Conventional and non-conventional seismic differencing in time-lapse

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Summary

We present a comparison between the conventional time-lapse differencing and the new non-conventional differencing method based on the theory of inverse data matrix. A time-lapse reservoir study is performed on a model of a 100 % oil saturated producing reservoir. The study monitors a waterflood scheme for a number of calendar days. Snap shots after day 1, 14 and 28 are used for the time-lapse analysis. The workflow developed follows four stages, that is velocity modelling, zero-offset synthetic modelling, migration modelling and difference modelling. 2D variable velocity plots in time-lapse are passed to a finite-difference algorithm generating zero-offset synthetic seismograms. Synthetics are migrated employing Split-step Fourier algorithm and conventionally and non-conventionally differenced. Conventional differencing consists of matrix subtraction in MATLAB and captures no amplitude patterns for time-lapse studies, hence proves to be of limited use in reservoir characterization. On the other hand, non-conventional differencing invoking inverse data matrix concept, captures some amplitude patters and offers more intuitive plots for interpretation.

Data

We use the 10^{th} Comparative Solution Project data set. Data set models one producing and two injecting wells, that is a 100% oil saturated reservoir as water saturation develops and breaks through in production after 28 days. Assume both oil and water, to be incompressible, irreducible and immiscible, namely they are fully displaced by one another, with no blending or density changes. The workflow is to take velocity models, to zero-offset seismic models, migrate them and allow differencing, that is conventionally and non-conventionally.

Stage I: Velocity Models	→	Stage II: Seismic Models	→	Stage III: Migrated Seismic Models	→	Stage IV: Conventionally and Non-conventionally Differenced Models

Table 1: 2D modelling workflow consists of four stages.

Theory

STAGES I and II: Velocity and zero-offset seismic modelling
A laterally varying 2D velocity model is assumed to model the above reservoir in time-lapse. Suppose waterfronts to dip at 90°. Velocity model invokes finite difference method, *afd_explode* MATLAB function from the CREWES toolbox, and generates 2D zero-offset synthetic data.

STAGE III: Migration modelling
Split-step Fourier migration algorithm (SSF) is known to handle lateral changes in velocity at each depth level and dipping events successfully. We assume 2D propagation of compressional (P) waves in acoustic medium and constant density. Wave propagation is defined as:

$$\nabla^2 d - u^2 \frac{\partial^2}{\partial t^2} d = 0, \qquad (1)$$

where t, $d = d(x,z,t)$ and $u = u(x,z)$ are time, pressure and slowness, respectively. The inverse of the half of the propagation velocity $u(x,z) = 2/v(x,z)$, where v, x, z are velocity, horizontal and vertical distance, respectively, denotes slowness. As the migration by SSF takes place partially in the frequency domain, equation (1) is Fourier transformed to:

$$\nabla^2 D + \omega^2 u^2 + D = 0, \qquad (2)$$

where ω is frequency and $D = D(x,z,\omega) = \int_{-\infty}^{+\infty} d(x,z,t) e^{-i\omega t}\, dt$.

Theory cont.

Now, the slowness term is decomposed from equation (2) in two components:

$$u(x,z) = u_0(z) + \Delta u(x,z), \qquad (3)$$

where $u_0(z)$ and $\Delta u(x,z)$ are the reference and perturbation slowness. Thus the homogeneous wave equation transforms into the inhomogeneous, constant-slowness wave equation:

$$\nabla^2 D + \omega^2 u_0^2 D = -U(x,z,\omega), \qquad (4)$$

where $U(x,z,\omega) = \omega^2[2u_0 \Delta u(x,z,\omega) + \Delta u^2(x,z,\omega)]D$ is a source like-term. The second order term in equation (4) is ignored as perturbation slowness is small when compared to the reference slowness. The solution of equation (4) delivers migrated data.

STAGE IV: Difference modelling
Time-lapse migrated seismic models are presented as matrices D_i, where i denotes time step. These sections are differenced employing conventional matrix subtraction:

$$D_{diff} = D_i - D_{i+1}. \qquad (5)$$

Equation (5) captures large scale physical changes of reservoir as production progresses.
Namely, hydrocarbon volume and its displacement changes are expected to be interpretable for use in enhanced recovery schemes development and monitoring.

Improved difference modelling
The Berkhout and Verschuur published a paper in 2005 useful in development of the non-conventional differencing concept. To analyze data in time-lapse, define migrated base study as:

$$D = D_0 + AD \qquad (6)$$

and define monitor surveys as:

$$D' = D_0' + D_0' A' D'. \qquad (7)$$

To account for reservoir parameters equation (7) can be further divided into smaller variables:

$$D_{diff} = (D_0 + D_0 A' D') + (\delta D_0 + \delta D_0 A' D'), \qquad (8)$$

where δD_0 denotes reservoir and overburden responses due to production. Employing matrix inversion, we move from multiple scattering data in forward data space (FDS), described by equation (7), to inverse data space (IDS):

$$D^{-1} = D_0^{-1} - A. \qquad (9)$$

Equation (9) describes a much simpler data set based on surface-free earth response and surface related properties at and around zero time.
The use of inverse data space can be summarized in five steps:
I. Conversion of data from FDS to IDS through least-squares algorithm, that is $D_0 => D_0'$.
II. Separation of surface operators from reflection data in Radon domain; that is further ignored for synthetic data.
III. Conversion of reflection data from IDS to FSD, that is $D_0' => D_0$.
IV. Identify surface transfer function, in FDS and IDS, that is $X_0 = -AD_0$ and $X_0' = -A' D_0'$.
V. Compute difference data employing least-squares subtraction to obtain $\delta X_0 = X_0 - F_{ls} X_0'$, where F_{ls} is a scaled version of the correlation between the overburden Green's functions of the base and monitor data set.
The improved difference modelling is expected to capture large and small scale physical changes as well as some amplitude patterns.

Examples

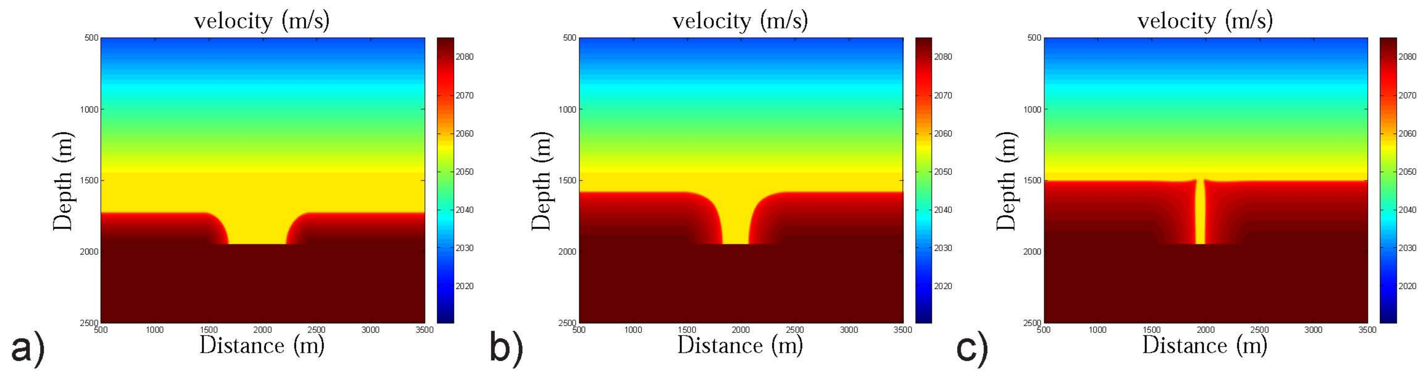

Figure 1: Padded velocity models describing 100 % oil saturated sandstone reservoir. Models (a), (b) and (c) show reservoir as water saturation increases. Two injectors are situated in lower left and right corners, while producer sits at half distance between them. P-wave velocity decreases from injector to producer in time-lapse steps after day $\tau = 1, 14, 28$, respectively.

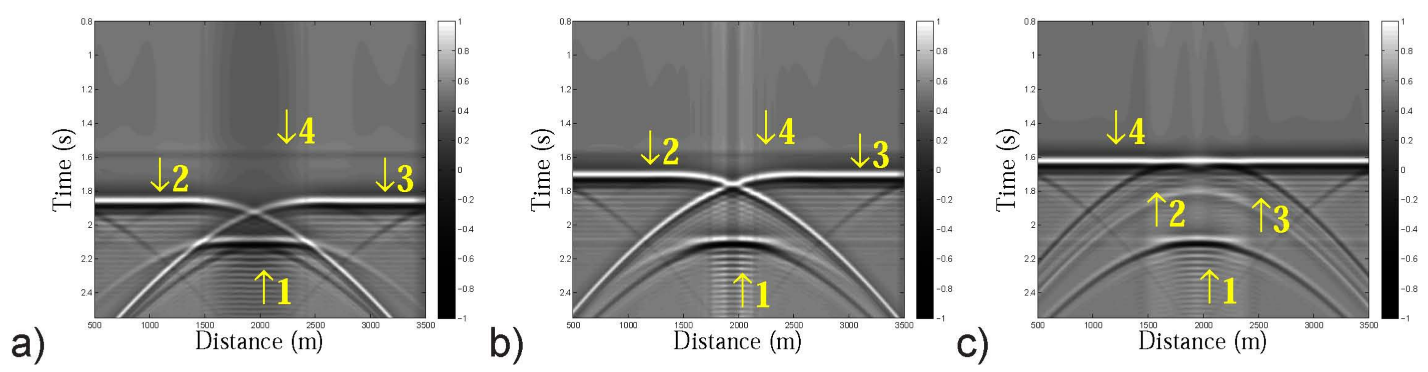

Figure 2: 2D synthetic seismic models generated employing exploding reflector algorithm. Models (a), (b) and (c) show reservoir in time-lapse steps after day $\tau = 1, 14, 28$, respectively. Reservoir bottom and top, denoted by arrows 1 and 4, respectively, stay stationary in time. Arrows 2 and 3 mark waterfronts as they progress upward in time. Oil amplitude is gray. Water saturated zones show linear trends.

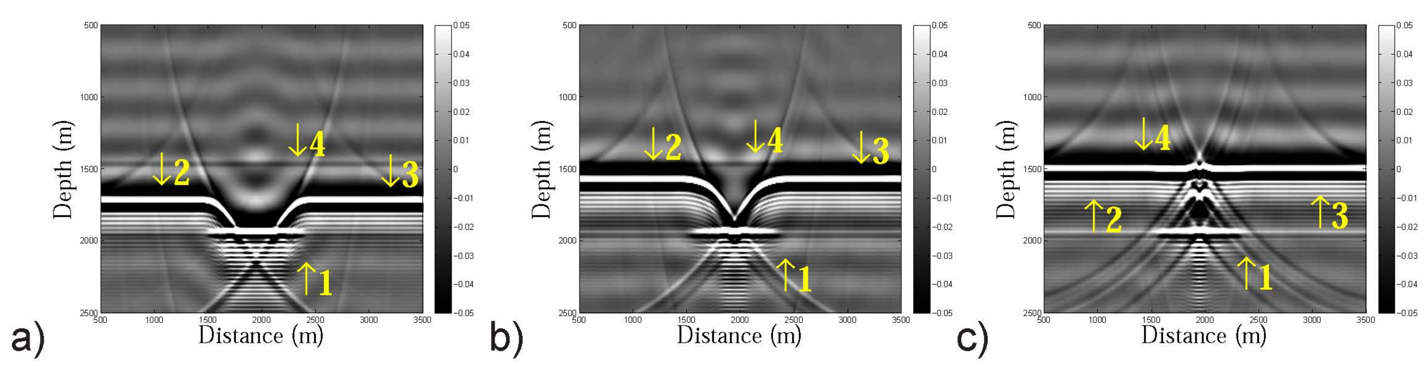

Figure 3: Split-step Fourier migrated seismic sections generated from velocity and synthetic models. Sections (a), (b), (c) capture flattening of hyperbolic events after day $\tau = 1$, 14 and 28, respectively. Arrows 1 and 4 point to the stationary events reservoir bottom and top, respectively. Arrows 2 and 3 point to two waterfronts propagating upwards in time. Oil amplitude is light gray and better focused. Water saturated zones capture linear trends and as well are better focused.

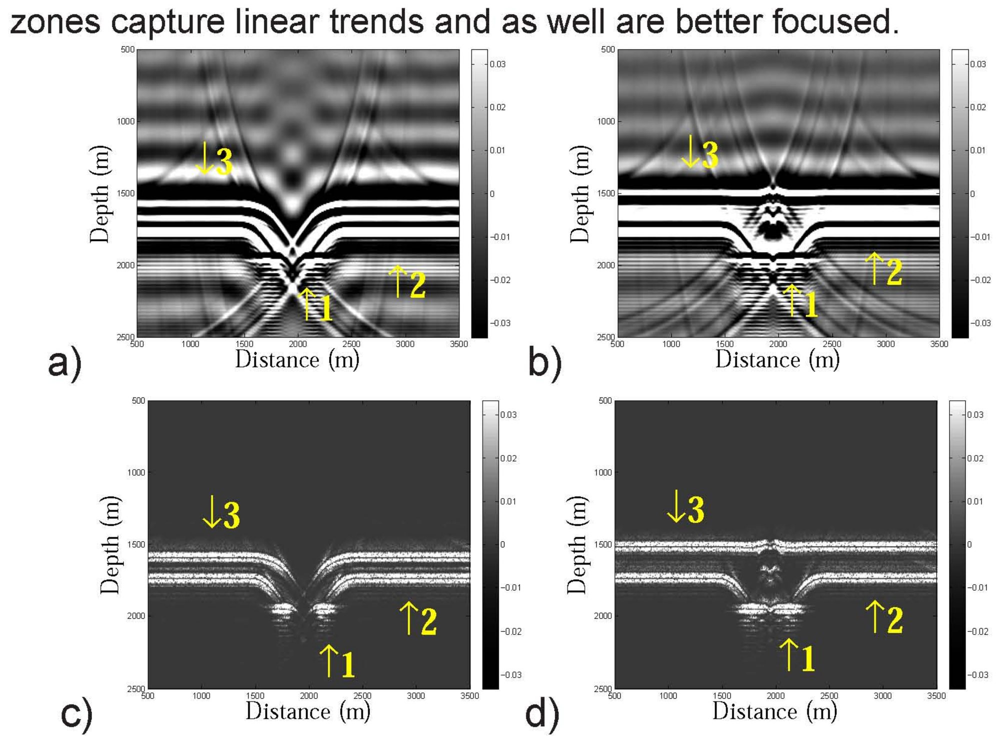

Figure 4: Differenced migrated models. Models (a) and (b) capture conventional difference of models after days 1 and 14 and days 1 and 28, respectively. Models (c) and (d) capture non-conventional difference of models after days 1 and 14 and days 1 and 28, respectively. Arrow 1 denotes reservoir bottom, whereas, no reservoir top reflection can be identified. Arrows 2 and 3 mark two waterfronts corresponding to differenced models. Produced areas are easily identifiable on non-conventionally differenced models. The areas of remaining production volume get easier to identify on non-conventionally to conventionally differenced models.

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