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Jack Dvorkin, Mario A. Gutierrez and Dario Grana
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Part I

The basics

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1 Forward modeling of seismic reflections for rock characterization

1.1 Introduction

Seismic reflections depend on the contrast of the *P*- and *S*-wave velocity and density between strata in the subsurface, while the velocity and density depend on the lithology, porosity, rock texture, pore fluid, and stress. These two links, one between the rock's structure and its elasticity and the other between the elasticity and signal propagation, form the physical foundation of the seismic-based interpretation of rock properties and conditions. One approach to interpreting seismic data for the physical state of rock is forward modeling. Lithology, porosity, stress, pore pressure, and the fluid in the rock, as well as the reservoir geometry, are varied, the corresponding elastic properties are calculated, and then synthetic seismic traces are generated.

These synthetic traces are compared to real seismic data: full gathers; full stacks; and/or angle stacks. The underlying supposition of such interpretation is that if the seismic response is similar, the properties and conditions in the subsurface that give rise to this response are similar as well. Systematically conducted *perturbational forward modeling* helps create a *catalogue* (field guide) of seismic signatures of lithology, porosity, and fluid away from well control and, by so doing, sets realistic expectations for hydrocarbon detection and monitoring and optimizes the selection of seismic attributes in an anticipated depositional setting.

Key to such perturbational forward modeling are rock-physics-based relations between the lithology, mineralogy, texture, porosity, fluid, and stress in a reservoir and surrounding rock and their elastic-wave velocity and density. To this end, our goal is to elaborate on the details of transforming geologically-plausible rock properties and conditions, as well as reservoir and non-reservoir geometries, into synthetic seismic traces and building catalogues of the synthetic *seismic reflections of rock properties*.

A common result of the remote sensing of the subsurface by elastic waves is the acoustic impedance, the product of the *P*-wave velocity and the bulk density. By itself, it is virtually meaningless to the geologist and engineer. Only after it is interpreted in terms of porosity, lithology, fluid, and stress, can it be used to guide reserve estimates and drilling decisions. A basic problem of such interpretation is that one measured variable (e.g., the impedance) depends on several rock properties and conditions,

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including the total porosity, clay content, fluid compressibility and density, stress, and rock texture. This means that often it is mathematically impossible to uniquely resolve this problem and predict rock properties from a remote seismic experiment. In other words, in any geophysical interpretation we deal with non-uniqueness, that is, the same seismic anomaly may be produced by more than one combination of underlying rock properties.

A way to mitigate this non-uniqueness is to produce a catalogue of seismic signatures of rock properties constrained by the common geologic sense and site-specific knowledge of the subsurface. The main question addressed in this book is: How to systematically produce such a catalogue within a realistic geology- and physics-guided framework?

1.2 Quantifying elastic properties of earth by forward modeling: a primer

The traditional use of seismic data is to obtain a high-fidelity geometry of geobodies, their boundaries, and accompanying structural heterogeneities, such as faults and folds. This makes the geologic interpretation for prospective hydrocarbon accumulations and their risking elements, including migration, traps, reservoirs, and seals, possible. Seismic impedance inversion techniques (e.g., Russell, 1998; Tarantola, 2005; and Sen and Stoffa, 2013) can be used to look *inside* a geobody, by providing volumes of the elastic properties of its interior. One of the established approaches to impedance inversion is the forward modeling of the seismic signatures of an earth model with an assumed spatial distribution of the velocity and density. This optimization process starts with designing an initial elastic earth model which is gradually perturbed to match synthetic seismograms with real data. Once this match is achieved (within a permissible accuracy tolerance) it is assumed that the underlying elastic earth model reflects the reality. The simplest way of assessing how well the synthetic and real traces match is by visual comparison of the main reflection anomalies at the prospective reservoir and in its vicinity. However, to quantify this process and apply it to a large seismic volume, many different inverse problem solution methods have been proposed and implemented (e.g., Tarantola, 2005; Sen and Stoffa, 2013). Let us concentrate on visual comparison since this is the simplest quick-look method of estimating what rock properties and conditions may be behind a seismic anomaly.

The visual trace comparison methodology is illustrated in Figure 1.1, where a real seismic gather with offset is displayed. The dominant frequency in the seismic data is 30 Hz. To match this gather, a simple 1D elastic earth model is created, where a sand layer with the fixed *P*- and *S*-wave velocity (V_p and V_s, respectively) and bulk density (ρ_b) is inserted in shale with fixed elastic properties. A synthetic seismic gather is generated by numerically sending a wavelet of specified shape (a Ricker wavelet with

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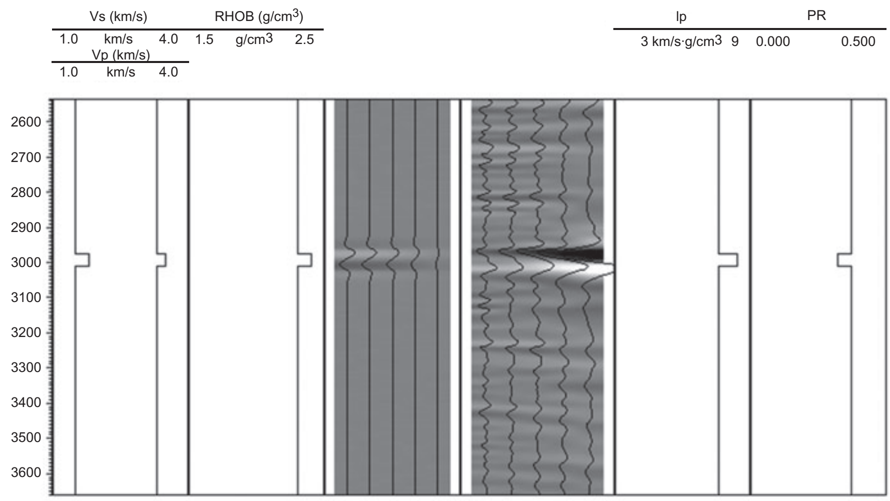

Figure 1.1 Real (fourth track from left) and synthetic (third track from left) seismic gathers. Black is a trough and white is a peak. The elastic earth model used to produce the latter is displayed in the first and second tracks (velocity and density, respectively). The fifth and sixth tracks display the *P*-wave impedance and Poisson's ratio, respectively. The vertical axis is the true vertical depth (TVD) in meters. The angle of incidence varies from zero to 50 degrees, meaning that the maximum offset is about 3 km. Synthetic gather was generated using a 30 Hz Ricker wavelet. Produced using iMOSS software (Rock Solid Images).

center frequency 30 Hz in this example) through this 1D elastic earth model. Figure 1.1 indicates that the initial guess of the elastic properties of the subsurface did not produce a match between the synthetic and real gather.

Next, we change the elastic properties of the sand layer by reducing its V_p and ρ_b. As a result, the *P*-wave impedance – $I_p = \rho_b V_p$ – in the sand becomes smaller than that in the background shale. The sand's Poisson's ratio – $\nu = 0.5(V_p^2 / V_s^2 - 2)/(V_p^2 / V_s^2 - 1)$ – reduces as well. This alteration of the elastic earth model produces a satisfactory match between the synthetic and real seismic gathers (Figure 1.2).

Finally, we vary the elastic properties of *both* the shale and the sand (Figure 1.3) and once again arrive at a satisfactory match between the synthetic and real gathers. This last example highlights the relative nature of the seismic amplitude: the same type of reflection can be produced by more than one set of velocity and density profiles.

Of course, visual comparison of synthetic and real traces is far from being quantitative. Still, it is sufficient for the purpose of this primer. To apply this approach to large seismic volumes, rigorous mathematical methods (e.g., cross-correlation) are employed (e.g., Russell, 1998; Tarantola, 2005; and Sen and Stoffa, 2013).

To further illustrate the relative nature of the seismic amplitude, consider the simplest earth model consisting of two elastic half-spaces. The example in Figure 1.4 shows that the normal reflection is negative as a wave enters the lower half-space where the I_p and ν are smaller than those in the upper half-space. The amplitude of

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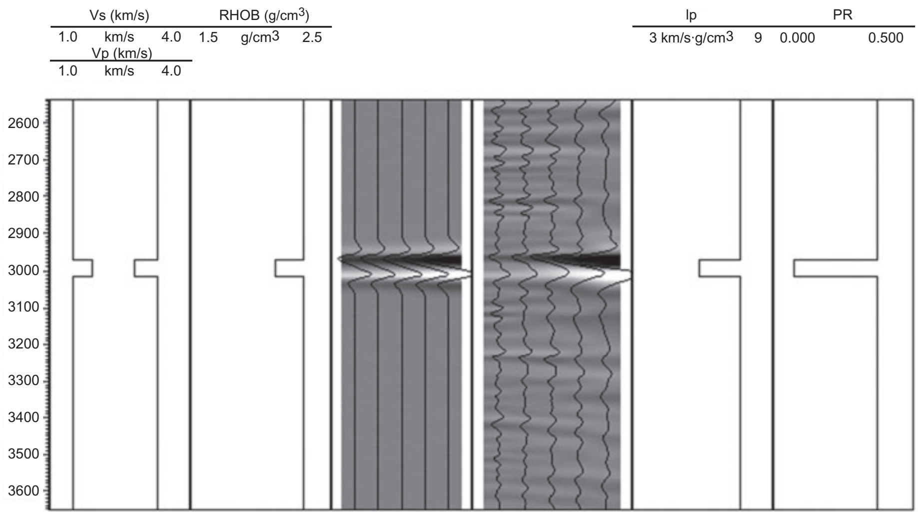

Figure 1.2 Same as Figure 1.1 but with different elastic properties of the sand layer.

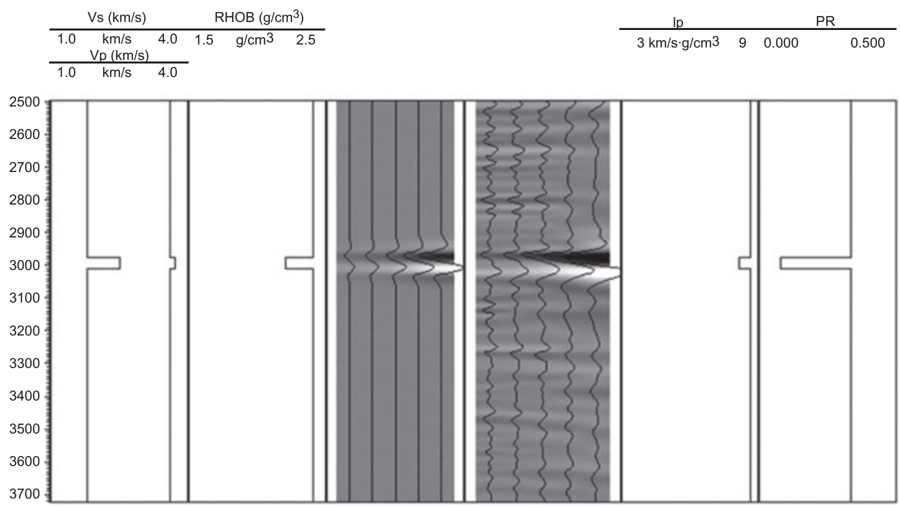

Figure 1.3 Same as Figure 1.2 but with different elastic properties of shale and sand as shown in the first two tracks.

the reflection becomes increasingly negative as the angle of incidence of the wave (or offset) increases.

As we perturb the original earth model by changing the sign of the impedance contrast between the two layers, the synthetic reflections change, both qualitatively and quantitatively (Figure 1.5). As we continue to perturb the elastic properties, we arrive at reflections very similar to those displayed in Figure 1.4 but with a different elastic input (Figure 1.6).

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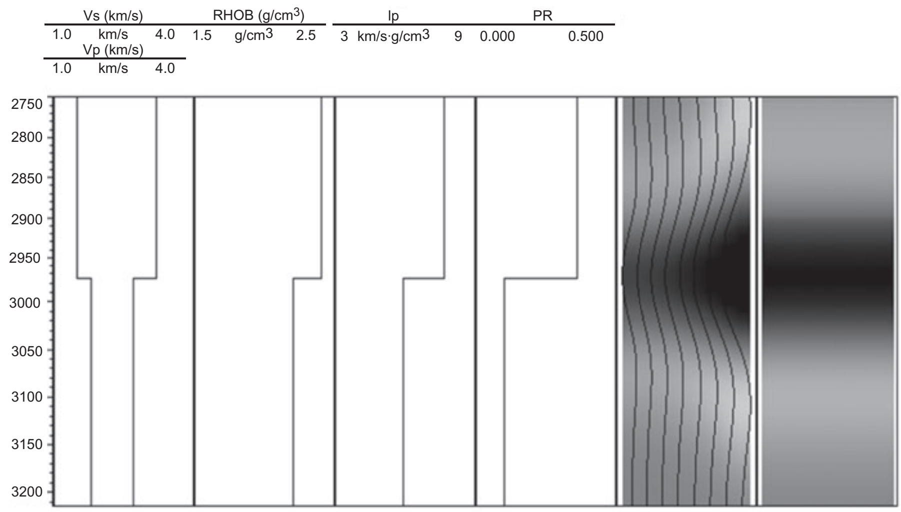

Figure 1.4 Synthetic seismic gather (fifth track) and full-offset stack (sixth track) versus depth (m). The first four tracks show the input elastic properties in this earth model. The angle of incidence varies from zero to 50 degrees. Generated by a 30 Hz Ricker wavelet. Produced using iMOSS software (Rock Solid Images).

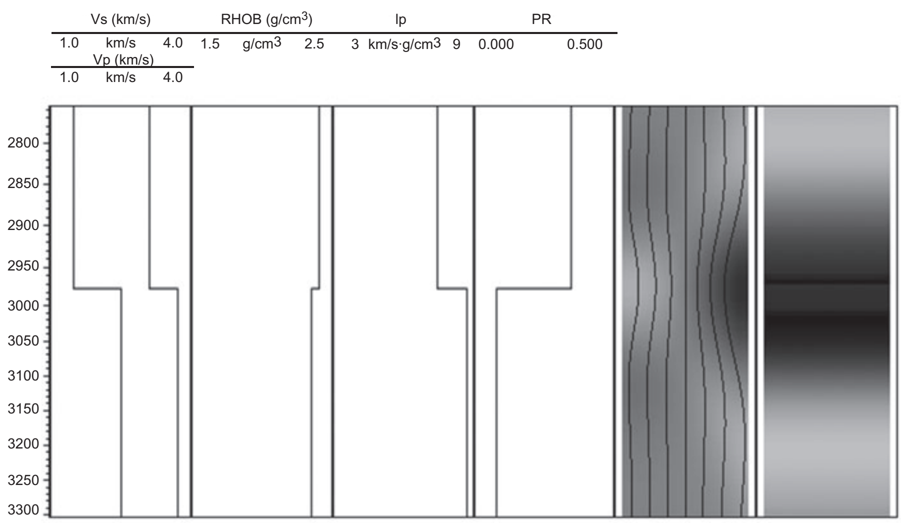

Figure 1.5 Same as Figure 1.4 but with different elastic properties of the layers (as displayed in the left-hand tracks).

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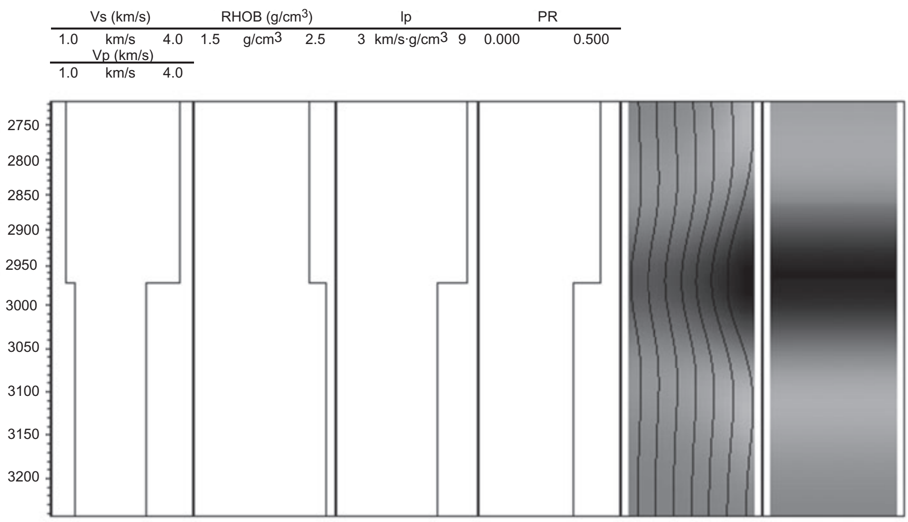

Figure 1.6 Same as Figure 1.4 but with different elastic properties of the layers (as displayed in the left-hand tracks).

This example illustrates the dichotomy in geophysical remote sensing, which is both relative and absolute: while the seismic reflection relates to the impedance contrast, the reservoir properties, such as porosity, relate to the absolute value of the impedance. One way of interpreting the relative in terms of the absolute is to perturb the absolute and calculate the corresponding relative.

Clearly, such interpretation is not unique. Different earth models can produce the same response. In traditional impedance inversion, this non-uniqueness is mitigated by anchoring the elastic properties to a nearby well. Once an absolute impedance volume is available, impedance–porosity, impedance–lithology, and impedance–fluid transforms can be applied to it to map these reservoir properties.

Still, even if a perfect impedance volume of the subsurface is available and appropriate transforms have been established, their application to seismic impedance may not be straightforward because usually such transforms are obtained at the laboratory or well log scale (inch or foot) while seismic impedance maps have the seismic scale which is much larger (hundreds of feet). This means that seismic interpretation for rock properties is never unique. This non-uniqueness comes from at least two sources: (a) the scale disparity between the traditional experiment-based (laboratory and/or well data) rock physics and seismic scales; and (b) the relative versus absolute disparity between the seismic reflection and the actual physical impedance. Yet another source stems from the possibility that the same elastic properties can, in principle, result from various combinations of mineralogy, porosity, and pore fluid (see Chapter 2).

The non-uniqueness can be reduced if geological reasoning is used in reducing the number of variants of an elastic earth model. This can be done by perturbing the

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fundamental rock properties, such as porosity and mineralogy, calculating the resulting elastic properties, and, finally, using these elastic properties in synthetic seismic generation. Such an approach helps constrain the range of the earth models by selecting porosity and mineralogy in a relatively narrow domain relevant to local geology.

Moreover, such an approach helps construct *what if* scenarios by moving rock in geologic space and time according to the laws of geology. This is why in the next example we perturb the bulk properties and conditions and arrive at a synthetic-to-real seismogram match.

1.3 Quantifying rock properties by forward modeling: a primer

In Figure 1.7 we first produce a synthetic seismogram by making an assumption about the porosity and mineralogy of shale and sand and also assuming that the sand is fully water-saturated. This first attempt at matching the real gather fails (Figure 1.7, top).

Next, we keep the porosity and mineralogy the same but partly replace water with large amounts of gas. As a result, we arrive at a reasonable match between the synthetic and real gather. Finally, we increase the water saturation and reduce the gas saturation accordingly. The resulting synthetic gather still matches the real one.

One conclusion of this exercise is that there are definitely hydrocarbons in the reservoir but their amount cannot be predicted from seismic data. That is, seismic reflections are weakly sensitive to gas saturation and, hence, apparently, in this case do not help discriminate commercial gas volumes from residual gas.

At the heart of this forward-modeling approach is a rock physics transform from porosity, mineralogy, rock texture, and fluid to the elastic properties of rock.

1.4 Rock physics transforms: a primer

One way of obtaining a relevant rock physics transform is by examining data which include the basic rock properties (e.g., porosity and mineralogy) *and* elastic properties measured on the *same samples*. If these data are matched by an existing rock physics model, then this model *is* the transform to be used in synthetic seismic modeling. These data may come from the laboratory or well logs.

An example is shown in Figure 1.8 where laboratory data from a large number of sandstone samples spanning ranges of porosity and clay content (Han, 1986) are matched by the Gal *et al*. (1998) velocity–porosity–mineralogy model.

The low-clay-content outlier at high porosity is unconsolidated Ottawa sand whose texture is different from that of the other competent-sandstone samples. The transform used works for the latter. Clearly, a different transform has to be found for unconsolidated sand.

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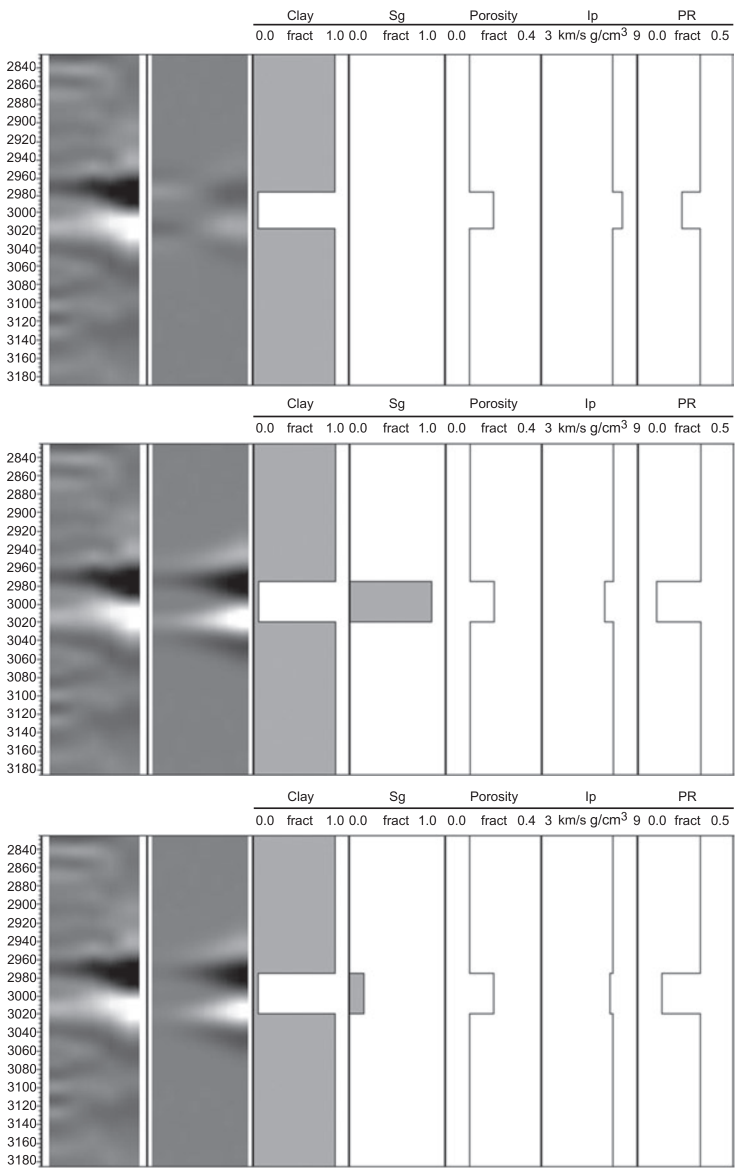

Figure 1.7 From left to right: real seismic gather, the same as displayed in Figure 1.1; synthetic seismic gather; clay content; gas saturation (one minus water saturation); total porosity; and the resulting *P*-wave impedance and Poisson's ratio. Top: Full water saturation. Middle: low water saturation. Bottom: High (but not 100%) water saturation. The angle of incidence varies from zero to 50 degrees. Frequency is 30 Hz. Produced using iMOSS software (Rock Solid Images).

1.5 Synthetic seismic catalogues

An example of a rock-physics-based synthetic seismic catalogue is displayed in Figure 1.9, where we vary the porosity of shale as well as the hydrocarbon saturation

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