

Distance Based Sensitivity Analysis for Joint Inversion of Time-Lapse Seismic and Production Data of Norne Field

Amit Suman¹ and Tapan Mukerji²

Abstract Dynamic data of the reservoir is used for efficient reservoir characterization, monitoring and forecasting. The dynamic data set includes production and time lapse seismic data. Both of these data sets can be used in history matching process for better description of the reservoir and thus for better reservoir forecasting. However joint inversion of time lapse seismic and production data is complex and challenging with uncertainties at each step of the process. So it is essential, before proceeding with large scale history matching, to investigate parameter sensitivity for both types of data. In this study the data set of Norne field is used to find out which reservoir rock and fluid parameters have the most impact on time lapse seismic and production data. We have used multi-dimensional scaling (MDS) on euclidean distances between flow and seismic response to investigate the sensitive parameters in joint inversion. The result of this study will be used in history matching of time lapse seismic and production data of Norne field.

1. Introduction

Reservoir dynamic data plays an important role in reservoir characterization, management and monitoring. Production data is affected by the petrophysical properties of the reservoir rock. Thus it can be used in history matching process for updating the reservoir model. Time lapse seismic data can provide information on the dynamics of fluids in the reservoir based on the relation between variations of seismic signals and movement of hydrocarbons and changes in formation saturations and pressure. Movement of fluids and changes in pore pressure depends on the

Amit Suman¹ Stanford University, 367 Panama St #65, Stanford, CA94305, USA
email : asuman@stanford.edu

Tapan Mukerji² Stanford University, 367 Panama St #65, Stanford, CA94305, USA
email : mukerji@stanford.edu

petrophysical properties of the reservoir rock. Thus reservoir monitoring by repeated seismic or time lapse surveys can help in reducing the uncertainties attached to reservoir models. Reservoir models, optimally constrained to seismic response as well as flow response can provide a better description of the reservoir and thus a more reliable forecast.

Huang et al., (1997, 1998) formulated the simultaneous matching of production and seismic data as an optimization problem, with updating of model parameters such as porosity. Walker and Lane (2007) presented a case study that included time-lapse seismic data as a part of the production history matching process, and showed how the use of seismic monitoring can improve reservoir prediction. Joint inversion of time lapse seismic and production data requires modeling of seismic as well as production data. These two processes are interrelated and there are uncertainties at each step. Figure 1 describes the workflow of joint inversion of time lapse seismic and production data. The general practice of history matching of time lapse seismic and production data is to update the porosity or/and permeability model till a minimum mismatch between observed and modeled data is achieved. In this process the parameters for reservoir and seismic simulator are considered as fixed. But in reality there are uncertainties attached with these parameters and it can give misleading results. Thus it is necessary to rank the sensitive parameters both in reservoir simulator and as well as seismic simulator for a better joint inversion of time lapse seismic and production data. This study is inline with the history matching of time lapse seismic and production data of Norne field. Norne field data set is used to identify and rank the sensitive parameters for joint inversion. In future the results of this study will be used in selecting the most important reservoir parameters for joint inversion of time lapse seismic and production data of Norne field. We have performed an experimental design on the parameters of reservoir and seismic simulator. The results are used to rank the parameters in terms of sensitivity to joint inversion of production and seismic data.

2. Norne Field Segment E

This study is focused on the segment E of the Norne field (Figure 2). Norne field is located in the blocks 6608/10 and 6508/10 on a horst block in the southern part of the Nordland II area in the Norwegian Sea. The horst block is approximately 9 km x 3 km. Segment E consists of 3 producer and 2 injector wells. The rocks within the Norne reservoir are of Late Triassic to Middle Jurassic age. The present geological model consists of five reservoir zones. They are Garn, Not, Ile, Tofte and Tilje. Oil is mainly found in the Ile and Tofte Formations, and gas in the Garn formation. The sandstones

are buried at a depth of 2500-2700 m. The porosity is in the range of 25-30 % while permeability varies from 20 to 2500 mD (Steffensen and Karstad, 1995; Osdal et al., 2006).

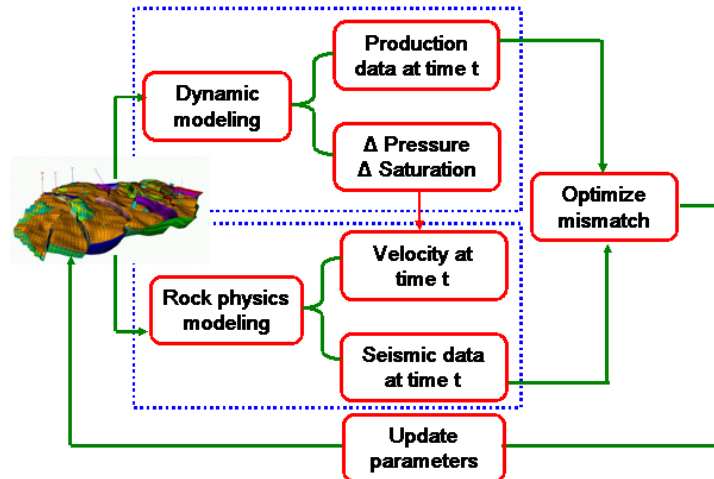


Figure 1: Workflow of joint inversion of time lapse seismic and production data. The blue dotted boxes indicate the flow simulator and the seismic/rock physics simulator. Often these simulators are taken as black-boxes without investigating the sensitivity of the simulator parameters on the flow and seismic response of the reservoir.

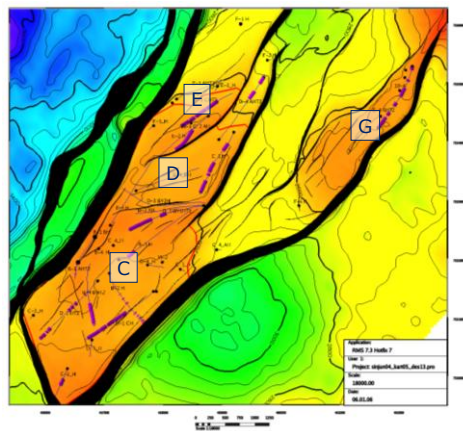


Figure 2: Map of Norne files with different sections. Segment E is used for this study

3. Available Data

Well log data are available for each of the wells. These logs consist of porosity, volume of shale, saturations, sonic log and density. The observed production data includes well oil, water and gas flow rates. Time lapse seismic data includes near, mid, far and full 3D stacks at four different years (2001, 2003, 2004 and 2006).

4. Sensitive Parameters

Joint inversion of time lapse seismic and production data consist of modeling of production data and time lapse seismic data. Modeling of production data is done by a reservoir simulator and requires petrophysical properties of the reservoir, such as porosity, permeability and relative permeability curves. Pressure and saturation distribution of reservoir at different times, and a rock physics model are needed for modeling of time lapse seismic data. Based on this workflow we selected the following parameters for a sensitivity study:

- Porosity and Permeability model
- Relative permeability curves
- Pore compressibility
- Rock physics models for elastic properties of the rocks
- Spatial scales of saturation distribution

In the following sections we describe in detail the variations in these factors that were used in the sensitivity study.

4.1. Porosity and Permeability Models

Reservoir rock properties are the basic input parameters for modeling of production and time lapse seismic data. Reservoir rock porosities and permeabilities are used to model the flow response. Porosities are linked to the seismic response through rock physics models. Thus spatial distribution of porosity and permeability is an important parameter to consider for this study. The generation and selection of these porosity and permeability models are described below.

The structure model for segment E of Norne field is generated in PETREL based on the horizon data (Figure 3). The 3D geo-cellular model consists of 168168 (84 X 91 X 22) cells. Next variogram models are generated for each zones based on the well log data. These variogram models are used to generate one hundred porosity realizations using SGSIM (Sequential Gaussian simulation). Permeability models are generated based on the correlation between porosity and permeability of each zone.

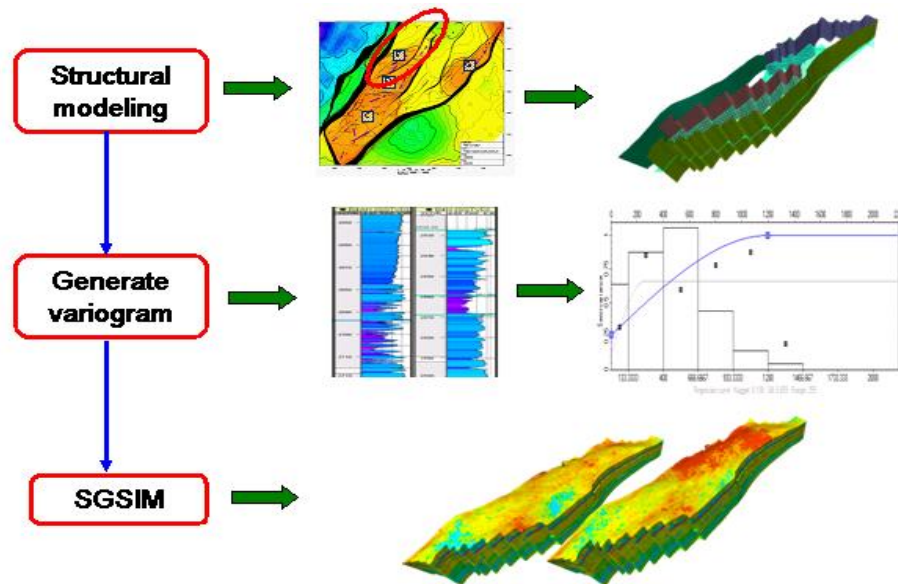


Figure 3: Workflow of generation of hundred porosity realizations for segment E of Norne field

Next, three porosity models are selected to capture the overall behavior of all of the hundred porosity models. The selection is based on a two-step process. At first multi-dimensional scaling is done on the Euclidean distances between the hundred porosity models and they are projected in 2D space (Scheidt et al, 2009). Then k-medoid clustering is done to select three representative porosity models as medoids of three different clusters. The reason for selecting three representative porosity models is to reduce the computational cost of experimental design.

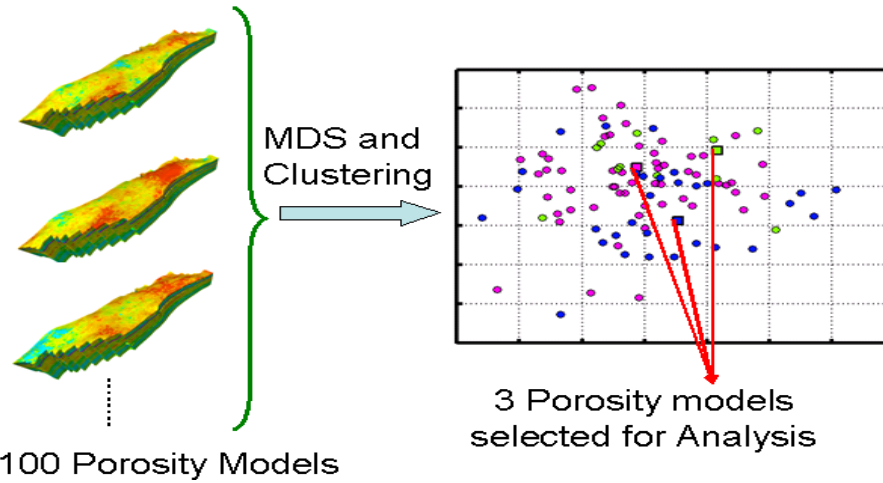


Figure 4: Selection of three porosity realizations based on MDS and k-medoid clustering

4.2. Relative Permeability

Relative permeability is an important part of modeling the flow response of the reservoir. The available data of Norne field includes eighty four combinations of oil-water relative permeability curves (Figure 5). These curves have different oil relative permeability end point and critical water saturations. Two pairs of relative permeability curves are selected for sensitivity analysis. These two relative permeability curves have minimum and maximum set of oil relative permeability end point and critical water saturations.

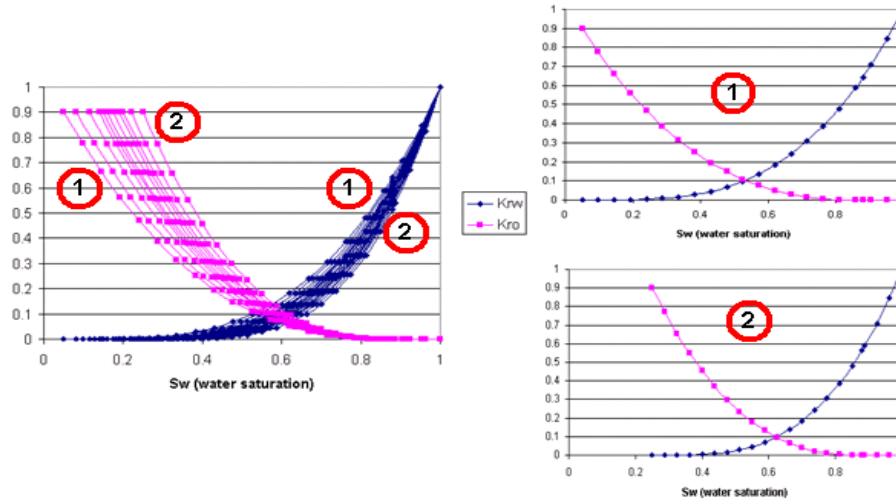


Figure 5: Oil-water relative permeability curves for Norne field. Curve pairs 1 and 2 are selected for this study

4.3. Pore Compressibility

Pore compressibility is a parameter that can impact both flow as well as elastic (and hence seismic) response of the reservoir. Compressibilities for porous media depend on two pressures (the external confining pressure, σ_c and the internal pore pressure σ_p) and two volumes (bulk volume, V_b and pore volume, v_p). Therefore, we can define at least four Compressibilities. Following Zimmerman's (1991) notation, in which the first subscript indicates the volume change (b for bulk, p for pore) and the second subscript denotes the pressure that is varied (c for confining, p for pore), these Compressibilities are

$$C_{bc} = \frac{1}{V_b} \left(\frac{\partial V_b}{\partial \sigma_c} \right)_{\sigma_p}$$

$$C_{bp} = \frac{1}{V_b} \left(\frac{\partial V_b}{\partial \sigma_p} \right)_{\sigma_c}$$

$$C_{pc} = \frac{1}{v_p} \left(\frac{\partial v_p}{\partial \sigma_c} \right)_{\sigma_p}$$

$$C_{pp} = \frac{1}{v_p} \left(\frac{\partial v_p}{\partial \sigma_p} \right)_{\sigma_c}$$

Note that the signs are chosen to ensure that the compressibilities are positive when tensional stress is taken to be positive. Thus, for instance, C_{bp} is to be interpreted as the fractional change in the bulk volume with respect to change in the pore pressure while the confining pressure is held constant. These are the dry or drained bulk and pore compressibilities. The effective dry bulk modulus is $K_{dry} = 1/C_{bc}$, and is related to the seismic P-wave velocity by

$$V_p = \sqrt{(K_{dry} + 4\mu/3)/\rho}$$

Where ρ and μ are the dry bulk density and shear modulus respectively.

Dry rock velocities can be related to the saturated bulk rock velocity through the Gassmann equations. The different compressibilities can be related to each other by elasticity theory using linear superposition and reciprocity. The compressibility C_{pp} appears in the fluid flow equations through the storage term, and can be related to C_{bc} (and hence to seismic velocity) by the equation

$$C_{pp} = \frac{C_{bc} - (1 + \phi) \frac{1}{K_{min}}}{\phi}$$

Where ϕ is the porosity and K_{min} is the solid mineral bulk modulus.

To test the sensitivity of the seismic velocity and fluid flow response to variations in pore compressibility, three levels of pore compressibility were selected based on its overall range estimated from well logs. Pore compressibility for each of the zone is calculated based on the well log data and using the relation between C_{pp} and C_{bc} as described above. Figure 7 shows histograms of pore compressibility in each of the zones. The plots show that the pore compressibility can vary within formations by factors of 2 to 4 and by an order of magnitude across different formations. Yet, often in flow simulations (typically simulations that do not account for geomechanics) though porosity is taken to vary over every grid block, the corresponding rock pore compressibility is taken to be a constant. This is clearly an inconsistent model. Suman

et al. (2008) showed that spatial variability in pore compressibility can play an important role in time lapse seismic modeling. Three sets of pore compressibility values ($1.5e^{-10} \text{ Pa}^{-1}$, $3e^{-10} \text{ Pa}^{-1}$ and $5e^{-10} \text{ Pa}^{-1}$) are selected for the sensitivity study. These values capture the range of pore compressibility variations observed in the Norne field.

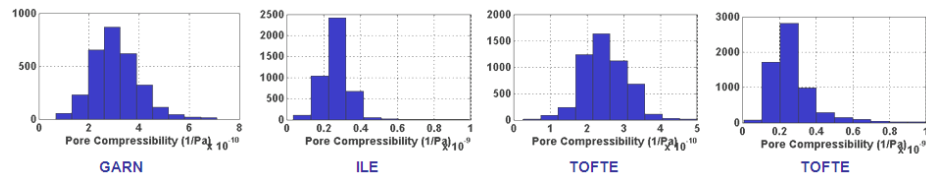


Figure 7: Histogram of pore Compressibilities in each of the formation

4.4. Rock Physics Model

Rock physics modeling is used to determine the change in elastic properties of rocks due to variations in mineralogy, change in fluid type, variation in saturation and pore pressure and change in the reservoir effective stress. It can also be used to populate acoustic and elastic properties (V_p and V_s and density) inside the reservoir away from the well. The basis of our approach is to relate elastic moduli and porosity near the well (based on the well log data) and use this relation to populate away from the well. Rock physics model selection is an important step in time lapse seismic modeling. The rock physics models can be different depending upon amount of cement present in the reservoir. In this study two rock physics models are selected for analysis. These two rock physics models are cemented sand model and unconsolidated sand model (Figure 8). Seismic velocity porosity trends can be established using well log data but uncertainties are always present away from the wells. Therefore it is necessary to consider the possibility of other scenarios not seen in the well.

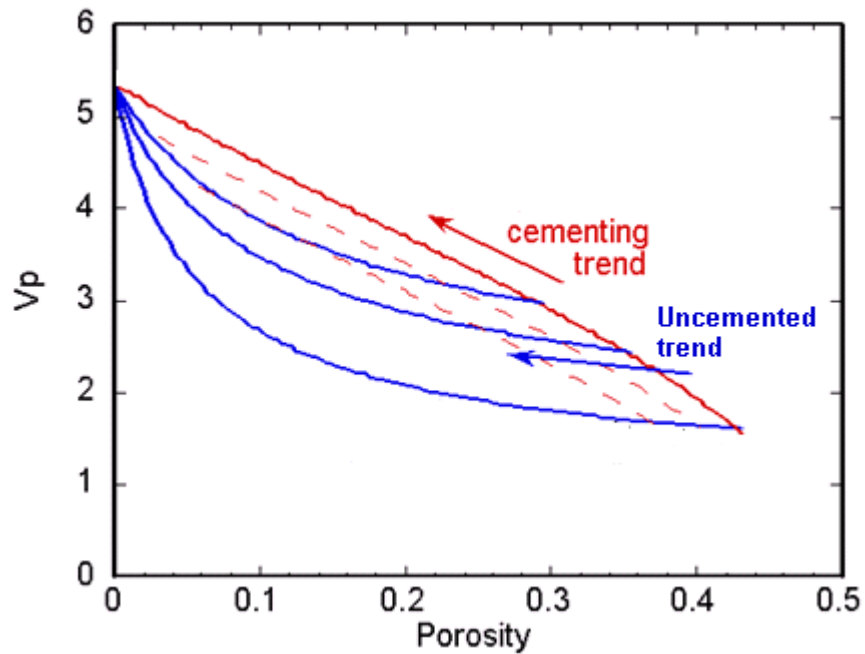


Figure 8: Schematic seismic velocity – porosity trend for cemented and uncemented sands.

4.5. Saturation Scale

Seismic velocities depend on fluid saturations as well as spatial scales of saturation distribution. Seismic velocities are different for uniform and patchy saturation distribution in the reservoir. Sengupta (2000) discussed the importance of saturation scales in modeling the changes in seismic velocity with respect to changes in the reservoir at different times. She also found that reservoir with gas are very likely to show patchy behavior. Norne field has gas in the Garn formation. Thus saturation scale is considered as a parameter for this study. Table 1 describes the selected parameters and their ranges for the sensitivity analysis. This leads to a total of 72 different cases to be simulated.

Table 1: Ranges of sensitive parameters for this study

<i>Pore Compressibility(1/Pa)</i>	<i>1.5e-10</i>	<i>3e-10</i>	5e-10
Relative Permeability	Low	High	
Rock Physics Model	Cemented	Uncemented	
Saturation Scale	Uniform	Patchy	
Porosity Model	Model 1	Model 2	Model 3

5. Methodology

5.1. Flow Simulation

Flow simulation is performed for all 72 variations of the parameters, starting from the initial condition of the reservoir. This provides us the spatial distributions of fluids and variation of pore pressure in the reservoir at different times after the start of production. In order to use Gassmann's equations we need the saturations of each fluid (Oil, Water and Gas) at every cell at different times. We have used an isothermal black-oil model and flow rates and controls are set up as observed in the field. Six years of oil production have been simulated. PVT and capillary pressure data are taken from original Norne field simulation model. Production and Injection schedule are the same as in the Norne field.

5.2. Time Lapse Seismic Modeling

5.2.1. Change in Saturation

The distribution of fluid saturations in the reservoir is obtained for seventy two different cases. These variations of saturations are responsible for change in the bulk

density, effective bulk elastic moduli, and finally changes in the seismic velocities as shown below. 3-D time-lapse changes in seismic velocities are generated using initial seismic velocities, density and Gassmann's fluid substitution equation (Gassmann, 1951). Gassmann's equation shown below is used to obtain the bulk modulus K_2 of the rock saturated with fluid 2, which is mixture of oil, water and gas in this case.

$$\frac{K_2}{K_{min} - K_2} - \frac{K_{fl2}}{\phi(K_{min} - K_{fl2})} = \frac{K_1}{K_{min} - K_1} - \frac{K_{fl1}}{\phi(K_{min} - K_{fl1})}$$

K_1 and K_2 are the rock's bulk moduli with fluids 1 and 2 respectively, K_{fl1} and K_{fl2} are the bulk moduli of fluids 1 and 2, ϕ is the rock's porosity, and K_{min} is the bulk modulus of the mineral. The shear modulus G_2 remains unchanged $G_2 = G_1$ at low frequencies appropriate for surface seismic data, since shear stress cannot be applied to fluids. The fluid bulk moduli are a function of the oil composition, pore pressure and temperature. The fluid moduli and densities are obtained from the usual Batzle-Wang (1992) relations. The effective fluid bulk moduli are different for uniform and patchy saturation distribution. The harmonic average of the individual fluid bulk moduli is used for the case of uniform fluid distribution while the arithmetic average is used for the patchy case. The use of the arithmetic average is an approximation and gives an upper bound (Mavko and Mukerji, 1998).

$$\frac{1}{K_f^{Uniform}} = \frac{S_w}{K_w} + \frac{S_o}{K_o} + \frac{S_g}{K_g}$$

$$K_f^{Patchy} = S_w K_w + S_o K_o + S_g K_g$$

The density of the rock is also transformed and the density of the rock with the second fluid is computed as:

$$\rho_2 = \rho_1 + \phi(\rho_{fl2} - \rho_{fl1})$$

Having transformed the elastic moduli and the density, the compressional and shear wave velocities of the rock with the second fluid are computed as

$$V_p = \sqrt{\frac{K_2 + \frac{4G_2}{3}}{\rho_2}}$$

$$V_s = \sqrt{\frac{G_2}{\rho_2}}$$

5.2.2. Change in Pore Pressure

In addition to saturation changes, the elastic moduli of the porous rock frame and hence seismic velocities are affected by pore pressure changes as well. Flow simulation provides us the variation of pore pressure and saturations with respect to time after the startup of the production. Using a proper pore pressure model seismic velocities of dry rock are first corrected for changes in pore pressure. The correction in seismic velocity of dry rock for cemented and unconsolidated reservoir rocks is different. Now corrected seismic velocities of dry rocks are used to calculate the seismic velocities by fluid substitution using Gassmann's equation as stated above. The pore pressure effect on the dry rock frame is modeled using an analytical curve fit to an empirical relation derived from dry core data for unconsolidated and cemented sands (Zimmer et al., 2002).

5.3. Sensitivity Study Using MDS

Flow and seismic responses are obtained for 72 different cases as described previously. Flow response is the cumulative oil production after four years of production. Seismic response is change in seismic p-wave velocity after four years of production. The flow and seismic responses are combined in a vector (called as joint response) and obtained for each 72 different cases. Euclidean distance is selected to define dissimilarity between different joint responses. The distance is evaluated between any two joint responses and a dissimilarity distance table (72 X 72) is derived. Multi-dimensional scaling (MDS) is then applied using the distance table (Borg and Groenen, 1997). This results in a 2D map of the responses, where the euclidean distance between any two responses is similar to the distance table. It is important to understand that only the distance between any two joint responses in the new space matters and the actual positions of responses are irrelevant. Once the responses are in MDS space we rank the sensitive parameters by observing the variation in distances between joint responses due to change in sensitive parameters.

6. Results

Figure 9 shows the 2D maps of joint responses obtained in MDS space. Only the distance between any two joint responses in the new space matters and indicated by 2D maps in the figure 9. It consists of five different 2D maps of joint responses, only color coded with different sensitive parameters. First 2D map is color coded with porosity models. Similarly second, third, fourth and fifth 2D maps are color coded with relative permeability, pore compressibility, type of rock physics models and fluid mixing (uniform or patchy saturation). We observed that distance between joint response due to change in rock physics models is highest. Based on the same criteria relative permeability, pore compressibility and porosity models are second, third and fourth most sensitive parameters. Fluid mixing has the least effect on joint inversion as shown in the last 2D map. The locations of points in 2D map for uniform and patchy saturation behaviors are almost the same.

7. Conclusions

Rock physics model is the most important parameter among the parameters considered for joint inversion of time-lapse and production data of Norne field. Presence or absence of cement in the rock has a strong impact on the sensitivity of seismic velocity to fluid saturation changes. Relative permeability and pore compressibility are the second and third most sensitivity parameter for joint inversion of both types of data. Also saturation scale is the least sensitive parameter for joint inversion time-lapse seismic and production data of Norne field.

5. Acknowledgment

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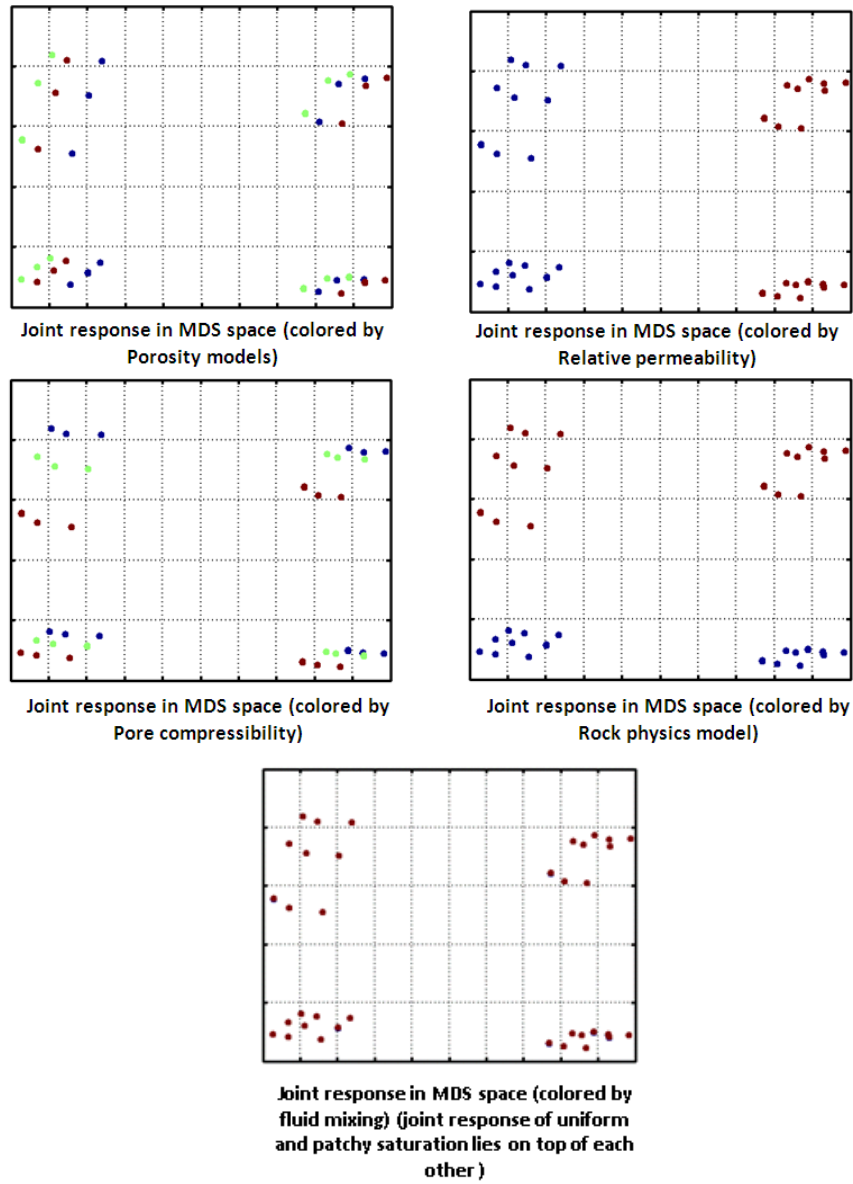


Figure 9: 2D map of joint responses in MDS space. Each 2D map is color coded by different sensitive parameters used in this study

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