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*'.

N.C. Nanda, *Seismic Data Interpretation and Evaluation for Hydrocarbon Exploration and Production*, DOI 10.1007/978-3-319-26491-2_8

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.

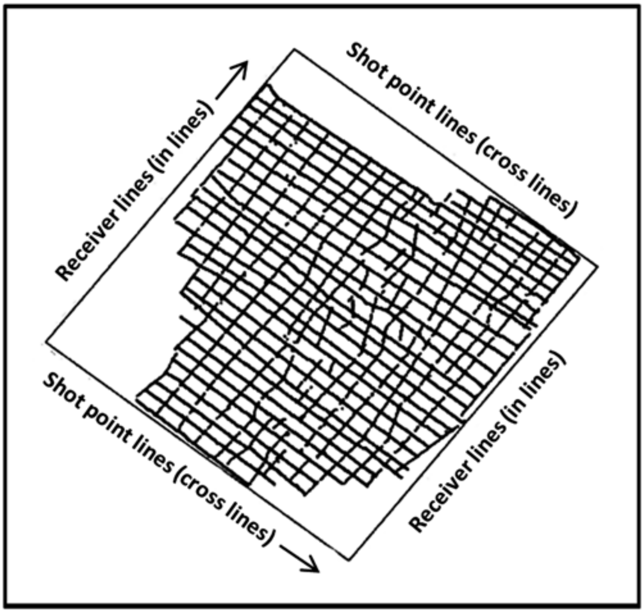

Fig. 8.1 A typical 3D swath survey lay out showing parallel receiver and source lines, orthogonal to each other. Receiver lines are called inlines and the shot point lines the cross lines. Breaks in the grid are due to ground logistic problems

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

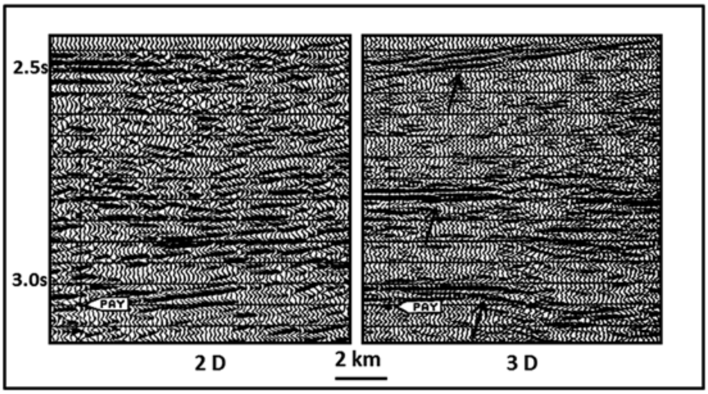

Fig. 8.2 Comparison of 2D and 3D seismic images. Note the improvement in clarity and continuity of events in 3D data (shown by *arrow*) notably by the process of migration, that reduces noise and improves spatial resolution (Image courtesy of ONGC, India)

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

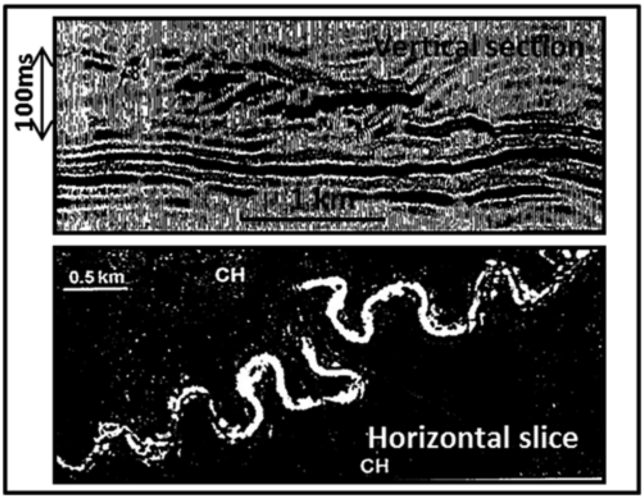

Fig. 8.3 Example of a channel geometry clearly revealed in seismic *horizontal* section (seiscrop), but not intelligible in the *vertical* section (Modified after Figs. 4 and 12 of Kolla et al. 2001)

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-

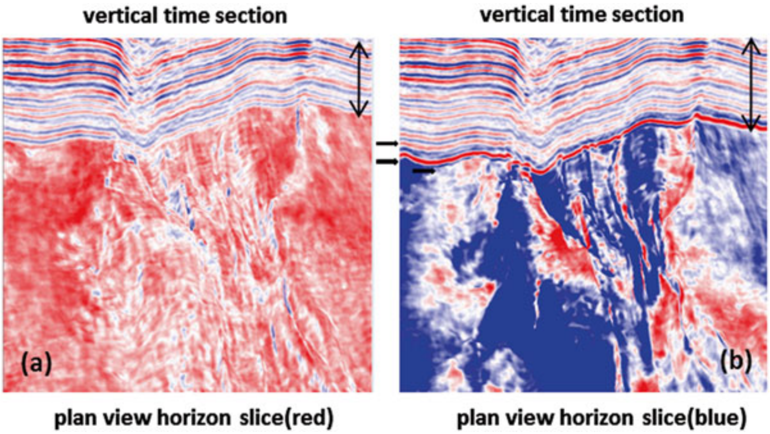

Fig. 8.4 Chair displays of horizon amplitude slices with vertical section. Plan view maps of amplitudes for the reflections (**a**) *red horizon* and (**b**) *blue horizon* shown by *arrows* in the vertical section. Note the differences in amplitude slices displayed in the horizontal views, despite the 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

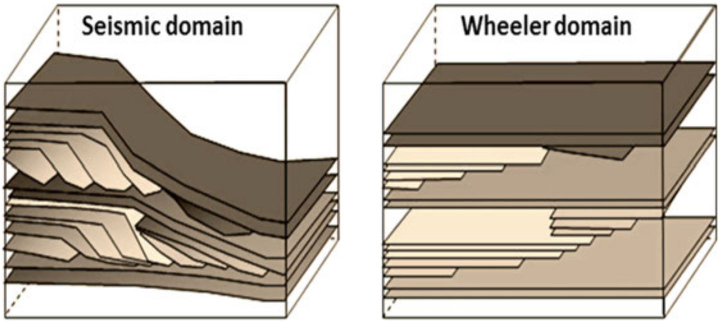

Fig. 8.5 Sketch illustrating transformation of events from seismic to Wheeler domain. Wheeler domain time slices are the horizon slices of seismic domain. Wheeler domain color display facilitates better interpretation of spatial distribution and timing of sediment deposition and environment (After Fig.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

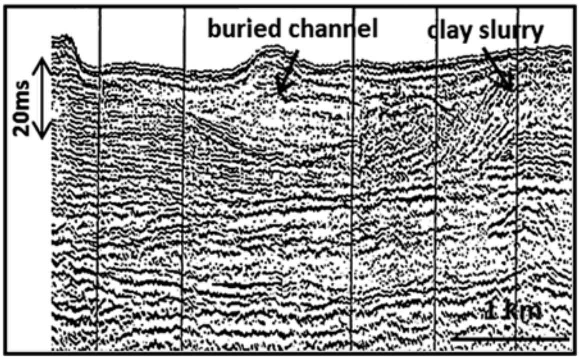

Fig. 8.6 Example of 3D seismic in prediction of shallow drilling hazards in offshore. Buried channel and clay slurry are extremely pliable and mobile which pose potent threats to installation and stability of jack-up rigs for safe operation (Image courtesy of ONGC, India)

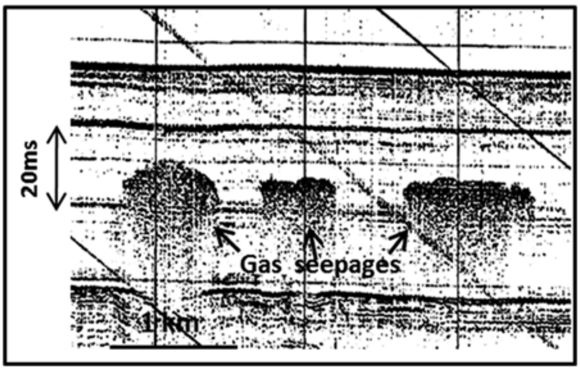

Fig. 8.7 Seismic image of shallow offshore gas seepages, used for prediction of drilling hazards. Gas leaking through sea bottom reduces buoyancy of water, endangering operation of semi-submersible floaters deployed for drilling (Image courtesy of ONGC, India)

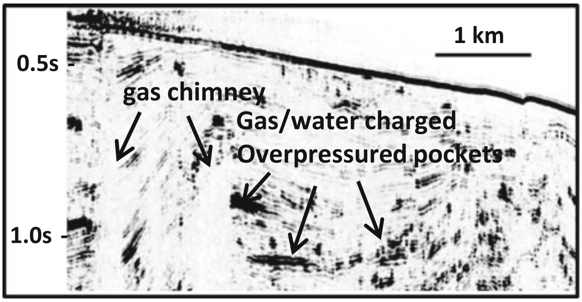

Fig. 8.8 Offshore seismic image of shallow gas/water charged high-pressured pockets (high amplitudes) and gas chimneys (transparent), that Indicate potential drilling hazards (Image courtesy of ONGC, India)

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

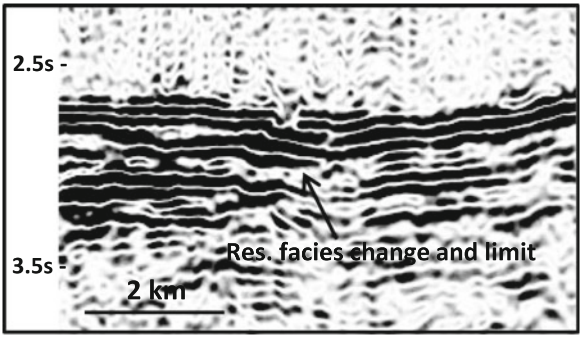

Fig. 8.9 3D seismic image offers better resolution that helps delineate the reservoir facies and its limit precisely (Image courtesy of ONGC, India)

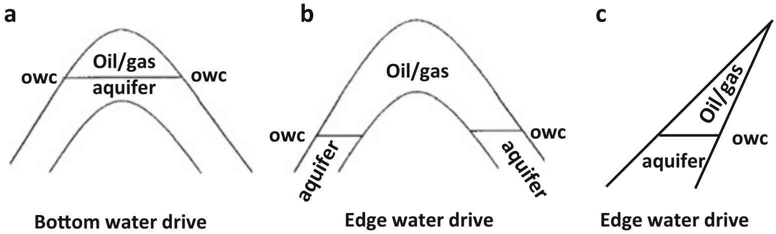

Fig. 8.10 Diagram illustrating common types of hydrocarbon-water contacts in structural (**a**) and (**b**) stratigraphic traps (**c**)

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

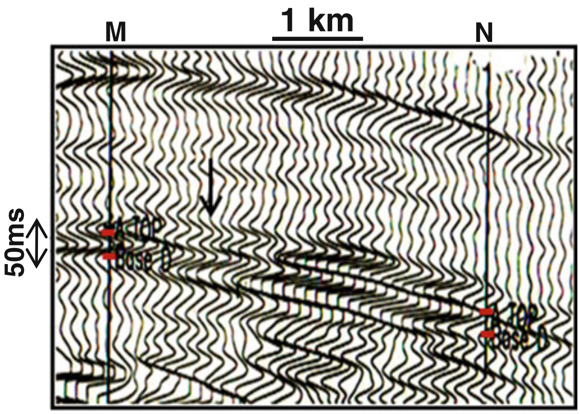

Fig. 8.11 Seismic evidence of reservoir heterogeneity. Note the big dissimilarity seen in reflection waveform and amplitude (indicated by *arrow*) between the wells M and N, indicating facies change and co-linked heterogeneity in the reservoir. Reservoir *top* and *bottom* identified from log is marked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

References

Anderson NR, Boulanger A, Wei He, Yu-Chiung Teng, Xu L, Meadow B, Neal R (1997) What is 4-D and how does it improve recovery efficiency? World Oil's 4-D seismic hand book, pp 9–13

Bousaka J, O'Donovan A (2000) Exposing the 4D seismic time-lapse signal imbedded the Foinaven active reservoir management project, OTC paper 12097

Brouwer F, Connolly D, Bruin GD, de Groot P (2008) Transformation and interpretation of seismic data in the wheeler domain: principles and case study examples. Search and Discovery Article #40314

He W, Anderson RN, Boulanger A, Yu-Chiung Teng, Xu L, Neal R, Meadow B (1997) Inversion of 4-D seismic changes to find bypassed pay. World Oil's 4D seismic hand book, pp 29–32

Kolla V, Bourges P, Urruty JM, Safa P (2001) Evolution of deep-water Tertiary sinuous channels offshore Angola (West Africa) and implications for reservoir architecture. AAPG Bull 85:1373–1404

Staples R, Stammeijer J, Jones S, Brain J, Smit F, Hatchell P (2006) Time-lapse seismic monitoring- expanding applications: CSPG-CSEG-CWLS Convention. Calgary, Canada 181–189

Wang Z (2001) Y2K tutorial fundamentals of seismic rock physics. Geophysics 66:398–412

Xu L, Anderson RN, Boulanger A, Yu-Chiung Teng, He W, Neal R, Meadow B (1997) 4-D reservoir monitoring, the business driver. World Oil's 4-D seismic hand book, pp 23–28

Zeng H (2006) Seismic imaging? Try stratal slicing. AAPG Explorer, June 28