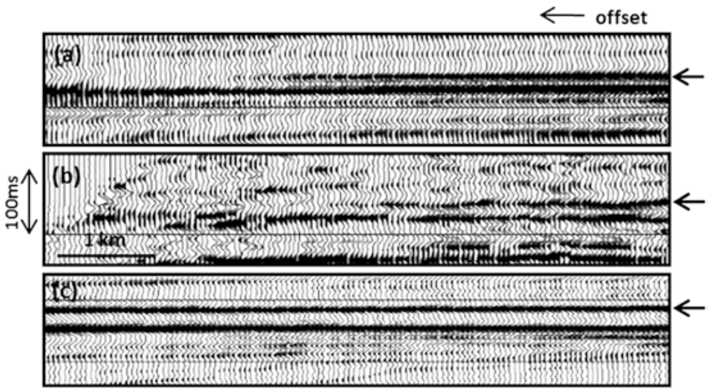

Fig. 9.8 Class 1 AVO (high impedance gas -sand) amplitude response, (**a**) synthetic gather for gas- sand (**b**) actual seismic and (**c**) synthetic gather for water saturated sand. The *arrow* shows the black-filled trough representing the positive reflectivity from *top* of gas- sand that diminishes with increasing offset (angle of incidence) in (**a**) and (**b**) in contrast to no such changes in the modeled water sand (**c**) (After Downton 2005)

(offset) the amplitudes again increase but with changed polarity, it becoming negative. The plot of reflectivity with incidence angle also shows a negative gradient (Fig. 9.7).

In a pre-stack synthetic gather model of high impedance gas sand, the high amplitude response at near offset is seen to decay with increasing offsets till it becomes too feeble (Fig. 9.8a). The reversal to negative polarity however is not clear, perhaps due to inadequate long offset considered in the model. This corroborates well with the decaying pattern seen in the corresponding actual seismic response (Fig. 9.8b). As is to be expected, no variation in amplitude with offset (AVO effect) is noticed in the modeled response for the sand saturated with water (Fig. 9.8c).

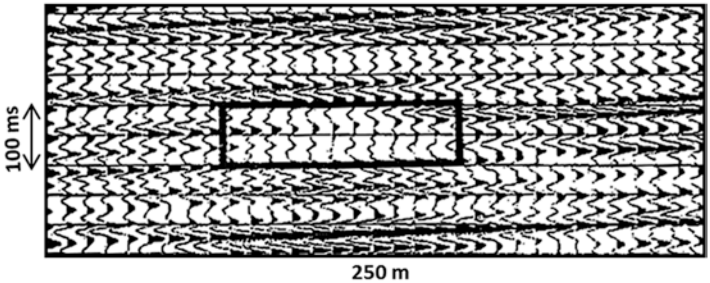

Fig. 9.9 An example of Class 1 AVO anomaly undetectable in normal stack section. The near trace positive amplitudes due to high-impedance gas- sand, decrease with offset and at a large offset change polarity to negative and increase with offset. Since all offsets in a CDP stack with both positive and negative amplitudes are summed, no reflection amplitude results in the stack section to be detected (After Rutherford and Williams 1989)

The reversal to negative polarity, however, occurs at a fairly large offset; an offset seldom used in routine acquisition and thus may be missed. Too large offsets also carry associated wave propagation problems and noise that can obscure the reflection polarity. However, in a conventional normal stack section, class 1 AVOs are generally difficult to find as near and far traces with opposite polarities are summed up over the entire spread of gather resulting in poor or no reflection (Fig. 9.9). Likely geologic examples may include the deeper and older, low porosity reservoir sands saturated with gas that may not show discernible seismic amplitude anomalies for analysis and consequently missed as exploration target.

Class 3 AVO (Low-Impedance Gas Sand) Model The class 3 AVOs are caused by low impedance gas sands, usually of relatively young age, with shale caps and at moderately shallow depths. They usually have a large negative normal-incidence reflection coefficient, which becomes more negative as offset increases. The anomalies appear on stack sections as very high amplitudes and are known as the classical 'bright spots' (see Chap. 6). The interface between gas-sand and the overlying shale is characterized by a large negative *P*-impedance contrast with velocity, density and the *Vp/Vs* ratio $(\sim\sigma)$ of gas sand being appreciably lower than those of the overlying shale. Mio-Pliocene and younger age unconsolidated gas-sands generally typify the model all over the world. The amplitude variation with offset for a real model is shown (Fig. 9.10) where the gather shows high negative reflection amplitude from the top gas sand in the near trace that continues to increase with offset. The figure also illustrates the AVO pattern for the reflection from the base of sand where the positive reflectivity increases with offset. The plot of reflectivity with angle indicates a negative gradient, similar to Class 1 (Fig. 9.7).

Class 2 AVO (Near-Zero Impedance Gas Sand) Mode Gas- sands compacted moderately and having impedance close to overlying shale, are considered Class 2

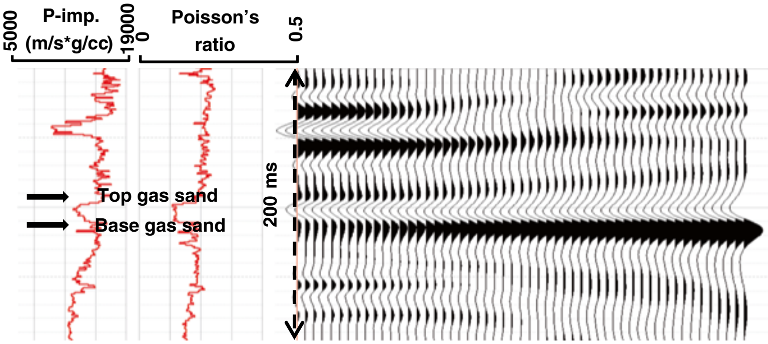

Fig. 9.10 Variation of seismic amplitude with offset seen on a modeled gather. The gas sand indicates lower P- impedance and lower Poisson's ratio. The negative amplitude (trough) increases (more negative) at the *top* and the positive amplitude at the *base* (peak) becoming more positive with offset (Image courtesy of Arcis Seismic Solutions, TGS, Calgary)

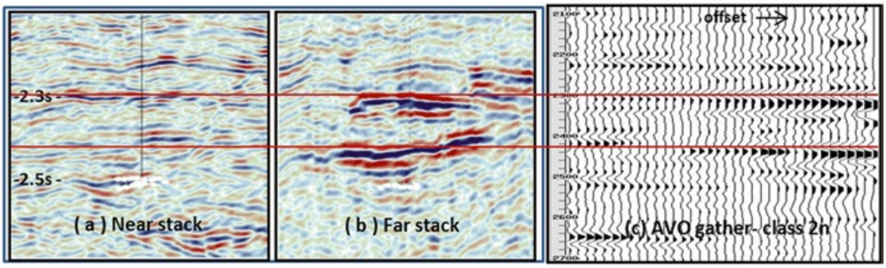

Fig. 9.11 Comparison of amplitudes in near and far angle stacks. Near stack section (**a**) shows weak/no amplitudes (between *lines*) where as far stack (**b**) shows bright amplitudes that was tested oil. AVO gather (**c**) supports the anomaly as class 2n (Image: courtesy ONGC, India)

AVO. The normal impedance contrasts are small and can be either positive or negative depending on the properties of the sand and the overlying shale. In case of positive reflectivity, it being small at near offset and decreasing with offset (Fig. 9.7), the class 2p (positive) AVO anomalies are likely to be missed in normal stack sections. On the other hand, the class 2n (negative) AVO amplitudes, though are small at near traces, increase with offset and can be appreciable in far offsets to be noticeable provided large offsets, adequate to record the AVO anomalies are used. For class 2n AVO, a simple comparison of amplitudes in angle stacks offers a quick and convenient clue to presence of hydrocarbon sands. Events with poor or no amplitude in near stacks but showing bright amplitudes in far stacks (Fig. 9.11) and to lesser degree in full stack (combined effects of near and far) suggest presence of hydrocarbon. On the other hand, anomalies having high amplitudes in near and with relatively lesser in full stacks but showing no to poor amplitudes on far stack section is likely to indicate water. Interpreters generally work on conventional full stack sections which may show high amplitudes in both the cases of hydrocarbon and water saturated sands, similar to class 3 AVO 'bright spot' amplitudes, which may be misleading. Qualitative studies of amplitudes in angle stacks – the near, full and the far, help judge the apt inference and is particularly useful where the interpreter may have constraints to access conditioned prestack gathers for detailed AVO analysis. The class 2n AVO amplitude display patterns in near, full and far stacks are in contrast with that for class 3 AVO, where all the stacks – the near, full and the far show near similar high amplitudes.

However, class 2 hydrocarbon bearing sands may or may not always correspond to amplitude anomalies on stacked data (Rutherford and Williams 1989). A reflectivity versus angle plot for this type of AVO shows negative gradients similar to Class 1 and class 3 (Fig. 9.7). Hydrocarbon sands showing class 2n (negative) AVO with no to poor amplitudes in near offsets but high amplitudes in full and far offset stacks typify Pliocene oil-sands in offshore blocks, India (Nanda and Wason 2013).

Class 4 AVO (Low-Impedance Gas Sand with Hard Top Seal) Model Class 4 anomaly occurs where low impedance gas-sand reservoir is capped by a comparatively hard rock, such as calcareous shale or limestone. Impedance contrast and *Vp/Vs* ratio of the gas reservoir being lower, it creates a strong negative contrast for the reflection from the top of reservoir. However, the reflectivity decreases with amplitudes becoming less negative with increase in offset. This is in stark contrast to amplitude changes seen in Class 3 where the negative amplitudes become more negative with offset. Despite the impedance and *Vp/Vs* for the gas-sand being lower, the AVO pattern is reverse solely because the *Vs* (~shear impedance) of the hard cap rock happens to be higher than that of the gas-sand, unlike in Class-3 where *Vs* of top shale is lower than the *Vs* of the sand. The *Vs* value, thus, has to be considered as a separate input in modeling. The seismic response of class 4 AVO showing a large negative reflectivity at zero offset with very high amplitude and diminishing with increasing offset and having a positive gradient is shown in Fig. 9.12.

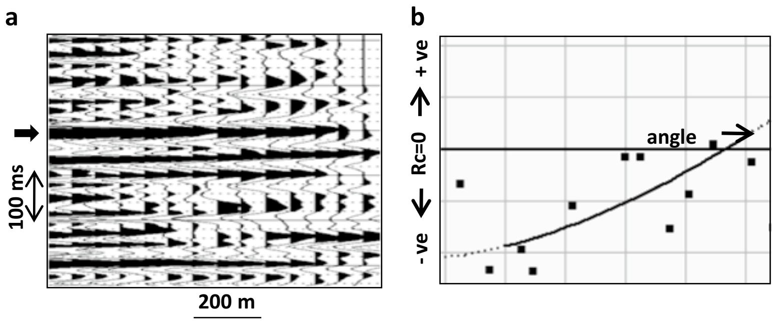

Fig. 9.12 Class 4 AVO attributes. (**a**) High amplitude, negative polarity (peak, *black*) reflection from *top* gas sand decreases with offset, (**b**) Plot of reflectivity versus angle of incidence *curve* shows negative reflectivity and positive gradient curve (Image: courtesy ONGC, India)

The reflectivity and angle plot (Fig. 9.7) shows a positive gradient different from that of the other classes of AVO. The AVO responses in a prestack gather and the gradients for the three major types may be summed up as below, where *Ro* indicates the reflectivity at normal incidence.

(a) Positive *Ro*, high amplitude decreasing with offset; with Negative Gradient… Class 1
(b) Negative *Ro*, high amplitude increasing with offset; with Negative Gradient… Class 3
(c) Negative *Ro*, high amplitude decreasing with offset; with Positive Gradient… Class 4

Typical examples of rock properties of Pliocene gas sands, Offshore, India, causing the AVO anomalies and their attributes are shown in Table 9.1.

Though AVO anomalies are categorized in four types, it is possible that there may be deviations in AVO attribute patterns as rock-fluid parameters of reservoir and of the overlying rocks vary greatly in diversified geologic settings. Rock and fluid properties are also dependent on temperature, pressure, degree of diagenesis and compaction, mineral composition and texture, saturation and viscosity, etc. These factors can significantly affect AVO analysis results and assigning a classification does not guarantee the presence of a commercial prospect.

Zero Offset Intercept, the Gradient and the Product and Cross Plot AVO analysis in a pre-stack gather is the simplest and most convenient way to look for the presence of gas using increases or decreases in amplitude with offset. However, amplitudes

Table 9.1 Rock and seismic properties of Pliocene gas sands, Offshore, India with AVO types

AVO type	Class 1 AVO		Class 3 AVO		Class 4 AVO	
Top seal lithology for gas sand	Shale	Gas sand	Shale	Gas sand	Cal.sh/Lst	Gas sand
Vp (m/s)	2520	3010	2620	2540	3040	2590
Vs (m/s)	1310	1750	1320	1560	1590	1490
ρ (g/cm^3)	2.4	2.2	2.3	2.1	2.3	2.2
P_{imp} - $m/s.\ g/cm^3$	6050	6620	6030	5330	6990	5700
Vp/Vs	1.9	1.7	2.0	1.6	1.9	1.7
AVO indicators for gas sands	Positive Rc, negative gradient, amplitudes decrease with offset		Negative Rc, negative gradient, bright amps. increase with offset.		Negative Rc, positive gradient, bright amps. but diminish with offset	

Examples of typical lithology with rock and seismic properties that cause AVO anomalies used for gas indicators are illustrated. The individual AVO attributes for each class of AVO is also shown. The class 4 AVO occurs when low impedance gas sand is capped by a tight rock having *Vs* higher than *Vs* of the gas sand. Since tight cap lithology is likely to have relatively higher velocity and density (impedance), the negative reflection from the top gas sand may be very bright at zero offset (*Ro*). Basically, the *Vs* of the seal rock decides the AVO type; class 3 (classical 'bright spot') when it is lower and class 4 when it is higher compared to *Vs* of gas sand can be corrupted due to several reasons and thus may impede AVO analysis. Further, picking the exact reflectivity polarity (positive/negative *Rc*) on data can be difficult, often due to noise and limited seismic resolution. In some cases, the polarity convention displayed in seismic may also be unknown to the interpreter as it varies from company to company.

Another way of studying the AVO anomalies is by using a plot of amplitude against square of sine of angle of incidence. Shuey's (1985) two term approximation of Zoeppritz's equations, for small incidence angles (up to ~30°), provides the following simple linear equation of straight line.

$$R(\varphi) = A + B\,sin^2(\varphi)$$

This expresses the convenient relationship between *P*-reflection coefficient $R(\varphi)$, intercept (A), and gradient (B) of amplitude changes with square of (sine of) angle of incident (φ). This is illustrated in the Fig. 9.13 for class 3 AVO showing amplitude variations (Fig. 9.13a), the plot of reflectivity with angle of incidence as a curve (Fig. 9.13b) and with square of sine of angle a straight line (Fig. 9.13c). The best straight line fit to the plot of reflection coefficient against angle of incidence in a pre-stack gather, thus provides a gradient (B) and an intercept (A) on the y-axis at zero offset (Fig. 9.13c). The AVO intercept '*A*' (Positive or negative) gives the

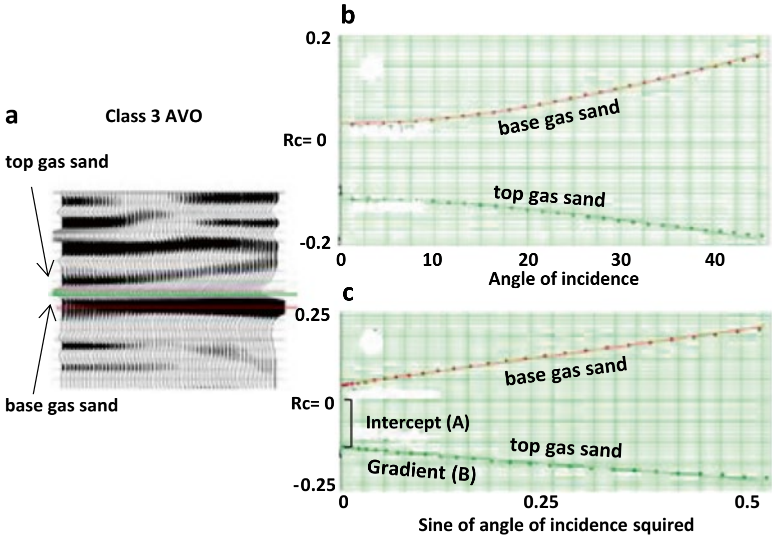

Fig. 9.13 Class 3 AVO (*bright spot*) attributes – (**a**) high amplitude reflection (top sand) with negative polarity increases with offset. (**b**) Plot of reflectivity versus angle of incidence showing a curve whereas (**c**) plot of reflectivity versus square of sine of angle of incidence shows a *straight line* with a negative intercept (A) and negative gradient (B). Attributes for the *bottom* gas sand reflection are also shown (Image courtesy of Arcis Seismic Solutions, TGS, Calgary)

reflectivity at normal incidence *(Ro)* with polarity and the AVO gradient *'B'* (positive or negative), indicates the rate of amplitude change with offset. Displaying the product '$A \times B$' highlights an anomaly that can be interpreted as a gas indicator characterizing 'bright spots' or Class 3 AVO anomalies. However, the product indicator does not work well for Class 2 anomalies and is hard to interpret without prior knowledge of the type of gas sand reservoir in the area. For instance, the Class 1 and Class 4 AVO cannot be discriminated on this basis as both indicate the product as negative.

Sometimes a more effective way of analysis may be creating a cross plot of *'A'* and *'B'* estimated for each sample of prestack CDP gather in the zone of interest which offers more insight to the application of AVO for better prediction results. The *'A' (reflectivity, Ro)* and *'B'* (grad*ient*) are key attributes and can be modeled for AVO to establish the background trend of shales and water sand responses in the area. Any deviation observed in AVO analysis of data may then be inferred due to the presence of hydrocarbon. However, the forward modeling requires *a priori* knowledge of the rock and fluid parameters in the area, desirably from well data. A quantitative AVO analysis, more sophisticated than the routine study of amplitude and intercept *('A')* and gradient *('B')* attributes, is to estimate *P*- and *S*-impedance from seismic by inverting data for predicting reservoir properties. The technique is known as AVO inversion and is discussed in the Chap. 11 on "Seismic modeling and Inversion".

Limitations of AVO Analysis

Despite detailed appraisal of AVO anomaly for qualifying as a hydrocarbon indicator, earlier on, many wells drilled for gas were found to be dry, which suggests that the interpreter should be aware of limitations of AVO which can be due to several reasons. Firstly, the Zoeppritz's equations, which allow estimating the reflection coefficient, the mainstay of the technique, is valid for a single interface only and has several other constraints. Assumptions of plane waves instead of spherical and non-inclusion of layering effects are some factors that may affect adversely the computation of reflection coefficients in model response (Allen and Peddy 1993). Thin-bed effects (tuning thickness), composite events from overlapping of reflections, restriction to ~30° incident angles (when approximations to Zoeppritz's equations are used for AVO analysis), presence of multiples and noise, anisotropy in overburden and its lateral variations, scattering in heterogeneous overburden and absorption are other factors that may affect the results of AVO analysis. In forward modeling for '$A \times B$' cross plot, the setting of the background trend may be ambiguous as rapid lateral changes in rock-fluid properties and varying depth of occurrence, often common in deep water geological plays, can affect the attributes and influence the results by showing a random distribution with heavy scatter and without a clear trend.

Acquisition and processing deficiencies can also cause spurious AVO effects, and appropriate quality of data is a prerequisite for meaningful AVO study. A feasibility study of data quality for AVO analysis may be made first and if found lacking in desired quality, it must be reprocessed. Reprocessing for conditioning the data is important and steps may be taken to improve signal-to-noise ratio that may include (1) removing acquisition footprints without compromising resolution; (2) stringent surface consistent amplitude balancing, and (3) efficient prestack migration to provide true reflectivities. Careful reprocessing of seismic data results in enhancement of effective signal bandwidth with noise muted and preservation of relative true amplitudes that offers better resolution of images. Although these are standard measures adopted in routine 3D processing, the data may not be yet of desirable quality and may require handling of the amplitudes with more care. Preconditioning of data, both 2D and 3D is a must before attempting AVO analysis. Often the constraints of time and access to data for reprocessing may impede AVO analysis posing challenges for an interpreter. In such difficult situations, the final judgment after an AVO analysis may have to come up from interpreter's confidence based on area geology, experience and wisdom.

Yet another limitation of AVO analysis is that it commonly works well in siliclastic reservoirs and often in a particular depth range, known as "AVO Window". The window is usually relatively shallow, where the nature of the geologic setting and the seismic data are agreeable for such studies. It may be recalled that at greater depths, the pore-fluid effect on seismic is less obvious (Chap. 1) and the image quality may be obscured due to reduced resolution and signal-to-noise ratio caused by absorption loss, presence of multiples and other wave propagation effects. This also emphasizes the point that AVO modeling must precede AVO analysis for reliable prediction of hydrocarbon sands.

Velocity Analysis (Vp/Vs) and Prediction of Rock-Fluid Properties

Seismic amplitudes are generally affected by several factors other than geological and its analysis on stand-alone basis can be unreliable for studies of material properties. Velocity analysis, on the other hand, is more dependable for the purpose. Sedimentary rocks are defined by matrix, porosity and fluid contents, which affect *P*- and *S*-wave velocities differently. The *P*-velocity is generally more sensitive and is commonly used for predicting reservoir properties. But predictions based on changes in *P*-velocity alone can sometimes be ambiguous as it depends on other factors such as lithology, clay contents and fractures. Further, several rocks may have overlapping *P*-velocities making it difficult to pin down the causative. The S-wave velocity attitudes, on the other hand, behave in a different way due to the dissimilar wave properties and become useful in identifying the rock properties. The *P*- and *S*-velocities vary differently for changes in rock-fluid properties with *S*-waves known to be insensitive to fluid. The varied differential responses of the *P*- and *S*- velocities to different elastic moduli of rocks can be normalized to a parameter, the *Vp/Vs*, ratio which provides a more reliable indicator of rock and

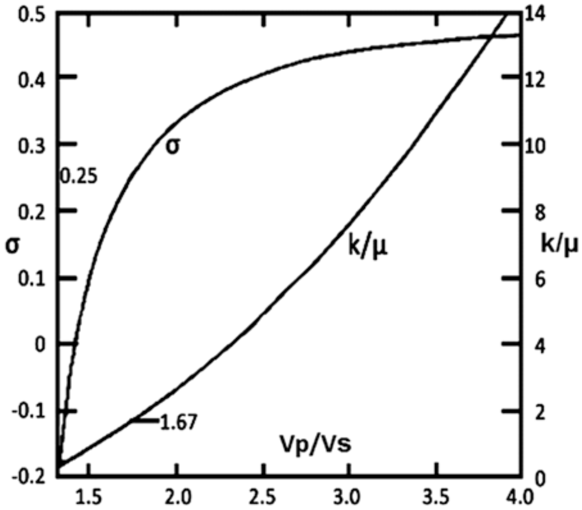

Fig. 9.14 A plot showing the inter-relation of Poisson's ratio (σ), bulk to shear modulus ratio (*k/μ*) and velocity ratio (*Vp/Vs*). Increase in one shows increase in other ratios as all vary similarly though not linearly (After Tatham 1982)

fluid properties than any single velocity can alone achieve. The *Vp/Vs* is a ratio directly related to Poisson's ratio 'σ', which is considered an important lithology and fluid discriminant.

The Poisson's ratio is an elastic constant which characterizes a porous reservoir rock with its fluid content. It is defined as the ratio of transverse strain to longitudinal strain and has correspondence to the ratio of bulk modulus to shear modulus denoted by *k/μ*. Simply expressed lower the bulk modulus (k) of a sedimentary rock (higher the compressibility), smaller is the likely value of 'σ' (Fig. 9.14). Poisson's ratio is linked to *Vp/Vs* by the equation,

$$\left(\frac{V_p}{V_s}\right)^2 = \frac{2(1-\sigma)}{1-2\sigma},$$

and both vary in the same way though not linearly; higher Poisson's ratio corresponds to higher *Vp/Vs* values and vice-versa (Fig. 9.15). Poisson's ratio for sedimentary rocks are reported to commonly vary between 0.2 and 0.4. A hard rock such as limestone has the highest value of Poisson's ratio, followed by shales and water saturated sandstones. Poisson's ratio for gas saturated soft sands mostly exhibit a much lower value of 0.15–0.17, commonly considered as a crucial index for gas saturation.

Vp/Vs for Fluid Content and Lithology Prediction It is often customary to express the Poisson's ratio by *Vp/Vs* as the velocities are better realized and conveniently measured in well and estimated from seismic. Compressibility of fluid in a rock

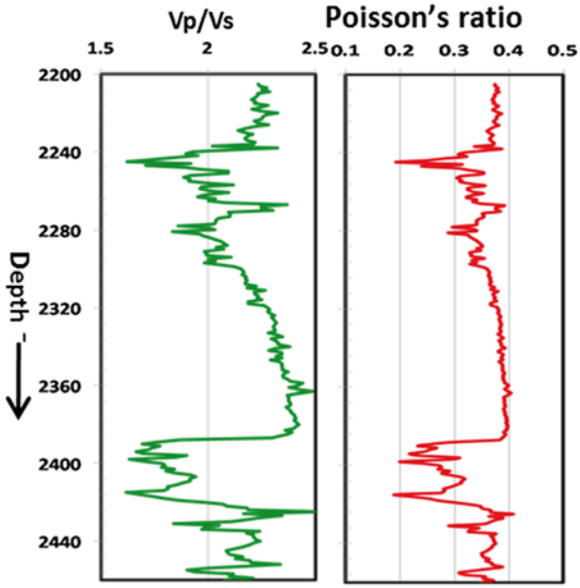

Fig. 9.15 An example showing variation of *Vp/Vs* in comparison with Poisson's ratio *(σ)* on well log curves; changes in one curve reflect similar changes in the other (Image: courtesy ONGC, India)

greatly affects *P*-wave velocity but hardly influences *S*-velocity as fluids have negligible rigidity. Presence of a highly compressible fluid like gas in pore space lowers *P*-velocity considerably whereas rocks saturated fully with water show higher *P*-velocity, water being relatively incompressible. On the other hand, the *S*-velocity is seldom affected in either case, except for marginal effects due to change in fluid density. Consequently, the *Vp/Vs* becomes an excellent indicator of pore fluid, a lower value signifying gas and higher value indicating water saturated sands.

Vp/Vs ratio is also sensitive to lithology. Lithology of a rock with P-velocity within a range of overlapping values of more than one rock can be discriminated by Vp/Vs as the S-velocity for these rocks varies differently. Unconsolidated sands have low P-velocity but can be distinguished by high Vp/Vs values, (around 2.1-2.3), because of relatively lower S-velocity caused by lesser rigidity of the under-compacted sands. The S-velocity of sandstone can be higher than that of limestone and with both having near similar P-velocities (depending on the depth of occurrence and geologic age), the Vp/Vs values may be lower (around 1.6–1.7) for sandstone compared to 1.8–2.0 values for limestone (Wang 2001; Pickett 1963; Castagna et al. 1985).

Shale rocks that play a vital role in hydrocarbon prospect appraisal can have a wide range of *P*- and *S*-velocities and densities depending on its clay minerals and depth of burial. Nevertheless, since shale has less rigidity, the *S*-velocity is likely to be relatively lowered, resulting in high *Vp/Vs* values, of the order 2.2–2.4, and mostly higher than reservoir sands. Clay-rich shales can even show higher *Vp/Vs* values that may be an indicator of depositional environment.

In the exploration for carbonates, *Vp/Vs* can be useful to discriminate tight limestones from porous dolomites despite having similar P-impedance which may help map accurately the reservoir facies (Rafavich et al. 1984). However, it may be mentioned that the *Vp/Vs* values cited for lithology and fluid saturation are empirical to only denote an order and range of values for classification of rock properties.

Vp/Vs for Porosity and Clay Content Prediction Predicting porosity and clay content in a reservoir are crucial to reservoir characterization. Increased porosity and clay content both decrease *P*- and *S*-velocity of a sand reservoir due to lowering of both the bulk modulus and the rigidity. Further, the lowering in *P*-velocity is affected more significantly by pore shapes than the porosity which affects S-velocity to lesser extent. Consequently, the *Vp/Vs* may not be a strong and reliable indicator for porosity. However, with increasing clay content lowering the rigidity, the *S*-velocity is affected considerably more than the *P*-velocity and accordingly, *Vp/Vs* is expected to show higher values with increase in clay content (Fig. 9.16). The *Vp/Vs* values derived from seismic inversion (see Chap. 11) help estimate sand-shale ratio, an important geologic parameter to identify favorable areas for petroleum exploration. Specifically for offshore shallow targets like Pliocene and Pleistocene hydrocarbon saturated channel sands, *Vp/Vs* derived from seismic inversion effectively differentiates good clean channel sands and clayey levee' sands, aiding greatly the field development and reservoir management.

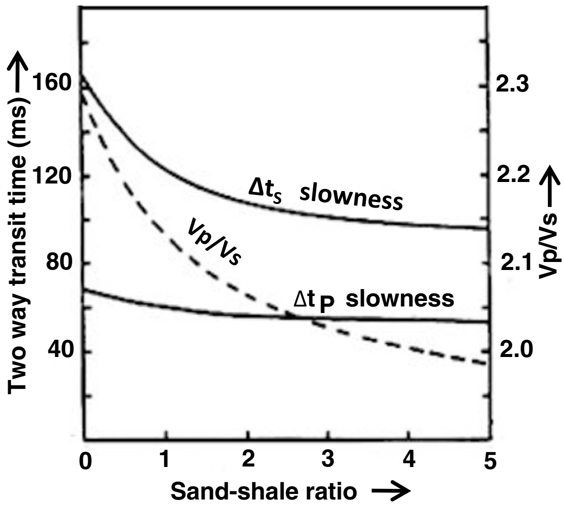

Fig. 9.16 A plot illustrating variations of *Vp, Vs* and *Vp/Vs* with clay content. Increase in clay content (decreasing sand-shale ratio) reduces considerably the *Vs* (increase in Δt) but to a lesser degree the *Vp,* resulting in higher *Vp/*Vs (After McCormack et al. 1984)

The values of *Vp/Vs* as a lithology and hydrocarbon indicator given above may be empirical, confined to a particular geologic area and can only be taken as a guideline to link the low *Vp/Vs* values to presence of sands and hydrocarbon in an unknown geological area. In nature it may indeed vary over a wide range, controlled by texture, porosity and pore shapes of rocks, deposited under varied geological settings. A case study in offshore, India has indicated the *Vp/Vs* ratio measured in the well for Pliocene rocks, varying from 2.1 to 2.4 for shale, 1.8 to 1.9 for oil sands and 2.0 to 2.1 for water sands (Nanda and Wason 2013).

Birefringence for Fracture Prediction When a shear wave travelling in an isotropic medium enters an anisotropic medium (e.g., a fractured reservoir) it splits into two orthogonally polarized waves having different velocities. Figure 9.17 (Martin and Davis 1987) illustrates an E-W polarized shear wave entering an anisotropic medium composed of vertical fractures with polarization oblique to fracture plane oriented NW-SE . The wave splits into two orthogonally polarized waves, S_1 (NW-SE) and S_2 (NE-SW). The polarized wave travelling parallel to fracture plane (S_1) is faster than the polarized wave (S_2) travelling across it. The difference in velocities results in a delay time (ΔT), characteristic of the phenomenon known as birefringence.

Considering a simple vertical fracture system, having fractures (open) oriented only in one direction, the faster polarized wave vectors correlate with the strike of the fracture system. The delay time between the fast and the slow polarized shear

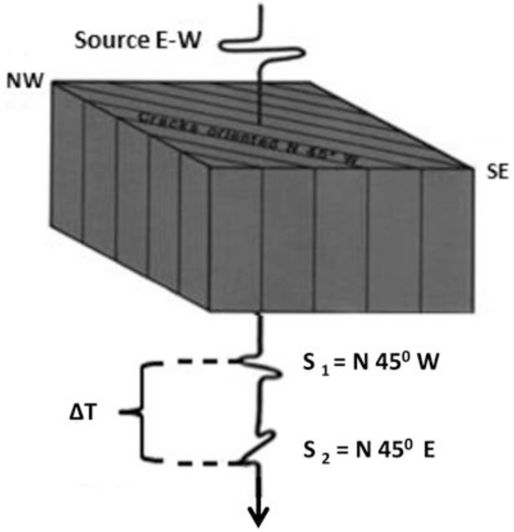

Fig. 9.17 A schematic illustrating 'birefringence'. An E-W polarized shear wave entering an anisotropic medium composed of vertical fractures with polarization oblique to fracture plane (NW-SE), splits to two orthogonal waves. The polarization of the faster wave (S_1) is parallel to fracture plane and the slower (S_2) wave perpendicular to it. The delay time (ΔT) due to difference in velocities of the split waves (birefringence) helps predict fracture geometry. (Modified after Martin and Davis 1987)

waves depends on the fracture density. The shear wave splitting can thus detect and describe the characteristics of a single fracture system present in a medium. Many hydrocarbon reservoirs in the world are observed to be naturally fractured, and it is essential to map fracture geometry for optimal management of fluid flow in the reservoir. However, in media where two sets of differently oriented vertical fractures are present, the use of shear wave splitting to characterize fracture geometry may be limited.

Though the utility and efficacy of shear waves in evaluating rock-fluid properties are immense, availability of shear wave data remains limited, specifically offshore, due to techno-economical constraints discussed in the beginning of this chapter. The only opportunity for using shear data is offered by mode converted waves *(P-S-S and P-S-P)* recorded on land and mostly in offshore by Multicomponent OBC mode or by conventional streamer. The AVO, and particularly the Poisson's ratio, is a sensitive discriminant and require careful assessment of data for feasibility study before attempting analysis.

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Chapter 10
Analysing Seismic Attributes

Abstract Extraction of seismic attributes and their analysis help to reveal geologic information concealed in the data. This requires close interactions between the interpreter and the processor, familiar with attribute processing software packages and the associated techniques.

Amplitude-based attributes are the most convenient and popular to predict rock-fluid parameters, and in some cases they act as direct hydrocarbon indicators. The thin-bed related 'tuning thickness' phenomenon and spectral decomposition techniques are discussed. Spectral decomposition is used extensively for mapping and characterizing thin pays and varying lateral facies in channel-levee complexes.

Geometrical attributes such as dip-azimuth, curvature and coherence are discussed with their geological significance and applications in reservoir engineering and the associated management problems. Composite display of multi-attributes and their analysis constrained with geologic, well and engineering data achieve reliable solutions. Limitations of attribute extraction and their studies are also mentioned.

Attributes are intrinsic properties of a seismic wave signal derived from seismic data. Seismic reflection waveforms carry concealed valuable subsurface geologic information embedded in it and extraction of attributes as well as their analysis provides means to retrieve this information. Attributes that can be measured on a single trace, i.e. amplitude, frequency and polarity, were discussed in Chap. 1. Multitrace 2D data also provide velocity and apparent dip of events along the profile. Multitrace 3D high resolution, high density (HRHD) seismic volume data, however, offer additional attributes, calculated with the aid of computer, which can be conveniently analysed and accurately estimated to provide input for interpreting subsurface geology including reservoir rock and fluid properties. The workstation-based attribute analysis is basically an advanced interactive interpretation coupled with processing, practiced generally to substantiate routine interpretation and improve predictions, sometimes quantitatively. It is, however, important that the geological objectives be well defined so as to select the appropriate attributes to be analysed for the purpose. This may at times necessitate forward modelling and rigorous advanced processing. Knowledge, experience and familiarity with processing

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softwares ensure proper selection of the technique and the apt input parameters to get reliable results. The discussion below briefly touches upon some of the most commonly analysed seismic attributes and their scope of application in petroleum exploration and production with geological implications. These attributes may be categorised as:

I. Primary attributes – amplitude, frequency, phase, polarity.
II. Geometric attributes – dip, azimuth, curvature and coherency.

The velocity is another primary attribute, discussed earlier and will be further addressed in the next Chap. 11

Primary Attributes

The seismic amplitude based attribute is the most convenient and widely used to predict rock-fluid parameters which also serve as a direct hydrocarbon indicator under certain conditions. Variation in amplitudes along a reflection horizon is the simplest means of providing lithology and porosity information, though several innovative and sophisticated approaches and techniques are since developed and are now in use to extract and interpret other attributes to predict rock properties quantitatively. The commonly used techniques for studying primary attributes, mostly for thin beds, include

- Complex trace analysis,
- Tuning thickness and
- Spectral decomposition which are briefly outlined below.

Complex Trace Analysis: Amplitude, Frequency, Phase and Polarity

The seismic trace can be considered as a plot of particle velocity or acoustic pressure with time. The wave form shape of a reflection from an interface, at any time, depends on amplitude and phase attributes of the reflections of individual frequencies contained in the signal bandwidth at a particular time (depth). It is also a function of bed thickness and impedance. Where the bed is thin and reflections from the top and bottom are not resolvable by the wavelet bandwidth, it leads to interference of the reflections, resulting in composite reflection. Most seismic events in nature are composite reflections created by superposition of a number of reflections from closely-spaced interfaces. The composite reflection recorded in time, thus carries the crucial geological information like rock-fluid properties and thicknesses of all beds, collectively. But, composite reflections do not allow reliable and detailed interpretation as they suffer from limited resolution. They exhibit a smeared or summed-up composite response of a group of beds as a whole, which exhibit no clues of individual bed attributes. A breakdown of the composite waveform is thus desirable to segregate the attributes of individual beds and is achieved by transforming the time sequence to frequency domain which offers convenient means to interpret reliably the stratigraphic details. Complex trace analysis is an early technique that delivers information on amplitude, phase and frequency attributes of individual components of a composite reflection event. This may be likened to a process of obtaining derivatives that provide more and detailed information than the whole data itself.

Seismic wave propagation in time is regarded as a complex signal, mathematically defined by a real and an imaginary part (Taner et al. 1979). The recorded seismic trace is the real part of an analytical signal, in x-t plane. The imaginary part, in the y-t plane, is the same sequence, but phase-shifted by 90 degrees. The two are then summed to construct the complex trace for extraction and analysis of individual attributes. The technique computes from a designated time window of interest, on a sample-by-sample basis, the *instantaneous amplitude*, *instantaneous frequency*, and *instantaneous phase*. The attributes are displayed commonly in colour in vertical sections and offer geologic details, both temporally and spatially, and are analysed by variability in attributes rather than their discrete values.

Instantaneous Amplitude (Reflection Strength) Reflection strength is the amplitude of envelope of an event (see Chap. 1). It is independent of phase, which means the reflection strength maxima may be different from the maximum amplitude seen at the peak or trough of the reflection. Reflection strength changes are considered to be more robust and meaningful than amplitude changes in interpretation of stratigraphic details (Anstey 1977). Sharp lateral variation in reflection strength is indicative of major changes in rock and fluid properties caused by sudden lithology change, faults, unconformities, and gas saturation. Gradual changes, on the other hand, may be linked to lateral changes in lithofacies and bed thickness. Though instantaneous amplitude represents the amplitude envelope of a composite reflection, its sample by sample plot may not always resolve the geologic details of its constituent thin beds properly. Instantaneous amplitude is also very sensitive to noise and can tend to be less reliable (Fig. 10.1).

Instantaneous Frequency Instantaneous frequency is a continuous measure of the dominant frequency of a wave with time, independent of phase and amplitude. Considering the genesis of composite reflection comprising of reflections based on individual frequency and bed thicknesses and that frequency is sensitive to bed thickness, the breakdown of the composite reflection, is expected to exhibit instantaneous frequency patterns that characterize it (Partyka et al. 1999). Extracting instantaneous frequency attribute from the composite reflection thus helps reveal the constituent thin beds and their acoustic properties.

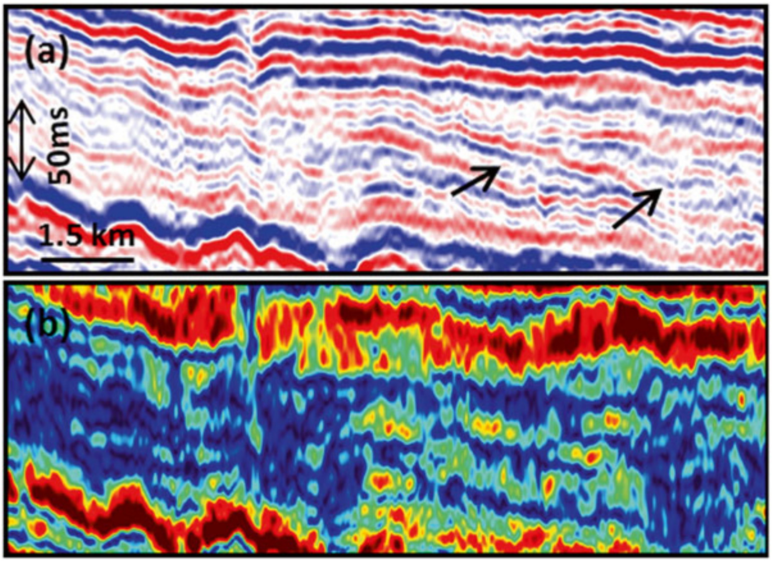

Fig. 10.1 Display of an instantaneous amplitude attribute (reflection strength) section (**b**), extracted from seismic (**a**). Note the obscured expression of the prograding features in the attribute section (due to noise) that is seen clearly (*arrow*) in normal seismic (Images courtesy of Arcis Seismic solutions, TGS, Calgary)

Analysis of instantaneous frequency attribute provides stratal details and is useful in pays identification and delineation of thin hydrocarbon reservoirs, particularly multiple thin pays embedded in a sequence. The limit of lateral pinch-out of reservoir can be precisely mapped from changes in pattern of instantaneous frequency. Instantaneous frequency values show increase as the bed thickness reduces and continues to remain high even as the bed thickness falls below the quarter wavelength limit. This is termed '*frequency tuning'*, a phenomenon likened to tuning thickness (*amplitude tuning*) (Robertson and Nogami 1984), described below.

Association of low frequency shadows observed sometimes with hydrocarbon reservoirs is believed to be due to high frequency loss linked to absorption. *'Sweet spot'* analysis softwares developed on this principle are often used by interpreters to predict presence of hydrocarbon promoting the prospect for drilling. However, the causes for these low frequency shadows are not clearly understood (Ebrom 2004, see also Chap. 6) as many hydrocarbon bearing reservoirs fail to show the shadow effect. Nevertheless, indications of high frequency loss in instantaneous frequency vertically in sections can be attributed to the absorption in rock matrix and the transmission losses due to presence of several thin beds (see Chap. 1), providing clues to type and texture of the reservoir rock. Evidence of frequency lowering laterally in a section, on the other hand, can be linked to change in facies and rapid variations suggesting deposition in fluvio-deltaic environment.

Instantaneous Phase Phase and polarity, often slackly considered the same by interpreters, are separate attributes. An instantaneous phase section displays the phase of a reflection wave form at the time corresponding to peak, trough and zero crossing. Polarity of a reflection, on the other hand, is an indicator of impedance contrast at the interface, either positive or negative. The instantaneous phase is independent of amplitude, does not vary with strong or weak reflections and conveys lateral continuity of reflection events.

Phase correlation can be extremely useful in tracking continuity of reservoir facies where amplitude correlation does not help due to poor impedance contrasts. Instantaneous phase sections emphasize lateral discontinuities of features like faults and pinch-outs better. In poor reflectivity areas, where seismic sequence identification and facies analysis may be difficult in conventional stack, instantaneous phase sections may be helpful in revealing better the discontinuities and the angular patterns of reflections for sequence and facies analysis. Important application of this can be the picking up of subtle *toplaps* and *shingle* prograding clinoforms that are commonly considered potential exploration play. Use of apt choices of colour in instantaneous phase section display is likely to augment visualization of features like faint bed discontinuities, subtle faults and facies changes for better reservoir characterization than that realized from a conventional section.

However, the early complex trace analysis technique for extracting instantaneous attributes yields results that are quantitatively less dependable. Recent advances in techniques dispensing more dependable and effective results like spectral decomposition, is presently more in use for reliable evaluation of instantaneous attributes.

Tuning Thickness: Amplitude Variation with Bed Thickness

Reflections from the top and bottom of a thick bed are well resolved and can be picked easily to determine the temporal bed thickness. But for thin beds, interference of reflections causes a composite event (also see Chap. 2) and makes it hard to estimate thickness. Widess's wedge model illustrates the phenomenon (Fig. 10.2). The top and bottom reflections are seen clearly up to the point of $\lambda/4$ (thickness), which provides the temporal thickness of the bed. At bed thickness of $\lambda/4$, the top and bottom reflections tend to merge and beds thinner than this cause interference. Thus $\lambda/4$ is considered the critical thickness where maximum amplitude is seen and is known as *tuning thickness*. Beds that measure less than this thickness are known as *thin beds* and are characterized by seismic tuning effects of '*amplitude tuning*' and '*frequency tuning*'. Further thinning of the bed, however, does not show any change in the width of waveform but shows gradual diminishing of amplitude to become zero at the end of the wedge (compare with '*frequency tuning*' which continues to show high frequency values despite thinning of bed). The information on thickness for a thin bed can thus be exploited from its amplitude value. To sum up,

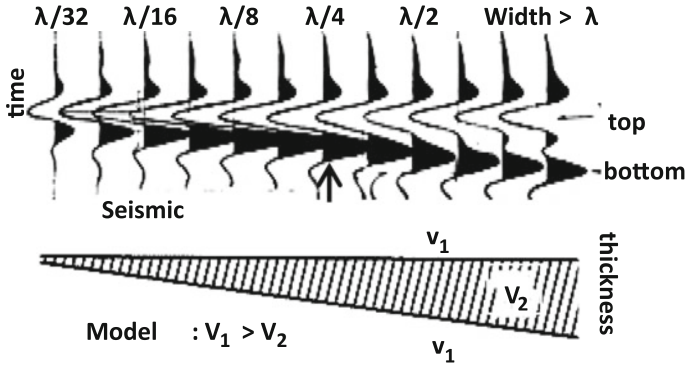

Fig. 10.2 Illustrating tuning thickness with Widess wedge model. Maximum amplitude is seen at λ/4 thickness known as 'tuning thickness' and defines the limit of a 'thin bed'. Below this no change in waveform width is noticed but a gradual decrease in amplitude is seen with thinning of wedge that offers a link between amplitude and thickness of thin beds (Modified after Anstey 1977)

the Widess classical model (1973) established two things: (1) occurrence of an amplitude maxima known as '*tuning thickness*' at quarter wavelength (λ/4) of bed thickness; and (2) defining '*thin beds'* as those lower than λ/4 that are characterized by diminishing amplitude with thinning.

The thin bed dimension at a particular depth, however, will vary depending on velocity and frequency at that depth. It may also be mentioned that the tuning thickness and thin bed classification based on the quarter wavelength (λ/4) criteria may vary if the conditions assumed in the Widess's model change, as discussed in Chap. 2. Phenomenon of *tuning thickness* can detect a thin bed by show of high amplitude, but being a composite reflection, its thickness cannot be resolved directly from the conventionally processed seismic sections. This requires separate processing techniques such as the *spectral decomposition* described below. Incidentally, it may be recalled that tuning thickness-related high amplitudes create impediment in AVO and other amplitude related analyses for attribute interpretation.

Spectral Decomposition (AVF)

As discussed earlier, most reflection events are commonly composite ones with reflections recorded from several closely spaced interfaces caused by the individual frequencies present in the seismic signal bandwidth. Under the circumstances, it is hard to define the geometry of individual thin beds from a collective, averaged seismic response, unless the component reflections are separated out. Spectral decomposition is such a segregation technique in frequency domain, somewhat similar to complex trace analysis. It provides output at each temporal sample of a trace to help estimate stratigraphic details of thin beds including layer thickness (reservoirs) from study of amplitude and phase variation with frequency (Castagna and Sun 2006). The amplitude spectrum provides the variability in temporal bed thickness of the reservoir while the phase spectrum reveals lateral discontinuity (Partyka et al. 1999), signifying facies variations. The frequency spectrum variability helps understand better the thin layers and their vertical and lateral facies changes. However, it is more common with interpreters to conveniently analyse only the amplitude spectrum. The study of amplitude variation with frequency through frequency slices may be termed as *AVF* (amplitude variation with frequency), analogous to AVO.

The technique is based on the premise that each individual thin bed has a natural frequency of its own, at which it is imaged best by showing an amplitude maxima. Essentially, spectral decomposition may be considered as an extension of 'tuning thickness' concept, elevated to a refined level of processing for an analytical solution to quantify thickness of thin beds. The composite reflection offers averaged amplitude as a response to a bandwidth, and if this amplitude is processed for a range of different frequencies, the response amplitudes will show variance. At a particular frequency, the response amplitude will show a maximum value which determines the tuning thickness for that thin bed to estimate layer thickness. The thinner the bed, the higher the frequency at which tuning thickness is likely to cause the amplitude maxima. From known benchmarks carried at wells, the range of amplitudes can now be calibrated to quantitatively estimate bed thickness. Spectral decomposition process creates a series of frequency slice maps, each showing amplitude response corresponding to the particular frequency (bed thickness) or frequency range. Separate amplitude maxima for different individual frequencies in a composite reflection event, thus, help estimate thickness of each (thin) bed (Fig. 10.3).

Spectral analysis, in frequency domain, can be accomplished by different ways of transformation and each has its advantages and limitations. It is not a unique process as a single seismic trace can have a variety of time-frequency analysis

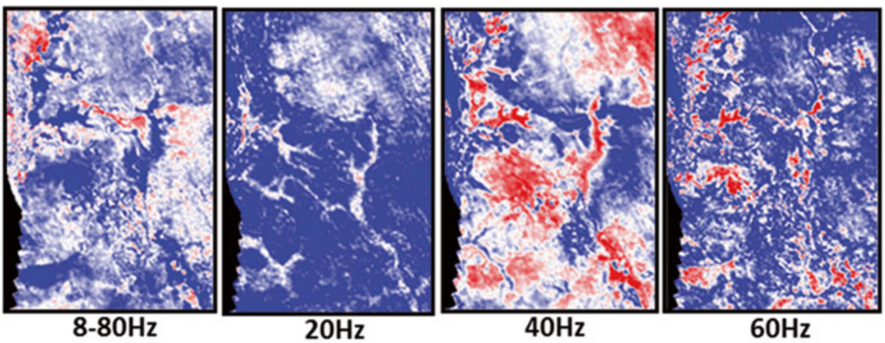

Fig. 10.3 Spectral decomposition and stratal slices (AVF)in plan view. A thin bed exhibits varying amplitudes depending on the frequency by which it is imaged. Amplitude shows maxima for a particular frequency that determines the tuning thickness for the thin bed. The geologic feature (a channel and fan complex) is best imaged by 40 Hz frequency which determines the bed thickness (Images courtesy of Arcis Seismic solutions, TGS, Calgary)

(Castagna and Sun 2006). Nevertheless, frequency-stripping to individual frequencies results in enhancement of seismic resolution, vertical as well as lateral. It provides better temporal resolution of bed thickness (~5–10 m, compared to usual 15–20 m) and lateral resolution superior to conventional amplitude horizon slices. Spectral decomposition helps reveal thin bed geology with stratal details of facies such as channel, levee', point bars and crevasse splays in a channel-fill complex geologic play that could be obscured or totally missed in the normal vertical reflection sections. It is important that the lateral variation in facies be precisely mapped to decide optimal drilling locations for maximum hydrocarbon production. Significant applications of spectral decomposition in hydrocarbon exploration and exploitation may be summarized as below:

- Exploration for subtle stratigraphic prospects.
- Characterization of multiple thin pays in a reservoir unit.
- Drilling for optimal pay in channel/fan complexes for optimal production.
- Understanding fluid-flow patterns in reservoirs vis-a-vis the *flow units* and heterogeneity.

Geometric Attributes

These attributes are so named because they define the geomorphology of subsurface structural and stratigraphic features including their lateral variations. These are very useful attributes which help in improved and reliable interpretation of subsurface geology, especially in reservoir characterization.

Dip and Azimuth

The dip and azimuth of a bed defines its magnitude and direction with respect to a reference. A 2D seismic section shows the apparent dips along the recorded profile without any azimuth information. But a volume based interpretation of 3-D data provides the true (seismic) dip and azimuth of beds. Computed from small time windows, the local lateral time gradients and their bearings derived from samples above and below, indicate the dip and azimuth of strata (Fig. 10.4). Analysis of dip-azimuth attributes provides quantitative estimates of size and shape of geologic bodies and their continuity and trend. Sharp discontinuities in dip-azimuth slices help detect presence of small-scale faults and probable fracture corridors that can have significant implications during hydrocarbon production. Faults are best expressed on the dip map when the fault plane dips are conspicuously different than that of the horizons and are well defined on the azimuth maps when the fault plane directions are opposite to the horizons (Rijks and Jauffred 1991) such as in a high angle antithetic fault.

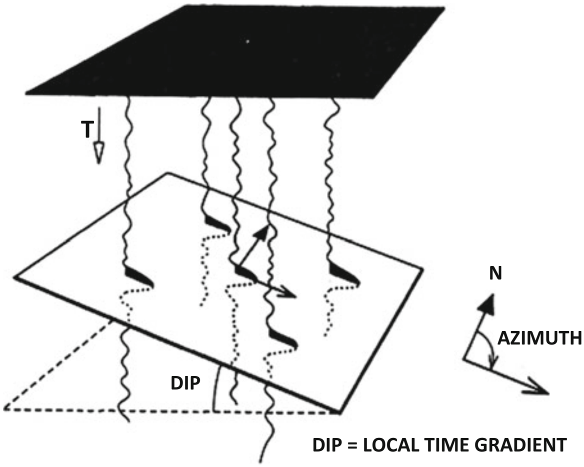

Fig. 10.4 Sketch illustrating extraction of dip-azimuth attributes from 3D seismic volume data (After Fig. 3 of Rijks and Jauffred 1991)

The dip-azimuth based seismic sequence stratigraphic interpretation (SSSI) was briefly discussed in Chap. 8. The technique helps create the tectono-stratigraphic framework in a basin required for a comprehensive 3D basin petroleum system modeling. More importantly, the dip-azimuth vertical section displays can enhance resolution to pick discordant patterns as parasequences within a seismic sequence, for targeting potential thin plays in exploration stage and help reservoir characterization to solve fluid flow problems during development and production stage. As described in Chap. 3, parasequences are thin beds, bounded by marine flooding surfaces that signify paraconformities. Parasequence boundaries may behave as separate flow units within the reservoir, and inhibit vertical communication causing anomalous flow patterns in hydrocarbon production or in water injection during EOR.

The volumetric data analysis for dip-azimuth is fast and accurate, which allows a large volume of data to be easily and quickly interpreted. Significantly, it is independent of pre-picked seismic horizons thereby avoiding an individual interpreter's bias, liable in correlation of horizons (Chopra 2001).

Curvature

Curvature is the rate of change of dip/azimuth of a surface which, in the simplest way, can be represented by arcs of circles with different radii and at any point. The reciprocal of the radius offers the curvature value. The shape of a two dimensional reflector can be defined locally from the curvatures determined from two orthogonal circles of different sizes, one small and the other large, tangent to the reflector (Chopra and Marfurt 2006). The smallest circle has the maximum curvature and the biggest the minimum. Positive curvatures signify anticlines and negative the synclines, whereas zero curvatures signify a planar surface (Fig. 10.5). Curvature

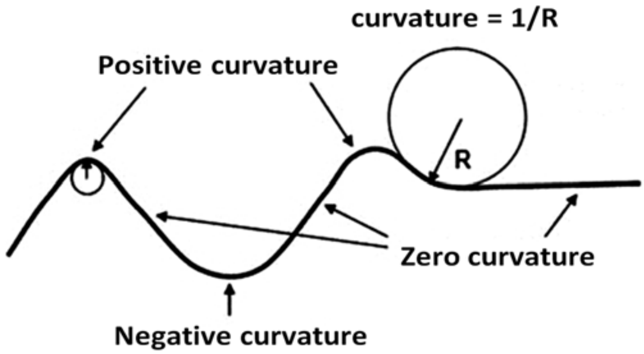

Fig. 10.5 Diagram illustrating curvature and its attributes for different structures. Positive curvatures signify antiforms and the negative the synforms. Zero curvatures signify a planar surface, flank of the structure

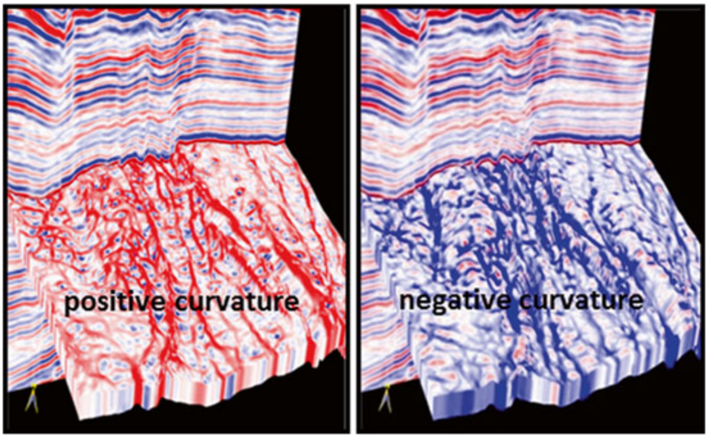

Fig. 10.6 Chair display of Curvature horizontal slices in plan view with vertical section. Positive and negative curvature attributes precisely delineate subtle high and low structural flexures (Images courtesy of Arcis Seismic Solutions, TGS, Calgary)

analysis is relatively insensitive to waveform and is independent of orientation of the surface (Sigismondi and Soldo 2003) but is sensitive to noise and horizon tracking mispicks.

Subtle features like warps and flexures in '*karsts'* and unconformity surfaces can be observed accurately in curvature attribute displays (Fig. 10.6). On the other hand, flat features like channels-fills may not be revealed well. An interesting application of this can be the evaluation of potential trough- fill prospects for exploration. Curvature displays for trough-fills can be conveniently viewed to discriminate the interesting progradational/chaotic mound sand-fills from continuous and flat clay-fill channels (seismic facies analysis, Chap. 3) for hydrocarbon potential. Volume-based curvature analyses can also indicate fracture lineaments, their density and trend and also faults with petty throws, not perceptible in normal stack sections due to resolution. Delineation of these fractures and faults may be the key to understand fluid-flow paths in a reservoir during production and water injection stages.

Coherence

Coherence (coherence coefficient) is a measure of similarity between two waveforms, and similarity can be determined in different ways. The two simpler ways of coherence computation are the cross-correlation and semblance methods. Both methods essentially are based on amplitudes, though exact mathematical treatments to derive the similarity are different. Seismic reflection waveform shapes depend on amplitude, frequency and phase, and are controlled by rock-fluid properties and thickness of layers. A change in waveform, detected by coherency would signify the changes in layer properties. Being sensitive to waveforms, coherency slices in a plan view offers better resolution to analyze stratal details which the amplitude slices may fail to provide.

The process involves a pilot waveform (average) to be computed from a number of traces in a selected window of data (Fig. 10.7), which is then used to measure the coherency of waveforms in the horizon window with respect to the pilot (Chopra 2001). Highly coherent waveforms signify lateral continuity of reflections,

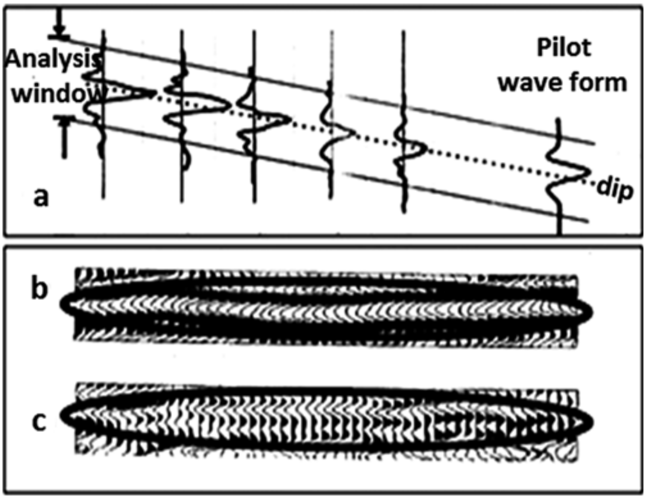

Fig. 10.7 Extraction of coherency attribute from 3D seismic volume (**a**) The pilot wave form is computed by averaging waveforms in a desired window from a number of traces. Semblance is computed by comparing the pilot with all the traces in the volume (**b**) lateral continuity of similar waveforms denotes high coherency and (**c**) dissimilarity as poor coherency of an event (After Chopra and Marfurt 2006, 2007)

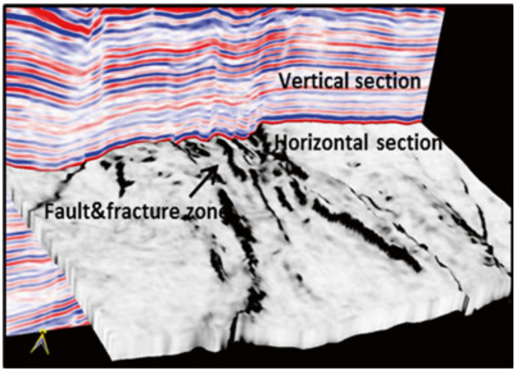

Fig. 10.8 Chair display of coherence slice with vertical section. *White* in horizon slice corresponds to good events on vertical section. The *black* in the plan view signifies poor/no reflection regions and signifies discontinuity/faults and fracture zones well corroborated by the vertical section (Image courtesy of Arcis Seismic Solutions, TGS, Calgary)

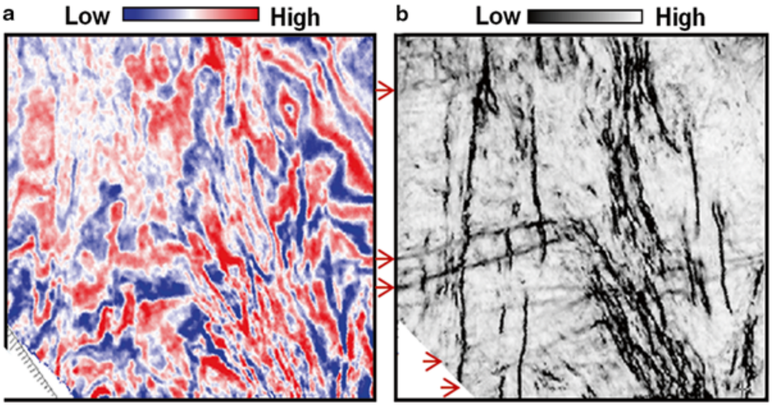

Fig. 10.9 A time slice (1392 ms) generated from (**a**) the seismic, and (**b**) coherence volumes. Notice, the clear faults and fracture details seen on the coherence slice and not so obvious on the seismic slice. There is no visible indication of the weaker faults marked by *arrows* (Image courtesy: Arcis Seismic Solutions, TGS, Calgary)

whereas poor coherency implies discontinuity, which are caused by unconformities, faults and fractures and facies changes.

A coherence slice chair display with vertical section for corroboration is shown in Fig. 10.8. The black in the plan view signifies poor/no reflection regions and signifies discontinuity/faults and fracture zones which is corroborated by the vertical section. Coherence is a powerful technique to map subtle stratigraphic features like channels and identify small faults, especially the strike-parallel ones, hard to notice in time slices (Fig. 10.9). Dip-azimuth, curvature and coherence attributes analysed together facilitate understanding subtle deformations and discontinuities within a reservoir that can greatly mitigate reservoir related engineering issues during production. Apparently innocuous minor faults, facies changes and permeability barriers such as shale strings can cause severe reservoir heterogeneity which if unknown, may significantly influence fluid flow patterns impeding production performance.

The coherence technique works well in good signal-noise data, where the coherence volume can be processed in the work-station automatically and fairly accurately. In seismically poor areas, however, a reflection horizon may have to be picked by the interpreter for extraction of coherence. In such cases, reliability of horizon coherence slices can be highly susceptible to the way the reflection is correlated by an interpreter. Semblance-based coherence can also be vulnerable to noise in data. Coherence being a very powerful and sensitive attribute, it's processing and eventual evaluation must be done cautiously and judiciously, especially in issues linked to reservoir development and production. Evaluation of attribute output slices along with the vertical sections and against the backdrop of the area-specific geologic information is desirable to back dependable predictions. Attribute analysis of seismic anomalies without geological support can be regressive, leading to debacles.

Composite Displays of Multi-attributes

Though used in both exploration and production related issues, it is in the latter that attribute analysis becomes more critical. Ideally, after the geologic problem is defined, the data is conditioned for trustworthiness and a feasibility study is made, only then a multi-attribute analysis project may be attempted. Different attributes under diverse situations offer a variety of information, of which some may be mutually agreeable and others not. Such interactive interpretation and processing of attributes poses a real challenge to the skill and knowledge of the individual analyst. Display of attribute overlays (Fig. 10.10) allows cross checks and helps in identification and corroboration of geologic features to arrive at a more reliable evaluation.

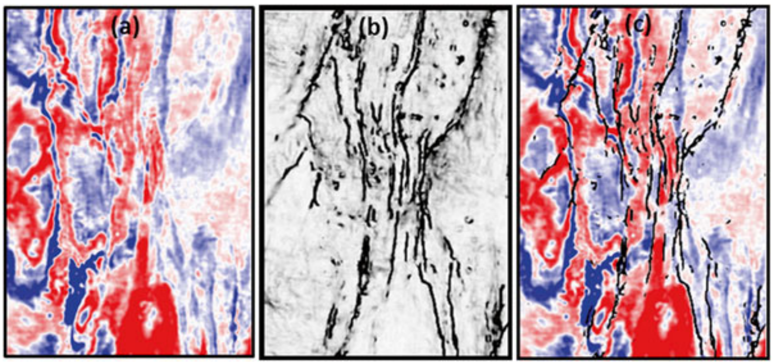

Fig. 10.10 Example of a composite display of attribute slices helpful in reservoir characterization – (**a**) amplitude (**b**) coherence and (**c**) amplitude overlain on coherence. The discontinuities (*black*) indicate faults and permeability barriers and help in reservoir characterization to assess fluid flow patterns (Images courtesy of Arcis Seismic Solutions, TGS, Calgary)

However, it is vital that evaluation of each seismic attribute processed be appropriately constrained with well and engineering data, to achieve reliable solutions. It is a conscientious collaborative task and not merely one of applying software to provide some values, especially in issues concerning reservoir management where the geophysicist's reputation and management's stakes can be high.

Limitations of Attribute Studies

To have meaningful and reliable geological information from analysis of seismic attributes, presence of reasonably noise-free reflections with good resolution is desirable. The seismic data is often of lower bandwidth which would require augmentation of frequency contents to the utmost of the range recorded. The expertise and experience of the data processor matters in proper data conditioning which includes noise cancellations, removal of acquisition footprints, correcting for zero phases, broadening the spectral bandwidth and preserving the true amplitude. Simple adjustment of display mode, scale and colour blending can sometimes be also revealingly important. Ultimately, lot depends on the agreeability of data quality to its object-specific processing modalities and it must be ascertained before starting the analysis.

Seismic response also depends largely on the depth of occurrence and the geologic environments which influence the rock-fluid properties. Responses are expected to vary widely, under different depositional and tectonic settings. Even within a limited small depth range in a well, sand and shale units can have dissimilar rock properties and different seismic responses. Attribute studies require appropriate calibration with well data to prove reliable and effective. Attribute interpretation is not unique and displays put in any form in plan view can be visualized to have some geologic pattern depending on the interpreter's perception. It is therefore important the inferences drawn about seismic geobodies be checked for veracity by geological entities probable in the area. For instance, an attribute pattern visualized as a channel by an interpreter, when verified by overlaying it on paleostructural map, showed the channel geometry and flow direction against the dip, thus failing the check.

Attributes are usually easy to extract but difficult to interpret. The interpreter needs to understand the specifics of the attribute processing methods, the assumptions in their built-in logics and, more importantly, their suitability to the geologic model before selecting the particular attribute analysis in the work-flow. If the attribute pattern cannot be correctly linked to the specific exploration or development objective at hand, the exercise can be pointless. Working familiarity with the various techniques and experience of an interpreter and more importantly one's harmonization with the processing expert can go a long way to insure effective results and indeed can offer true tributes to attributes.

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Chapter 11
Seismic Modelling and Inversion

Abstract Modeling is a computational process to determine the seismic response of a given geologic model and can be 1D, 2D and 3D and structural or stratigraphic. Synthetic seismogram is the most elementary and common example of one-dimensional (1D) modelled seismic response of the earth. Field of application, benefits and limitations of forward modeling are briefly stated with examples.

Inverse modeling is the reverse process of forward modeling where the subsurface geologic model is synthesized from the seismic data. Seismic inversion transforms seismic reflectivity to inverted reflectivity or the impedance. This provides an effective and powerful tool to interpret seismic data based on impedance, the layer property, instead of its interfacial property given by reflection amplitude. Reservoir rock and fluid parameters determined from improved resolution of inverted impedance sections are input to reservoir modeling and flow simulation making it an integral part of interpretation work flow for reservoir management.

Several other inversion techniques and their outputs, linked to impedance-related properties, are also outlined. Inadequacies in processing seismic inversion are stressed.

The seismic reflection method provides images of the subsurface in the form of its 2D or 3D seismic response. 1D seismic response in a trace may be considered a simple convolution of the earth's subsurface reflectivity sequence with the source signal wavelet. Geoscientists interpret seismic data consisting of multiple traces as they look for indication of oil and gas, a task which is fraught with challenges. In their quest for understanding data in terms of the arrival time, impedance, reflectivity and amplitude of the seismic events for predicting subsurface geology and presence of hydrocarbons, they look for tools that can help them in such exercises. Seismic modelling is a very useful simulation tool employed for such a purpose.

Modelling is a computational process to determine the seismic response of a given geologic model. The propagation of seismic waves from the source to the subsurface lithologic interfaces and their reflections back to ground receivers is simulated to obtain a synthetic seismic section. The process of computing the response is known as seismic forward modelling. Conversely, the reverse process of deciphering the geologic model from the observed seismic data is termed inverse modelling (Fig. 11.1).

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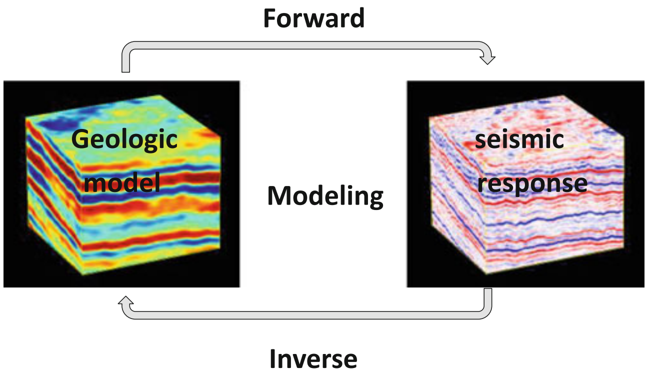

Fig. 11.1 A conceptual diagram of seismic modeling. Forward modeling generates the seismic response from a geologic model where as inverse modeling generates a geologic model from a given seismic response (Image courtesy of Arcis Seismic Solutions, TGS, Calgary)

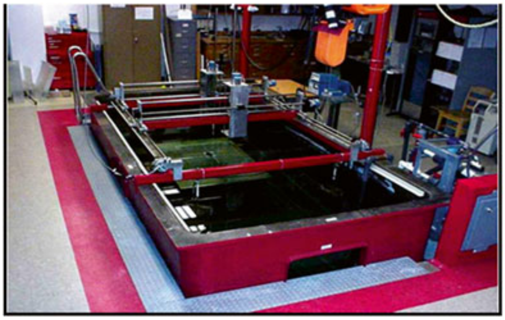

Fig. 11.2 Marine/acoustic physical modeling system at University of Houston. The tank is equipped with a positioning mechanism, and a measuring and recording devices. Marine experiments can be simulated in the tank using sources and receivers (Image courtesy of AGL, Houston)

Seismic responses can be simulated for models that are physical, as in laboratories, or mathematically (numerical), wherein the rock properties are specified as model inputs. Though laboratory physical models (Fig. 11.2) are real and can be made to imitate the earth model, the computed response may still not replicate the actual seismic image that would have been recorded on the ground. This is primarily because of the limitations in simulating the subsurface geology in a laboratory, which is much different from the in situ set up in nature. The most challenging factor, perhaps, is the huge order of inequality in dimensions of the models involved in nature and in the laboratory. Consequently, numerical modelling is most common in practice in the industry.

Simulating the response of subsurface geology through modelling serves several purposes for application in diverse fields of seismic. Forward modelling is widely used in seismic data acquisition for optimising survey lay out designs and acquisition parameters and in data processing for testing and calibrating algorithms. Typically, interpreters employ seismic modelling to gain better insight to understanding of observed seismic responses to subsurface geologic changes so as to relate these response changes assertively to variation in rock and fluid properties. Modelling application in interpretation includes development of geological models to investigate structural and stratigraphic problems, especially in geologically complex areas and often to validate interpretations, such as in cases of direct hydrocarbon indicators (DHI). The input geologic models can be structural or stratigraphic, for which seismic responses can be computed in 1D, 2D or 3D mode depending on the objective. Once the input model parameters are given, the seismic response is computed and then compared with recorded seismic for an acceptable match. Generally it involves repetitive computations and comparisons. Each time a discrepancy between computed response and real seismic is observed, the model parameters are suitably modified, response recomputed and compared until a desired match with actual is achieved.

Seismic Forward Modelling

1D Modelling, Synthetic Seismogram

The most elementary and common example of forward modelling is the computation of the synthetic seismogram, which is a one-dimensional seismic response of the earth. The synthetic seismogram is essentially a trace of computed normal incidence reflections from a series of points aligned vertically in depth. It is generated by making use of the reflectivity series of the subsurface rock strata, measured by the well log curves and convolved with an appropriate wavelet meant to match with field seismic trace (Fig. 11.3). The purpose and process of generating a synthetic seismogram, the challenges involved in seismic match at the well and the possible reasons for mismatch are described in Chap. 3. A properly prepared synthetic seismogram and its comparison with real seismic not only provides insight to typical seismic response of subsurface rocks at the well, but also indicates the quality of resolution in the acquired data. 1D modelling in the form of synthetic seismograms is employed extensively for the customary well calibration for a desired good match. But often the synthetic and seismic match is poor and it then becomes important that the causes for the mistie be analysed, instead of ignoring the calibration exercise by putting it away. The mismatch analysis can help get insight to sort out certain aspects like ensuring well location, velocity and sonic measurements in the wells and the seismic data processing efficacy.

In seismic modelling, a Ricker wavelet of a chosen dominant frequency is sometimes used for computing response. It is a zero phase symmetrical wavelet with maximum amplitude at zero time – the arrival time of the wavelet (Fig. 11.4a). Ricker wavelet is simple to realize, useful for resolving power and convenient for picking reflection events (peak/trough). Seismic acquisition systems, however, commonly use dynamite source which generates minimum phase wavelets, with asymmetrical concentration of energy following the arrival time (Fig. 11.4b). The

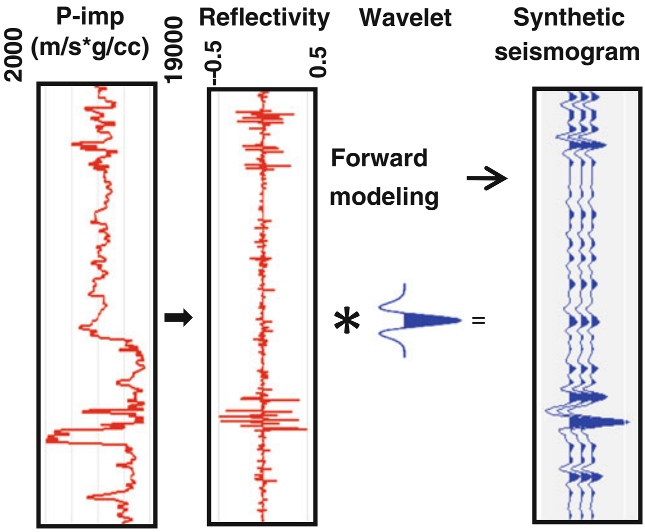

Fig. 11.3 A schematic depicting the forward modeling work flow. It computes the seismic response (synthetic seismogram) of a given geologic model defined by a reflectivity series by convolving it with a chosen source wavelet. The reflectivity series is derived from the impedances well log curve calculated from the sonic and density measurements in the well (Image courtesy of Arcis Seismic Solutions, TGS, Calgary)

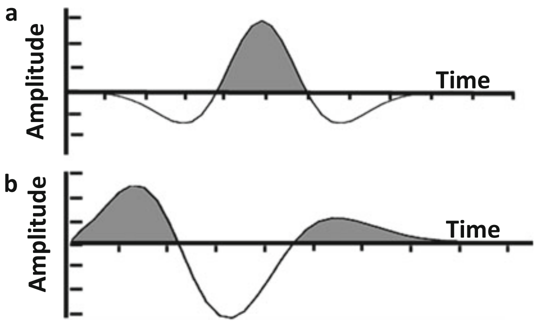

Fig. 11.4 An illustration of wavelet characteristics. (**a**) Zero phase wavelet is symmetrical with maximum amplitude at arrival time and is commonly used for generating synthetic seismograms. (**b**) Minimum phase wavelet has asymmetrical concentration of energy (front loaded) following its arrival time

wavelet has longer duration than its zero-phase equivalent and offers relatively less resolving power. Seismic interpreters prefer to work with data offering better resolution, and the seismic minimum-phase data is processed close to zero-phase data.

Vibroseis source, however, has no such problems as it produces the embedded zero-phase wavelet, the *Klauder wavelet.* Some prefer to use the source wavelet that is measured during generation, often a practice in marine offshore surveys. Nonetheless, a more common option these days is to extract the wavelet from the stacked data being interpreted. This is done either by using a statistical method for estimation of the wavelet, or by comparing the seismic trace at the location of the well with the impedance reflectivity derived from the well log data.

2D/3D Modelling, Structural and Stratigraphic

Structural Modelling Tectonically complex areas are known to impact wave propagation and generate poor seismic images that are confusing and challenging to interpret. The subsurface with warped and layered reflectors cause several problems like (1) focusing and defocusing effects; (2) absorption and transmission losses; (3) inter-bed multiples; (4) severe lateral and vertical near-surface velocity variations and (5) generation of mode converted waves. These create complexities and result in poor images. Also, in highly deformed zones, such as fold and thrust belts, the steeply dipping layers and complicated structural geometry of thrusts, overthrusts and associated fault splays combined with frequent velocity changes cause complications in wave transmission and create obscure images that do not depict the subsurface correctly. Another area where wave propagation can be intricately affected is in zones of high-pressured shale and salt diapirs with associated near-vertical structures, characterized by a significant velocity contrast with surrounding sediments. Reflection seismic (P) also produces poor and unreliable images below gas chimneys and especially below salt overhangs, failing to delineate accurately the salt geometry and the related hydrocarbon traps. Other geologic examples of poor or no seismic imaging include those of formations underlying thick section of high-velocity intrusive rocks and the zones below fault planes at the foot wall side, often referred as ‘fault shadow’ area.

Use of 2D/3D forward modelling tool offers clues to understand the complex deformations vis-a-vis the wave propagation problems and help map subsurface stratal geometry better from seismic. Modelled response may be used to test diverse geometries of structures such as tight folds, thrusts, and salt diapirs, to see which configuration gives the best match to the recorded seismic data to help reduce uncertainties in interpretation in such cases. An example of simulated response of a depth model of a salt dome with abutting flank beds, commonly a hydrocarbon trap for exploration, is shown in Fig. 11.5. The synthetic response behaves as a guide as it shows the geometry, arrival times and amplitudes of the dome flank and of the abutting beds. It also shows the degree of deterioration in image quality that is generally expected due to steep dips of the flank at the top part.

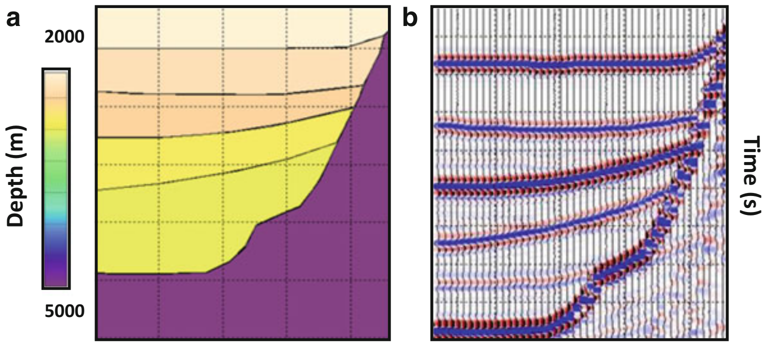

Fig. 11.5 An example of a 2D forward modeling. (**a**) Geologic model in depth showing beds abutting against the flank of a salt dome (**b**) synthetic seismic response computed for the model. Such synthetic models are useful to realize seismic response in terms of arrival time, amplitudes and geometry of beds and salt dome flank. Note the image deterioration due to steep dome flank at *top part* (Images courtesy of Arcis Seismic Solutions, TGS, Calgary)

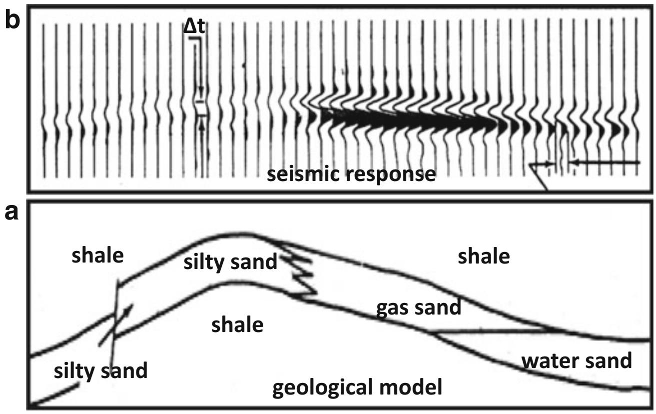

Fig. 11.6 An example of a stratigraphic modeling of a strati-structural trap. (**a**) A low-impedance gas sand with a water contact on one flank of an anticline, that changes facies to silty sand at the crestal part is modelled to help interpret seismic. (**b**) The computed seismic response. Note the increased number of variable inputs needed for stratigraphic modelling (After Schramm et al. 1977)

Stratigraphic Modelling Stratigraphic modelling is more elaborate due to the involvement of larger number of variables as input. In addition to geometry of the geologic feature, variations in rock-fluid properties, i.e. porosity, fluids and contacts, bed thickness and lateral changes in velocities, are also taken for consideration. A strati-structural trap, hosting gas sand with contact on one flank and changing facies to silt at the crestal part of the anticline is modelled to interpret the observed seismic (Fig. 11.6). The modelled amplitude response clearly shows the gas and water saturated sands though it does not pick the fault perhaps due to its

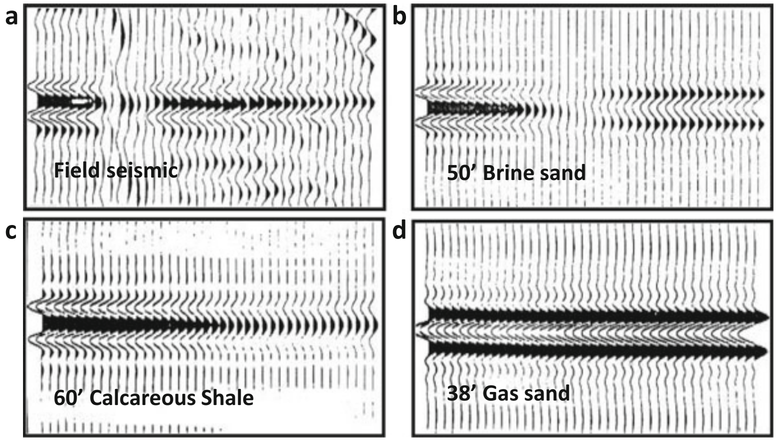

Fig. 11.7 Examples illustrating seismic model used to validate a DHI anomaly. Three lithologic layers with varying thickness and fluid content at (**b**), (**c**) and (**d**) were modeled to match field seismic (**a**), suspected as a gas sand. The response at (**c**) matches best and helps interpret correctly the high amplitude due to calcareous shale layer (After Neidell 1986)

small throw. Another application is exemplified in Fig. 11.7 where modelling is used for validation of a high amplitude anomaly suspected for gas sand. Responses of three likely geologic models with different lithology and fluid content were computed and compared with observed seismic. The one with best fit offers the obvious answer – the anomaly was caused by calcareous shale (Fig. 11.7c). Many times the interpreter may be handicapped by data without access to prestack gathers and modeling in such cases may come in handy for authentication of DHI anomalies. Subtle variations in amplitude and waveform observed in seismic often necessitate modelling to guide or corroborate interpretation in making reliable prediction of reservoir parameters.

2D/3D forward modelling requires the input of a geologic section in depth with density and velocity assigned to each of the individual layers and a wavelet to generate the seismic response. The input also includes an assigned overburden velocity function to transform the depth domain to time in the modelled version to indicate arrival times of different events. The 2D synthetic is commonly generated by simple convolution process using ray-tracing procedures, a fast and generally adequate representation of the earth model. Whereas 3D modelling involves a more detailed wave equation approach to get better insight to seismic response needed in structurally complex areas. 3D modeling has most applications in fundamental research projects for creating, checking and/or calibrating processing algorithms. Wave equation solution takes into consideration the propagation effects such as refraction, diffraction and attenuation but requires migration and other necessary processing steps to provide accurate model response. Typically, the wave equation modelling is seldom a part of common interpretation work flow.

Ideally, forward modelling should be used before undertaking expensive and intricate acquisitions (Chopra and Marfurt 2012) such as multi-component 3C/3D, time lapse 3D and wide angle surveys aimed at solving specific geological or engineering problems. Responses simulated for a wide range of layouts of source and receiver line geometry and other crucial recording parameters such as spread length, bin size, fold, etc., for designing and parameterizing a survey, offer insight to performance evaluation of different sets of configurations which helps decide the most favourable cost-effective option to choose from. Sophisticated data acquisition techniques may fail at times in providing desirable geological information either because the survey is not object-specific or because of inadequate parameterization of survey elements.

Limitations of Forward Modelling

One of the critical issues for achieving a good 'model-actual' match is the selection of the wavelet for computing model response. Response calculated with a Ricker wavelet, for subtle as well as complicated stratigraphic models may not match well with the actual seismic, necessitating a more appropriate wavelet for convolution. This would require, ideally, the knowledge of exact seismic waveform at the depth where the feature is to be imaged. The source wavelet, though known at the surface, changes in form due to propagation effects and is hard to determine the waveform precisely at depths. It is usually estimated statistically from seismic data and often constrained by log data at a well where available. But again, the estimated wavelet can greatly differ from the real wavelet away from the well due to lateral changes in attenuations, reverberations, or variations in near surface conditions and in data acquisition parameters. Another problem, as faced in stratigraphic modelling for hydrocarbon reservoir characterization is the appropriate choice of the large number of geological variables and their physical values as input to the model. Often the lack of adequate knowledge about the laterally varying velocity field can be a great impediment. It may be also mentioned that solutions offered by modelling are not unique as the computed seismic response can match more than one geologic version of the model.

Inverse Modelling

The forward modelling process as illustrated in Fig. 11.3, has the model input of log curves displayed on the left and computed seismic output response on the right. Turning around the display with seismic as input on the left and the impedance curve as output on the right, would represent the reverse process of forward modelling, called the inverse modelling (Fig. 11.8) where the subsurface geologic model is synthesized from the seismic data (also see Fig. 11.1).

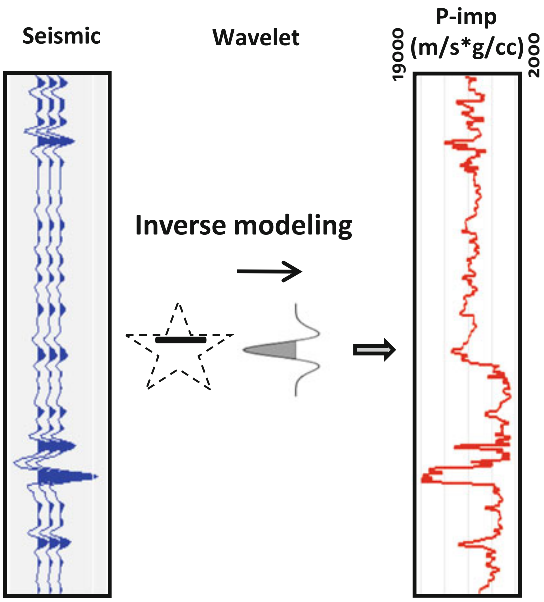

Fig. 11.8 A schematic illustrating the general workflow of inverse modeling, which is essentially following the reverse process of generating a synthetic seismogram. Forward modeling generates seismic from a geologic model where as inverse modeling generates a geologic model from the seismic data (Image courtesy: Arcis Seismic Solutions, TGS, Calgary)

Inversion of seismic data to obtain the geologic information is a great innovation in seismic technology, immensely useful in hydrocarbon exploration and production. Seismic inversions enhance resolution and deliver details of layer properties that are not feasible to get from normal stacks. Inversions can be of several types such as: (1) operator based; (2) recursive; (3) model based; or (4) geostatistical (stochastic).

Operator-Based Inversion

The seismic waveform changes its amplitude and frequency during propagation in the subsurface by physical processes like absorption, scattering and refraction etc. To obtain the true amplitude and frequency responses that can be related to interfaces of layers and their properties, it will need appropriate corrections for the propagation effects created by the travelling wave. Reversing these effects is achieved to certain extent during data processing. Compensation of attenuation losses, deconvolution and migration are a few examples of such processes in which operator-based inversions work numerically in the reverse way, to compensate for the propagation effects. Operator-based inversion is essential and is indispensable in data processing workflow to provide reliable data for interpretation. Nonetheless, the operator based compensation cannot fully compensate and negate the effects to restore the real responses, as that would entail the actual process of propagation occurred in the earth to be physically reversed, by all means an impossibility.

Recursive Inversion

Recursive inversion is of an earliest and elementary type. It essentially assumes that seismic amplitudes are proportional to reflection coefficients and transforms the input seismic traces to acoustic impedance traces. This, however, does not fully satisfy the basic assumption, as the wavelet is not removed. Consequently, the wavelet side lobe (wavelet length) effects are not eliminated, which impedes resolution. Also, the results are produced within the initial existing seismic bandwidth, so that the method does not offer a significant advantage relative to interpreting conventional seismic data. A broadband reflectivity series, on the other hand, can be obtained by removing the embedded wavelet from the seismic traces, a process somewhat similar to deconvolution. However, the removal of the wavelet from the trace to arrive at a suitable reflection coefficient series is not unique, and there can be more than one geologic solution. To overcome this mathematical limitation, some inversion methods adopt ways to get constrained with a priori model for the best possible solution within the seismic bandwidth.

Model-Based Inversion

An important aspect of seismic interpretation is to carry out detailed investigation of seismic properties to extract information pertaining to reservoir lithology and hydrocarbon fluids. One way to approach this goal is to convert the observed seismic through an inversion process into impedance and velocity which are the fundamental physical properties of a rock, to infer lithology and fluid. Model based inversions are deterministic in nature and are achieved by performing inversion on a seismic trace constrained with *a priori* model (well data), attempting essentially to improve resolution. With advances and innovations made in inversion techniques, additional rock moduli like Poisson's ratio, incompressibility (Lambda), shear modulus or rigidity (Mu), and Young’s modulus (stiffness modulus) etc., can also be estimated, which provides more information on rock-fluid properties for better geoscientific and engineering evaluations. Because of its efficiency and quality, most oil and gas companies now use seismic inversion to increase the resolution and reliability of the data to improve porosity, pay thickness and fluid saturation estimates in reservoirs.

Geostatistical (Stochastic) Inversion

Geostatistical inversion is performed on post or pre stack seismic data and is a probabilistic approach to estimating reservoir properties away from the well, crucial inputs for reservoir modeling. The technique uses integration of multidisciplinary data from many sources and allows obtaining multiple earth-model realizations, each of which honours the seismic as well as the well data. This also helps bring out the uncertainty in the results that can be quantified. The earth-model estimation is constrained with the seismic, regional geostatistics as well as the high resolution acoustic impedance data from the well logs to match the known geological patterns in the area.

Essentially many different input models are generated using distributions of earth property models from well data to computes synthetic for comparing it to the input seismic data. The error between the synthetic and the seismic being inverted is minimized in an iterative way leading to the output inversion model. The large number of realizations generated are sometimes averaged to represent a single best fit property model (Cooke and Cant 2010), as it is considered close to the deterministic inversion (model-based inversion).

Rock-Fluid Properties and Seismic Inversion

Reflection events are caused due to contrast in impedances across interfaces. The observed amplitude changes, however, may be due to lithology variations of rocks above, below or on both sides of the interface. The amplitude attribute information is thus limited to information of the interface only. By contrast, the impedance (product of density and velocity), is a distinctive property of a layer, obtained from the two entities measured directly by well logs. Thus, while impedance is a layer property, seismic amplitude is an attribute of the layer property. If quantitative interpretation of seismic data for thin reservoirs is to be attempted, it is to be based on analysis of formation properties (impedance), instead of the interfacial reflection amplitude attribute. Seismic inversion achieves this by transforming seismic reflectivity to inverted reflectivity or the impedance.

Seismic inversion can be done with post stack or prestack data and most techniques employ *a priori* model which is typically built from well log data. Constrained with a model, it not only helps increase resolution but also reliability in the inverted results that improves confidence in estimation of reservoir properties. Seismic inversion techniques that enable to quantitatively estimate the important rock properties are briefly discussed.

- Interval Velocity *(Vp)* inversion
- Acoustic impedance *(AI)* inversion
- Elastic Impedance *(EI)* inversion
- Simultaneous inversion*(SI)*-
- AVO inversion

Interval Velocity Inversion

One of the simplest forms of inversion is the decades- old velocity inversion. Reflectivity at an interface can be expressed simply as $Rc = V_2 - V_1/V_2 + V_1$, without considering the density. Assume the post stack seismic trace amplitude as a measure of normal-incident reflection coefficients, *Rc* with time. If velocity V_1 of the first layer is known, from the above simple equation, velocity of the second layer V_2 can be estimated. Similarly, velocity of following layers can be estimated successively to produce a plot of interval velocity with time. Velocity inversion technique essentially transforms the seismic reflectivity trace, after enhancement of seismic bandwidth through special processing, to a continuous velocity log *(CVL)* in depth domain, likened to a sonic log recorded in the well. The pseudo sonic log, known as 'Seislog' (Lindseth 1979), has relatively better resolution and provides valuable information about lateral change in lithology and porosity, convenient for stratigraphic correlation and interpretation of layer properties (Fig. 11.9). However, with recent development of sophisticated impedance inversion techniques, it is now seldom used.

Acoustic Impedance Inversion

Operated on post-stack normal incident seismic data, acoustic impedance inversion is relatively simple, and provides P-impedance only. A priori model for acoustic impedance inversion is usually built from well log data. The reflection coefficient

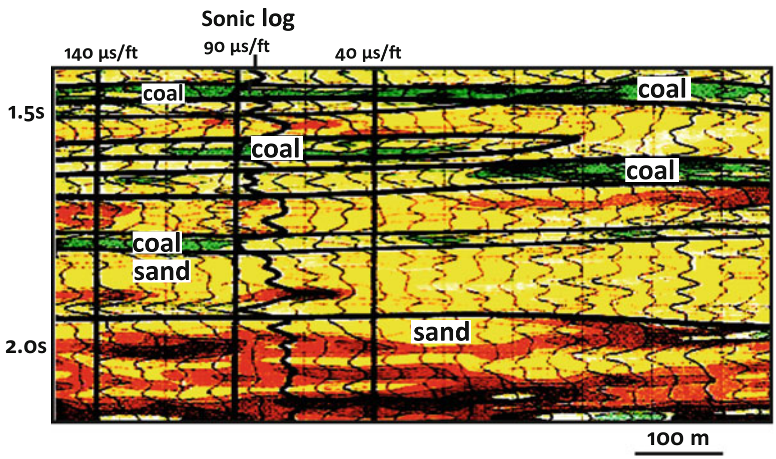

Fig. 11.9 An example of velocity inversion. Inversion is carried out on seismic traces ('Seislog') in which the amplitudes (*Rc*) are converted to interval velocities *(CVL)*. Each trace is like a sonic log which makes interpretation of layer properties easier and more accurate. Note the excellent match of inverted velocity with sonic (*solid black trace*) at the well (After Mummery 1988)

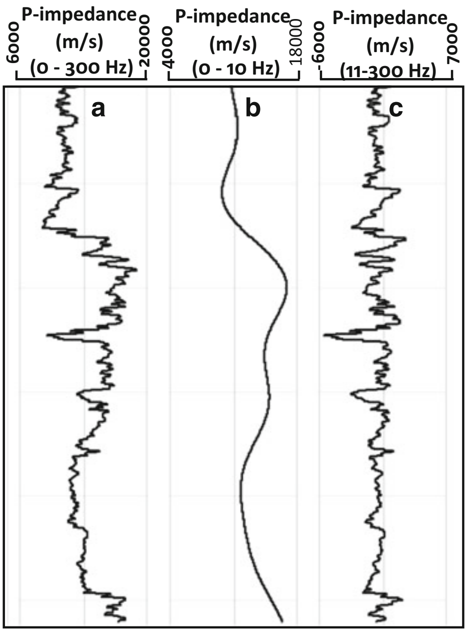

Fig. 11.10 An example illustrating the filtering effect on a well impedance curve. (**a**) Broad band (0–300 Hz), (**b**) filtered with low pass (0–10 Hz) and (**c**) filtered with high pass (11–300 Hz) frequencies. The low pass curve (0–10 Hz) yields the crucial low velocity trend used in impedance inversion to obtain values that are comparable to well impedance values. The high pass curve (**c**) shows finer velocity variations without any trend (Image courtesy of Arcis Seismic Solutions, TGS, Calgary)

series derived from sonic and density logs are used to estimate statistically the wavelet from seismic data. The wavelet is used to compute the response of the model reflectivity series at the well for a comparison with the seismic data. The starting model may be iteratively updated in a way till a reasonable match with seismic is met and the estimated wavelet is considered appropriate. Inversion of seismic volume data is then carried out with the wavelet to create an impedance sequence.

The inversion process involves broadening of the limited seismic bandwidth by adding low frequency and enhancing high frequencies and delivers impedance sections of superior resolution. The low- frequency trend, which forms the basis of impedance or velocity structure, is usually derived from well logs and is added-on to the inverted impedance traces for making crucial quantitative interpretation (Fig. 11.10). In the absence of well data, the low-frequency trend can be derived from seismic stacking velocity, and used as *a priori* information during the inversion process. Inversions with data lacking in high frequency components in seismic may end up in outputs wanting in resolution for defining thin layers. Larger band width is a necessity and the high-frequency enhancement is achieved by pulling up the weak high- frequency signal components present in data by a process of deconvolution with the derived wavelet.

Acoustic impedance sections make it simpler to identify lithological and stratigraphic details which can be conveniently converted to reservoir properties such as porosity, fluid fill and net pay. An example of a stack seismic and the acoustic

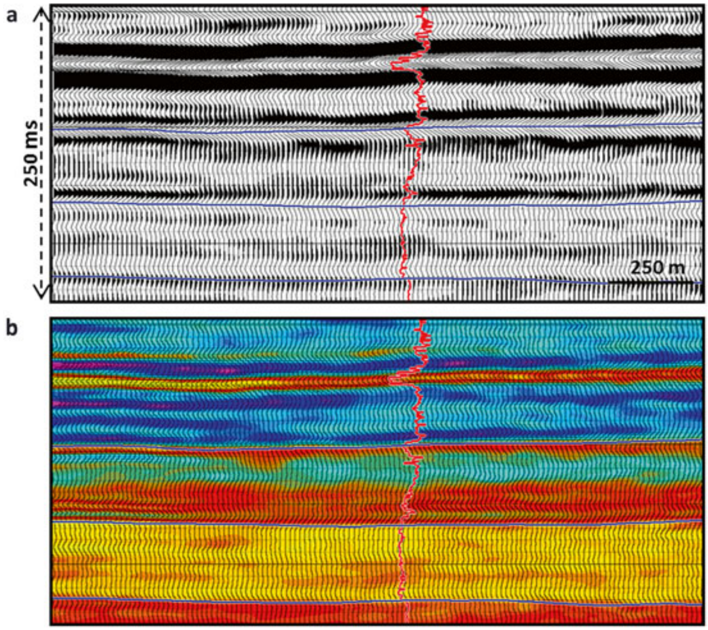

Fig. 11.11 Acoustic impedance inversion from seismic. A segment of stacked seismic section (**a**), and the impedance section (**b**) derived by inversion are shown for comparison. Overlaying the measured log impedance curve on the extracted impedance for calibration check shows good event correlations. The lateral variation of impedances characterizing thin layers is seen clearly and predicted with confidence (Images courtesy of Arcis Seismic Solutions, TGS, Calgary)

impedance section, derived by inversion is shown (Fig. 11.11a). The impedance log derived from well logs is overlaid on the impedance section (Fig. 11.11b) for quality check. The good correlation between the log curve and the section lends confidence in generation and interpretation of impedance data. Consequently, inverted impedance volume can be used straight away to interpret three-dimensional geobodies from a 3D seismic volume.

Elastic Impedance Inversion

Elastic impedance is a more involved angle-dependent inversion performed on prestack gathers. The technique exploits geological information in near angle traces as well as on far angle traces, manifested by the amplitude variability in a gather. The CMP gather at the well position is picked up and different angle ranges are selected to generate angle stacks. Given the V_P, V_S and density log curves, the elastic impedance is calculated for different angles of incidence. For each input partial stack, a unique wavelet is estimated for preparing a synthetic trace. The angle stack traces from the gather and those derived from the log curves (elastic impedance) are compared for assessment. However, there can be some practical problems in the approach. Amplitudes of the near-offset traces are related to the changes in acoustic impedance, and can be calibrated with well log curves or synthetic seismograms. By contrast, if a far-offset or a far-angle stack has to be calibrated with the log data or synthetic seismograms, there are no corresponding set of log curves that could be used for the purpose.

Elastic inversion delivers near- and far-angle *P*-impedances in contrast to normal incidence *P*-impedance (acoustic inversion) extracted from stack data. The near-traces in a gather contain structural/stratigraphic information in terms of their amplitudes and arrival time whereas, the far-traces contain information about the fluid and lithology. Analysed together, much more useful information can be retrieved than the acoustic inversion alone can achieve.

Simultaneous Inversion (SI)

Angle-dependent inversions offer angle dependent P-impedances that can characterize lithology, porosity and fluid content of reservoirs. However, inclusion of S-impedance in analysis can help estimate the properties better and with more confidence. Conjoined studies of *P*- and *S*- impedances, *Vp/Vs* ratio and density information are necessary to minimise prediction risks of parameters for reservoir characterization (see Chap. 9). This is achieved by *simultaneous inversion* (*SI*), a technique that employs angle or offset-limited sub-stacks to deliver P-impedance, *S*-impedance and density. Simultaneous inversion deliverables lend more credibility to estimation of reservoir rock-fluid properties, needed for crucial reservoir modelling. Specifically it may be useful to distinguish hydrocarbon pay from brine sand and shale, in situations where they may not be resolved based on any single seismic attribute. *S*-impedance sections, derived from *SI* may also help detect subtle seismic onlaps, toplaps and stratal interfaces, not noticeable in high resolution inverted *P*-impedance sections due to feeble contrast.

Density Inversion

Of the three vital parameters, *P*-, *S*- impedance and density, the density is the most difficult one to quantify from seismic. Bulk density can be related to important reservoir parameters such as porosity, fluid type and saturation, mineral composition and shaliness and its accurate estimation is beneficial for improved reservoir characterization. Density can help distinguish oil sand reservoir from shale where P-impedance can be similar to that of shale and *Vp/Vs* values for oil sand and shale show wide scatters to be considered as reliable hydrocarbon discriminators.

Density changes within a reservoir can generate significant changes in amplitude with varying offsets (Quijada and Stewart 2007). Shear wave (*P-SV*) reflections are known to be more sensitive to density contrasts at large incident angles (about 40°) than the *P*-reflections, characterized by increase in amplitude with increasing angles. It is thus possible to estimate density by inversion using very large offsets on prestack data. However, such large angle incident data are not commonly used, and wherever recorded, showed the reflection quality highly deteriorated and infested with noise for any meaningful study. A small amount of noise results in reduced reliability of density estimates, which thus remains an arduous task.

AVO Inversion

Analysis on AVO attributes like amplitudes, intercepts and gradients were discussed earlier in Chap. 9. Inversions for AVO analysis can also be done for Poisson's ratio (~Vp/Vs). AVO response for a reservoir is modelled using Zoeppritz's equations, where the contrasts in P- and S-impedance, density and Poisson's ratio are known at a well. Conversely, from pre-stack seismic data, constrained with the model log data and using angle-dependent seismic reflectivity, AVO intercept and gradient values, it is possible to obtain Poisson's ratio by inverting angle dependent amplitudes. This is achieved in simultaneous inversion. Once *P*-impedance, *S*-impedance and density are obtained, a number of elastic modulii like Vp/V_S ratio, Lambda-Rho, Mu-Rho, young's modulus (stiffness) and Poisson's ratio volumes are calculated. This process in general is referred to as AVO inversion, and is a powerful technique that integrates all types of data – seismic, geological, borehole, rock physics, and petrophysics.

Though several inversion techniques are available, the approach to adoption of a particular inversion will depend on the geologic objective and the type of data at hand. Nevertheless, whichever inversion approach is adopted, i.e. recursive, constrained model-based, or geostatistical, the impedance volumes generated have generally significant advantages. These include increased frequency bandwidth, enhanced resolution and reliability of true amplitude for estimating layer property that affords convenience in understanding an integrated approach to geological interpretation. However, since the inversion process transforms seismic amplitude directly into impedance values, special attention needs to be paid to true amplitude preservation to ensure that the amplitudes represent the actual geological effects. The seismic data thus needs to be free of multiples, acquisition imprints, coherent noise, and have high signal-to-noise ratio with zero-offset migration and with no artefacts.

Seismic Inversion in Modelling and Reservoir Management

Seismic inversion is widely used in the industry because of convenience and improved resolution of impedance sections offering more details on reservoir information. It makes up an integral part of interpretation work flow for reservoir characterization and flow monitoring, pressure prediction and estimate of elastic modulii for various other engineering applications. Highly-detailed petrophysical models are generated by integrating rock and fluid parameters inverted from 3D and time-lapse 3D, as input to reservoir modeling and flow simulation to help assess and reduce risk for improved reservoir management.

Limitations of Inversion

All model-based inversion techniques essentially consist of three components (a) generation of an initial impedance model (b) wavelet extraction and (c) broadband seismic data. Building an initial appropriate earth model, though usually constructed from the log data (where some properties are measured and some are interpreted), can be tricky and needs experience. Because the computed response can be same with differently varying model parameters, inversion results may not offer an exclusive solution. Many times, the subtle changes in reservoir rock and fluid properties, though detectable, may remain ambiguous for quantification in inversion data, even at moderate depth where the quality of data is good.

Accurate wavelet estimation for computing synthetic is critical to the success of any seismic inversion and in turn depends on an accurate well tie to seismic. The inferred shape of the seismic wavelet may strongly influence the seismic inversion results and, thus, subsequent assessments of the reservoir quality. Lack of an appropriate low frequency trend will prevent the transformed impedance traces from having the absolute impedance or velocity structure (low-frequency trend) crucial to making quantitative interpretation of reservoir parameters. The well to seismic tie must be meticulous in matching phase and polarity. Often the data to be inverted is not exactly zero-phase and may end up showing a shift with log impedance curve. This may require several repeated calibration exercises to determine the phase corrections to be effected by rotating the phase of processed seismic data. Density determination may be another issue as it may not be feasible to achieve this with certainty by inversion for reasons stated earlier. The inversion process is very sensitive to the quality of seismic data, and if noise and phase corrections in data are not well taken care of, it may offer unacceptable solutions in the framework of a multi-disciplinary integrated work-flow.

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Chapter 12
Seismic Pitfalls

Abstract All seismic anomalies are not related to geology. Spurious anomalies and their misinterpretation often lead to drilling results substantially disappointing from those expected. This phenomenon is commonly referred as 'seismic pitfalls'. Pitfalls can originate due to inadequacy in data acquisition, processing, and interpretation of the subsurface geology. Each of these is discussed and some common amplitude and velocity-related pitfalls are exemplified.

Pitfalls may arise out of deficient workflow, personal bias and eagerness for quick-fix solutions by work-station based interpretations. They may be also caused by the natural system restraints such as wave propagation problems, time-domain recording and subsurface geological impediments that are elaborated with examples.

Synergistic interpretation of multi-set data by experienced and skilled interpreter can mitigate pitfalls to a large extent but cannot completely eliminate them.

In simple geological settings such as layer-cake sedimentation, the seismic images generally replicate the subsurface stratal geometry and are not difficult to interpret (Fig. 12.1). But in complex structural settings, e.g., highly tectonic belts of overthrusts and recumbent folds and salt/shale tectonics and in areas of intricate depositional systems on shelf margins and slopes, seismic images may not imitate the subsurface geology. Structural complexities, rapid variations in sedimentary thickness and lithology, growth faults and roll-over structures with associated fault splays may cause rapid velocity variations and geometry related problems for wave propagation and impede generation of reliable seismic reflections. Aberrations in obscured images cause anomalies which can make interpretation difficult and ambiguous. All anomalies thus seen in the seismic are not related to geology and spurious anomalies and misinterpretation often lead to drilling results substantially different from that expected. This can land an interpreter in a spot and allegorically speaking, in a 'pit'. Such seismic anomalies that put interpreters in a predicament are commonly referred as 'seismic pitfalls' and tend to be plentiful in the early stage of exploration.

The seismic pitfalls can originate due to any or all of the limitations of data acquisition, processing, interpretation of the subsurface geology. Pushing data interpretation beyond the confines, too, can at times generate false anomalies leading to pitfalls. Clearly, this needs to be avoided through understanding of the whole gamut

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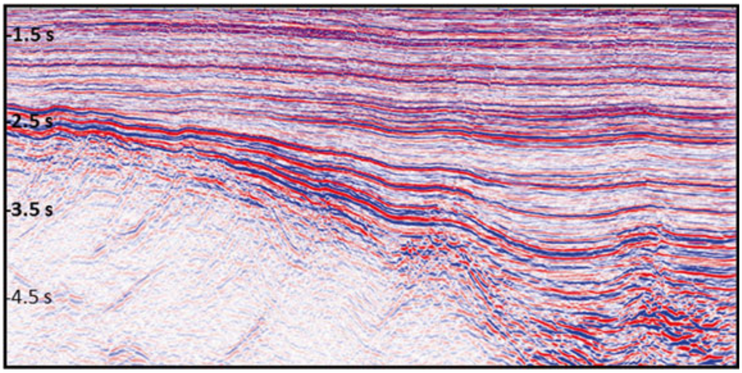

Fig. 12.1 A seismic section exhibiting uncomplicated geology, a replica of the subsurface stratal geometry that makes interpretation easy and straightforward (Image: courtesy ONGC, India)

of seismic technology- the seismic data acquisition, processing and interpretation (seismic API) and the geological aspects. Pitfalls are described succinctly in a monograph by Tucker and Yorston (1973) who classified three main types: (1) stratal geometry; (2) seismic velocity; and (3) seismic recording and processing. The first two categories of pitfalls are nature's creation (described at the end of this chapter) and some of these, of more complex type, may even be beyond the realm of current seismic technology for a solution. The pitfalls originating from data acquisition, processing and interpretation, however, are under human control and can be avoided to a large extent.

Acquisition and Processing Pitfalls

Spurious anomalies or artefacts may originate due to limitations, intrinsic to the data acquisition and processing schemes, or in their faulty executions. Seismic recorded amplitude and velocity are the principal attributes, and their lateral and spatial variations are extensively used for interpreting subsurface geology. But how reliable and representative of rock and fluid properties are these attributes? The common and most important attribute, the seismic amplitudes, recorded at the surface are dependent on generation of source in the type of medium and its strength, the wave propagation effects and the ground receivers. Take for example land data acquired with dynamite source. The shot-hole depth deciding the medium where the charge is exploded, the variations in velocity and thickness of near-surface weathering zone, and the vertical positioning and contacts of the geophones with ground, are some of the important factors which influence the recorded amplitude. Any lapse in these elements in the scheme of acquisition can create fake amplitudes. Additionally, the survey geometry, shooting direction and recording parameters may not be optimally parameterized for the specific geologic objective and can suffer in offering desired quality for interpretation. Although the modern processing techniques are well advanced and may be designed to remove deficiencies to a large extent, it may still not be adequate to eradicate the aberrations. After all, how effective can the processing be if the data is acquired with geophones lying on ground with poor surface contact? These on-land problems, fortunately, are fewer in marine data, which is generally superior in quality to land data.

Velocity is the other vital attribute that builds the foundation of exploration seismic technology. Seismic velocity is an apparent velocity derived from stacking (stack velocity) of traces in a common depth point gather during data processing and is employed, albeit with a correction, in all types of applications in processing and interpretation in early stage of exploration. Stack velocity is influenced, among other things by the quality of reflections, the stratal dips and the recording spread length. Picking velocities during velocity analysis on gathers is thus important and needs to be done judiciously. The reflection quality commonly deteriorates with depth due to reduced signal-to-noise ratio and velocity picking can be often subjective in these ranges. Some interpreters may believe depth migration as the panacea to improve reflection quality, but if the kernel, the primary reflection is poor or not properly recorded, neither a higher fold nor a migration stack can improve the data. Nevertheless, interval velocities deduced from stacking velocity are used for inferring rock properties. Stacking velocities are often highly sensitive to subjectivity, and the derived interval velocities can be highly ambiguous being especially sensitive to small intervals. Though seismic velocity, constrained by the measured velocity at the well, is used subsequently for time-depth conversion, elsewhere, away from the well, it still remains worrisome due to its uncertain lateral variations. A well-defined accurate velocity field is thus essential for time–to-depth conversion and for effective depth migration. Ironically, this most crucial attribute happens to be the most common source of pitfall.

Pitfalls, discussed by Tucker and Yorston (1973), were mostly from old 2D seismic vintage and the problems could be traced to the then prevalent inadequacies, in data acquisition and processing. Tremendous improvements in modern day seismic technology and techniques in acquisition and processing have made it possible to obtain much better subsurface images and avoid to a great extent many of the earlier geometry and velocity related artefacts that could cause pitfalls. Acquisition of 3D and 3D-3C seismic data with improved equipment and techniques followed by sophisticated volume processing techniques have made a tremendous change in acquiring high quality images. Surface-consistent deconvolution and statics, azimuthal velocity analysis, one-pass prestack time and depth migration and demultiple and noise suppression methods, have in recent times made seismic data offer reasonably dependable and representative subsurface images in relatively more difficult geologic areas (Fig. 12.2). Appropriate geological interpretation, however, depends on the interpreter's skill, experience and knowledge of depositional systems and tectonic styles. Seismic processing today, though highly evolved and sophisticated, can sometimes be worryingly susceptible to faulty or inadequate data interpretation due to shortcomings on the part of an interpreter. Data quality can

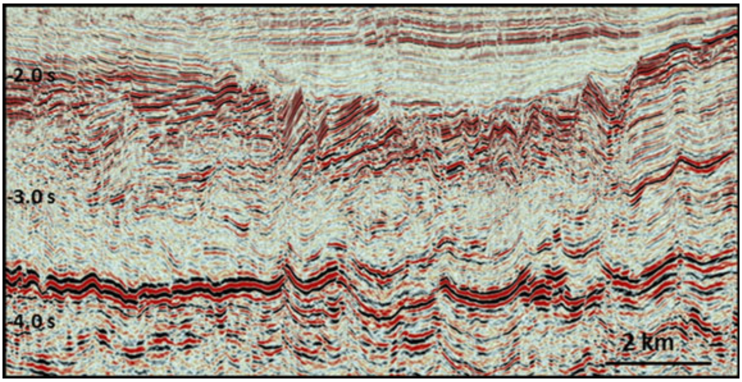

Fig. 12.2 A segment showing an example of a seismic image in a tectonically disturbed complex geological area. Though advanced acquisition and processing techniques create improved good quality images, interpretation may still remain problematic. Quality interpretation depends on the interpreter's skill, experience and knowledge of depositional systems and tectonic styles (Image: courtesy ONGC, India)

also be extremely sensitive to processing parameters and algorithms and different work centres can produce seemingly different images for the same data set leading to diverse interpretation results. The interpreter should be aware of these types of processing pitfalls and try to work on several variants of data sets, if possible, and validate the interpretive results by analysis of other kinds of data.

Interpretation Pitfalls

Despite good quality data as is common in recent times, seismic interpretation can be complicated and pitfalls may occur. The modern-day pitfalls can originate due to the interpreter's perception and the way one manages the interpretation workflow to achieve the task. Different people view the same data differently and may end up with diverse interpretations. Image visualisation by the intuitive human mind can be deceptive and often an interpreter starts 'seeing' features in seismic data that his brain wants to see. Guided by instinct or intuition, the interpretation may ensue in a fallacy – a confidently mapped feature that is nonexistent in the subsurface. It is though important to have instinct and imagination for an interpreter, it is also necessary to be aware of one's proneness to bias. Reflecting on different ways or reasons for possibility of being incorrect, discussing the results with peers and seeking opinions and welcoming criticisms, can help reduce the source of potent pitfalls.

Many of the pitfalls, in the author's opinion, may be arising out of quick-fix solutions by work-station based interpretations, employing fast and powerful softwares. Work-stations and softwares are extremely useful and indispensable but these are only tools. Their capabilities and limitations must be well understood for their judicious application. The usefulness of the software depends on the type and quality of data and often the software design can be geology-specific. Software algorithms may too have innate assumption of certain physical conditions that are not in harmony with specific geology of an area. Workstations should not be expected to provide solutions and over-reliance on softwares without human intervention, may lead to risks of interpretation pitfalls. Often interpretation is carried out without adequate integration of geological, geophysical, petrophysical and engineering data. Integration is an unrelenting and an involved process which needs critical evaluation by the human brain. In some situations, though, the need to confirm or corroborate interpretation results may require acquisition or reprocessing of data, which, unfortunately, may not be possible because constraints of time or accessibility of data due to time bound drilling pre-commitments.

Some of the common interpretation pitfalls often can be traced to one's lack of skill and experience in following the work flow. This includes preliminary but crucial steps such as elaborate seismic ties with wells, identifying the target horizon and its correlations based on reflection character and attitude. Reflection continuity must be based on amplitude, phase (peak/trough), frequency, waveform and the dip attitude of events that constitutes the character of a reflection and not on the sole basis of phase (peak/trough) and cross-line time-ties. Character based correlation helps delineate areal extent of reservoir with certainty. Commonly, horizon correlations are in auto-track mode because it is fast and accurate. However, auto-tracking cannot recognize splits in reflection waveform or lateral polarity changes caused by variations in rock and fluid properties and also does not fare well in areas of poor and/or patchy reflections. Auto-tracking pitfalls may lead to flawed contour maps resulting in erroneous reservoir geometry and volumetric estimates. Faults and their delineation is another area where impromptu alignment and lack of fault integrity analysis may generate pitfalls by mapping pseudo structures and traps.

Amplitude Related Pitfalls

Many common pitfalls unfortunately accrue from casual interpretation of seismic amplitudes as seen on the data without analysing the phase and polarity and understanding the geology of rocks involved. Since the advent of 'bright spots', high amplitudes are often considered by many interpreters as related to hydrocarbon sands irrespective of the geological setting and are recommended for drilling on flawed analysis. As a rule of thumb, high amplitudes associated with rocks of old age and at depths may be considered a discouraging criterion for hydrocarbon occurrence. Such high amplitude anomalies can be due to calcareous sandstones or intrusive sills and need thorough investigation before drilling (Fig. 12.3). In Fig. 12.4, another case is exemplified where a genuine-looking, high amplitude channel cut–and-fill sand prospect in deep waters was drilled for gas. Drilling results, however, proved the feature as clay-filled and devoid of reservoir and turned

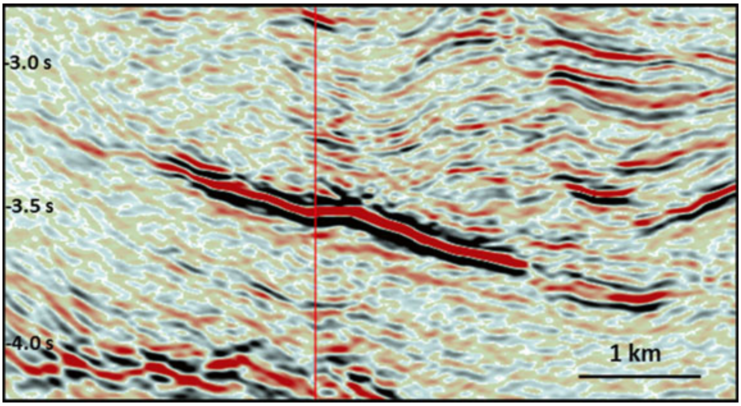

Fig. 12.3 A seismic segment showing an example of amplitude related pitfall. An inferred high amplitude DHI anomaly turned out an intrusive body (Image: courtesy ONGC, India)

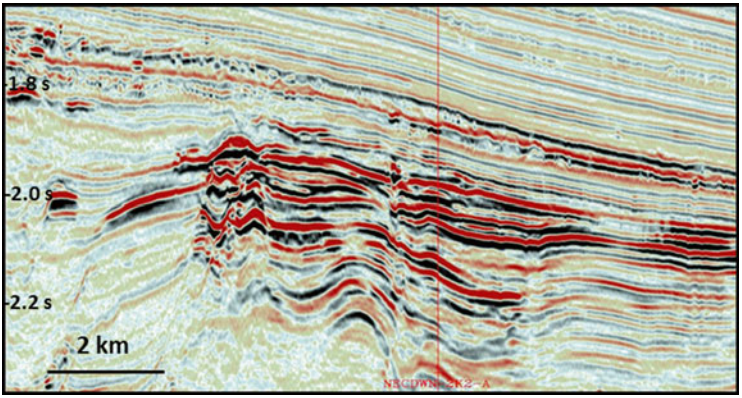

Fig. 12.4 A segment of seismic section showing another example of amplitude related pitfall. The high amplitude anomaly drilled for a prospective channel-fill gas sand in offshore proved to be clay-filled. The high amplitudes are apparently caused due to density contrasts within the clay (Image: courtesy ONGC, India)

up as an interpretation pitfall. The bright amplitudes seemed to have been caused ostensibly due to density contrasts within clay.

Pitfalls may also occur sometimes due to the interpreter's overreliance on attribute slices in isolation without considering the vertical sections. An inconsistent amplitude pattern on time slices is perceived as a hydrocarbon bearing geobody (e.g., channel crevasse'/fan complex?) without seeking corroborative evidences or an appropriate sedimentological model. The interpreter should be able to differentiate genuine amplitude anomalies from those due to defects in data coverage, processing and propagation effects including amplitude focusing and defocusing effects related to reflector geometry or thin beds. Difficulties may also be faced in identifying accurately the reflection polarity to ascertain the nature of reflectivity (Rc) and its precise subsurface position due to reasons beyond one's control. Polarity, the key to validation of high amplitude anomalies associated with thin hydrocarbon-charged sands, are sometimes hard to diagnose on seismic sections. There are also instances where strongly-backed positive AVO analysis has led to drilling of dry wells. In another instance, two Pliocene offshore high amplitude anomalies, stacked one above the other and expected to be gas bearing, on drilling turned out to be normal grade oil bearing sands (Fig. 12.5). And interestingly, the seismic angle gather showed both the sands as of AVO class 2(negative) anomalies (Nanda and Wason 2013) with the deeper sand showing absence of amplitude in the near offsets. Both the sands, however, were typified by very similar strong amplitude anomalies on normal seismic stack section. Such surprises will of course continue to be there but in many cases, the pitfalls crop up due to lack of proper understanding of the intricate relationship between rock-physics and seismic.

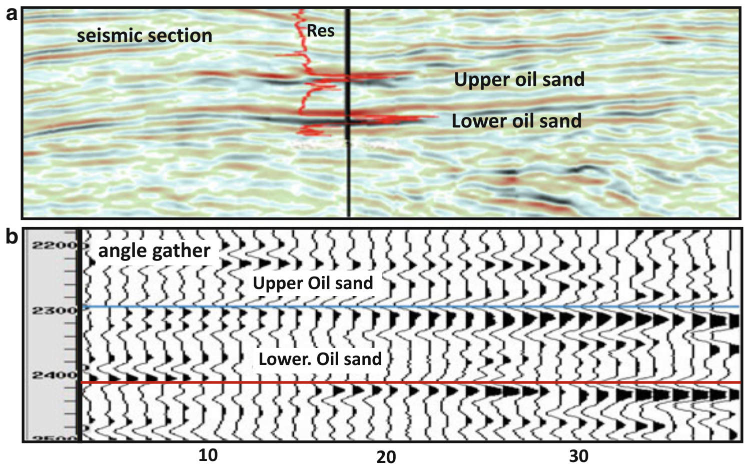

Fig. 12.5 Bright spots drilled for gas proved oil bearing. (**a**) Seismic expression of high amplitude (*red*, negative Rc) anomalies associated with oil sands. (**b**) An angle gather shows AVO class 2 negative anomalies for both the pay sands. Note the feeble amplitudes of the upper pay and none for the deeper in the near offsets though high amplitudes of both the anomalies are similar on normal seismic stack section (Images: courtesy ONGC, India)

Velocity-Related Pitfalls

Estimation of accurate velocity is the most crucial factor as errors in depth prediction to reservoir (pay) top and its thickness can lead to disappointing drilling results. Most common pitfalls are due to the uncertainty in velocity estimation leading to erroneous depths. An appraisal well encountering the pay top deeper than predicted and ending in water, can seriously downgrade the exploration venture at this stage. Determining variability in lateral velocity has always been a difficult and challenging task despite employing techniques such as depth migration. Figure 12.6 exhibits an example which illustrates how the actual structural geometry of the reservoir proved substantially different from that seen in time domain due to severe lateral variation in overburden velocity in the area. Proper understanding of the geological reasons accounting for the velocity variance in the overburden may be established, which can bring confidence and certainty in depth predictions.

Velocity related pitfalls can be due to presence of localised high or low velocity zones above the reservoir, such as an extra patch of carbonate mound or a channel filled with low-velocity shale that can cause serious discrepancies in depth predictions. These are known as "time anomalies", 'pull up'/'pull down' or 'sag' effects (Fig. 12.7) which the interpreter must be cautious of (see Chap. 3). The channel morphology and the continuous and parallel internal reflections configuration, typically indicates clay fill. Further, the position of the 'sag', vertically beneath the

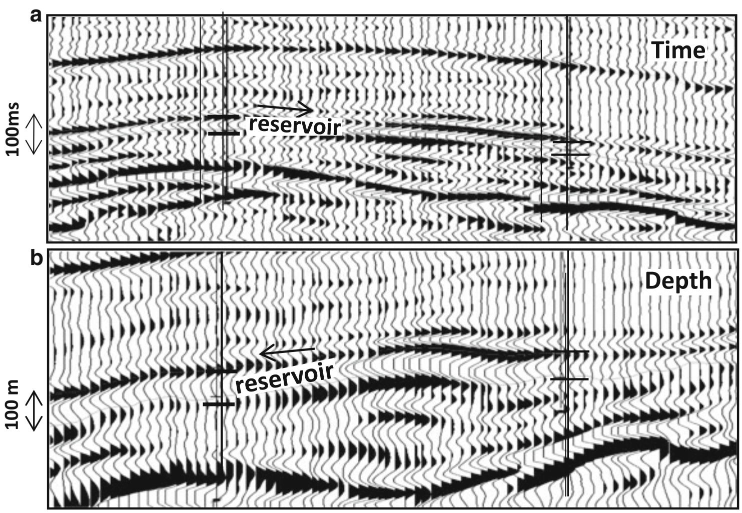

Fig. 12.6 A seismic segment exhibiting illustrations of a velocity related pitfall. The time section (**a**) shows the reservoir with a crestal reversal (*arrow*) at the well and continues dipping showing it deeper at the well to right. (**b**) depth migrated section does not bear out the reversal and shows the reservoir, continuing up dip to right to become shallower at the next well. Note the change in look due to stretch in depth section (Images: courtesy Hardy Energy, India)

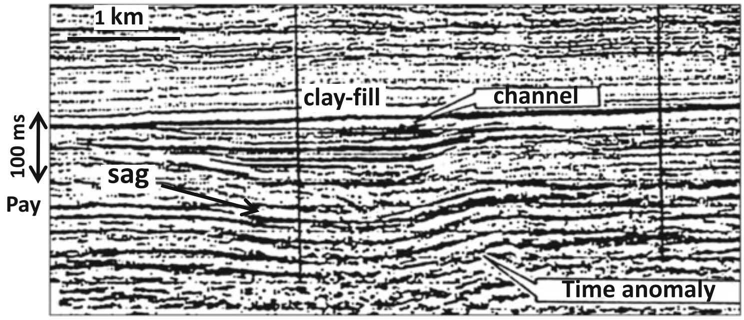

Fig. 12.7 A seismic segment showing an example of a velocity related pitfall ('time anomaly') where pay top was encountered much shallower than expected resulting in increased reserves. The channel morphology above the pay, with parallel flat internal reflections typifies the low velocity clay fill. This caused the 'sag' effect seen at the pay level *vertically* below the channel (Image: courtesy ONGC, India)

channel at reservoir level and continuing below also confirms the potent pitfall. The pitfalls generally have negating effects but can occasionally include positive outcome when the pay top is encountered shallower as in this case, resulting in increased reserves (Nanda et al. 2008).

Summing up, interpretation happens to be a scientific art to provide solution to inverse problems and suffers from its usual innate shortcomings of uncertainties and not being unique. Lack of adequate expertise, and more significantly, impromptu application of information without verifications may cause an interpreter to stumble, despite having excellent seismic images to work with. The risks, however, can be mitigated to a great extent by the skill and experience, though cannot be completely eliminated. An interpreter needs to be careful in judging inferences through all kinds of validations possible to cut down exploration and development risk. Seismic 'pitfall' is a normal and professional hazard for an interpreter to get ditched occasionally. Nevertheless, the challenge lies in bouncing back out of the pit, getting wiser each time from experience so as to avoid repeats of such stumbles in the future.

Natural System Pitfalls

Regardless of advanced and sophisticated acquisition, processing and interpretation (seismic API) techniques, there are natural limitations in the seismic system itself and in the complexity of subsurface geology that cannot be entirely eliminated. These eventually cause pitfalls that cannot be avoided. As the technology has advanced, so has the complexity of geologic targets to be explored. These include

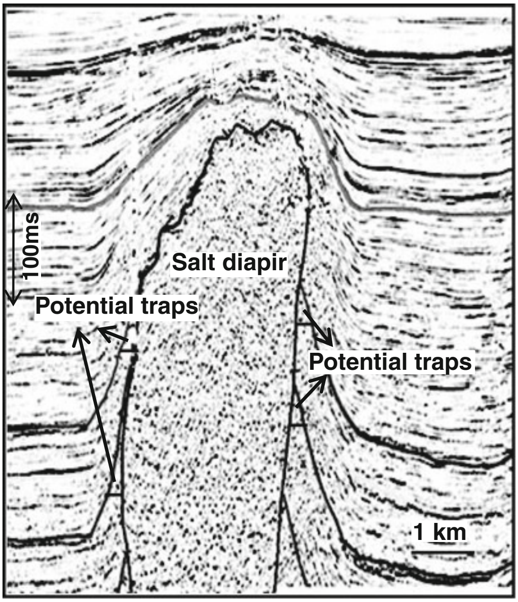

Fig. 12.8 Salt diapirs with *vertical* geometry and high velocity contrasts impede wave propagation and the resulting inaccuracy in seismic images. The salt-core delineation and the linked traps formed at its flanks are poorly defined and can lead to pitfalls in exploring salt associated traps. Note the small lateral extent of the traps and the small margin of error to risk

highly deformed fold-thrust belts, subsalt and sub- basalt targets where structural geometry and lateral velocity variations and complex stratal geometry pose major wave propagation problems impeding proper imaging and thereby hampering exploration ventures. Uncertainty in imaging geometry of salt diapirs even in a relatively simple salt tectonic area is illustrated in Fig. 12.8. One can easily disagree with the interpretation of the image shown, but it is surely arguable as to delineating the exact outline of salt core geometry. This leads to uncertainties in defining the up- dip traps formed at the flanks by the reservoir beds and consequently in pinpointing precise drilling locations to find hydrocarbons. As one can make out, the margin of error in positioning the drilling location is too small, which immensely increases scopes for pitfalls. Sophisticated migration processes do improve images but at times can lead to overreach and the processing marvels may baffle the interpreter (Fig. 12.9). One version of depth migration (Kirchoff) is interpreted as a salt diapir whereas, the other version (Beam) is inferred as vertically folded beds. These two versions are significantly diverse and the dilemma is to pick which version of the migration as correct. Obviously the regional geologic syndrome will decide the model, though the author is inclined to pitch in for the interpretation of the image as that of a salt diapir.

Another pitfall in a frontier venture for sub-basalt exploration is shown in Fig. 12.10, where Mesozoic sequence beneath the basalt (Deccan trap) is known to exist. A Mesozoic angular unconformity with basalt forming an up-dip trap was mapped from seismic and the prospect was drilled. Drilling was terminated deep in

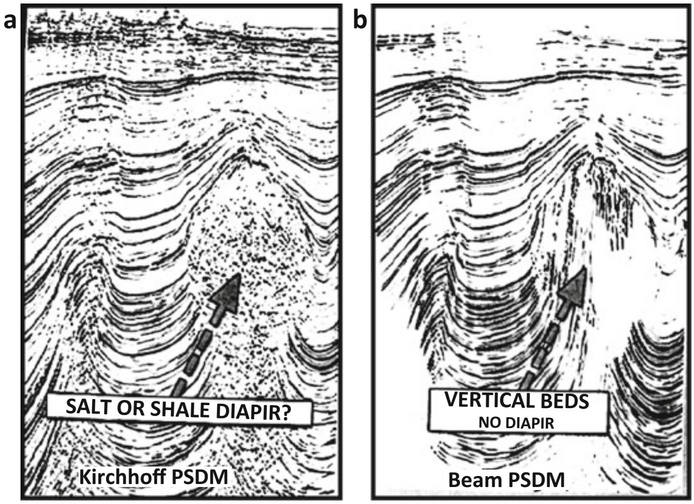

Fig. 12.9 A seismic segment showing example (not to scale) of pitfall due to inapt processing. Two prestack depth migration algorithms (**a**) Kirchhoff migration and (**b**) beam, show different results that have significant geological consequences. It can be baffling but knowledge of the area geology can come handy in picking the appropriate interpretation version

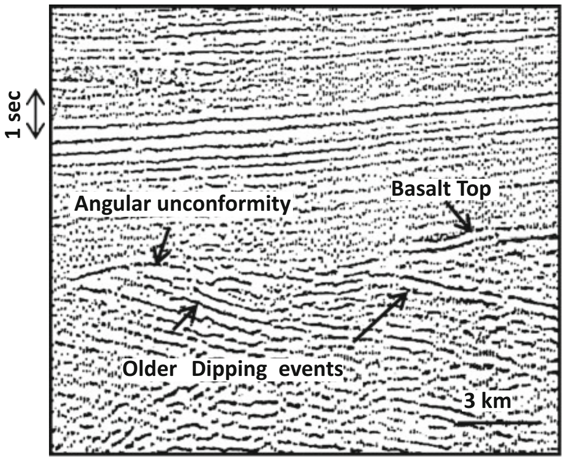

Fig. 12.10 A segment of a seismic section showing an example of an interpretation pitfall in sub-basalt Mesozoic exploration. The dipping beds were interpreted as an angular unconformity related Mesozoic prospect with over-lying basalt as cap. Drilling proved the seismic dipping events to be from within the basalt, supposedly caused by the different layers of episodic basalt flows (Image: courtesy ONGC, India)

basalt without any evidence of sedimentary section. The strong stratal dips seen in seismic turned out to be within the massive basalt section and are seemingly the layers of episodic lava flows.

Wave Propagation Complications

Highly heterogeneous and anisotropic earth media hamper subsurface image quality due to distortions caused by propagation. Complex and unclear images are formed due to irregular subsurface reflectors having complicated intricate stratal geometry and strong velocity variations. Add-ons such as generation and recording of mode converted waves (*P*-*SV*), intrabed (peg-leg) multiples, losses due to attenuation, scattering and diffraction noises further deteriorate the images. Anisotropic sequences such as fractured rock and thick shale sections have strong azimuth dependent velocities and their presence in the overburden creates birefringence effects and scattering that get recorded contaminating the *P*-reflections. This creates huge problems for estimating velocity for stacking and eventually for migration process to construct reliable images. The bottom line is that the seismic processing algorithms are mostly based on assumptions of isotropic, homogeneous earth and cannot handle processing for elastic data propagation in an inhomogeneous and anisotropic media to create proper images.

Time Domain Data Recording

The single most important and fundamental drawback in the seismic technology system is the recording of seismic data in the time domain. Though the time values are ultimately converted to depth by velocity, its spatial variation over the area remains unknown for accurate seismic depth predictions. Seismic measurements of signals and their attributes including arrival times are controlled to a large extent by velocity, and lack of its precise information can be a great impediment in the interpretation of data. Prestack depth migration however, mitigates the problem to a great extent. But ironically, it cannot offer a perfect solution without a priori knowledge of velocity which has to follow from the data itself, ‘a chicken first or egg first’ paradoxical situation!

Geological Impediments

Seismic properties and attributes are employed to exploit geological information on rocks and fluid properties and their lateral variation from data. What if the two different rocks have similar seismic property or marginal difference that is insensitive to seismic response? Obviously, even a high-resolution seismic inversion will miss the stratigraphic boundary between two different lithologies with similar rock properties. Other common pitfalls may include cases where, (1) a mapped low impedance layer, thought to be a reservoir sand, may be an organic-rich shale, (2) a poor or transparent reflection associated with an old and deeper feature turns out to be oil sand, and (3) a massive carbonate mound mapped from seismic does not turn out to be a porous reef. Usually, four-way closures with strong amplitude anomalies are the first preferred natural picks for exploratory drilling despite occurrence of earlier failures. In contrast, how many features without structural closures and with no or poor reflection anomalies are singled out initially for drilling?

Sometimes the changes in rock and fluid properties interact in opposite directions, which weaken the resultant seismic response to be discernible. For instance, increase in porosity and hydrocarbon saturation in an older thin sand tends to lower impedance and amplitude, which works in the reverse direction to the tuning effect of the thin layer thickness. Further, seismic is reasonably sensitive to changes in rock and fluid property at shallow depths and can have responses that can resolve bed properties. But as seismic sensitivity deteriorates with increase in depth, the images may suffer in quality and unable to define the layers and their properties, clearly and unambiguously. Obviously, despite best-quality data, acquired under such unfavorable geological circumstances, seismic prediction of rock properties in many cases may be ambiguous, ending up in interpretation pitfalls.

Synergistic interpretation of multi-set data by an experienced and skilled interpreter in many cases can mitigate pitfalls to a large extent but cannot eliminate it completely. Nevertheless, it may be recalled that serendipity has been an indispensable component in finding hydrocarbon in the exploration gamut and will continue to do so in the future, despite all measures taken.

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