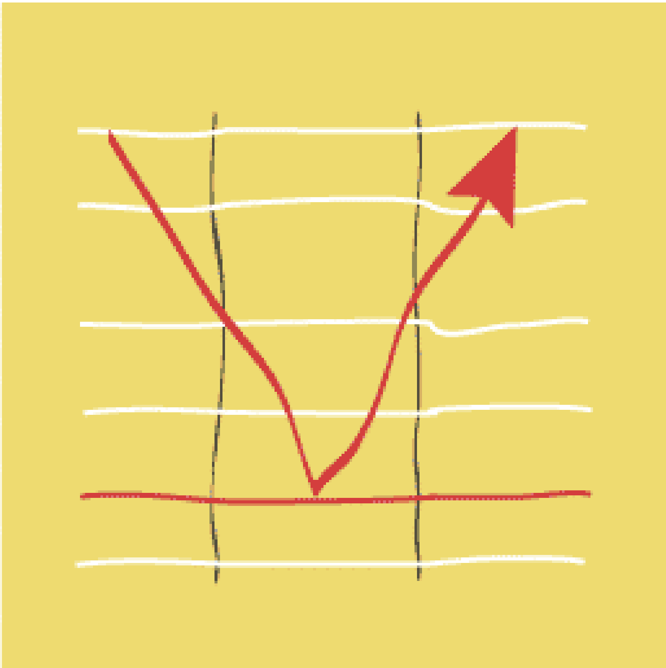
WELL SEISMIC



Online course of geophysic

University of Lausanne · Institut Français du Pétrole

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Well Seismic Method

1.1 Introduction

The seismic technique is the geophysical method most-commonly used to define sub-surface structures. The most common implementation of this technique consists in reflection seismic with multiple coverage. This method provides imaging of the sub-surface in 2 or 3 dimensions (Figure 1). In order to obtain a more accurate depth tie than that provided by velocities resulting from surface seismic data, geophysicists use well data such as velocity surveys and sonic logs, and more recently information extracted from well seismic.

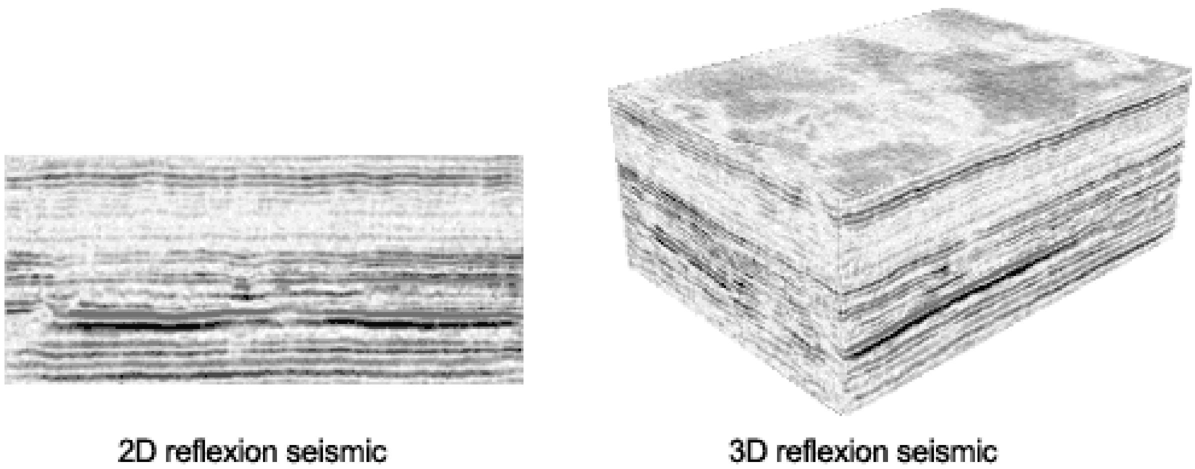

Figure 1: Sub-surface imaging. A) 2D seismic reflection. B) 3D seismic reflection.

Well seismic methods are used for a better knowledge of the reservoir in the exploration phase, but these can also be used in the exploitation development phase with repetitive seismic for the study of the reservoir as a function of time (monitoring).
Three types of well seismic techniques can be distinguished: surface shots with receivers in the well, shots in the well with receivers at the surface and shots in a well with receivers in another well.

1.2 Surface Shots

The well seismic method, most commonly implemented as a vertical seismic profile (VSP) with or without a source offset, presents a vertical resolution of the order of one to ten meters and a lateral depth of investigation of several tens to several hundreds of meters. Figure 2 shows an unprocessed VSP record obtained in well B. In this type of display, the horizontal axis represents the different depths of the well geophone and the vertical axis represents the listening time. In this example, the receiver depth varies between 1,045 m and 105 m, and the surface source is slightly offset (30 m) with respect to the borehole. The distance between successive positions of the geophone in the well varies from 3 m to 23 m. After processing, the VSP provides a seismic trace without multiples that is directly comparable to a surface seismic section recorded near the well. With the added constraints of log data (sonic and density), this trace represents an acoustic impedance log for the well and below the bottom of the well.

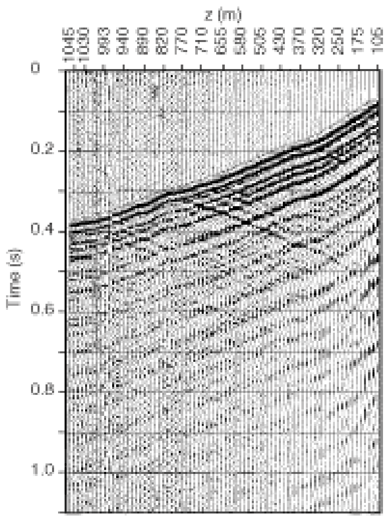

Figure 2: VSP Example - Well B (Gaz de France)

The lateral depth of investigation of the VSP can be improved by offsetting the source with respect to the well. This technique is called Offset Vertical Seismic Profile (Offset VSP) or Oblique Seismic Profile (OSP). The image obtained after processing is then a single-fold seismic section. Figure 3 presents an example of imaging from an OSP with a small source offset (70 m). The horizontal axis represents the distance of the mirror point with respect to the wellbore.

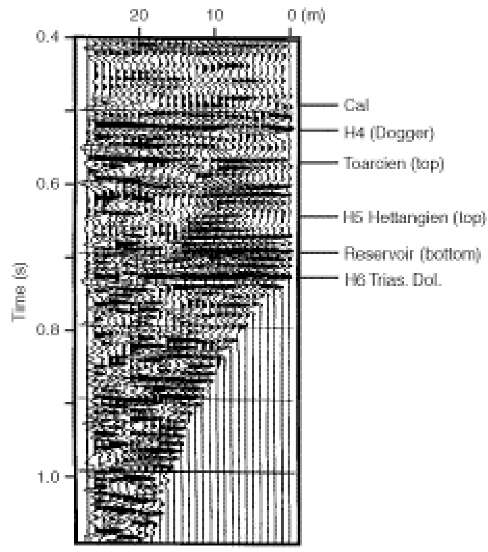

Figure 3: Example of imaging with an offset VSP (Gaz de France)

A seismic <u>walkaway</u> is a series of offset VSPs, with the surface source successively occupying several locations corresponding to successively increasing offsets with respect to the borehole. The image obtained after processing is a low-multiple fold section. Figure 4 illustrates the implementation of a seismic walkaway.

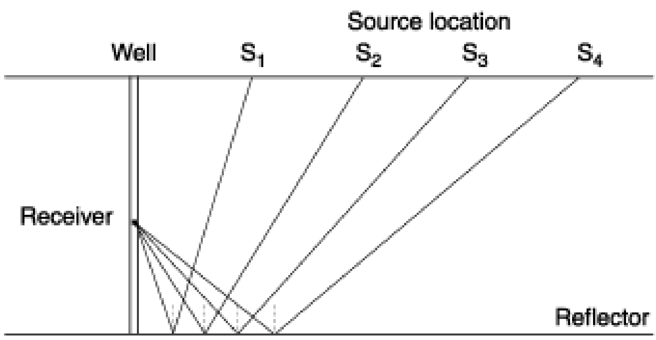

Figure 4: Seismic Walkaway (Gaz de France- IFP)

The number of positions of the well geophone is generally limited with this type of setup. Figure 5 shows an example of imaging with a seismic walkaway. However, the lateral range of investigation of a seismic walkaway is limited (several hundred meters to a kilometer) compared to that of a classical seismic reflection profile. This underlines the local character of a reservoir study using a well seismic method.

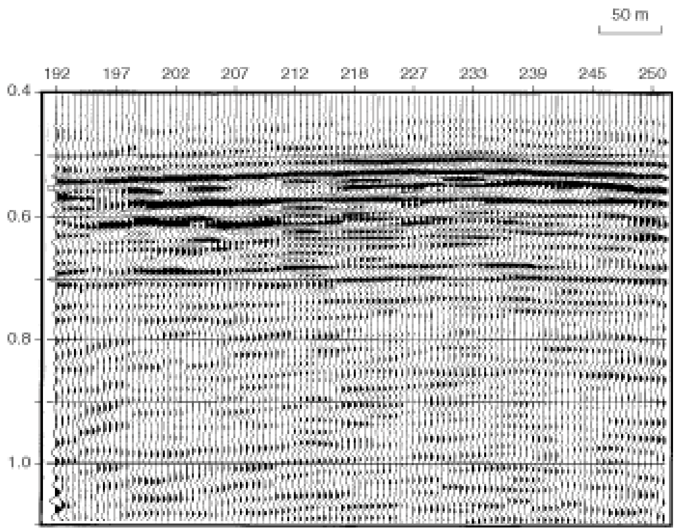

Figure 5: Example of imaging by seismic walkaway (Gaz de France - IFP)

1.3 Well Shots

VSPs or O-VSPs provide an image of the reservoir below the bottom of the well. The drill bit itself can be used as a well source during drilling, thereby permitting the imaging of yet-unreached formations while the well is being drilled (prediction ahead of the bit). Figure 6 shows a comparison between a reverse VSP obtained with the drill bit as the source, and a classical VSP obtained in the same well after drilling with a surface source and a well geophone.
The VSPs presented in Figure 6 provide images comparable to those of surface reflection seismic.

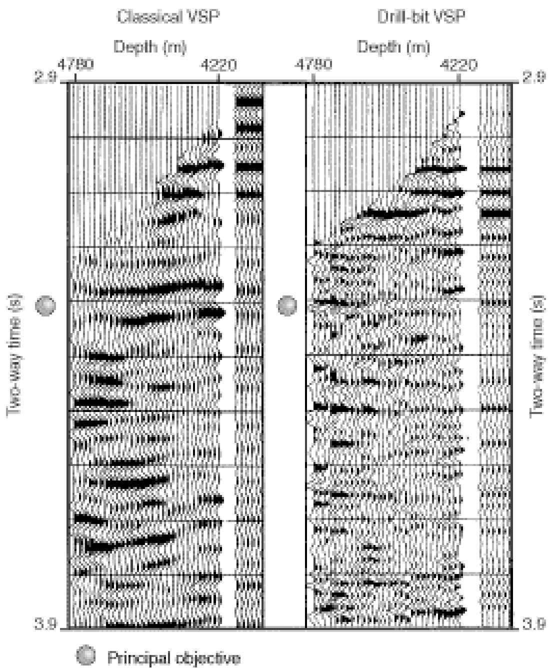

Figure 6: Comparison between a <u>reverse</u> VSP (drill bit) and a classical VSP (modified from Miranda et al., 1996)

1.4 Well-to-Well Seismic

The well-to-well seismic method can provide images of the formations between wells, in the form of seismic reflection sections showing acoustic impedance contrasts (Figure 7) or in the form of velocity models obtained by inversion of first-arrival times (transmission tomography, Figure 8).

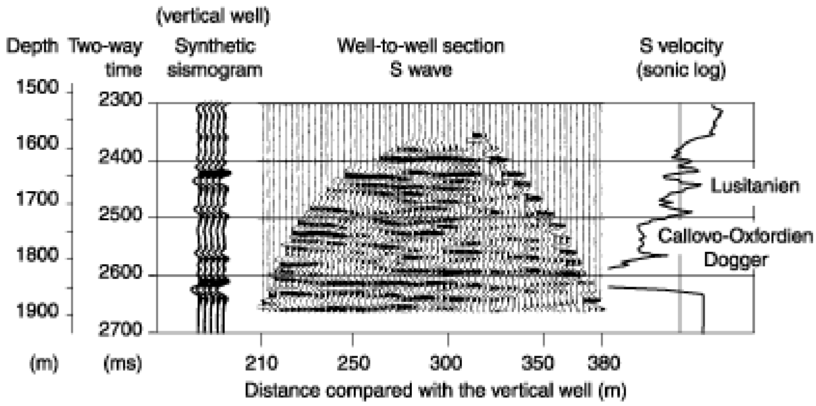

Figure 7: Example of well-to-well seismic - Reflections of S waves between a vertical well and a deviated well (from Becquey et al., 1992)

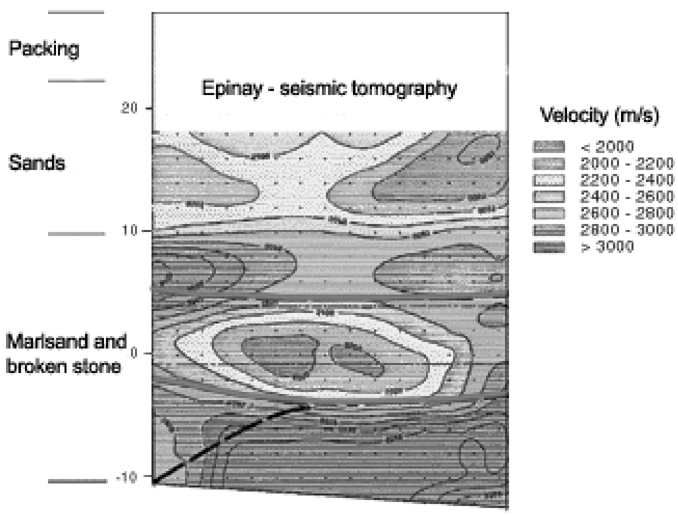

Figure 8: Example of transmission tomography in civil engineering (F. Lantier, consultant)

The various implementations of well seismic methods can be grouped under the general term of <u>well seismic profiles</u>.

2 Implementation

Typically, a well seismic profile is obtained with seismic sources at the surface and a receiver system located in the well. The receiver system is done with the use of a specific geophone that is successively lowered at different depths in the well.

The well geophone includes a receiver, generally with three components, an anchoring system and a digitization unit (for recent tools).
Recording can be done with a single receiver or a receiver array composed of a master unit and a set of satellites.
An example of a tool equipped with a 3-component geophone, a hydrophone and an inclinometer is shown in Figure 9.

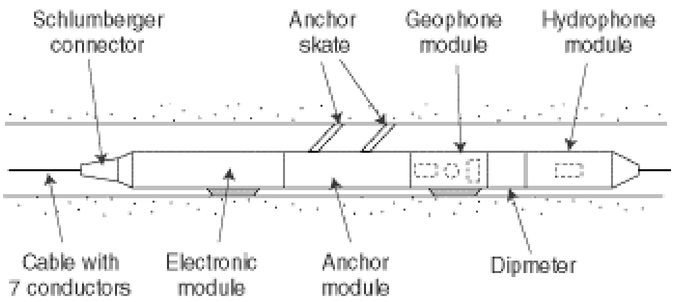

Figure 9: SPH Well Tool (CGG- IFP) : A) tool schematics; B) imaging

In order to reduce the acquisition time of well seismic data, and thus downtime well costs, most receiver systems used in the petroleum industry are array tools including a master unit and satellite tools. These permit the simultaneous recording at several depths and are particularly useful in operations of seismic walkaways. The master tool includes the telemetry system, which provides the transfer of data from the bottom of the hole to the surface. Each of the tools includes an anchoring system and a seismic module. We will present two examples among systems available on the market.

Figure 10 illustrates the characteristics of Schlumberger's receiver system called “Combinable Seismic Imager” (CSI). A schematic of the master tool is shown in the left part of the figure. In the seismic module, the geophones are mounted on gimbals and decoupled from the tool body in order to obtain a better quality of the seismic signal. The right part of the figure shows the classical configuration used with the CSI system.

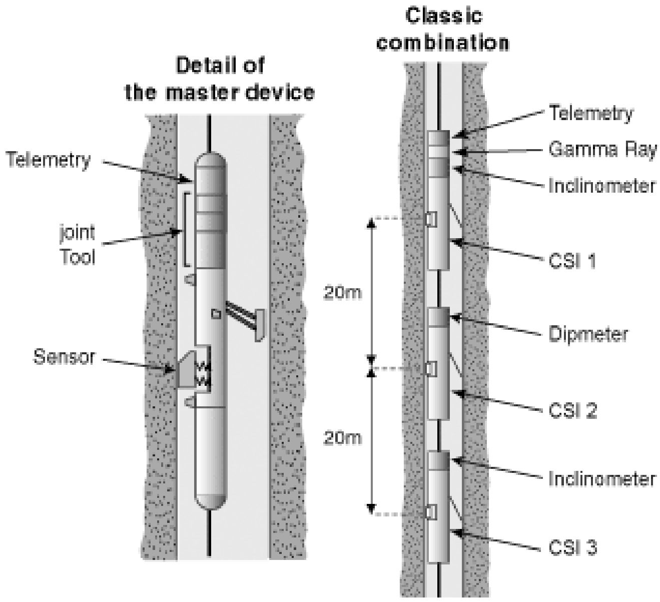

Figure 10: Schematics of the CSI tool (modified from a Schlumberger document)

In Compagnie Générale de Géophysique's SST 500 system, illustrated in Figure 11, each satellite tool is equipped with 3-component geophones and a hydrophone as an option. Seismic acquisition can be done with a maximum of 16 satellite tools with 3-component geophones, or 12 satellite tools with 3-component geophones and a hydrophone. These types of tools minimize well downtimes for seismic walkaway operations.

Figure 11: Satellites of the SST 500 tool (CGG)

The surface source is a classical seismic source (vibrator or weight drop on land, air or water gun in water). A hammer can also be used for civil engineering applications.

These well seismic operations can be conducted in vertical, deviated or horizontal wells, in open or cased holes.

The distance ΔZ between two positions of the well geophone must be small enough (a few meters) to permit processing of the data and avoid any aliasing phenomenon. A simple rule applies:

$\Delta Z \leq Vmin / 2\ Fmax$
Vmin: Minimum formation velocity
Fmax: Maximum recorded frequency
Example : Vmin = 1500 m/s
Fmax = 150 Hz
$\Delta Z \leq 5m$

The offset D depends on the depth of the objective H. Incidence angles must not exceed 30 degrees for reflection imaging. A practical rule gives D < 3/4 H.

3 Processing

A VSP record is composed of upgoing and downgoing P and S waves, as well as of interface-guided waves related to the presence of the well and of the fluid. These guided waves are Stoneley waves, also commonly called tube waves.

The VSP of Figure 12 shows a high level of tube waves labeled TW1 to TW6. The surface waves generated by the source create a field of tube waves (TW1) that is reflected at the well bottom (TW2) and at the top of a porous and permeable zone located at a depth of 440 m (TW3). TW3 is again reflected at the surface, on the fluid-air contact (TW4). As it enters the permeable zone at 440 m, the downgoing P wave creates a tube wave (TW5), which is reflected at the bottom of the well (TW6). One can also note the presence of secondary tube waves with a low apparent velocity; these are due to the geophone itself. Sometimes, Stoneley waves can be used to obtain information on the velocity of shear waves and the permeability of the formations encountered by the well.

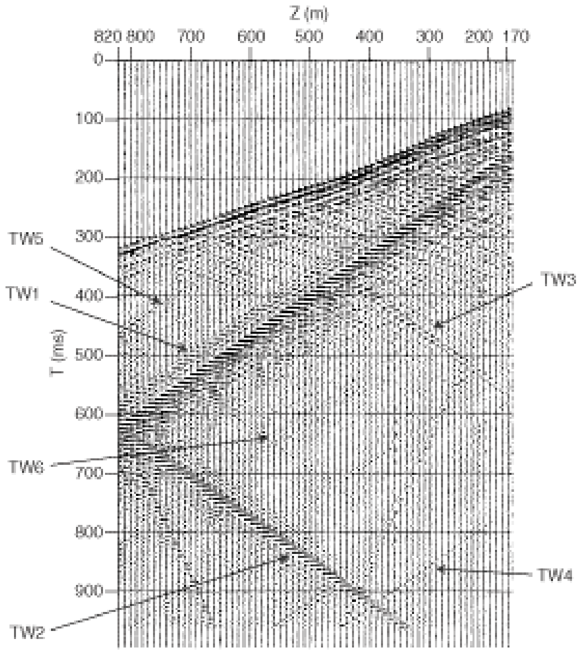

Figure 12: Example of a VSP with tube waves (Gaz de France – IFP)

This figure presents a synthetic VSP calculated with the use of the 1-D wave equation, for a two-layer model over an infinitely-long substratum. The first layer is 200-m thick and has a velocity of 1400 m/s and a density of 2.12 g/cm^3. The second layer is 150-m thick, with a velocity of 2400 m/s and a density of 2.25 g/cm^3. The substratum has a velocity of 3400m/s and a density of 2.45 g/cm^3. The seismic signal used in the simulation is zero-phase with a 0-90 Hz band-pass. The VSP is calculated for 54 depth values with a spacing of 10m in the depth interval from 0 to 530 m. The simulation was conducted with a sampling rate of 0.5 ms. The horizontal axis represents the well geophone positions expressed in trace numbers.

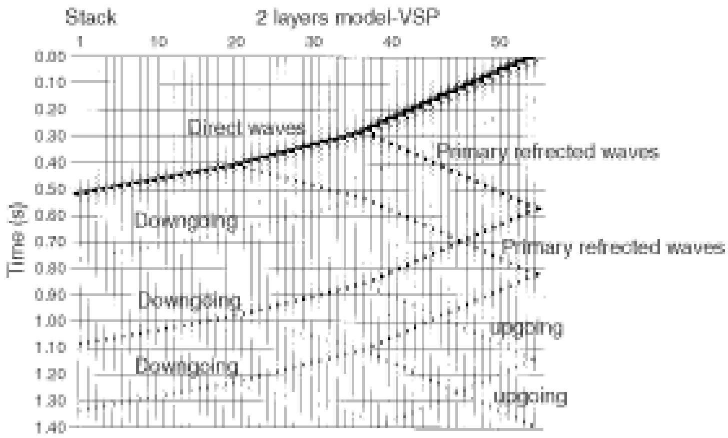

Figure 13: Wave propagation in a VSP - Synthetic example

Downgoing volume waves are emitted by the source. They result in direct arrivals and all the downgoing multiple events created by markers located above the well geophone. Upgoing volume waves are the primary reflected waves or the upgoing multiples.

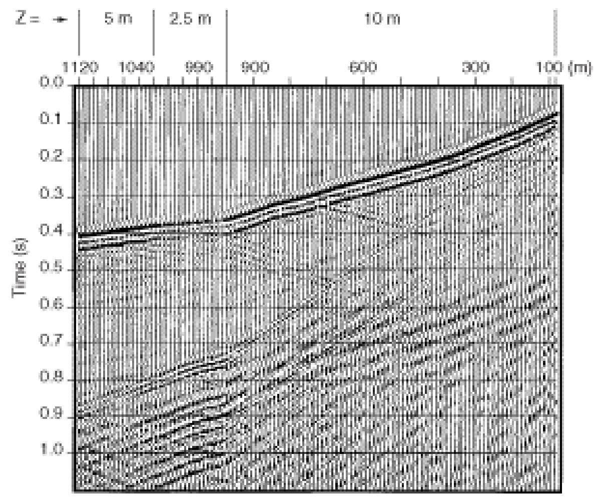

Figure 14: Example of an actual VSP (Gaz de France – IFP)

The VSP section (Figure 14), recorded in well A, is composed of 130 traces. It shows the direct downgoing wave, a series of upgoing reflected arrivals that cut the direct arrival, and downgoing tube waves that are reflected at the bottom of the well.

Conversion phenomena are observed when the source is offset. To properly understand wave propagation, it is necessary to record data with multi-component receivers.

Figures 15 and 16 show an offset VSP recorded with a two-component well geophone (vertical component Z and horizontal component H). For both components, the first arrival is the direct P wave. One observes a downgoing S wave with a low apparent velocity, that is more visible on the horizontal component. Upgoing waves are visible on both components, since the apparent velocity of S waves is lower than that of P waves.

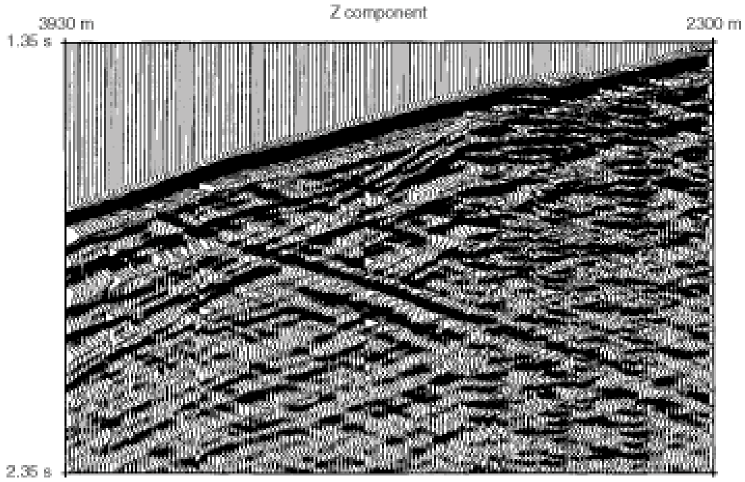

Figure 15: Example of offset VSP recorded with a two-component well geophone - Z component (modified from J. Mars et al.,1999)

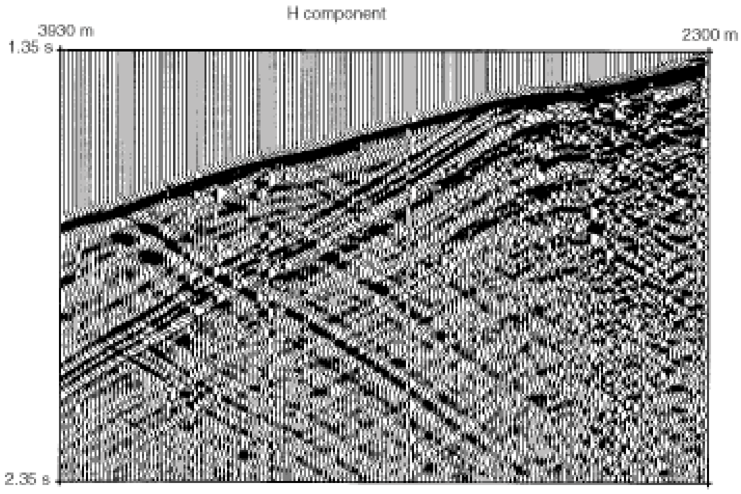

Figure 16: Example of offset VSP recorded with a two-component well geophone - H component (modified from J. Mars et al.,1999)

In the case of well-to-well seismic (Figure 17), the observed wave field is complex.

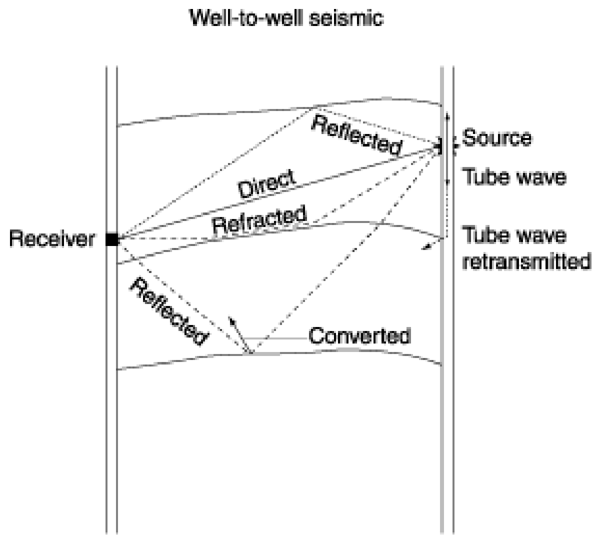

Figure 17: Wave raypaths in well seismic

In general, the following waves are observed:
- Direct wave;
- Waves reflected and/or refracted on markers located above or below the depth of the receiver, with and without conversion phenomena;
- Conversion waves created by tube waves generated by the source. These conversion phenomena (tube waves-volume waves) occur at layer boundaries associated with strong acoustic impedance contrasts and at the bottom of the well.

Regardless of the acquisition geometry, data processing can be subdivided into several sequences.

3.1 First Sequence : Pre-Processing Phase

This sequence includes:
Demultiplexing of the data;
Correlation, if the seismic source is composed of surface vibrators or if the source is the drill bit;
Correction of the effect of signature fluctuations;
Corrections for tool rotation and well deviation;
Removal of poor-quality records;
Summing of same-depth records;
Corrections relating to spherical divergence and absorption;
Component sorting, if a three-component tool is used.

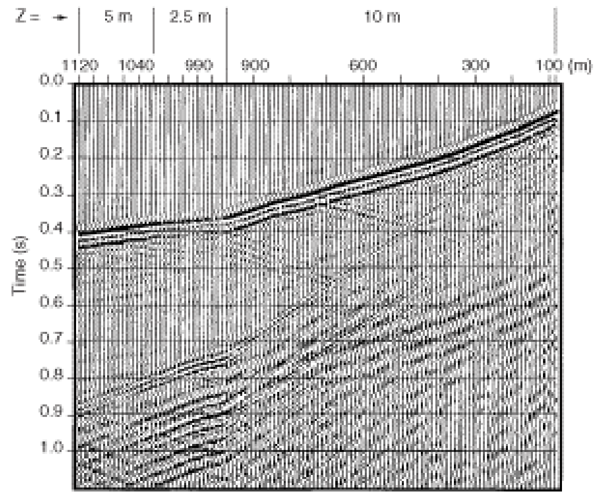

Figure 18: VSP after pre-processing - Well A. (Gaz de France – IFP)

The section shown in Figure 18 is composed of 130 traces recorded between 80 m and 1125 m. It shows the downgoing waves (green), a group of upgoing reflected waves (blue) and tubes waves (brown red).

3.2 Second Sequence: Picking of first arrival times

The second processing sequence consists in picking first arrival times, which provide the time-depth relationship and the various velocity logs (Figure 19).

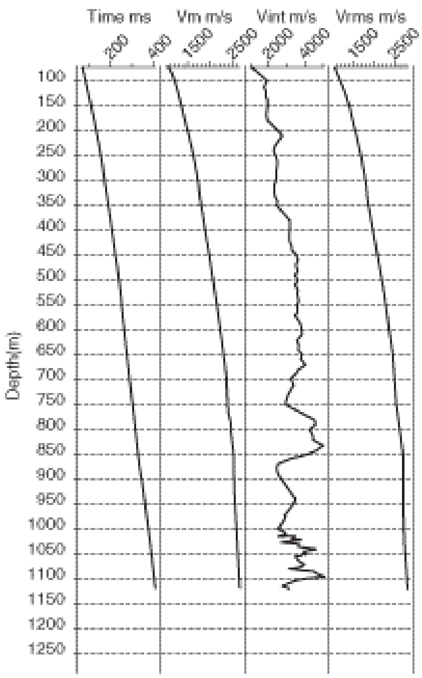

Figure 19: Seismic logs in well A (Gaz de France – IFP)

Third Sequence: Wave Separation

The third processing sequence consists in separating the various waves.

A well seismic record is composed of downgoing and upgoing P and/or S volume waves, as well as of interface-guided waves related to the presence of the well (tube waves).

The downgoing waves are waves emitted by the source. They result in direct arrivals and all the multiple events created by seismic markers located above the well geophone. The upgoing volume waves are primary and multiple reflected waves. Only primary reflected waves intersect the downgoing first arrivals.

On a record, downgoing waves are characterized by positive apparent velocities ($\Delta z / \Delta t$), and upgoing waves by negative apparent velocities.

The separation between upgoing and downgoing waves is based, explicitly or implicitly in the various separation methods, on the fact that both wave types have positive or negative apparent velocities. These wave separation methods can be divided in two categories (Mari, Glangeaud and Coppens, 1997):

- Methods requiring <u>flattening</u> of the well seismic section at the time of the direct arrival, before applying the separation algorithm;
- Methods not requiring flattening.

Among the methods or <u>filters</u> belonging to the first category, one can mention:

- Sum and difference filter;
- Median filter;
- Wiener filter;
- Apparent-velocity filter, if the distance between adjacent recording depths is irregular;
- Filtering by singular value decomposition (SVD).

Filters belonging to the second category are:

- Filters based on the spectral matrix (SMF);
- Parametric methods;
- Apparent-velocity filter, if the distance between adjacent recording depths is regular.

Separation methods that are not based on a criterion of apparent velocity also exist, namely <u>polarization</u> filters to extract P and S waves.

It is often necessary to combine several methods in order to obtain an optimum wave separation. For instance, for an offset VSP, one will use an apparent-velocity filter to separate upgoing and downgoing waves, followed by a polarization filter to separate P and S waves.

3.3 Fourth Sequence: Output of the Seismic Image

After wave separation, the processing sequence leading to a seismic image (optimum for a geologic interpretation) differs depending the acquisition geometry : source and receiver being or not on a line perpendicular to the layers.

1 Generation of the seismic image when source and receiver are on the same line perpendicular to the layers

This is the simplest case corresponding to a vertical well drilled through horizontal layers, with the surface source located close to the borehole. The processing sequence includes:

- Deconvolution of upgoing waves by downgoing waves. Deconvolution removes the effects of both source signal and downgoing multiples.
- Flattening of deconvolved upgoing waves. This operation makes the VSP record comparable in time (two-way time) to a surface seismic reflection record.
- Generation of the VSP stack trace. Deconvolved and flattened upgoing waves are stacked within a corridor and immediately following the first arrival. The result is a stack trace comparable to a synthetic seismogram without multiples in the frequency band of the received signal. This trace is therefore comparable to the seismic trace obtained from surface seismic after multiple-fold stacking.

Figures 20 to 24 illustrate the classical sequence of VSP processing:

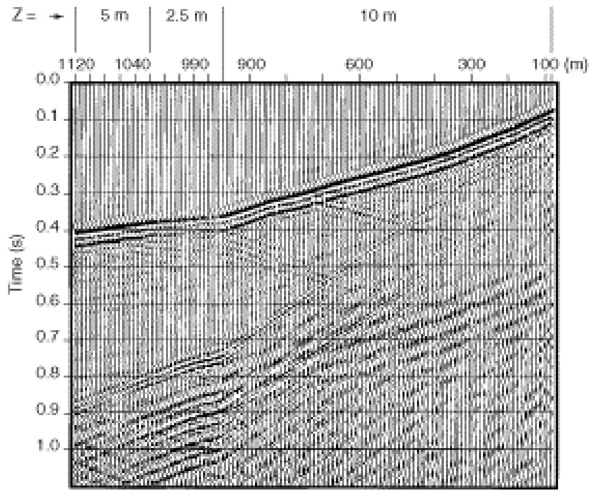

Figure 20: Classical VSP Processing - After pre-processing (Gaz de France – IFP)

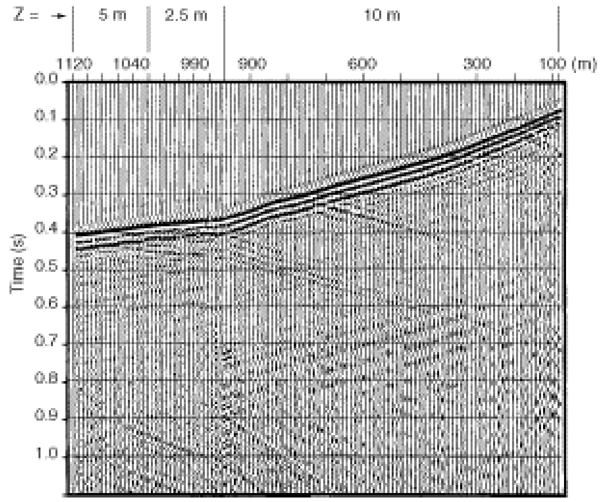

Figure 21: Classical VSP Processing - Filtering of tube waves (Gaz de France – IFP)

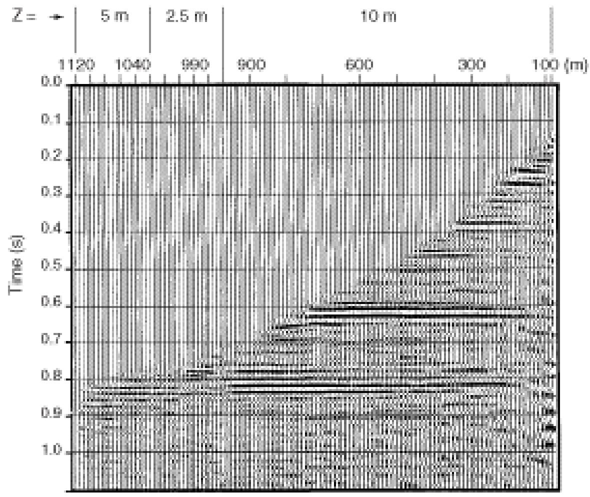

Figure 22: Classical VSP Processing - Extraction and flattening of downgoing waves (Gaz de France – IFP)

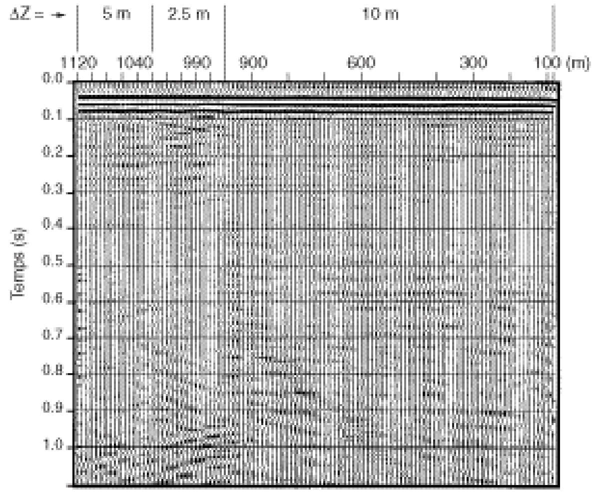

Figure 23: Classical VSP Processing - Extraction and flattening of upgoing waves (Gaz de France – IFP)

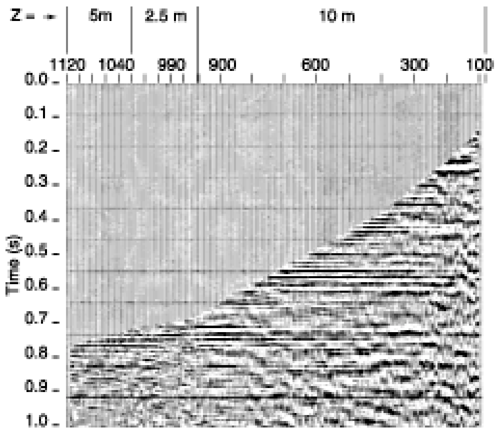

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Figure 24 A: Classical VSP Processing - Deconvolution of upgoing waves by downgoing waves (Gaz de France – IFP)

A source offset of about 50 m was used for data acquisition. The offset was neglected in processing. The resulting image is a single trace called stack trace and shown in B.

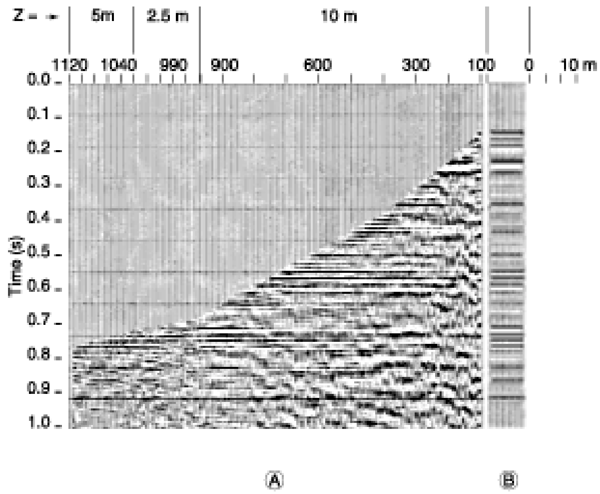

Figure 24 B: Classical VSP Processing - Stack trace (Gaz de France – IFP)

The section presented in C, called migrated VSP section, was obtained after a processing step which takes into account the fact that source and receiver are not exactly on the same vertical line; this particular aspect is discussed in the following paragraph.

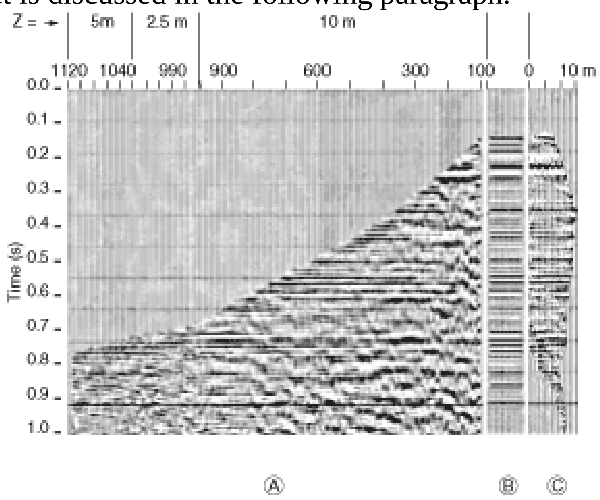

Figure 24 C: Classical VSP Processing - Migrated section (Gaz de France – IFP)

2 Generation of the seismic image when source and receiver are not on the same line perpendicular to the layers

This is the most general situation. It applies to the following cases: offset VSP, VSP in a deviated well, seismic walkaway and well-to-well seismic. The processing sequence includes:

- Deconvolution of upgoing waves. The deconvolution operator is unique. It is extracted from traces at the bottom of the well and permits the removal of the effects of the source signal.
- Normal moveout (NMO) Correction and conversion in two-way time of deconvolved upgoing waves. The purpose of this correction is to compensate for the obliquity induced by the

source offset, and its object is to take the acquisition geometry into account. Knowledge of the velocity model is necessary to perform this correction.

- Migration: The method most commonly used with a VSP is that proposed by Wyatt and Wyatt (1982). The VSP seismic section obtained after migration is directly comparable to a surface reflection seismic section. The migrated VSP section has a lateral range of investigation of a few tens to a few hundreds of meters.

The example below shows a seismic section obtained from data recorded in a highly deviated well on the Wytch Farm Field on behalf of BP-Amoco and partners.

Well data were acquired in the F18 deviated well (which reaches a maximum deviation of 88.5°) with a vibrator source located at a distance of 1,865 m (Jerry's Point -JP-) with respect to the wellhead. Recording was done with a 3-component well geophone of CSI-type (Schlumberger's Combinable Seismic Imager Tool). The well geophone was equipped with sensors having a natural frequency of 10 Hz. Acquisition filters were a 2 Hz low-cut filter with a 6 dB/oct slope, and a 330 Hz high-cut filter with a 30 dB/oct slope. The source signal was emitted within the 10 Hz -80 Hz band -pass range. The duration of the frequency sweep was 16 seconds.

The velocity model used to process seismic data was created using the information provided by surface seismic and velocity curves from all the wells in the vicinity of the F18 well. The velocity model was refined by inversion of first arrival time picks, minimizing the difference between measured times and the times calculated by the inversion algorithm. This difference did not exceed 3 ms. Figure 25 shows the velocity model, the well trajectory, the different positions of the well geophone and the location of source points. For each source point, ray-tracing shows the path followed by the downgoing wave.

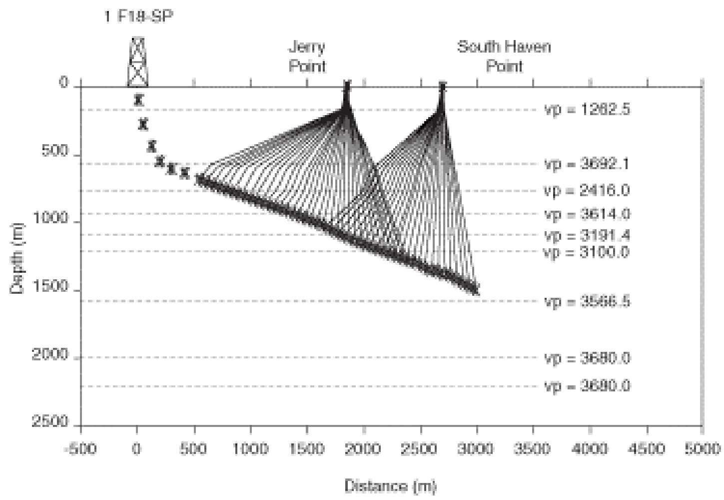

Figure 25: VSP in a deviated well - Velocity Model and well trajectory (BP Exploration)

Figures 26 to 32 illustrate the processing sequence applied to well data obtained with the source located at Jerry Point (JP). The processing phases are as follows:

- Frequency filtering and amplitude recovery. Seismic data were filtered in the 5 Hz -80 Hz bandpass and compensated for the spherical divergence effect by application of a gain law. Each VSP trace was then normalized to the direct arrival to compensate for transmission losses. The result of this pre-processing is shown in Figure 26. The horizontal axis of the VSP section represents the cable length deployed along the well trajectory.

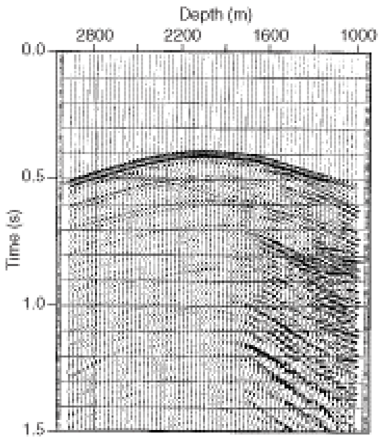

Figure 26: VSP in a deviated well - Frequency filtering and amplitude recovery (BP Exploration)

- Picking of first arrival times and wave separation. The VSP section was flattened on first arrival time picks. A 7-term median filter was applied to flattened data to extract the downgoing waves. These are shown in Figure 27. The downgoing-wave section was subtracted from the initial data. The residual section was corrected by the first arrival times to restore each VSP trace to its initial time. The residual VSP section of Figure 28 mainly shows the upgoing waves.

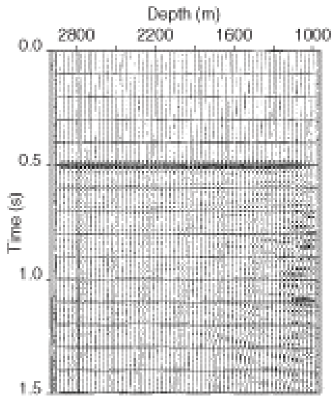

Figure 27: VSP in a deviated well - Flattened downgoing waves (BP Exploration)

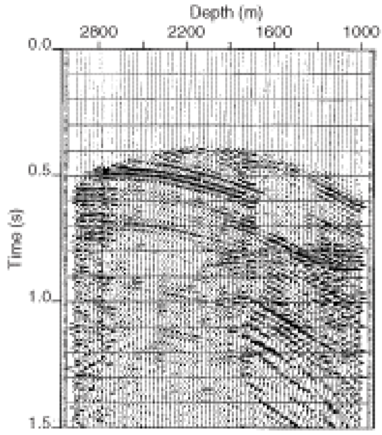

Figure 28 : VSP in a deviated well - Residual VSP section (BP Exploration)

- Deconvolution. A Wiener-Levinson deconvolution was applied to the downgoing waves (Figure 29) and to the upgoing waves (Figure 30). The operator, calculated on the downgoing field for the purpose of transforming the downgoing wavelet into a zero-phase signal, is applied to the upgoing and downgoing fields. A different operator is calculated for each VSP depth.

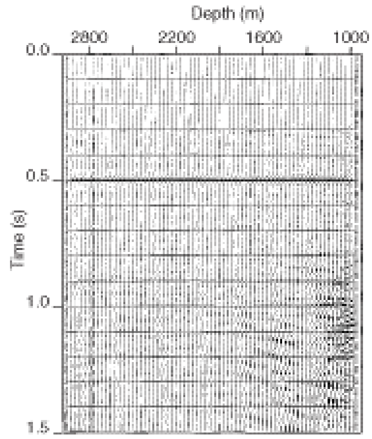

Figure 29: VSP in a deviated well - Downgoing waves after Wiener deconvolution (BP Exploration)

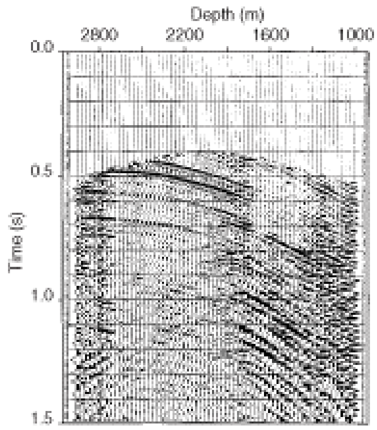

Figure 30: VSP in a deviated well - Upgoing waves after Wiener deconvolution (BP Exploration)

- Generation of the seismic image. The seismic image is obtained from the section representing the deconvolved upgoing waves. This operation takes place in four successive steps:

1. Calculation of the velocity model
2. NMO corrections and conversion of upgoing waves in two-way times (Figure 31)

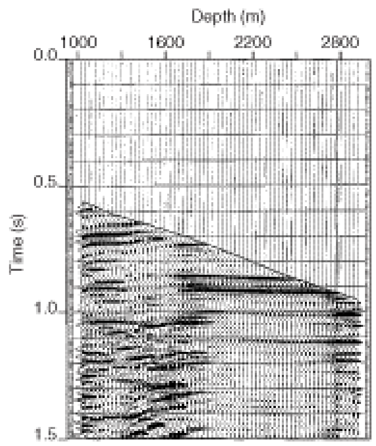

Figure 31: VSP in a deviated well - Upgoing waves after Wiener deconvolution and NMO corrections (BP Exploration)

3. Calculation of equal-abcissa lines for mirror points. Figure 32 shows the distribution of equal-abscissa lines (iso-X lines) on the section displayed in Figure 31 after application of a gain law. The distance chosen between two iso-X lines was 25 m.

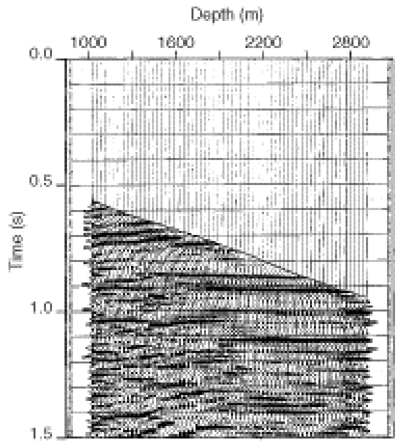

Figure 32: VSP in a deviated well - Upgoing waves after Wiener deconvolution and NMO corrections; Equal-abscissa lines (iso-X lines) displayed every 50 m (BP Exploration)

4. Migration using the method presented by Wyatt (1981). The migrated VSP section is shown in Figure 33. The horizontal axis represents the horizontal distance between the well (0 m) and the different mirror points. The distance between two mirror points is 25 m. The lateral range of investigation of the VSP section is of the order of 1000 m. The section is redisplayed in normal polarity according to the SEG convention. Under normal polarity, an upgoing compression wave reflected by a marker associated to an increase in acoustic impedance is represented by a negative amplitude value (trough).

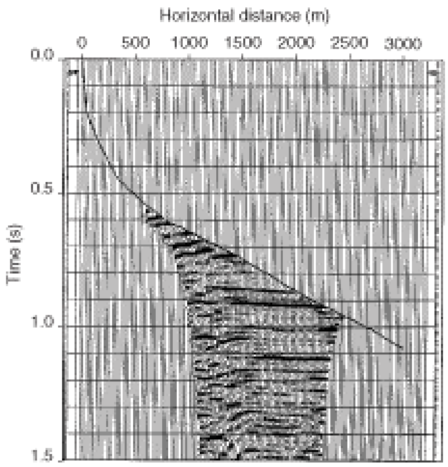

Figure 33: VSP in a deviated well - Migrated section (BP Exploration)

4 Examples of imaging and applications of well seismic

4.1 Tying of surface seismic

Figure 34 illustrates the tying of a surface seismic section going through the A and B wells. The distance between the two wells is 1600 m. Tying is done using the deconvolved upgoing waves of the VSPs recorded in wells A and B.
The same processing sequence was used for both wells.

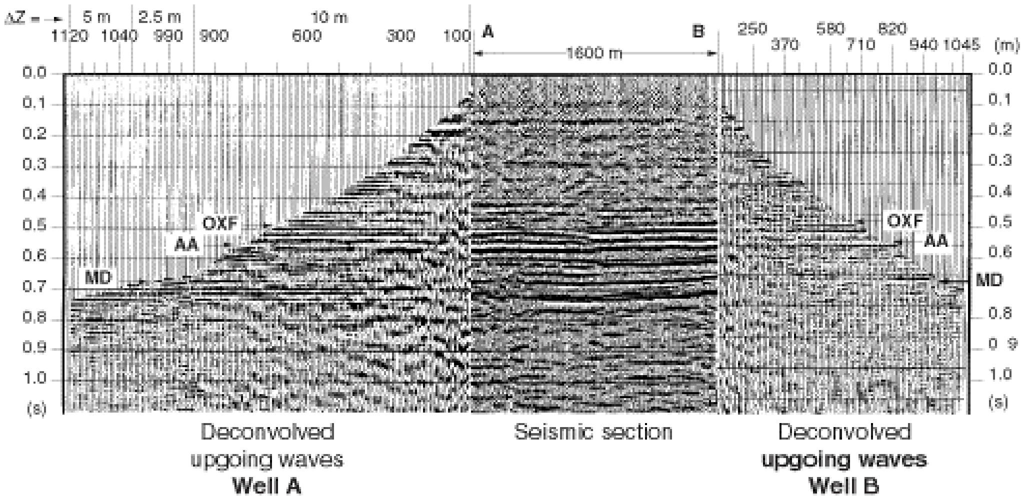

Figure 34: Correlation between surface seismic and well seismic data (Gaz de France)

Figure 35 shows the tying of surface seismic to VSP stack traces.

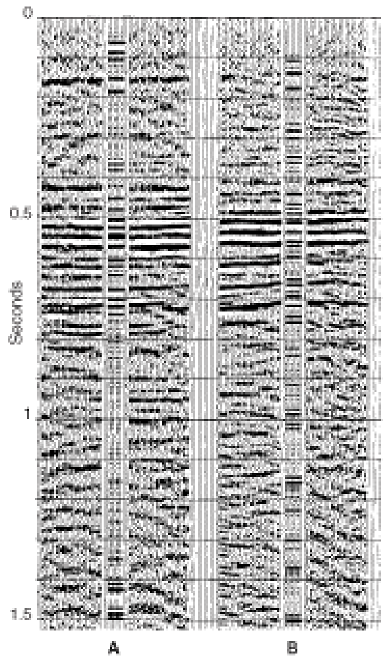

Figure 35: Correlation between surface seismic data and VSP sack traces (Gaz de France)

4.2 Prediction below the well with a seismic walkaway

This example (Figure 36) shows a series of offset VSPs acquired on a receiver array composed of 15 permanent sensors located in the depth interval between 540 m and 680 m (the maximum source offset is 800 m).

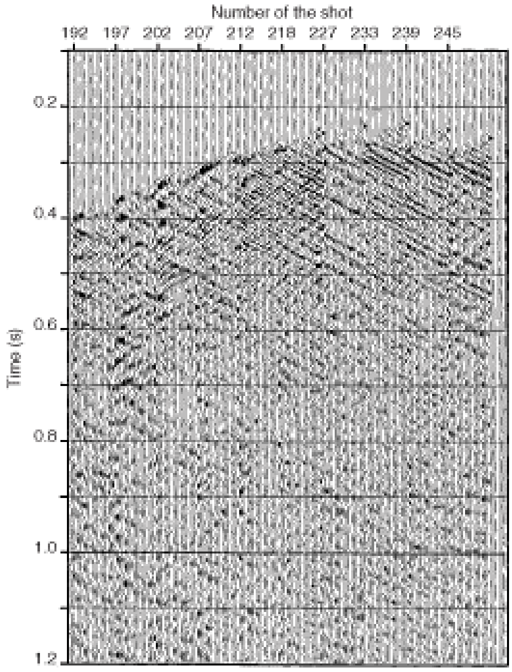

Figure 36: Seismic Walkaway - Initial data acquired on an array of permanent sensors (Gaz de France)

Figure 37 shows the stacked section obtained after a processing sequence including: editing, amplitude compensation, wave separation, NMO corrections, VSP-CDP stacking, static corrections and frequency and apparent-velocity filtering.

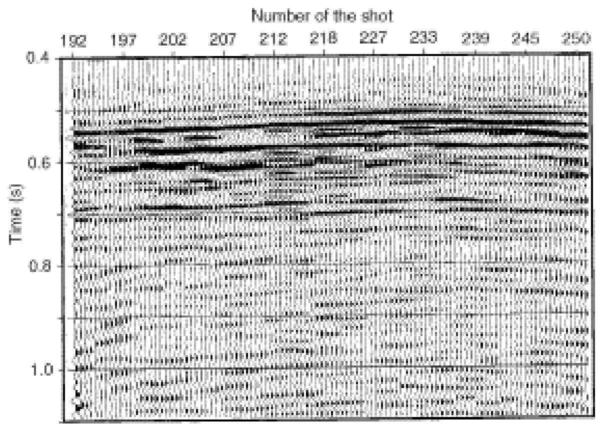

Figure 37: Seismic Walkaway - Stacked section (Gaz de France)

Figure 38 shows a classical VSP with a 50 m offset, recorded in the interval between 100 and 1,040m, with:
In A, a VSP section (the processing is done to take the offset into account);
In B, a VSP stack trace (the processing does not take the offset into account).
We have also included a seismic walkaway section. This section was obtained from permanent sensors located at depths between 540 m and 680 m. It shows coherent seismic horizons below 1000 m, and prediction below the last sensor is therefore of the order of 400 m.

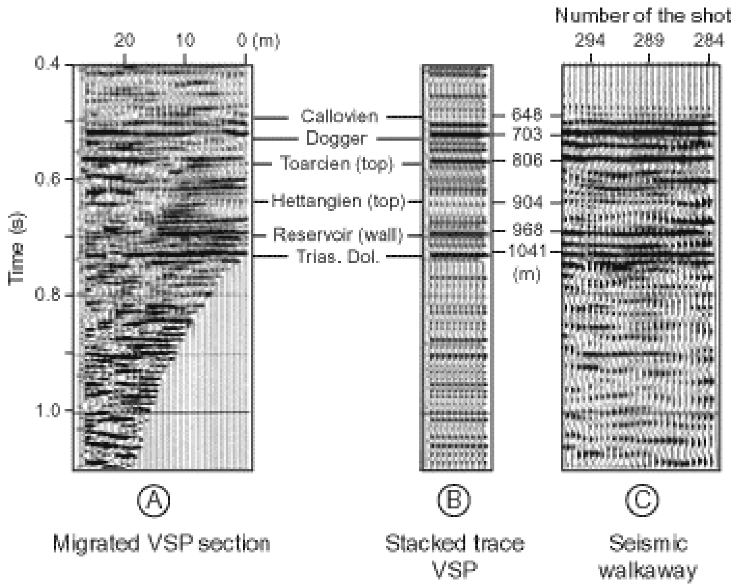

Figure 38: Correlation between well seismic sections and lithology (Gaz de France)

4.3 Well seismic while drilling (reverse VSP)

Numerous authors have widely discussed the possibility of using one or several sensors located on the drilling unit and/or sensors planted on the ground surface to obtain geophysical information on the layers encountered and seismic images generated while drilling. Namely, Staron et al. (1988), Ng et al. (1990), Naville et al. (1994). Miranda et al. (1996) show the impact of well seismic while drilling on exploration wells.

Figure 39 schematically shows the implementation principle of the transposed well seismic method. A drilling unit is composed of the rig and a drill stem. The drill stem includes drill pipes (DP) and a lower part called the Bottom Hole Assembly (BHA). The BHA includes drill collars, stabilizers, a downhole motor, eventually a system of Measurement While Drilling (MWD), a bumper sub, a shock absorber. Below the BHA is located the actual drill bit, which is used as seismic source during drilling. Two types of seismic waves are generated by the drill bit: waves propagating in the formation that will be used for imaging (waves 1, Figure 39) and waves propagating in the drill pipes that will be transmitted to the formation through refraction (waves 2, Figure 39). Waves 2 are organized noise, which is undesirable for imaging. A sensor located on the drill pipes records the propagation of waves guided within the pipes. Commonly, this sensor, which is a vertical-axis accelerometer, is located at the top of the drill stem. The use of a shock absorber in the BHA attenuates vibrations in the drill stem and reduces the amplitude of waves propagating trough the pipes (Naville, 1994).

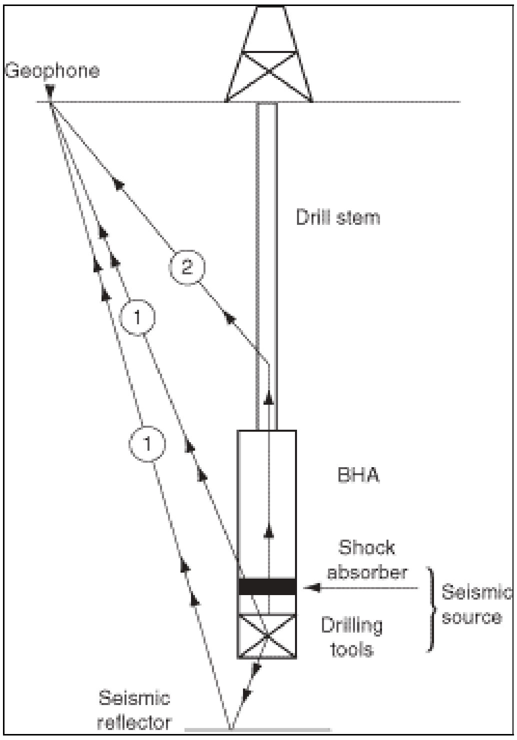

Figure 39: Principle of implementation of the reverse well seismic technique (modified from Naville, 1994)

The device used for an industrial implementation of the transposed well seismic technique is shown in Figure 40. This includes the drilling unit with a BHA equipped with a shock absorber, measuring equipment with memory storage and electromagnetic remote command (Geoservices) that includes a bottom hole unit and a surface unit interfaced with a surface seismic recorder, seismic sensors located on the drill stem (at the surface and/or downhole), a series of surface geophones connected to the surface seismic recorder.

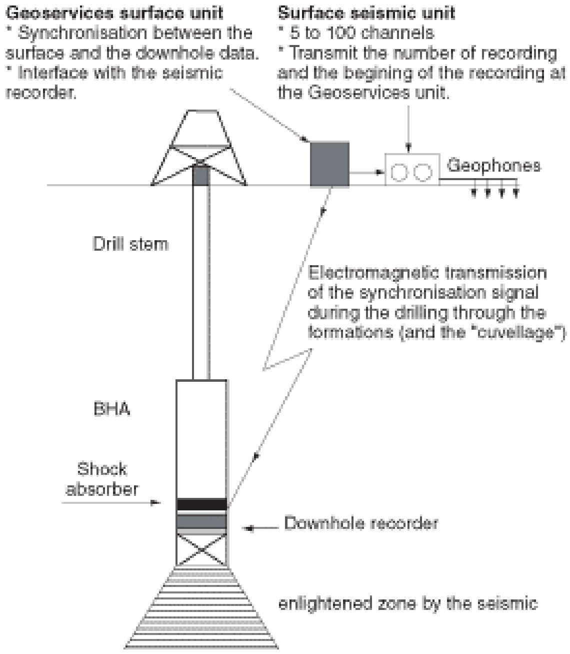

Figure 40: Device for the implementation of the reverse well seismic technique (Naville et al., 1994)

The seismic device for surface listening is composed of a series of vertical-axis or 3-component geophones positioned along a line for 2D imaging or distributed on a surface for 3D imaging. The location and orientation of the surface sensors are perfectly well known. Pre-processing of seismic data consists in deconvolving or correlating the surface geophone records by the record from the sensor located on the drill stem.

Figure 41 shows an example of imaging from a transposed VSP recorded during drilling using the TRAFOR transmission system implemented on a Gaz de France site (Naville et al., 1994). The correlation of surface records is done using the downhole record obtained on a vertical-axis accelerometer located in the BHA below a shock absorber. The source zone corresponds to the depth interval from 800 to 950 m. The transposed VSP section represent a lateral depth of investigation of 370 m with respect to the well axis. Figure 41 shows a comparison between three independent methods, from left to right:

- Synthetic seismogram obtained from sonic and density logs. The synthetic seismogram is filtered in the 10 Hz – 80 Hz bandpass;
- Stack trace of a classical VSP acquired after drilling of the well;
- Seismic section obtained from the reverse VSP acquired while drilling.

One can note the excellent correlation between the different records in the vicinity of the well. The transposed well seismic method permits prediction through 400 ms below the well.

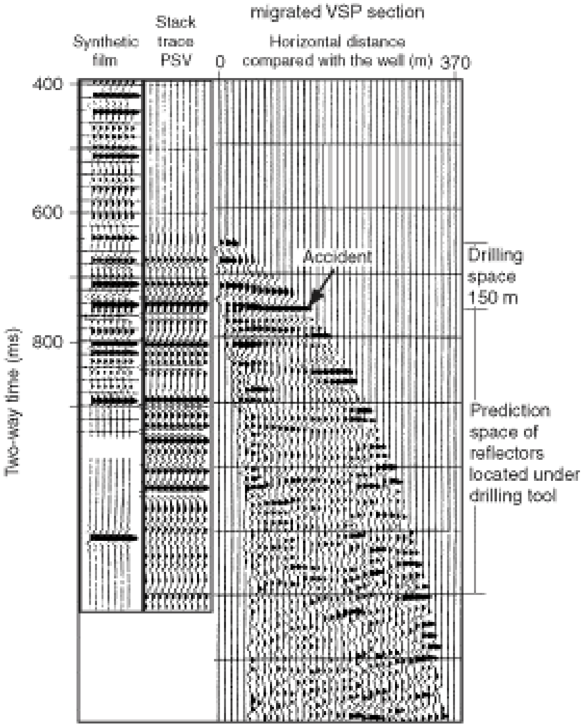

Figure 41: Well seismic while drilling (Courtesy Gaz de France, modified from Naville et al., 1994)

4.4 Imaging by Tomography Study

When two or more wells are available, a tomography study can be done to precisely define the zone between the wells.
Several techniques can be used:
Transmission tomography;
Reflection tomography;
Diffraction tomography.

Figure 42 is an example of transmission tomography in civil engineering. It was conducted in vertical wells ahead of a tunnel digger used for laying out a large-diameter sewer pipe. This shows an important alteration of the rocks in the project zone.

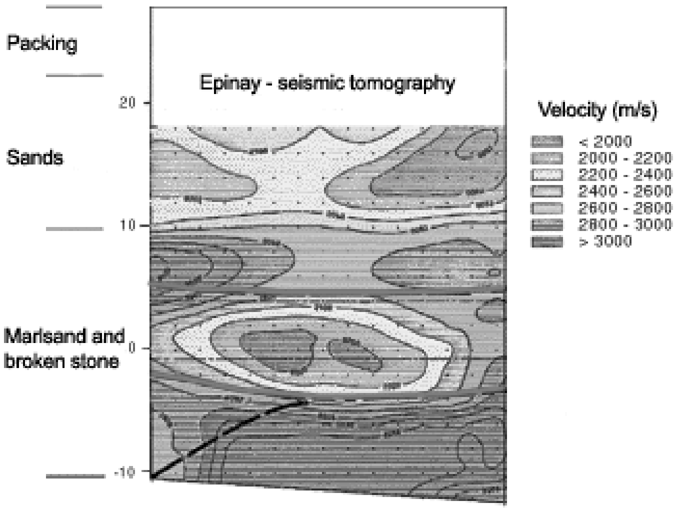

Figure 42: Example of transmission tomography (F. Lantier)

Reflection tomography can be used to image the zone between wells by processing data as those obtained in an offset VSP (Figure 43). One of the wells is treated as the source, the other as receiver.

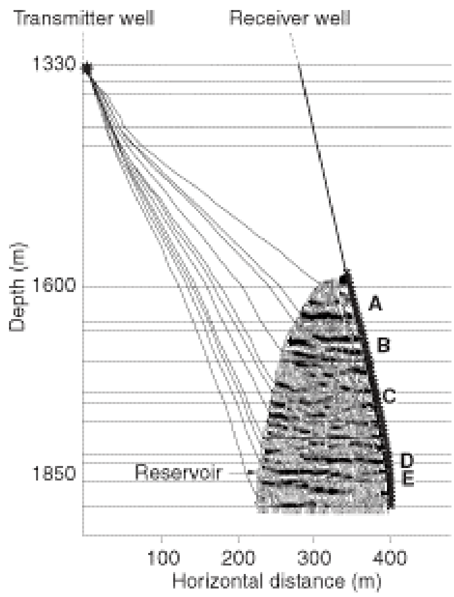

Figure 43: Well-to-well imaging by reflection tomography (modified from Becquey et al., 1992)

In the example presented in Figure 44, the source is a weight drop generating S waves. After processing, the resulting S waves section presents a better vertical resolution than that obtained with a P-wave VSP acquired in the receiver well.

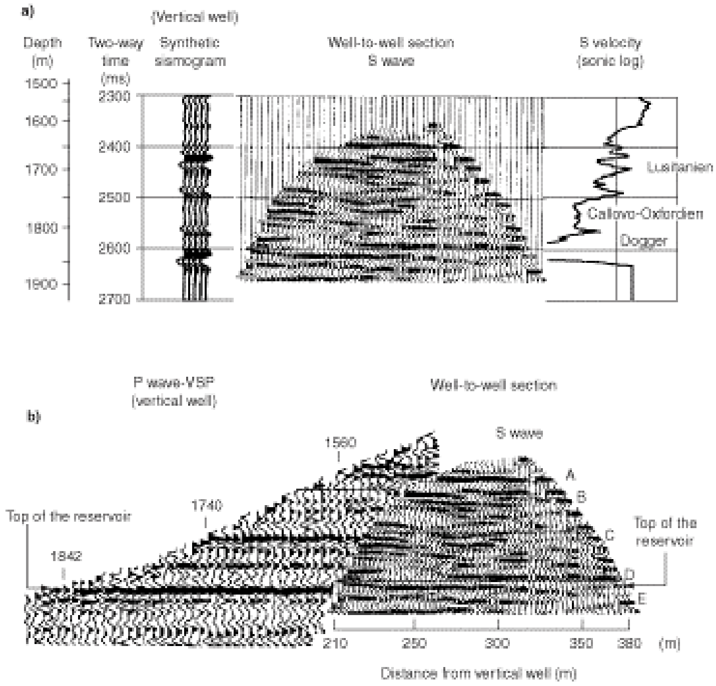

Figure 44: Example of well-to-well seismic in S-wave reflection tomography between a vertical well and a deviated well (modified from Becquey et al., 1992). In B, Comparison between the well-to-well section (S waves) and a VSP (P waves)

4.5 Well Seismic and Dip Measurements

VSP data are often recorded along three components. Under these conditions, the analyses of hodograms of the motion velocity of particles on upgoing P waves permit the determination of the strike and the dip of a reflector (Hardage,1985). This method is presented in Figures 45 A and B. In these diagrams, the ellipticity of the compression wave is exaggerated with respect to reality where the particle motion is quasi-linear for a P wave. With this approach, the orientation of the well tool must be known. In a deviated well, when the deviation of the well exceeds 8°, geophone systems mounted on universal joints permit a proper reorientation. In an open hole, the reorientation can be obtained from data provided by a system composed of 2 inclinometers and a magnetometer commonly used in combination with dipmeters. In a cased hole, one has to use a gyroscopic system or a system with inclinometers for well deviations exceeding 3°.

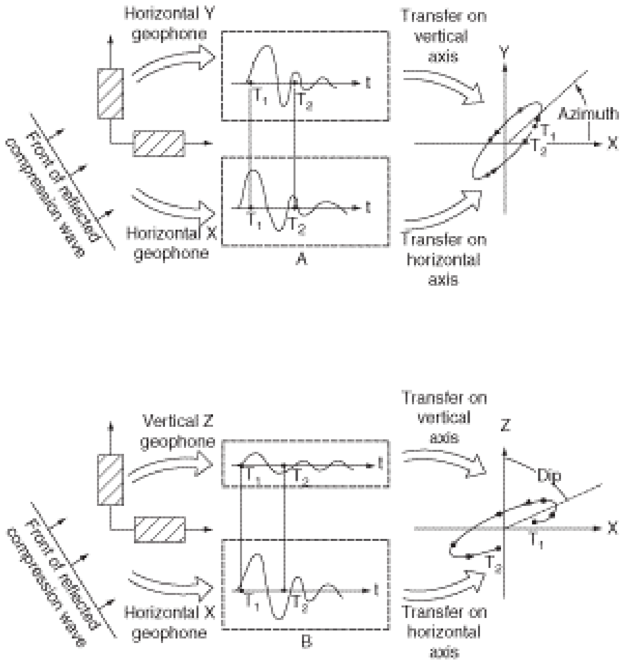

Figure 45: Determination of strike (A) and dip (B) directions of the upgoing P-wave front with the use of hodograms. (modified from Hardage, 1985)

In the case of reflectors that are dipping with respect to the well, and in the hypothesis of a constant-velocity medium, the reflection point of a wave is located on an ellipsoid whose focal points are the source and the receiver (Figure 46). At the receiver location, the knowledge of the direction of propagation of the wave reflected permits the localization of two reflection points on the ellipsoid, one below the receiver (most probable case), the other above the receiver (rarely realistic). This method permits one to obtain both the strike and dip of a reflector (SEISDIP process, IFP patent). In a vertical well, for a zero-offset VSP and reflectors immediately below the receiver, the polarization angle of the reflected wave is twice that of the dip (Figure 47 A), and the polarization direction, H, in the horizontal plane corresponds to the strike. A more general scheme for the calculation of the dip in the stacking corridor field is given in Figure 47 B, regardless of the well geometry and the source location. The line, N, perpendicular to the reflector is obtained by calculating the bisector of the angle formed by the polarization direction, D, of the direct wave and the polarization direction, R, of the reflected wave recorded on a geophone located immediately above the reflector. The study of polarization requires a so-called isotropic processing, which preserves the relative amplitudes of waves on each component. In general, processing of the 3 components permits the most reliable identification of the nature of reflected or diffracted waves, converted or not, that are not actual downgoing waves.

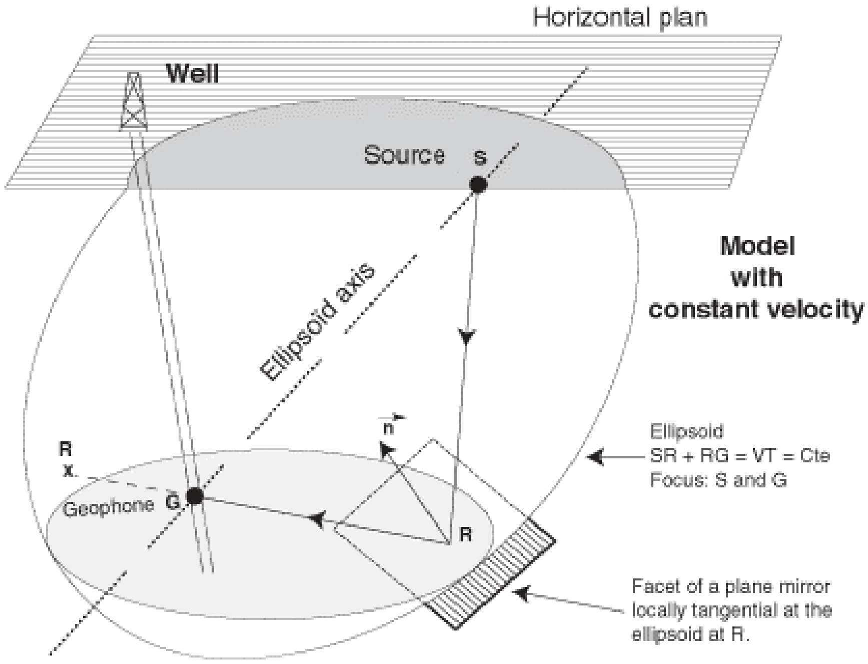

Figure 46: Principle of the SEISDIP method (IFP patent)

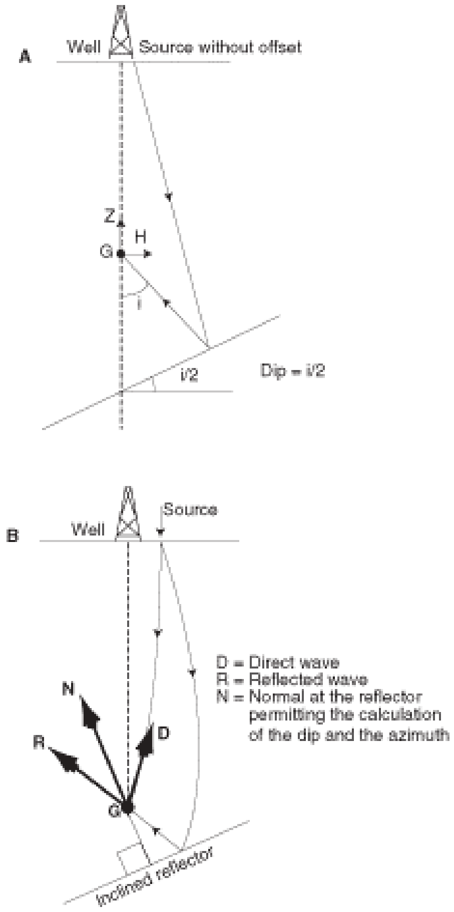

Figure 47: Estimation of the dip by the SEISDIP method (modified from Giot et al., 1992)
A: Vertical well and zero-offset VSP, measurement of the polarization direction of the reflected wave
B: General case, measurement of the polarization directions of the direct wave and reflected wave

Figure 48 is an application example of isotropic processing. The three components of reflected waves are shown in two-way time, after flattening and static corrections. The horizontal radial component HR is in the vertical plane of the well deviation including the source. The horizontal transverse component HT is perpendicular (+90° in the trigonometric direction) to the HR component. Four reflectors are clearly visible on the vertical component. Reflectors H1 and H2 are sub-horizontal reflectors that appear continuous on the Z component. Reflectors H3 are H4 appear to be dipping and of limited extent on the 3 components. This is characteristic of dipping reflectors that are no longer seen beyond a certain depth of the well geophone. Figure 49 shows the localization of reflectors obtained with the SEISDIP method in the vertical plane of the well deviation and in the horizontal plane defined by the north and east directions. The west dip of horizon H3 varies from 6 degrees to 15 degrees from west to east, thereby showing a flexure of the marker that is confirmed by geologic knowledge. The flexure shape, which is a simple geometric shape, produces a complex seismic response (Figure 48) marked by a discontinuity that could have been interpreted as a fault if the 3-component information had not been taken into consideration.

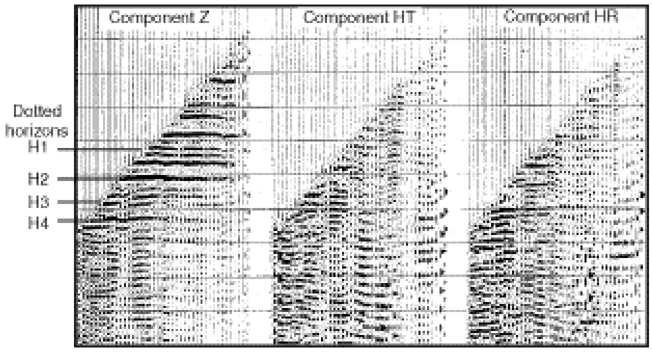

Figure 48: Application example of isotropic processing on 3-component well data (mofified from Naville and Japiot ,1989, unpublished)

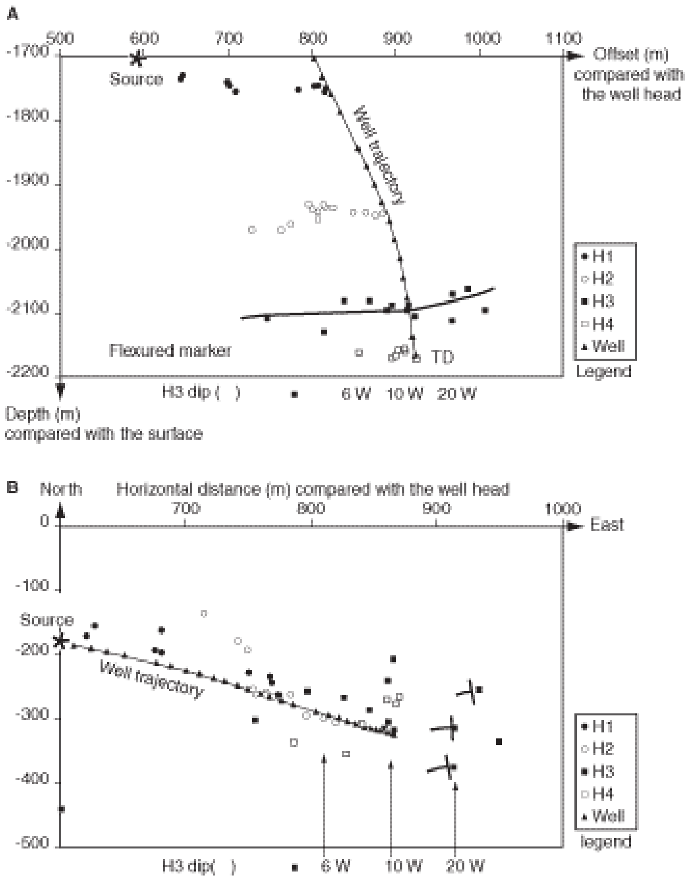

Figure 49: Localization of seismic reflectors by the SEISDIP method
A: in the vertical plane of well deviation

B: in the horizontal plane defined by the north and east directions. The well trajectory is indicated with triangles. (modified from Naville and Japiot ,1989, unpublished)

4.6 Well seismic and monitoring

Seismic methods can be used to track the production of a reservoir by mapping the location of anomalies related to the presence of hydrocarbons though time during the various development phases of a field (monitoring). The technique consists in comparing 2D or 3D seismic data at different periods. One thus introduces a new dimension, which is the date of acquisition of the seismic data. If seismic data are acquired in 3D, repetitive seismic is typically called 4D seismic, with the acquisition date being the fourth dimension.

Time lapse seismic is a rapidly emerging technique, with low implementation costs, and leading to an anticipated gain of a few percents (1% to 7%) on the productivity of a field. It is also used to monitor gas storage in an acquifer.

Production tracking by repetitive seismic represents active monitoring. We present an example of active monitoring by a repetitive seismic walkaway done on the gas storage site of Céré-la - Ronde. Two seismic walkaway profiles, M01 (Figure 37) and M02, were recorded on the structure.
The evolution of the gas bubble through time can be shown by measuring time delays and comparing seismic data recorded at different periods. Indeed, in a reservoir, density and velocity of compression waves decrease when gas replaces water. Velocity and density changes induce a decrease of the acoustic impedance of the reservoir, which corresponds to a change in the amplitude of seismic traces. The decrease in velocity leads to an increase in the time of reflectors located below the reservoir. This time increase can be estimated by measuring a time delay Δt calculated for two mirror-point traces recorded at the same location but at different periods. The comparison of mirror-point traces, on the basis of correlation techniques, permits the measurement of both the time delay Δt and the time-height Ht associated to the portion of the reservoir where gas replaced water (Mari et al., 2000).

Figure 50 shows the time-delay maps at different periods (from February 1994 to November 1995). Analysis of the changes in delay times shows a disorderly gas replacement in the north-south direction along the M01 profile, and a progressive gas replacement along the M02 profile, with a more important gas infilling in the west-to-east direction in November 1995. These maps were obtained during an injection period. This example shows the capacity of the seismic technique to track the evolution of a gas bubble in an acquifer.

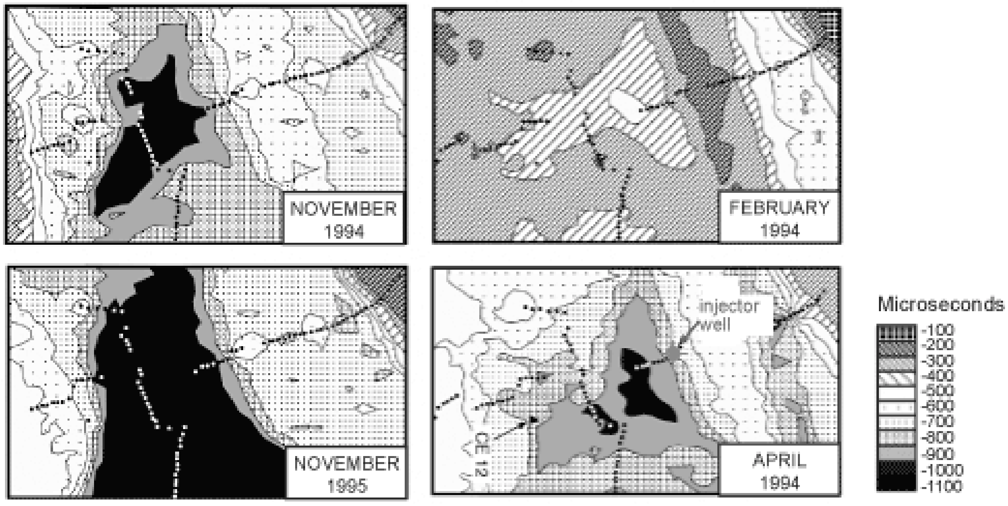

Figure 50: Maps of delay times observed between February 1994 and November 1995 (Gaz de France - IFP, Huguet et al., 1998)

Gas saturation is estimated from the measurement of the quantities Ht and Δt. The estimation is based on Gassmann's model (Gassmann, 1951) used to predict the change in compressional velocity as a function of gas saturation. The method was applied to the M01 profile and the results, which were validated at the CE12 well by acoustic measurements (Dumont et al., 1999), are presented in Figure 51.

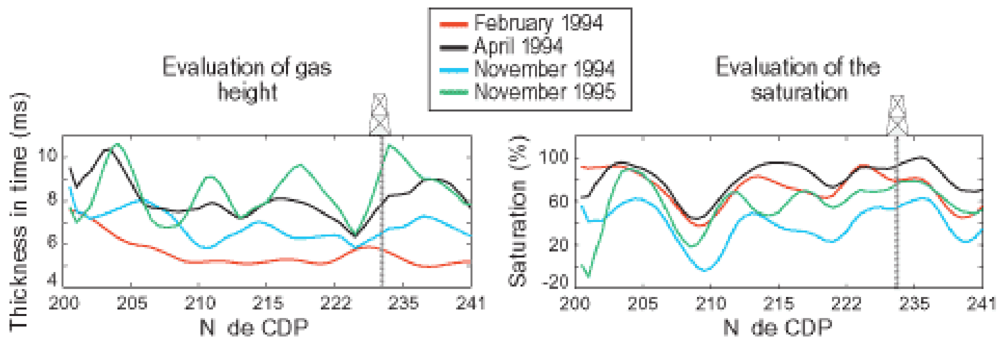

Figure 51: Evaluation of the height infilled with gas and of saturation with the use of well seismic (modified from Dumont et al., 1999).

This example shows that monitoring of gas movements can be done by measuring the evolution of time delays associated with horizons located below the reservoir; the geographic distribution of time-delay anomalies at different periods permits one to track the migration of the gas bubble in the reservoir. Gas migration is also confirmed by amplitude anomalies observable on seismic profiles at the level of the reservoir zone.

The method permits the quantitative tracking of the reservoir height infilled with gas and the evolution of the reservoir saturation at a distance of a few hundred meters from the well.

The results obtained are consistent with in-situ measurements conducted in the well (height infilled, saturation).

5 Conclusion

The main applications of well seismics are:

- Establishing the time-depth relationship;
- Providing detailed seismic in the vicinity of a well;
- Tying surface seismic;
- Identifying primary and multiple reflections;
- Predicting the presence of reflectors or anomalous zones ahead of the drill bit, i.e. below the well for a vertical well and ahead of the drilling front for a horizontal well or tunnel;
- Providing structural information as well as an estimate of mechanical parameters and some petrophysical parameters;
- Estimating the dip of a marker;

The offset VSP and seismic walkaway permit the extension of the lateral range of investigation, which varies with depth, and they provide detailed seismic in the vicinity of the studied objective.
If the lateral range of investigation of well seismic methods is in any case limited, the fact that receivers are close to the objectives permits a good vertical resolution, which is mainly due to the wave train being filtered only once by the weathered zone.
During drilling, one can use the drill bit itself as the well seismic source. This permits the imaging while drilling of the formations not-yet drilled.
Finally, well-to-well seismics should allow one to obtain detailed lithologic information in the reservoir zones. Various well seismic techniques permit the monitoring of the evolution of a reservoir if data acquisition is repeated through time (active monitoring).

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