CHAPTER 2

ESSENTIAL THEORIES AND METHODS

A seismic attribute is a quantitative measure of a seismic characteristic. There are 50 distinct seismic attributes that can be calculated from seismic data and applied to the interpretation of geologic structure, stratigraphy, and rock/pore fluid properties. A good seismic attribute either is directly sensitive to the desired geologic feature or reservoir property of interest or allows defining the structural or depositional environment. It, thus, allows inferring some feature or properties of interest (Chopra and Marfurt, 2005).

A seismic attribute is a measurement derived from seismic data and is usually based on measurements of time, amplitude, frequency, and/or attenuation. Generally, time-based measurements relate to structure, amplitude-based ones to stratigraphy and reservoir characterization, and frequency-based ones, though often not clearly understood, to stratigraphy and reservoir characterization. Attenuation measurements are usually very uncertain. Measurements are usually based on stacked or migrated data, but pre-stacked data are used in determining such attributes as stacking velocity and amplitude variation with offset. Because there are many ways to arrange data, attributes constitute an open set, and because they are based on so few types of measurements, attributes are generally not independent. Attributes are useful to the extent that they correlate with some physical property of interest. The primary usefulness of attributes is that they sometimes bring out features, relationships, and patterns that otherwise might not be noticed.

Seismic measurements usually involve appreciable uncertainty and do not relate directly to any single geologic property. With so many geologic variables, correlation with a particular property in one situation is apt not to hold in another situation. Attributes can be measured either along a single trace or throughout a volume. The first attributes identified as such were the one-dimensional complex-trace attributes of envelope amplitude, instantaneous phase, instantaneous frequency, and apparent polarity and acoustic impedance determined by inversion. Attributes may be measured along a defined surface, such as amplitude extraction, dip magnitude, dip azimuth, artificial illumination, and coherence. These are horizon attributes. Attributes can be combined to make new attributes. Transformations of attributes are sometimes given physical property names, such as porosity, fluid saturation, lithology, and stratigraphic or structural discontinuity. Being usually based on local cross plots or local correlations with borehole log or other measurements; they may be reasonable approximations locally but they are apt to give erroneous values under different circumstances.

To predict and map porosity by using three-dimensional seismic attribute analysis, several Hampson-Russell® software programs were used in this study. A simple flow diagram, Figure 2.1, shows the use of seismic attributes to predict reservoir properties, such as porosity. The first critically important step is accurately tying the well and seismic data, both vertically and areally. Following this, seismic attributes believed to be related to the reservoir property are chosen. Then using that attribute or set of attributes, the dense seismic data are used to guide the prediction of reservoir properties between sparse well data. A number of methods can be used for this prediction step – linear or nonlinear regression, geostatistics, or neural networks.

All of the prediction methods identify which seismic attributes to use on the strength of their observed correlations with reservoir properties measured at wells (Kalkomey, 1997).

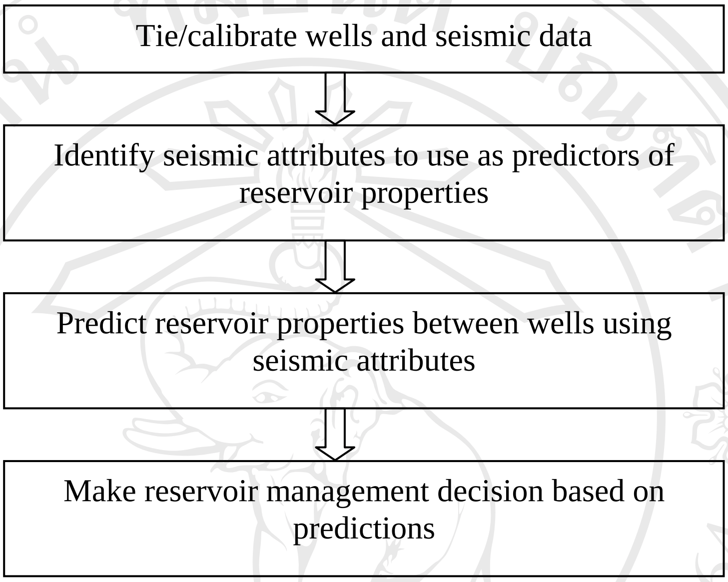

Figure 2.1 Simple flow diagram showing use of seismic attributes to predict reservoir properties (after Kalkomey, 1997).

2.1 Well log correlation to seismic data

The starting point of geophysical interpretation is the correlation of well logs to seismic data. Log correlation is the process of aligning the synthetic seismogram calculated from well logs with one or more seismic traces near the well location. The synthetic seismogram is a one-dimensional single-trace seismogram at a well that is generated from the well's sonic and density logs. Its purpose is to simulate the appearance of the seismic reflection trace as it would appear on a two-dimensional section through the well location. The synthetic seismogram is generated by convolving the time series of reflectivity derived from the digitized sonic and density logs with the theoretical seismic wavelet that is assumed to be reflected from interfaces of geologic layers in the well. By comparing marker beds or other correlation points picked on well logs with major reflections on the seismic section, the seismic section is converted to depth and is calibrated to the geology. The quality of the match between a synthetic seismogram and the reflection data depends on well log quality, seismic data processing quality, and the ability to extract a representative wavelet from seismic data.

In the present study The Hampson-Russell® GEOVIEW® program was used to load and maintain the well log database. The Hampson-Russell® eLOG® program was used to correlate well logs with seismic data. Synthetic seismogram generation and wavelet extraction was done with the eLOG® program. In the eLOG® program, correlation is done with a composite trace. A composite trace is an average of adjacent traces around the borehole location. If the well is deviated, the averaging follows the deviation path. Averaging was done taking traces within +/- 1 inline and crossline of the borehole.

Log correlation is a type of check-shot correction where depth-time pairs are provided manually by selecting points on the synthetic seismogram and tying them to corresponding points on the composite trace. The trace shown in blue in Figure 2.2 is the synthetic trace calculated from the well log and defined wavelet and the trace shown in red is the composite trace generated by averaging seismic traces around the borehole location.

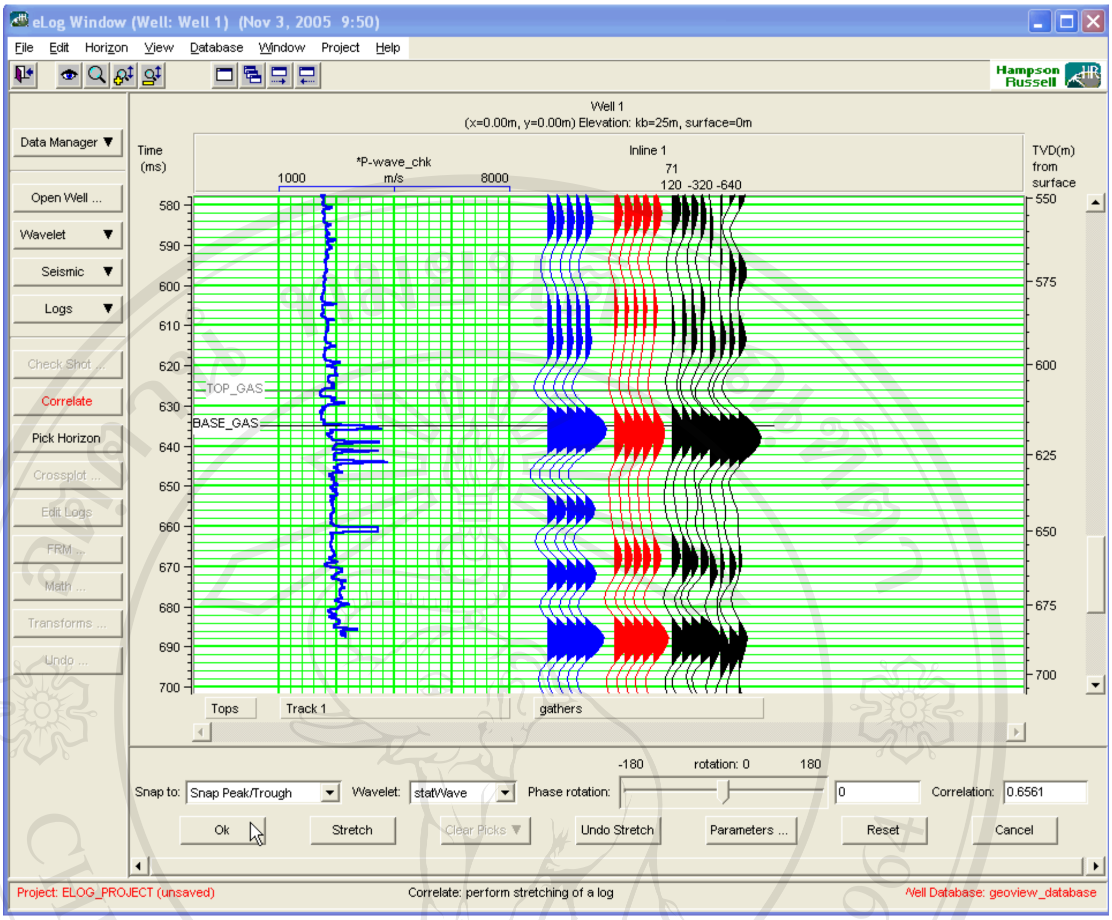

Figure 2.2 An example of well log correlation with seismic data (from Hampson-Russell® eLOG® user's manual)

2.2 Acoustic impedance inversion

An acoustic impedance inversion result is also a seismic attribute because it has been derived mathematically from seismic data. Acoustic impedance is the best attribute that has a close relationship with porosity. So, it is important to use this attribute with other seismic attributes in the process of porosity prediction. Acoustic impedance is the product of density of the material and the acoustic wave velocity through that material, that is, AI = Density x Velocity. Porosity has an inverse relation with density, a high porosity tend to give low density. As well, acoustic velocity has inverse relation with porosity, for example, the acoustic wave velocity through the near surface weathered layer (which has higher porosity of about 50-60% compared to deeper layers containing 10-30% porosity) is as low as 500-800 m/sec and which is about 2000-3000 m/sec in deeper consolidated rocks. So, acoustic velocity is low in a high porous media. In combination, acoustic impedance has also an inverse relation with porosity. Higher porosity gives a low acoustic impedance.

Acoustic impedance is too complex to be calculated by the EMERGE® program, which is used only for attribute analysis purposes. That is the reason the STRATA® program was used to generate an acoustic impedance inversion volume to supply this important attribute to the EMERGE® program as an external attribute.

2.2.1 STRATA® program

STRATA® is a program that is used to perform post-stack inversion of seismic data. The input data for this process are:

- One or more well logs.
- A seismic volume, either two- or three-dimensional.
- A set of horizons that are used to guide the interpolation of the initial guess model.

The STRATA® output data are a volume of derived acoustic impedance. The basic concept of the STRATA® program is shown in Figure 2.3. From two input streams consisting of stacked seismic data and velocity/density information in the form of well logs, a basic velocity model of the Earth's subsurface is derived and then used to aid in a full inversion of the seismic data.

The program includes the following:

- Synthetic seismogram generation
- Interactive stretching and squeezing of well logs
- Wavelet extraction
- Post-stack seismic processing
- Seismic picking
- Model building with both vertical and lateral interpolation
- Inversion using several inversion algorithms

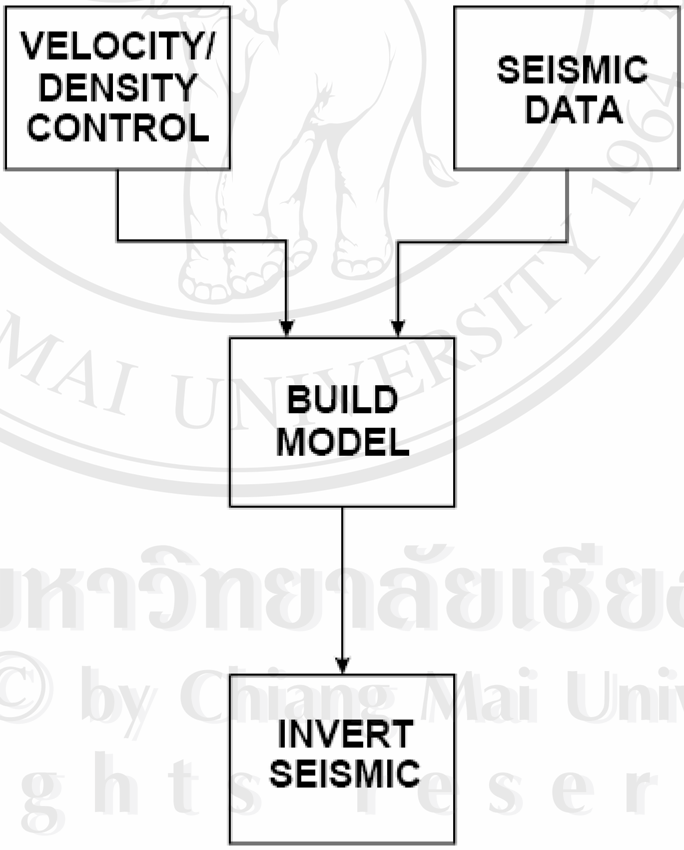

Figure 2.3 The basic concept of the STRATA® program (from Hampson-Russell® STRATA® manual)

Inversion is the process of extracting from seismic data the underlying geology that gave rise to the seismic data. This process tries to determine the input by looking at the output. Transforming a noisy, processed seismic trace into a density log or a sonic log is the inverse of transforming these two logs into a synthetic seismogram. Hence, the name inversion. Inversion is the flip side of forward modeling (Figure 2.4). Generally, inversion has been applied to post-stack seismic data with the aim of extracting acoustic impedance volume.

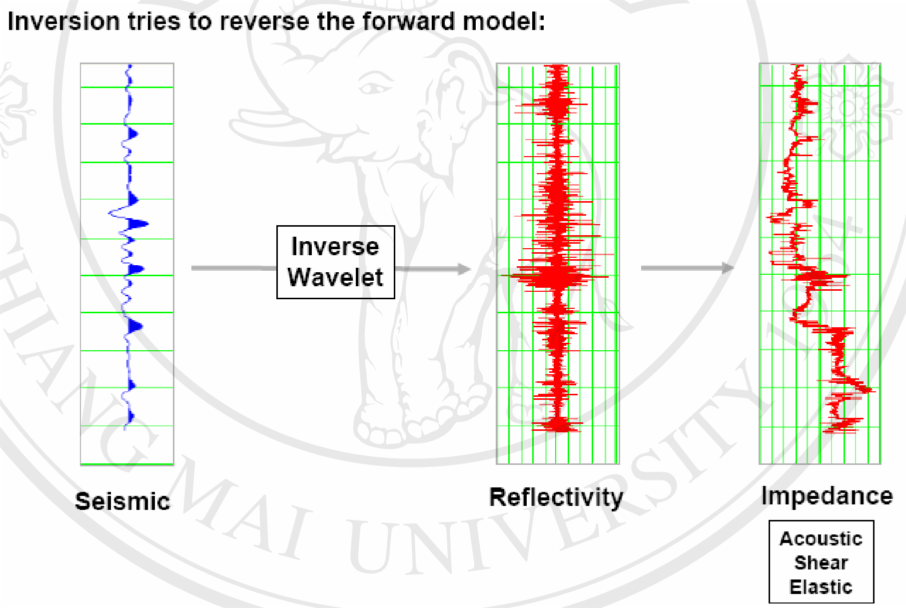

Figure 2.4 Concept of inversion is to reverse the forward model (STRATA® guide).

The general inversion flow for the STRATA® program is:

1) Create model
    - Select wells
    - Correlate each well
    - Extract wavelet
    - Import/pick seismic horizon

2) Perform inversion

- Select inversion type and parameters
- Quality control inversion results

3) Interpret results

- Create data slice
- Create cross plots
- Input to EMERGE® program for further analysis

2.3 Seismic attribute analysis and porosity prediction

The derivation of reservoir and rock properties from seismic data is a major task in exploration geophysics. The complex response of the Earth to wave propagation makes this task difficult and challenging. Taner and others (1979) introduced the complex seismic trace and instantaneous attributes. Since then, seismic attribute technology has seen great interest and new seismic attributes are introduced routinely. However, the interpretation of the seismic attribute volumes is ambiguous and it is difficult to derive quantitative information from these attributes.

The method for deducing rock properties/reservoir properties, such as porosity, based on the integration of seismic attributes and measured well log curves has the basic idea of finding a relationship between the measured rock/reservoir properties and some seismic attributes at the well location. Once derived, it can be applied to the seismic volume and a predicted log property volume is generated. The derived relationship can be linear, using linear multi-regression analysis, or non-linear, using neural networks. The reliability of the derived relationship is determined by cross-validation tests.

2.3.1 EMERGE® program

The Hampson-Russell® EMERGE® program was used for attribute analysis and porosity prediction from the integration of three-dimensional seismic data and well log data. EMERGE® is a program that uses a combination of multiple three- or two-dimensional seismic attributes to predict reservoir properties. The idea of using multiple seismic attributes to predict log properties was first proposed by Schultz and others (1994). They pointed out that the traditional approach to using seismic data to derive reservoir parameters has consisted of looking for a physical relationship between the parameter to be mapped and some attribute of the seismic data and then using that single attribute over a two-dimensional line or a three-dimensional volume to predict the reservoir parameter. Although relationships have been inferred between these attributes and reservoir parameters, the physical basis is not always clear. Schultz and others (1994) proposed deriving statistical, rather than deterministic, relationships. This approach, which they called a data driven methodology, is summarized in the Figure 2.5 flow chart.

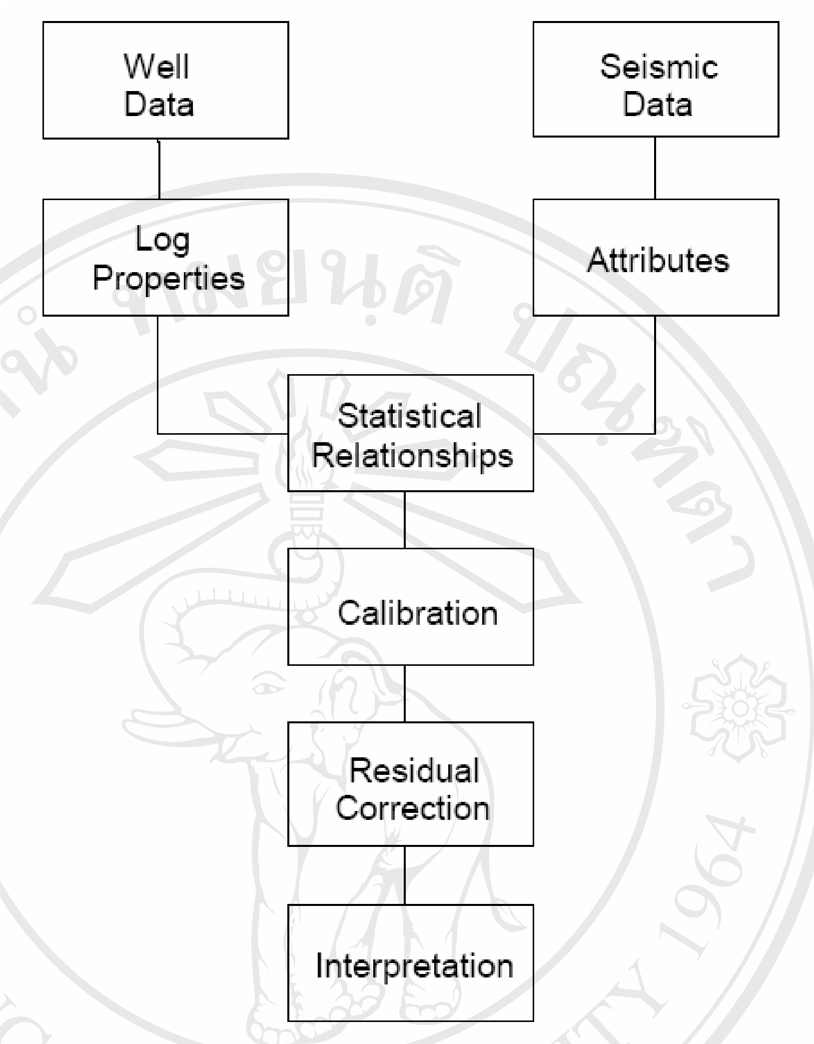

Figure 2.5 The data driven statistical interpretation (after Schultz and others, 1994).

The general objective of the EMERGE® program is to predict a well log property using seismic data attributes. These attributes may be calculated internally or they may be provided as external attributes. The analysis in EMERGE® proceeds in several stages, which are:

1) Examine the log and seismic data at well locations to determine which set of attributes are appropriate.
2) Derive a relationship using multi-linear regression or neural networks.
3) Apply a derived relationship to three-dimensional SEGY volume.

The first step in the EMERGE® program is to find a set of seismic attributes that can be used to predict the target porosity log. These attributes are volume attributes, such as instantaneous amplitude, that can be calculated from the input seismic data on a sample-by-sample basis. There is an infinite variety of possible volume attributes. EMERGE® contains a list of about 20 attributes that can be calculated from the seismic trace. The seismic inversion result, which is acoustic impedance, is one of the attributes that is too complex to be calculated within EMERGE® itself. The Hampson-Russell® STRATA® program was, therefore, used to generate an acoustic impedance volume and then supply this to the EMERGE® program as an external attribute. To accommodate the possibility of external attributes, EMERGE® divides all possible attributes into two categories, internal attributes and external attributes. Once an external attribute has been loaded, EMERGE® treats both sets of attributes identically. To derive a relationship between seismic attributes and target logs, EMERGE® uses two prediction methods, linear multi-regression analysis and neural networks.

2.3.2 Linear multi-regression analysis

EMERGE® searches for groups of attributes that can be combined to predict the target logs. It does this by a process called step-wise regression. Step 1 is a search for the single attribute from the list that predicts the logs best by itself. The criterion for evaluating the prediction is the root mean square (RMS) error. In other words, EMERGE® tries each attribute, calculates the root mean square error, and determines the single best attribute as the one with the lowest error. Step 2 is a search for the best pair of attributes, assuming that one of the pair is the single attribute found in step 1.

This is also done by trial and error, solving the system of equations as many times as there are other attributes to pair up with the single attribute. Having found the best pair of attributes, Step 3 is a search for the best three, the best four, and so on.

2.3.3 Neural networks

Artificial neural network is a set of electronic components or computer programs that is designed to model the way in which the brain is thought to perform. The brain has been described as a highly complex, non-linear, parallel information processing system. The structural constituents of the brain are nerve cells called neurons, which are linked by a large number of connections called synapses. This complex system has the great ability to build up its own rules and store information through what is usually refer to as experience.

The neural network capabilities of EMERGE® is used to improve the porosity prediction. The non-linear characteristic of the neural network helps to increase both the predictive power and the resolution of the derived porosity volume. EMERGE® contains four neural network algorithms. These are probabilistic, multi-layer feed forward, discriminant analysis, and radial basic function.