3D and 4D Seismic Data Integration in Static and Dynamic Reservoir Modeling: A Review

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ABSTRACT

Reservoir modeling is the process of generating numerical representations of reservoir conditions and properties on the basis of geological, geophysical, and engineering data measured on the Earth's surface or in depth at a limited number of borehole locations. Therefore, reservoir modeling requires an incorporation of the data from a variety of sources, along with an integration of knowledge and skills from various disciplines. In particular, recent advances in 3D and time-lapse 4D seismic data acquisition, processing, and quantitative interpretation have led to an increasing use of seismic data in the reservoir modeling processes. This paper provides an overview of static and dynamic reservoir modeling and outlines the key roles of 3D and time-lapse 4D seismic data in reservoir characterization and model building/updating processes. The review focuses on the methods, workflows, and challenges in the incorporation of 3D/4D seismic data into the static and dynamic reservoir model building/updating processes.

Keywords: Reservoir Model, Static and Dynamic Properties, 3D Seismic, Time-Lapse 4D Seismic

INTRODUCTION

Subsurface reservoir model estimation is a fundamental practice in many geoscience disciplines, including geothermal studies, hydrology and ground water analyses, exploration and recovery of fossil fuel energy resources, and CO_2 geo-sequestration among others. In particular, numerical reservoir models play a central role throughout a hydrocarbon field's life cycle. During exploration, appraisal, development, and production stages of any field life cycle, reservoir models are widely used to broaden the available knowledge of the geological, geophysical, and engineering components of the reservoir.

In general, there are two categories of reservoir properties: first, time-independent static properties such as porosity, lithology, and shale content, and second, time-varying dynamic fluid flow properties such as fluid saturation and pore pressure. Static reservoir models simulate time-independent reservoir properties; typically, such models are constructed from static data that have been measured or interpreted on a single occasion (once in time); these models include well logs, core measurements, sedimentology and stratigraphy interpretations, and baseline (pre-production) 3D

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seismic surveys. Usually, such models are used for initializing the dynamic reservoir modeling process, which involves the dynamic simulation of fluid flows within a reservoir. Typical dynamic datasets in hydrocarbon energy applications include historical production data (flow rates or volumes and pressure data) and time-lapse 4D seismic data. Borehole measurements are often the main information source for reservoir modeling; however, boreholes are sparsely distributed, and these measurements are not sufficiently informative to yield accurate and detailed representations of the whole 3D reservoir volume. There are many non-unique models that fit the sparse well data despite the huge challenge posed by extrapolating these data to an entire reservoir volume. Due to their excellent spatial coverage, 3D seismic data play a key role in defining the structure and geometry of the reservoir, and in setting constraints to variations in reservoir properties. To produce realistic models of reservoir lithofacies and corresponding petrophysical properties while avoiding non-physical results at the same time, 3D seismic information should be actively incorporated into the static reservoir property of modeling process. On the other hand, 4D seismic data are powerful constraints on dynamic reservoir models because of its valuable information relating to production-induced reservoir changes such as fluid movements and pressure and saturation changes.

This paper is organized in two main sections as follows. In section 1, the fundamentals of static reservoir modeling and 3D seismic data are provided and followed by a review of the methods and challenges in 3D seismic data incorporation into static reservoir models. In section 2, the basics of dynamic reservoir modeling and time-lapse 4D seismic data are described and followed by a review of the methods and challenges in 4D seismic data incorporation into dynamic reservoir models [1].

EXPERIMENTAL PROCEDURES

Static Reservoir Modeling

Generating a static reservoir model that is consistent with geological knowledge and pre-production seismic data is a fundamental step of reservoir characterization and performance forecasting [2]. Currently, 3D static reservoir models are commonly used in [3]:

- estimating reserves;
- targeting new producer or injector locations;
- performing uncertainty and risk analysis;
- geosteering (i.e. well-path steering during drilling);
- providing a basis for production forecasting and cost estimation when coupled with reservoir hydrodynamic simulators; and
- providing a basis for rock mechanics modeling and fracture analysis.

To construct a static reservoir model, the reservoir-specific input data are the key to achieve the real representation of the reservoir conditions. These input data include [4]:

- horizons and fault surfaces interpreted from 2D or 3D seismic data to define the size, shape, and geometrical framework of the reservoir container (including the top and base of the different intervals);
- geological information such as sedimentology maps and analogue outcrop data;
- forward sediment modeling datasets such as geometrical data, stacking patterns, and spatial information for porosity and permeability;

- complete well datasets, including wellhead coordinates, top markers, well paths, logs, and interpretations;
- core measurements, where applicable;
- seismic data, including seismic amplitude maps, seismic attribute volumes (for reservoir property modeling), and seismic velocity cubes (for time to depth conversion process);
- Other geophysical measurements (gravity, magnetic etc.), where applicable; and
- Engineering data, for example in the hydrocarbon energy applications, which includes historical production, drill stem test (DST), and repeat formation test (RFT).

A typical workflow for generating a static reservoir model involves the following key steps [5-6]: (1) define the geometric structure and framework of the reservoir, (2) construct cellular grids within the reservoir, and (3) create reservoir property models.

Three-dimensional static reservoir models may include reservoir properties in two categories: discrete reservoir properties (e.g. lithofacies, fluid volume, and hydraulic flow units) and continuous reservoir properties (e.g. net to gross, porosity, permeability, and initial fluid saturations). As shown in Figure 1, the construction of a static reservoir property model is typically performed in a two-stage sequential approach: modeling reservoir lithofacies to define the main lithologies and/or flow units, and modeling petrophysical property to simulate the petrophysical properties facies-by-facies or layer-by-layer. Both of these steps can be performed using either deterministic or stochastic techniques [7].

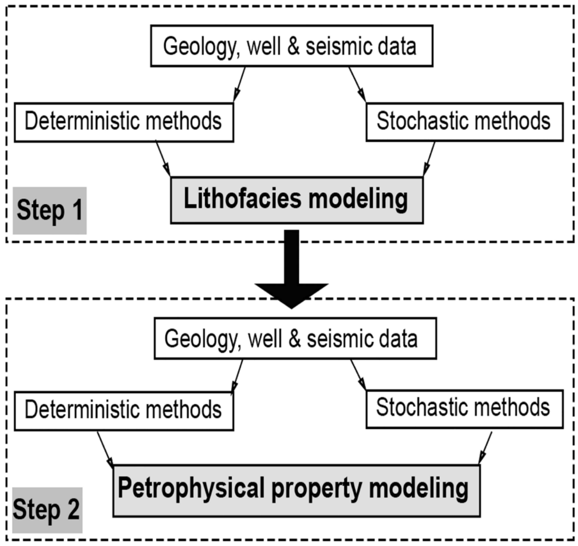


Figure 1: A two-stage sequential approach to reservoir lithofacies and petrophysical property modeling [1].

However, it should be noted that deterministic techniques cannot effectively describe the reservoir conditions and interdependency of reservoir properties. This is mainly due to: (i) the complexity of reservoir heterogeneity and spatial variations of the reservoir properties, and (ii) sparseness in the sampling of a reservoir at limited numbers of well locations, leading to incomplete information about the reservoir. In this context, stochastic methods provide a framework for generating a set of reservoir models (not merely one model, as is the case with deterministic methods) to account for the uncertainties and spatial variations in discrete and continuous reservoir properties [8-10].

3D Seismic Fundamentals

The main objective of seismic exploration is to provide an accurate representation of subsurface geological features. Seismic reflection data is typically acquired by transmitting energy into the specific portion of the Earth and recording the reflected energy from the subsurface geological boundaries (Figure 2).

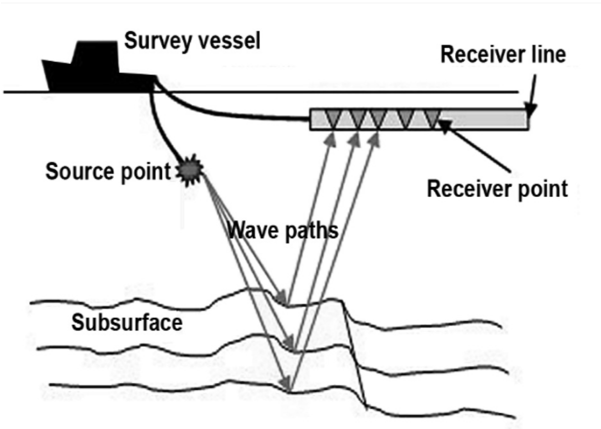
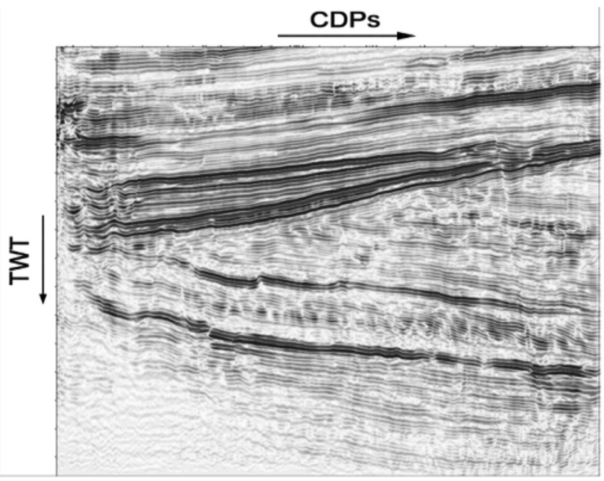


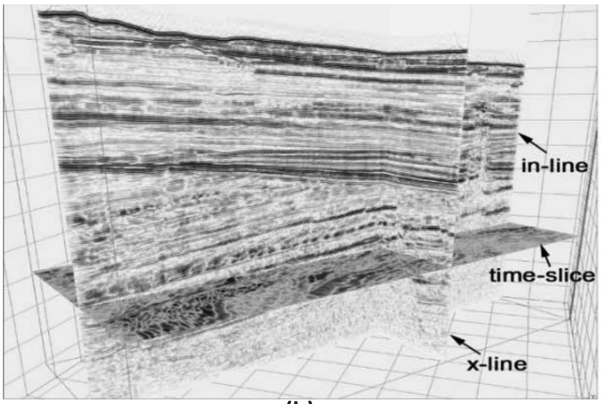
Figure 2: Seismic reflection data are typically acquired by transmitting energy into the Earth and recording the reflected energy from subsurface geological boundaries.

When processed, these data produce images that effectively evaluate the potential targets. Two-way travel times and amplitudes, or any other attributes of the reflected energy can also be used to derive useful information about subsurface geological features and their properties.

Seismic surveys conventionally involve two-dimensional (2D) and three-dimensional (3D) surveys. Two-dimensional seismic data is typically acquired along a single seismic recording line; therefore, it is displayed as a single vertical cross-section through the subsurface (e.g. Figure 3a).



(a)



(b)

Figure 3: (a) A 2D post-stack seismic section, and (b) a 3D seismic visualization along an in-line, an x-line, and a time slice.

The nearest seismic recording line may typically be kilometers away. Two-dimensional seismic data are generally used for regional or large-area assessments, and provide information about the location and orientation of subsurface geological features [11]. The critical problems with 2D seismic surveys are (i) coverage problem (2D seismic data only cover the thin cross-sections of the subsurface) and (ii) sideswipe or off line reflection problem (2D seismic cannot distinguish features which are not on the plane of the 2D seismic section) [12].

Three-dimensional seismic surveys solve both the coverage and the sideswipe problems [13]. They are typically designed with multiple source and receiver lines to enable the acquisition of large volumes of seismic data. In other words, 3D surveys use closely spaced grids of shot lines such that the data are acquired at the surface over an area on which several seismic recording lines are located; moreover, the interpreted data is displayed as a 3D volume or cube which may then be sliced into multiple cross-sections (e.g. Figure 3b). Three-dimensional seismic intuitively provides a more precise and spatially continuous image of the subsurface geological structure.

Seismic attribute: a seismic attribute is a quantity derived from 2D or 3D seismic data that can be analyzed in order to extract or enhance information that might not otherwise be visible in the seismic images, leading to a better geophysical or geological interpretation of the seismic data [14]. Time, frequency, and amplitude are the examples of seismic attributes.

Seismic inversion: transformation of seismic reflection data into subsurface physical properties such as elastic parameters is called seismic inversion [15]. There are two classes of seismic inversion techniques [16]: (i) deterministic inversion, which gives one single realization of the physical properties of the rock (e.g., P-wave impedance); (ii) stochastic inversion, which generates multiple equiprobable realizations of the subsurface physical properties of the rock. Colored inversion [17], sparse-spike inversion [18], and simultaneous elastic inversion [19-20] are common examples of deterministic seismic inversion techniques. Geostatistical inversion [21] and Bayesian inversion [22] are two main types of stochastic seismic inversion.

3D Seismic Data Incorporation in Static Reservoir Modeling

3D seismic data, due to its excellent spatial resolution, play a key role not only in defining the reservoir structure and geometry, but also in constraining the reservoir property variations. To produce realistic models of reservoir lithofacies and corresponding petrophysical properties while avoiding non-physical results at the same time, seismic information should be actively incorporated into the reservoir modeling process. Three main frameworks for deriving reservoir properties from seismic data [23] are described below.

Deterministic relationships: First, deterministic relationships is established between seismic attributes and reservoir properties at borehole locations, then, these relationships are employed in generating a 3D cube of the reservoir property (Figure 4) [24].

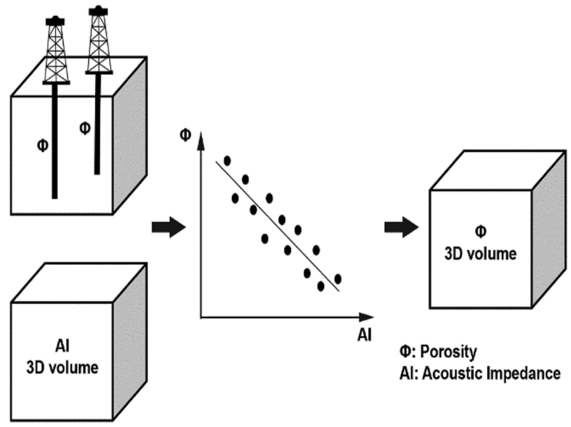


Figure 4: A schematic view of generating a static reservoir model based on deterministic relationships between seismic attributes and reservoir properties [1].

Geostatistics: Seismic data (e.g. seismic amplitude map and inverted seismic attributes) are incorporated as extra information for guiding geostatistical interpolation of the reservoir properties in areas far away from the wells, and multiple equiprobable realizations of the reservoir properties are produced (Figure 5).

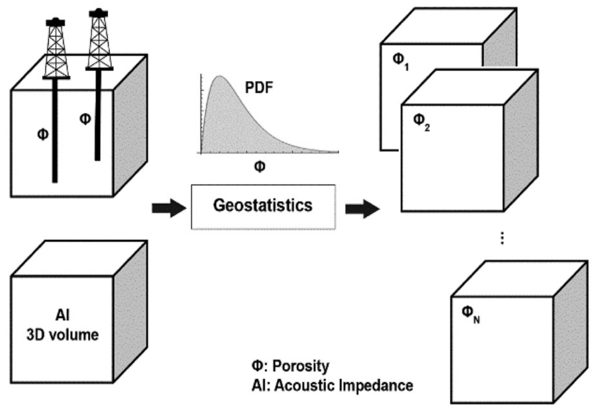


Figure 5: A schematic view of generating multiple equiprobable realizations of reservoir properties using geostatistical simulation [1].

Examples of geostatistical techniques for seismically-constrained reservoir property modeling include generalized regression methods such as cokriging [25-26], kriging with locally variable mean [27], stochastic simulation [28-30], and geostatistical inversion [21].

Seismic matching loop: The seismic response of the model is computed using a forward-modeling operator; moreover, the synthetic seismic response is compared with the real seismic data, and the best match is obtained by iteration (Figure 6). This process can be conducted manually or by using an optimization algorithm [31].

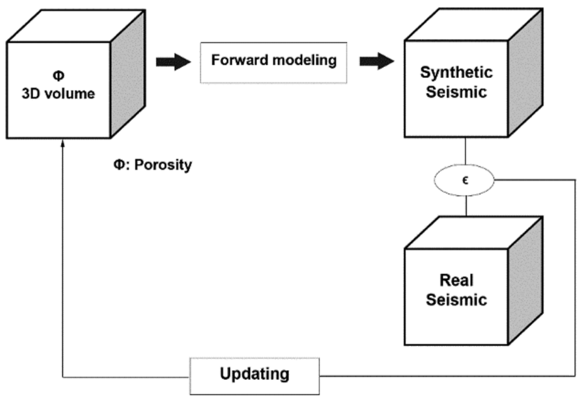


Figure 6: A schematic view of reservoir model building or updating by the seismic matching loop process [1].

Recent developments have combined geostatistics and a seismic matching loop (from either deterministic or statistical rock-physics relations) to estimate reservoir properties from seismic data. This process may be performed (i) by using a sequential or multistep inversion scheme [23,32-34], or (ii) based on a unified inversion scheme [35].

Seismic-constrained Static Reservoir Modeling

A typical workflow for constructing a seismically constrained static reservoir model is summarized in Figure 7. It consists of three main stages: data preparation, reservoir property modeling, and seismic matching loop. The details of each step are described below.

Data preparation: This is the first stage in the workflow where all the required input data, including the geology, geophysics, petrophysics, rock physics, and engineering data are transferred to a common framework. A 3D structural framework of the model in the depth domain is constructed. Moreover, this requires the interpreted horizons and faults to be converted from time to depth using an accurate velocity model derived from seismic velocities and calibrated to well logs. The zones between the horizons and the layers within each zone are defined. In addition, the cubes of the depth-converted seismic inverted attributes (if available) should be rescaled to the reservoir model grid size. Typically, multiple log datasets including measured depth, true vertical depth, lithology, porosity, resistivity, and so on are available at some wells, which also need to be rescaled to fit the cellular framework of the model. If core measurements, well test analyses (e.g., pressure transient), and other static and dynamic datasets are also available, they should be rescaled appropriately [36].

Reservoir property modeling: The second stage in the workflow is reservoir property modeling. This is usually carried out in a geostatistical framework and is based on two sequential steps:

First, reservoir lithofacies/flow units are drawn from the input data. There are two main classes of geostatistical technique for lithofacies modeling: object-based and pixel-based. Pixel-based methods offer more effective (or natural) ways of incorporating seismic data into a reservoir lithofacies model. Lithofacies modeling using a Bayesian classification technique is an example of a pixel-based simulation ([37-40]. Other seismic-constrained lithofacies modeling techniques are sequential indicator simulation (SIS) with seismic constraints [41,34], the truncated Gaussian simulation (TGS) method [7], and pluri-Gaussian simulation (PGS) [42].

Second, petrophysical properties such as porosity and net to gross are simulated facies-by-facies by utilizing some other class of geostatistical methods such as sequential Gaussian simulation (SGS) [43]. In practice, SGS coupled with collocated cokriging is widely used in the sense that a seismic attribute such as impedance is used as a secondary variable in the cokriging part of the SGS [6,44].

Seismic matching loop: The main objective of the seismic matching loop is to update the reservoir models to replicate the real seismic data as closely as possible. A key step in a successful seismic matching loop is the definition of an accurate (deterministic or statistical) petro-elastic model [34] that enables the reservoir properties to be inferred from the seismic data and vice versa. In the workflow, the seismic response of the reservoir models is iteratively determined using a well-designed petro-elastic model, and is then compared with the real seismic data to evaluate the match. Any resulting discrepancy is then used to guide the updating process of the reservoir models. As shown in Figure 7, the seismic matching loop can be performed at different levels: level 1, the seismic time domain [31], and level 2, the elastic depth domain [23, 45].

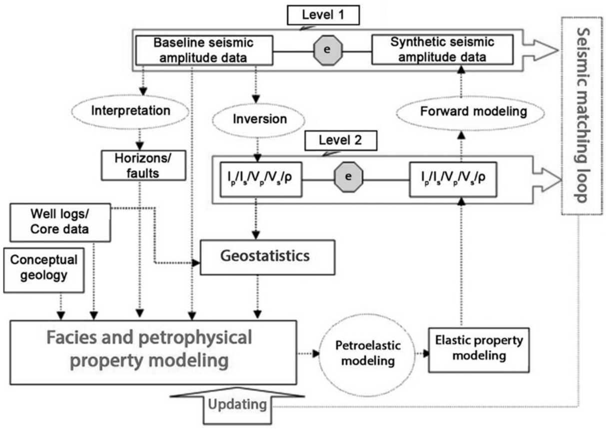


Figure 7: A typical workflow for seismic-constrained static reservoir modeling [1].

Challenges in 3D Seismic Data Incorporation into Reservoir Models

Integrating 3D and 4D seismic data into reservoir models presents several challenges and difficulties, some are still at the forefront of research and development (R&D) specialists. In this section, some of the challenges in the incorporation of 3D seismic data in static reservoir modeling are reviewed.

Reservoir modeling at seismic scale or at a finer grid scale: To model a reservoir, it is important to find a common grid scale that merges different data types on different scales. A common approach is either to scale up or to scale down; however, even the most sophisticated (upscaling/downscaling) techniques necessarily eliminate some parts of the data [46]. As an example, a reservoir containing highly porous and permeable layers about 1 m thick requires a fine-scale reservoir model. To integrate seismic data into such a model, the data must be scaled down accordingly. Different seismic downscaling techniques have been proposed, but these are generally not physics-based and suffer from simplifying assumptions about the seismic averaging process [47].

A promising strategy to define an optimum grid scaling system can be described as follows. When the lateral grid scale of a reservoir model is chosen, the seismic bin spacing is the best option because it preserves all the potential information that can possibly be extracted from the seismic data. However, the challenge is the choice of the vertical- or z-scale of the model. Seismic data typically have a lower resolution in the vertical direction than the other sources of information (e.g. well log data and core measurements). For modeling reservoir properties, the vertical scale should be related to the scale of the geological heterogeneities in the volume to be modeled. This scale is highly dependent upon the types of rock in the reservoir. It is essential to note that, while it is not the purpose of a reservoir model to include every small geological detail extracted from the geological analyses, neither large-scale nor regional information of interest is in this context. The purpose of the model is to simulate a specific volume of reservoir rocks that allow fluid flow through it. Thus, the optimal vertical scale of a reservoir model depends on the scale of the reservoir flow unit, which may vary from one or two centimeters to several meters.

Deterministic or stochastic seismic inversion: Deterministic inversion gives just one realization of any rock physical property, whereas stochastic inversion generates multiple equiprobable realizations. No single inversion technique is guaranteed to solve every kind of problems; moreover, every implementation of the deterministic or stochastic inversion might be suitable, provided it is applied to the right case.

Cascaded seismic and petrophysical inversion or direct petrophysical inversion of seismic data: A two-step sequential approach is often used to infer reservoir properties from seismic data: first, a seismic inversion is performed to estimate elastic properties; second, a petrophysical inversion is used to predict reservoir properties such as lithology and porosity from the inverted seismic data. Some other techniques have been proposed for direct petrophysical inversion of seismic data [31]. Although these techniques improve coherence between the reservoir property model and seismic data, the well calibration and quality control steps tend to be more complicated [44].

Reservoir model-to-seismic matching loop in amplitude time domain or in elastic depth domain: The reservoir model-to-seismic matching loop allows the validation of the reservoir properties introduced into the reservoir model by generating synthetic seismic impedance or amplitude data from the model and by attempting to match them to real seismic data. To perform reservoir model-to-seismic in the best domain in which matching loop is problematic, it is necessary to choose between the amplitude versus elastic property domain and between the time and depth domain.

The petro-elastic model gives absolute values of the elastic properties, whereas seismic inversion provides both absolute and relative values of the elastic properties. Therefore, in the elastic domain, it is necessary to first choose which form of the elastic parameters should be used for comparison: absolute or relative. Also, it should be noted that the low-frequency model used in the seismic inversion and the background trend used in the petro-elastic model are not the same. In addition, there is always

uncertainty and instability in the seismic inversion process [48]. All of these challenging issues imply that the reservoir model-to-seismic matching loop in the elastic domain should be cautiously applied in order to reduce the risk of misinterpretation.
In the amplitude domain, a key challenge is the correct positioning of the modeled 3D seismic data in time versus real seismic amplitude data. A possible solution is to stretch the reservoir model in time between two interpreted horizons, for example, by using petro-elastic-derived velocities. In addition, since the modeled data usually does not match the real seismic data, using purely mathematical algorithms for comparison (e.g. subtraction and correlation) may not always work [48].

Manual or assisted reservoir model-to-seismic matching loop: A key question in the reservoir model-to-seismic matching loop process is the possibility of employing an assisted process for reservoir model estimation. A reservoir model matched only with seismic data is not a comprehensive solution; moreover, this only provides a set of reservoir properties that are consistent with the seismic data but not necessarily with well log data and geological information. Similarly, a reservoir model that takes account of geological knowledge is not only necessarily consistent with seismic data. The ultimate goal of an assisted reservoir modeling process is to generate a set of reservoir models that best match all the available static data (well logs, geological, and pre-production seismic data) to better initialize the subsequent history-matching process. Emami Niri and Lumley [1,34] proposed a solution to this problem by developing a multi-objective optimization approach for the reservoir model estimation process. From this approach, the resulting reservoir property models not only satisfy the seismic response of the models, but also match the well log data and the geological information defined in the parallel objective functions. An ensemble-based stochastic optimization algorithm simultaneously reduces the mismatch in all objective functions and produces optimal reservoir models that are the best compromise solutions to the defined objective functions.

Dynamic Reservoir Modeling

Dynamic reservoir modeling simulates the reservoir fluid flow behavior over production calendar time and contributes to the optimization of reservoir future production in terms of the recovery and economics. In the context of dynamic reservoir modeling, the term “history matching” is frequently used. History matching is the process of adjusting the dynamic reservoir flow model to match the production data measured at wells. In other words, it evaluates the past and present behavior of the reservoir and forecasts its future performance on that basis. Conventionally, a static model is initialized to be consistent with the geological, geophysical, and well log data for the reservoir, and then it is adjusted to match the historical production data in order to predict the future behavior of the reservoir as flow stimulation proceeds [49,50]. History matching process may be carried out either manually [51] or automatically by using optimization algorithms [52]. The main characteristics of these two approaches are summarized in Figure 8, which is adapted from elsewhere [49].

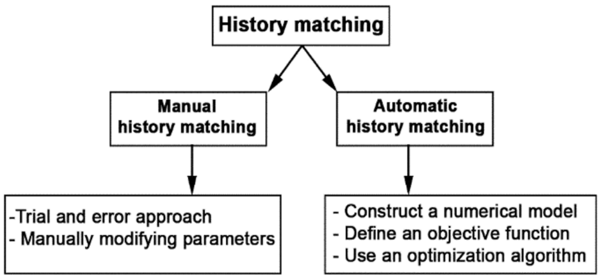


Figure 8: Manual versus automatic history matching.

Several researches such as single fluid phase history matching in a gas reservoir using adjoint methods [53], history matching in a two-phase oil-water reservoir [54], and 3D, three-phase oil-water-gas history matching studies [55] have been conducted on addressing history matching problems in hydrocarbon energy applications.

The quality of business decisions in reservoir management is highly dependent upon the quality of the history matching. However, it is notable that history matching is a time-consuming, costly, and ill-posed inverse problem and requires a large number of iteration runs, leading to non-unique predictions which make reservoir management decisions difficult [56].

4D Seismic Fundamentals

Four-dimensional seismic data is a series of 3D seismic datasets acquired over a producing reservoir in a calendar time period. It is used for imaging fluid movements, fluid contacts, monitoring flow paths and barriers, locating bypassed oil, placing new wells, identifying sealing faults, and mapping pressure compartmentalization and heat effects [57-60]. In general, there are two categories of reservoir properties which affect 3D seismic images: (i) time-independent geological properties such as lithology and porosity, and (ii) time-varying fluid-flow properties such as fluid saturation and pore pressure. The difference between two consecutive 3D seismic survey images approximately cancels out the static properties since, in effect, these do not change in that period of time; thus, the resulting image difference is caused only by dynamic property changes [46].

Figure 9 is a schematic outline of the physical principle of time-lapse seismic reservoir monitoring. If survey-1 data are acquired before production or injection in an oil and gas field, and survey-2 data are acquired afterwards, then production/injection has resulted in changes to the reservoir fluid saturations and pressures (Figure 10), and hence to the seismic compressional and shear wave velocities and density; therefore, ideally, no change has occurred in the upper and lower bounding formations during this time.

Changes in the elastic properties of the reservoir interval may then be inferred from the observed changes in the timing and amplitude of the seismic traces of monitor survey (δt and δA). Thus, each subsequent time-lapse seismic survey captures a new snapshot of the changes that have occurred in the reservoir in a given production time period. This simplified description explains how 4D seismic surveys help identify the production-induced changes.

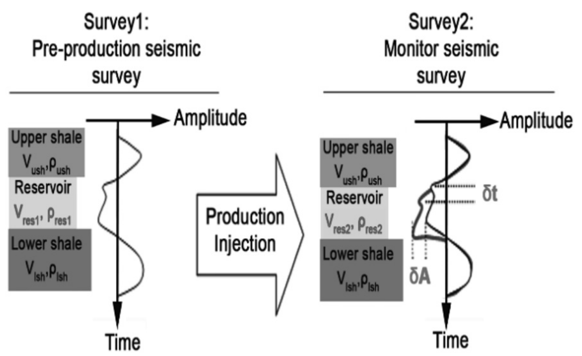


Figure 9: The physical principle of time-lapse seismic reservoir monitoring; production or injection results in changes in P- and S-wave velocities and density, which appear as changes in amplitude and timing in the monitor seismic survey (adapted from [59]).

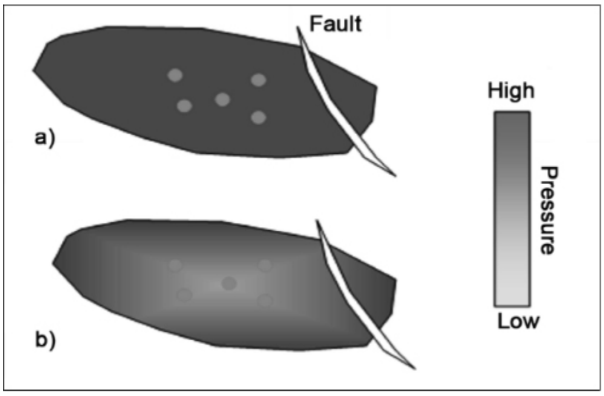


Figure 10: A schematic map of the reservoir pressure (a) before and (b) after production; green circles are the producer locations (adapted from [60]).

4D Seismic Data Incorporation in Dynamic Reservoir Modeling

Most of the data for reservoir surveillance and management studies come from well measurements. In the hydrocarbon energy applications, this includes well production data (e.g. oil, gas, and water flow rates), well-head and bottom-hole pressure measurements, production logging tools (PLT's), repeated logs (e.g. thermal decay time logs for water saturation changes), and so on. There are usually many reservoir model parameters, but often there are only a few wells. Obviously, there can be many non-unique models that fit the sparse data at the wells in part due to the huge challenge that is involved in extrapolating the well data to the entire volume of a reservoir. Other complementary dynamic datasets such as pressure interference tests and chemical tracers can provide useful information on the volumetric measurement of reservoir connectivities; however, such datasets cannot provide information on the location of reservoir heterogeneities [60]. Four-dimensional seismic data are considered to complement conventional reservoir surveillance techniques, and to reduce the level of uncertainty associated with the monitoring process [58,59]. Time-lapse seismic data in conjunction with geological and fluid-flow history matching yield a reservoir description which is more efficient and produces a better prediction of reservoir performance. The basic philosophy of this process, which is usually known as "4D seismic history matching", is illustrated in Figure 11.

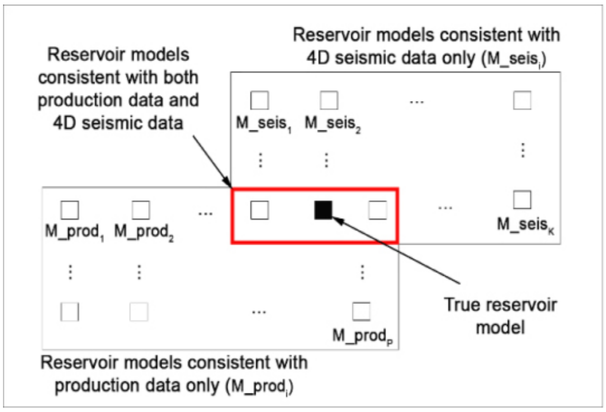


Figure 11: The basic philosophy of integrating 4D seismic data into the reservoir history matching process (adapted from [1]).

RESULTS AND DISCUSSION

The reservoir history matching process itself may produce several reservoir models which are consistent with production data only (M_prodi). There are also several other reservoir models which match 4D seismic data only (M_seisi). Constraining the reservoir models to be consistent with both production data and time-lapse seismic data reduces the uncertainties which are associated with the history matching process by narrowing the range of possible outcomes (which ideally bracket the true reservoir model).

Several authors have pointed out the benefits of incorporating 4D seismic data into a reservoir history matching procedure [61-66]. Most of the published work in this area used either synthetic data, or included 4D seismic data in a qualitative way. However, quantitative incorporation of 4D seismic in reservoir dynamic flow modeling has received considerable attention and is currently an active area of research in both academia and industries.

Qualitative approach: A perfect example of a qualitative integration of 4D seismic data in reservoir dynamic flow modelling is at the Draugen oil field, offshore Norway, where a 4D seismic image of the reservoir water flooding has given an outlook into what has been happing beyond the wells. Based on Pre-4D history matching, three possible dynamic flow model scenarios (depending on aquifer support, permeability assumptions, and fault transmissibility) are shown in Figure 12.

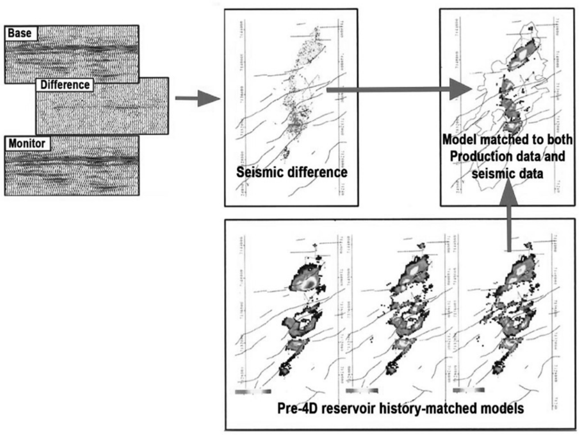


Figure 12: reservoir model updating at the Draugen oil field, offshore Norway (source: [59]). Based on Pre-4D history matching, three possible dynamic flow model scenarios are shown. All of these scenarios are consistent with only production data. On the other hand, the amplitude difference map of 4D seismic surveys gives another possible scenario of water flooding. An updated reservoir dynamic flow model has been built by selecting the correct features from the pre-4D history matched flow models and the 4D seismic images.

All of these scenarios are consistent with only production data. On the other hand, amplitude difference map of two seismic surveys acquired before and during production gave another possible scenario of water flooding. An updated reservoir dynamic flow model was built by selecting the correct features from the pre-4D history matched flow models and the 4D seismic images, resulting in a model that honored both the production and 4D seismic data [67].

Quantitative approach: The Workflow of the quantitative integration of 4D seismic data in reservoir dynamic fluid-flow simulation process is given in Figure 13.

This process, sometimes known as "parameter estimation using 4D history matching [56]," is essentially an underdetermined and nonlinear inverse problem. In this workflow, reservoir hydrodynamic simulator and time-lapse seismic simulator are inter-related. Using a reservoir flow simulator, flow rates and changes in saturations and pressure are modeled. A seismic simulator is then employed to map the changes in saturations and pressure into changes in P- and S-wave velocities and density, and consequently into changes in amplitude and timing of the seismic response of the reservoir model. The difference between the observed and simulated production data and the discrepancy between the observed and simulated seismic data are simultaneously used to update the reservoir parameters using an optimization algorithm. This iterative process helps improve the consistency of the dynamic behavior of the reservoir with both 4D seismic and production data.

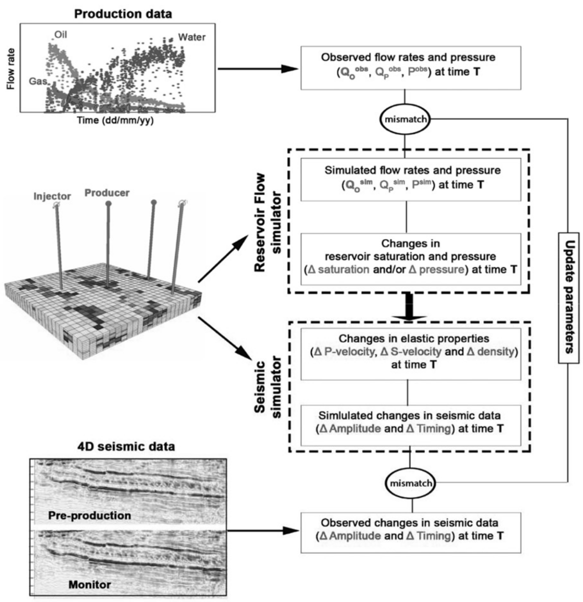


Figure 13: The Workflow of the quantitative integration of 4D seismic data in reservoir simulation process.

This joint quantitative matching of production and 4D seismic data usually consists of minimizing an objective function with two terms (e.g. Equation 1 from [68]): the first term accounts for the fit between the flow-simulated and the measured production fluid-flow data, and the second term measures the fit between the real (observed) and the synthetic (simulated) seismic data.

$$F = \sum_{j=1}^{nseries} \frac{w_j^P}{ntime_j} \sum_{i=1}^{ntime_j} \left(\frac{d_{i,j}^{obs} - d_{i,j}^{cal}(\alpha)}{\sigma_{i,j}^P} \right) + \sum_{j=1}^{ndata} \frac{w_j^P}{nvalues_j} \sum_{i=1}^{nvalues_j} \left(\frac{S_{i,j}^{obs} - S_{i,j}^{cal}(\alpha)}{\sigma_{i,j}^S} \right) \quad (1)$$

where, nseries and ndata are the number of production and seismic data series to be matched respectively; ntimej is the number of measurement times, and $nvalues_j$ is the number of observed seismic data; σ^P and σ^S represent standard deviations for production and seismic data errors respectively, and w is the weighting factor.

Challenges in 4D Seismic Data Incorporation into Reservoir Models

Integrating time-lapse 4D seismic data into the reservoir modeling and history matching processes poses a significant challenge due to the frequent mismatch among the initial reservoir model, the reservoir geology, and the pre-production seismic data. It is essential that synthetic 3D seismic data modeled from the initial static reservoir model closely match the real baseline 3D seismic data. Without such initial 3D seismic match, risks are introduced into the subsequent use of 4D seismic datasets to update reservoir simulation models [46,23].

Another key challenge is to determine which type of seismic data is the most suitable for comparison, and at what level it can be best incorporated into the history matching process [69]. According to Figure 14, the joint seismic history matching problem can be performed at any one of three different levels [70]:

Level 1: Amplitude level, in which the seismic amplitude or waveform data (forward-modeled from flow simulator outputs using a petro-elastic model and wavelet convolution) are compared with the real 4D amplitudes or waveforms [71,72]. In this level, seismic data have not been inverted and do not suffer from the errors related to seismic inversion; however, an additional seismic forward modeling step at each iteration step of the reservoir history matching loop is compulsory. Landa and Kumar [72] showed that although there are some difficulties and challenges in the seismic modeling step, the associated uncertainties are better recognized in the seismic forward modeling in comparison with the seismic inversion.

Level 2: Impedance level, in which the elastic impedances (forward-modeled from a flow simulator using a petro-elastic model) are compared with the inverted seismic impedance values [73,74]. This is the most popular level of 4D seismic history matching due to less computational cost, less time of the process, and more convenience in comparison with the production data; therefore, it is considered by some of the authors as the optimum level of the 4D seismic history matching. Level 3: Pressure or saturation level, in which flow simulator outputs are directly compared with saturation and pressure values computed from the seismic inversion by using a petro-elastic model [75]. This level is a more intuitive level of comparison for the reservoir specialists, but it contains more uncertainties due to an additional step of the direct inversion of the seismic data into reservoir properties.

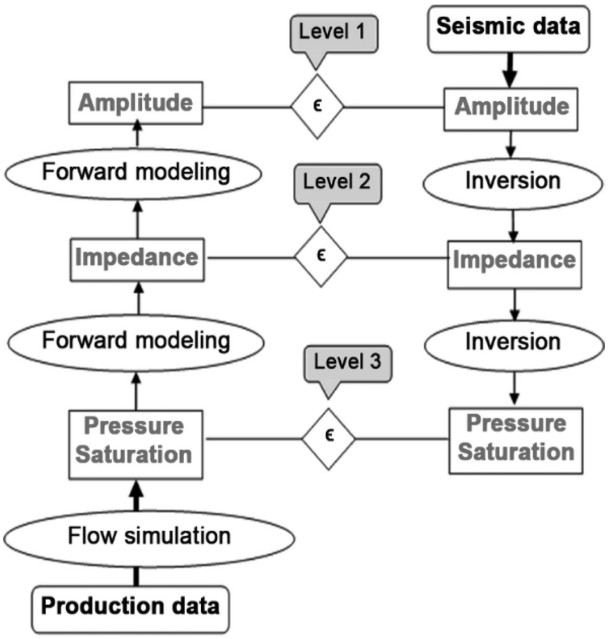


Figure 14: Joint seismic history matching can be performed at three different levels: amplitude, impedance, or pressure/saturation

Many other challenges are posed by the quantitative incorporation of 4D seismic data into the reservoir dynamic flow modeling process, including:

Weighting misfits: since each of reservoir production and 4D seismic datasets has a different sample density and accuracy, weighting the corresponding misfits in the global objective function is a challenging issue.

Data calibration: usually, the observed time-lapse seismic attributes are derived as a relative property, so they require calibration to be compared with reservoir properties.

Scaling issues: the observed data and simulated outputs have different scales; consequently, scaling either down or up is compulsory for a correct comparison.

Discrepancy in optimum parameters suggested by 4D seismic compared to production data: this can be related to calibration or rescaling, or to the seismic modeling process itself [76].

CONCLUSIONS

Static and dynamic reservoir modeling plays a central role in the energy industry. The successful integration of 3D and 4D seismic data in reservoir modeling process not only adds tremendous information on the spatial distributions and variations of the reservoir properties, but also minimizes the risks and uncertainties of the reservoir management decisions. This paper demonstrates the key roles of 3D and 4D seismic data in static and dynamic reservoir modeling processes, followed by a review of the workflows, algorithms, and associated challenges of the incorporation of 3D and 4D seismic data in reservoir model building and updating processes.

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NOMENCLATURES

DST	: Drill Stem Test
PGS	: Pluri-Gaussian Simulation
RFT	: Repeat Formation Test
SGS	: Sequential Gaussian Simulation
SIS	: Sequential Indicator Simulation
TGS	: Truncated Gaussian Simulation

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