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SEISMIC MONITORING AND MODELING OF AN ENHANCED OIL RECOVERY PROJECT AT COLD LAKE, ALBERTA, CANADA

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ABSTRACT

Reservoir monitoring during an enhanced oil recovery (EOR) process is critical for efficient management of the EOR process. 3-D high resolution surface seismic is used in an experiment by Mobil Oil of Canada that involves *in situ* thermal EOR processes in the heavy oil sands at Cold Lake, Alberta, Canada.

Finite difference modeling of seismic waves in acoustic and elastic media was performed in the region over the steam-heated zone. Imaging of the 3-D surface reflection seismic data before and after steam injection was also performed with a one-pass 3-D poststack depth migration in the space-frequency domain.

During steam stimulation, seismic effects such as time delays of the reflectors below and amplitude changes within the steam area are important for the imaging of the heated zones on the monitor seismic data volumes. These effects were observed and mapped by analyzing the before (base) and after steam (monitor) 3-D seismic data.

INTRODUCTION

Enormous reserves of bitumen or heavy oil are present in complex reservoirs in sands of Lower Cretaceous age in Alberta, Canada. This heavy oil or bitumen is a low gravity high viscosity oil which under reservoir conditions is immobile. Since only 7% of these deposits are accessible to surface mining, pilot studies are being carried out to recover the oil through *in-situ* methods. Most of these involve steam injection or fire flood methods to reduce the viscosity of the bitumen so it may be pumped to the surface. The movement of fluids away from the heat sources at the perforation level is controlled by permeability, even small heterogeneities or anisotropy can play a major role in the efficiency of the EOR process. Therefore, it is important to image the shape and areal extent of the heated zone and determine the rate of movement of the thermal front.

3-D seismic surveys repeated over specified time intervals can be used to generate 4-D images (3-D plus calendar time) that can give valuable information regarding the management of EOR projects. The 3-D seismic data volume evolves continuously and as a result seismic interpretation and reservoir model become more detailed and sophisticated.

Laboratory experiments on the effects of EOR processes on acoustics velocities in reservoir fluids and rocks were carried out by Wang and Nur (1988) and showed large changes with temperature and pressure changes. As temperature increases, the increase of compressibility and decrease in viscosity of the crude and tar, thermal cracking of the heavy hydrocarbons, and the melting of the solid or semi-solid hydrocarbon fractions all contribute to velocity decreases. The effect of high pore pressure due to the steam injection is to mechanically oppose the closing of cracks and grain contacts resulting from the confining pressure, thus leading to low effective moduli and velocities.

During steam injection in the oil sands, the steam displaces the pore fluid (oil) resulting in an increase of the overall compressibility of the reservoir rock and as result the compressional velocity decreases. If the velocity decreases, the seismic wave is time delayed. As Briton et al. (1983) reported, using a conventional seismic survey over a steam-flooded area, the seismic section clearly shows travel time delays around the steam injection well. Macrides et al. (1988) showed that the waves that traveled through the steam zone are time delayed and have significant changes in seismic signature.

Matthews (1992) used multiple 3-D seismic surveys to monitor steam injection processes in a tar sand reservoir. He performed pushdown analysis and velocity differencing and reported that the decrease in the seismic velocity exceeds 30 per cent in some areas of the heated zone. Eastwood et al. (1994) have analyzed and integrated data from two monitor

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3-D seismic surface surveys obtained during production and steam cycles, crosswell data obtained during production cycles, well log data (temperature and pressure), and data from thermal reservoir simulations at Imperial Oil's Cold Lake oil sands.

Siewert (1993) has interpreted seismic monitoring data (base and steam-monitor) for changes in seismic travel times, attenuation and reflectivity. Also, he discussed rock and fluid effects of the steam stimulation process under frac pressures, at Mobil's pilot project at Cold Lake, which were observed on the seismic data and confirmed in triaxial core tests. Furthermore, he showed that reflection amplitude changes track reservoir pressure, with frac anomalies emanating from known well locations. In this paper modeling and imaging of the same data sets are performed.

GEOLOGY AND RESERVOIR DESCRIPTION

The origin of the oil sands has long been a subject of speculation among geologists. Bailey et al. (1973) suggested that tar accumulations were created by water washing and bacterial degradation of medium gravity crude oils. Water washing removes the more water soluble light hydrocarbons and normal paraffins, resulting in an increase in density and sulfur content which is tied to the more bacteria-resistant heavy and complex cyclic organic compounds. Oil sands may be considered as a four-phase system: a dense interlocked skeleton of predominantly quartz sand grains, with pore spaces occupied by bitumen, water, gas and minor amounts of clay. Typical Alberta oil sand porosity is 32% with tar saturation 81% and water saturation 19%.

The heavy oil is contained in various sands of the Upper and Lower Mannville Group of Lower Cretaceous age (Harrison et al., 1979). At Cold Lake the Mannville Group was deposited near the eastern edge of the Western Canadian sedimentary basin on a Palaeozoic erosional surface as a nearshore-deltaic to offshore transition sand-shale complex. It is overlain by marine shales of the Colorado Group. These Mannville sands are noncemented and vary considerably in thickness, areal extent and reservoir quality. the Paleozoic unconformity occurs at a depth of around 500 to 600 m and the top of the Precambrian crystalline basement is at a depth of 1020 m. Both these horizons are prominent seismic reflection markers.

At Cold Lake, the Mannville averages 210 m in thickness. In the area of study, the Mannville Group consists of a sequence of sands and interbedded shales, containing the following formations: Colony, McLaren, Waseca, Sparky, Gen Petroleums (G.P.), Clearwater and McMurray. The best reservoirs are in the Sparky and Waseca formations. The Sparky consists of three sands separated by shales that result in the Upper Sparky, the Middle Sparky and the Lower Sparky. The sands are saturated with bitumen that has a very high viscosity (about 150,000 cp). Generally, the reservoir has excellent horizontal continuity. However, the vertical continuity is occasionally interrupted by discontinuous shale barriers, tight cemented siltstones and calcified tight streaks that can affect the vertical conformance of the steam stimulation.

EXPERIMENT BY MOBIL OIL CANADA

The goal of *in-situ* process is to recover oil from the heavy oil or tar sands. The principal method of recovery evaluated is steam stimulation sometimes referred as "Huff and Puff", (Farouq Ali, 1974). According to this method steam is injected into a well at the highest possible rate (in order to minimize heat losses) for several weeks. The injected steam heats the rock and the fluids around the wellbore. Vertical inhomogeneities such as shale barriers, cause only partial vertical sweep while maintaining a radial advance of the fluids in the zone that is contacted. After injecting the desired volume of steam, the well may be shut in for about two weeks. This is called the *soak* period. Finally production takes place from the same wellbore.

Mobil Oil of Canada had a 23 vertical well pilot (presently abandoned) in the Cold Lake area of Alberta where steam stimulation was used as an enhanced oil recovery method. In this experiment the steam was injected starting at a depth of approximately 360 m in three different levels of the Sparky sands that are separated by shales. The steam was injected at a constant rate of 200 m^3 per day at wellhead pressures of 8 to 10 MPa. The injection pressure in some wells had to be gradually increased to maintain this injection rate. This resulted in differential pressure states between some wells.

In 1987, Mobil Oil Canada initiated a 3-D high resolution seismic reflection acquisition program at the Cold Lake area. The program consisted of a base survey carried out in 1987 and a monitor survey carried out in 1988 nearly at the end of the 2nd cycle. Both surveys were recorded over the same pad that included 23 injector-producer wells and 3 observation wells (Figure 1). At the time of the second survey only five wells (3, 6, 13, 16, 18) were under steam injection pressures, the rest were on flow back or drawdown pressures.

For both experiments the field acquisition geometry was identical. Each survey had 10 receiver lines laid out in E/W direction with line spacing of 88 m, group interval of 22 m and with each geophone array consisted of 18 geophones. Also, it had a total of 16 source lines laid out in N/S direction with source line spacing of 66 m, shot point interval of 22 m and a total number of 374 shots. The type of energy source was Vibroseis (2 vibrators) with a non-linear sweep over a frequency range of 8-178 Hz. The field data were recorded, 478 traces per record, with sample rate of 1 ms using a DFS VII system. After stacking, each survey has 73 inlines and 90 crosslines with bin size of 11 x 11 m (Figure 1).

RESERVOIR CONDITIONS AND SEISMIC CHANGES DURING EOR PROCESSES AT COLD LAKE

During steam injection the reservoir conditions are at the local maximum in terms of temperature and fluid pressure. Therefore, overall the rock frame and fluid compressibility increases. This results in a decrease of the compressional wave velocity and an increase in wave attenuation in the steam affected reservoir.

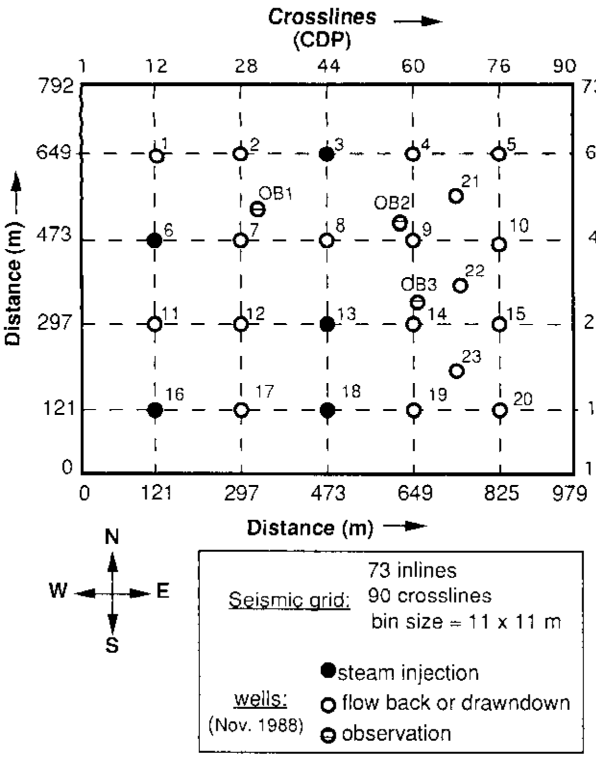


Fig. 1. The site map of Mobil's pilot project showing the locations of the injection/projection and observation wells, and the seismic grid.

The velocity decrease, the increase in attenuation and the variable fluid saturation imply that time delays (pushdowns or velocity sags), amplitude and spectral anomalies of seismic reflections from subsurface zones invaded by the steam zone can be observed on seismic sections. The reflector at the top of the reservoir, usually the boundary between the shale above and hot fluid saturated oil sands below, has an increased reflection amplitude ("bright spot"). On the other hand, reflectors below the steam affected reservoir are time delayed and are decreased reflection amplitude ("dim spots").

Amplitude anomalies on the monitoring seismic images can be used to indicate gas saturation changes in the reservoirs, to monitor the contacts, mobility, phase and temperature change of reservoir fluids, to determine distribution and continuity of the reservoirs as they are produced over time, to map reservoir heterogteneities and changes in pressure. Seismic analysis, such as pushdown, amplitude and spectral differencing between the seismic images from different phases of an EOR process are used to track the steam fronts and map their spatial heterogeneity (Kalantzis, 1994).

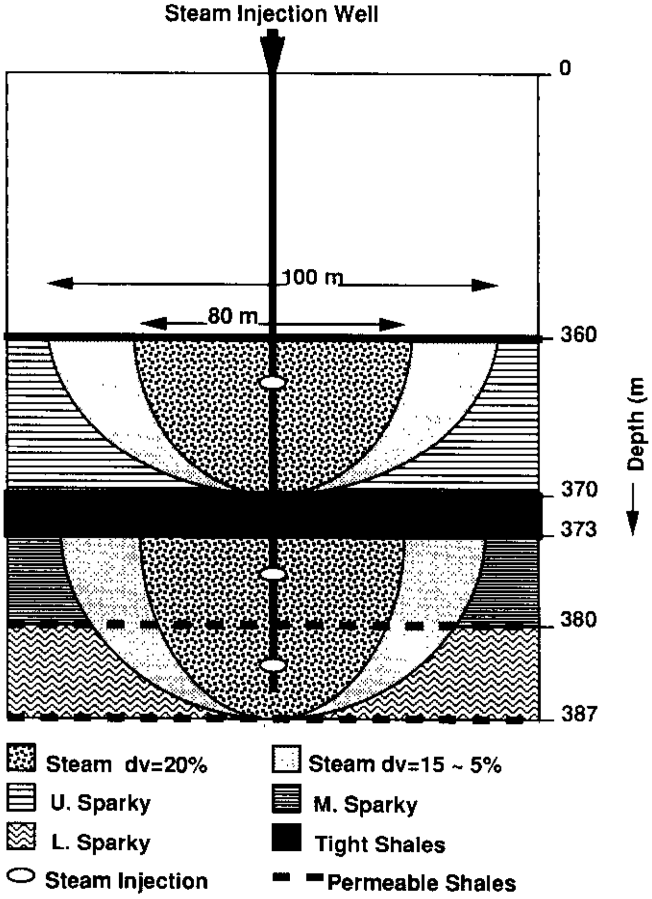


Fig. 2. The steam zones used to simulate steam injection in the Sparky Sands.

SEISMIC WAVE PROPAGATION SIMULATIONS

Computer simulations of seismic wave propagation were essential for the interpretation of field data. Finite difference modeling of seismic waves in acoustic and elastic media in the region over the steam-heated zone was performed in order to examine the relation between reservoir conditions with seismic characteristics such as velocity, amplitude and frequency modification with time. For the generation of the velocity models (base) we used sonic logs, stacking velocities and time migrated sections.

In order to understand the effects caused by the steaming process, we introduced steam zones of various characteristics into our base model. In the field experiment the steam was injected at three perforation levels corresponding to the three Sparky Sands. However, there are two hydraulic reservoir systems; an upper system that consists of the Upper Sparky Sands with leakoff to the Waseca above and a lower system that consists of the Mid Sparky and the Lower Sparky with leakoff to the G.P. (Siewert, 1993). There is a thick shale between the Upper and Mid Sparky that acts as a very effective permeability barrier. The shale between the Mid and Lower Sparky is not as efficient and there is some cross-flow through joints and cracks. Also, the shale between the Lower Sparky and the G.P. is very thin and permeable. For this reason, we introduced a double steam zone at each well location at the Sparky level (Figure 2). Both steam zones are semi-ellipses. The upper steam zone simulates the hydraulic system in the Upper Sparky Sands and it is 10 m thick. The lower steam zone simulates the hydraulic system in the Mid and Lower Sparky Sands and it is 14 m thick. In the modeling we did not include the high velocity shales that separate the steam zones.

Acoustic modeling

Zero offset acoustic modeling was performed using a simplified flat multi-layer velocity model with and without the steam zone (Figure 2). The modeling was performed with a 2-D ω-x algorithm that uses the Exploding Reflector Model (ERM) and a 65 degree approximation of the one-way scalar wave equation (Kalantzis, 1994). In Figure 3a the zero offset section is shown for the simplified model without the steam zones. In Figure 3b the zero offset section clearly resolves the steam-heated zones and shows the time delay (push-down) of the reflectors below. Figure 3c shows the migrated section with the steam zones clearly imaged and the reflectors below the zones corrected from the velocity sags.

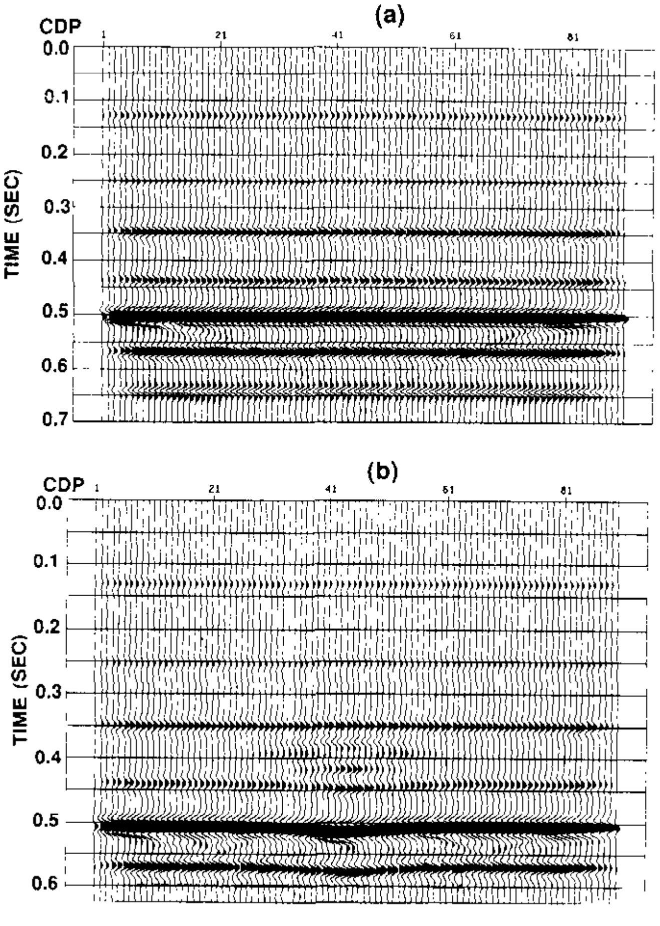


Fig. 3. Acoustic ω-x modeling generated zero offset sections without (a) and with steam zone (b). 2-D ω-x migration of the zero offset section with the steam zone generated the migrated section (c).

Elastic modeling

Elastic wave (P-SV) computer simulations were performed on velocity models with and without steam zones. The dimensions of the model were 968 m in the x-direction and 1200 m in the z-direction. The finite-difference mesh size was 2.75 m (1/4 of the CDP spacing) in the x-direction. The total numbers of grid nodes in the x-direction was 393 including 20 nodes at each side of the model for absorbing region. The mesh size in the z-direction was 2.5 m and the total number of nodes was 501 including the bottom absorbing region. The finite difference time step was 0.1 ms. The sampling interval was 1 ms and data were recorded for 0.8s. Therefore, for this model a computational grid of 393 x 501 nodes and 8046 time steps were used. The elastic wave simulation for this model required 2.01 hours of CPU time on a Convex 210.

A 2-D velocity model (Figure 4a) for the Mobil pad along the inline 12 of the seismic grid was generated using sonic wells from the pad and the impedances from the inversion of the base (before steam) migrated inline 12. This velocity model is considered as the base model from which we generated base (pre-steam) synthetic seismic data. Using this model and a 50 Hz gaussian line source, P-SV seismograms for the vertical component of the particle velocity were generated. Eight synthetic shot gathers were generated by setting the source along the model at 132 m spacing (in the field experiment 16 shotlines with 66 m spacing were used). Figure 5a shows the synthetic shot gather with the source in the middle of the model and with trace spacing of 11 m. We applied normal moveout (NMO) correction on the shot gathers using the same velocity function as the one applied on the real data and then we stacked with CDP spacing of 11 m and the same muting pattern as the one applied on the real data. Figure 6a shows the resulting stacked section for the base model.

Along the seismic inline 12 there are five injection/producer wells. Assuming that they are all steaming, we can simulate this by setting steam zones at the corresponding locations on the base velocity model. Thus, we generate a monitor velocity model on which elastic modeling is performed in order to generate monitor synthetic seismic data (Figure 5b). Synthetic shot gathers and stacked zero offset sections were generated for five different models that all had five steam injection wells but the steam-heated zones varied in areal dimensions (areal conformance) and in the degree of velocity decrease (compressibility increase) due to the combined effects of temperature (high), pressure (high fluid pressure – small effective stress) and gas (gas reduction – small gas saturation). However, here we present only one case.

Figure 4b shows the velocity model (monitor) with five steam injection wells. The steam-heated zones (two semi-ellipses) generated in the Sparky reservoir have a core

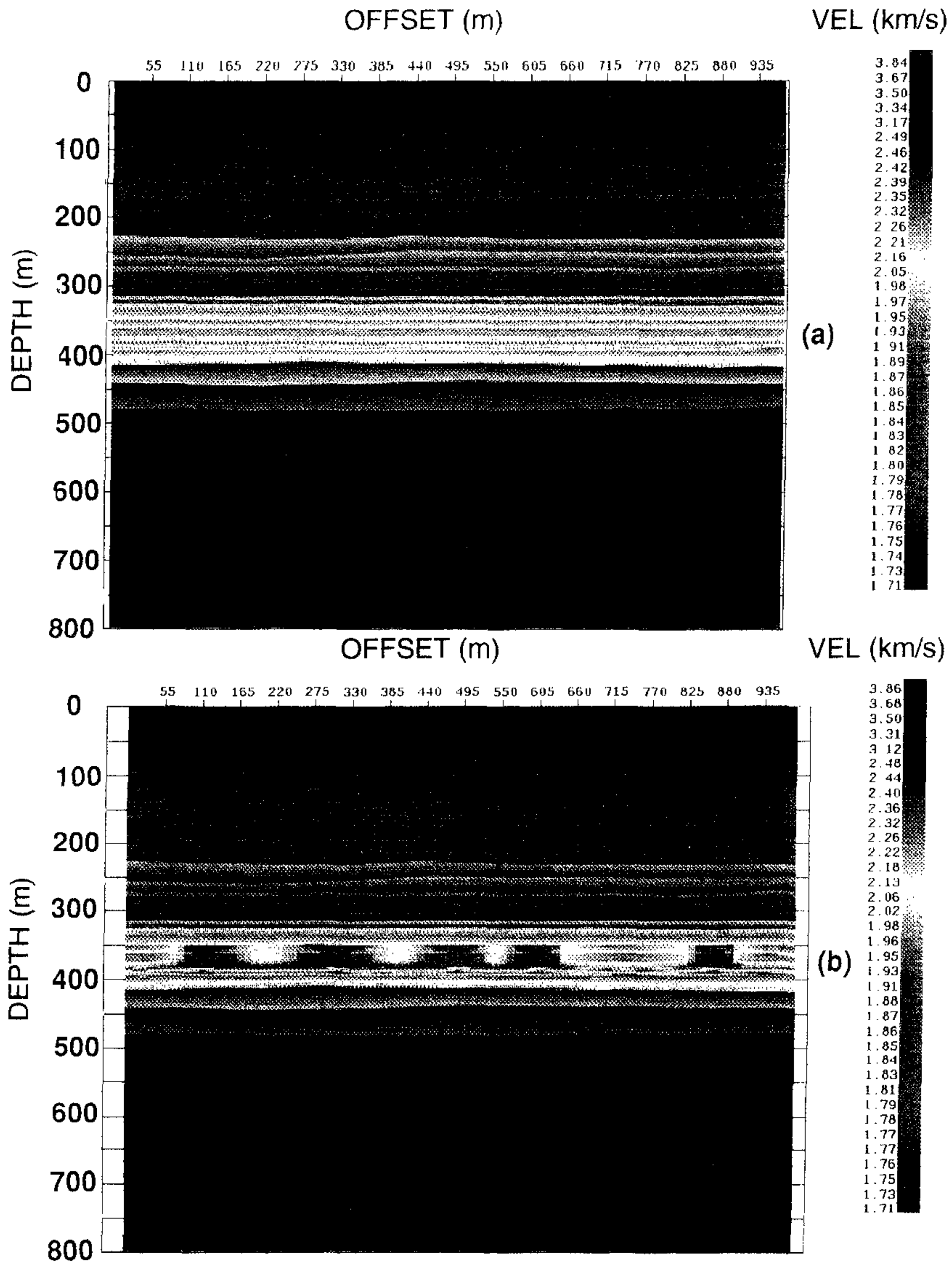
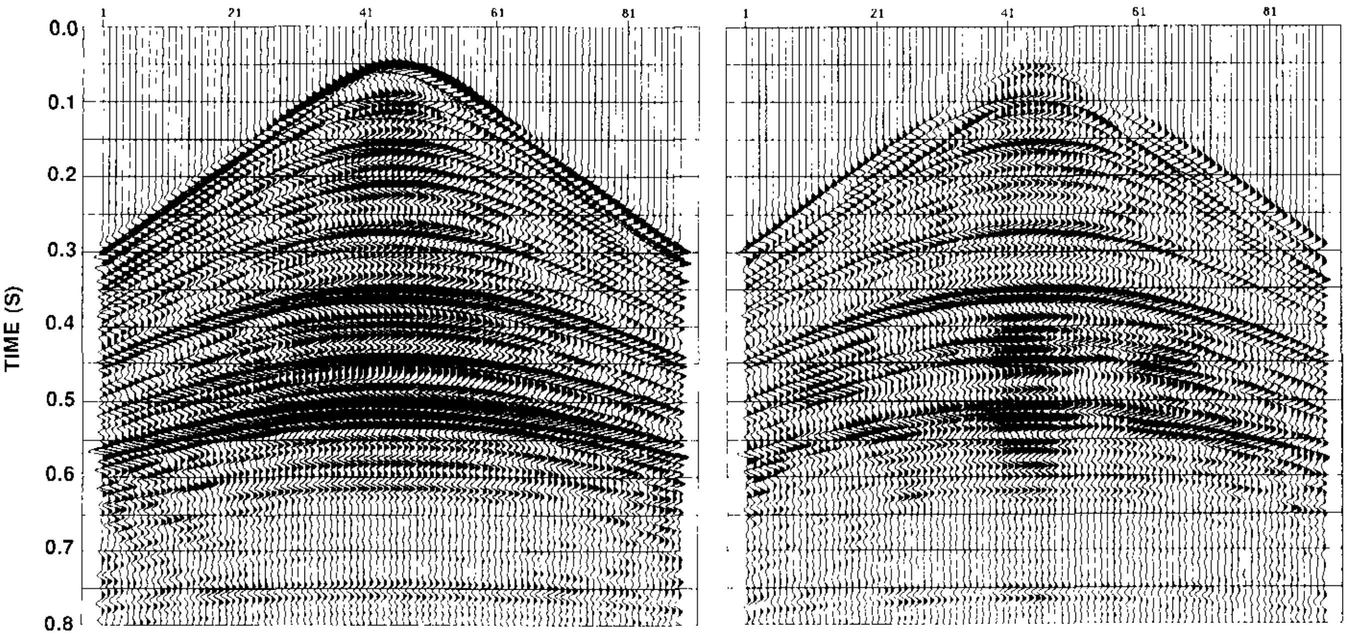


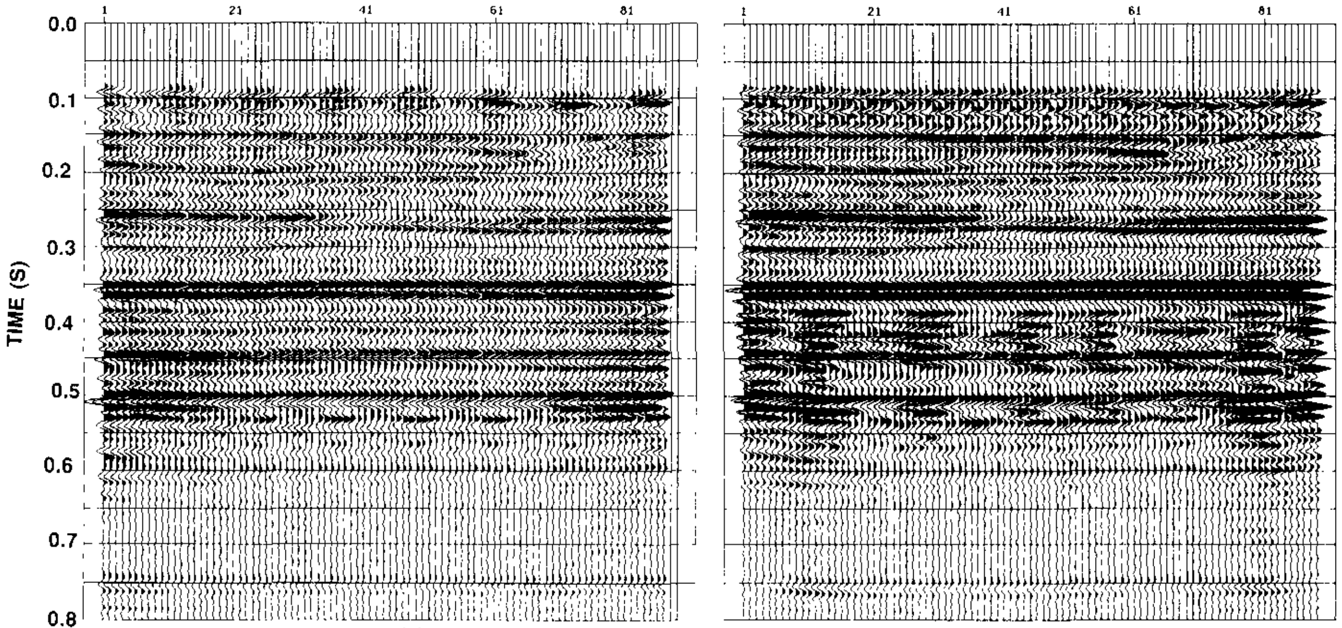
Fig. 4. Velocity models used for 2-D elastic wave propagation simulations: (a) before the steaming process (base, no steam zones) and (b) during steam injection (monitor, steam zones).

(steam) of about 80 m areal extent and a 20% velocity and density reduction. However, the velocity and density continues to change gradually (heated area) to that of the surrounding material. Considering that the wells along the inline direction are 96 m apart, our modeled steam zone expansion may create communication paths between the low velocity steam-heated zones (Figure 4b). Using the above model, we generated P-SV shot gathers for eight shot locations (one is shown in Figure 5b). The synthetic shot gathers after NMO were then stacked (Figure 6b). On both the shot gather and the stacked section we clearly observe reflections and diffractions from the steam zones. Amplitude increases (bright spots) are generated on the top of the steam-heated zones (0.375 ms). Also, amplitude changes (dim spots) and time delays are observed at reflectors below such as the Devonian reflector at 0.5 s. These changes are more dramatic



(a) (b)

Fig. 5. Synthetic shot gathers (vertical particle velocity component) from elastic wave simulations for the models (Figure 4): (a) before the steaming process (base, no steam zones) and (b) during steam injection (monitor, steam zones).



(a) (b)

Fig. 6. Stacked sections for the models (Figure 4): (a) before the steam stimulation process (base) and (b) during steam injection (monitor-steam).

when the shot gather and the stacked section (Figures 5b, 6b) are compared with the corresponding ones (Figures 5a, 6a) from the model without steam-heated zones.

PROCESSING OF THE 3-D SEISMIC DATA

The processing sequence that was applied on both data sets (base and steam-monitor) by Mobil Oil was as follows: demultiplexing, static computations, true amplitude recovery, first break mute, deconvolution, dephase filter, equalization, velocity analysis (datum referenced), automatic surface consistent residual statics, big bin velocity analysis, normal moveout correction, CDP stack, dephase, filter, two-pass 3-D Kirchhoff f-k migration (dip controlled, stack velocity function), time invariant filter and equalization (Figure 7). On the other hand, our own processing involved energy balancing and one-pass 3-D depth migration of both base and steam-monitor stacked data volumes (Figure 7).

Energy balancing of the stacked data

A global trace balancing was applied on both stacked sets (base 1987 and steam 1988) and it was calculated as follows. From the 3-D stacked data volume (base survey) a time window between 150 ms and 300 ms was selected. The reason for the selection of this time window is that within this interval the reflections are consistent and continuous and are located well above the steam-heated zone in the Sparky Sands. A *global factor* was calculated from the base data. Next for each trace in both data volumes (base and steam) a *trace factor* was computed. The ratio between the "global factor" and each "trace factor" results in a balancing factor (scaling factor) for that trace which is applied to all samples in the trace for both data sets. Consequently, both data sets have been normalized to a uniform amplitude energy. Therefore, differences between the two seismic data volumes that may be due to differences in the seismic source, water-table or any other effect not related to the EOR process are not present anymore.

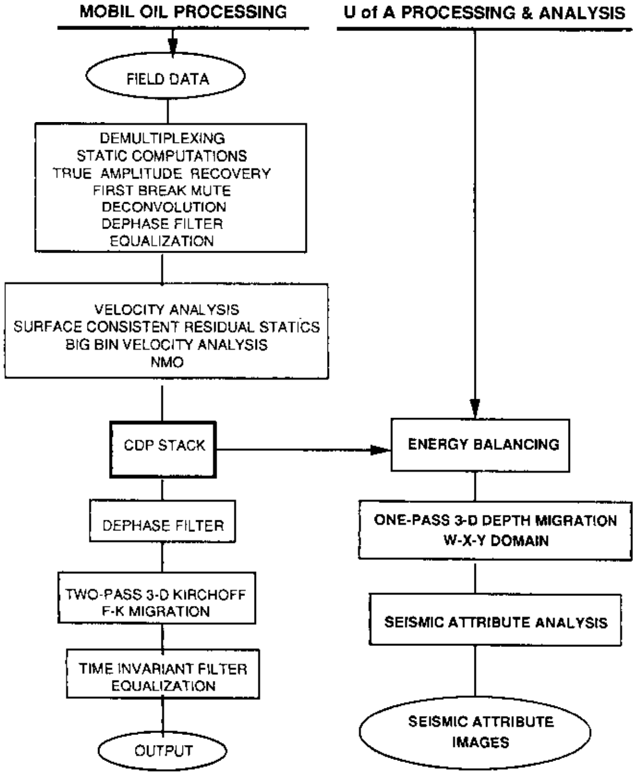


Fig. 7. The processing flows as they were applied on both data sets (base and steam-monitor) by Mobil Oil and the Seismology Laboratory, University of Alberta.

3-D depth migration of the energy balanced stacked data

3-D depth migration of the energy balanced stacked data volumes (base 1987 and steam 1988) was performed in order to generate seismic images with higher spatial and vertical resolution. Also, since we depth migrate the data the resultant seismic sections are in depth thus avoiding time to depth conversions and making the interpretation process easier. We used a one-pass 3-D depth migration algorithm (Kalantzis, 1994) with a small extrapolation step of 1 m which produces migrated images of high vertical resolution. both data sets were migrated using the same velocity model in order to preserve the differences in amplitude and time/depth of reflectors within and below the steam-heated reservoir. The migration was performed on 44 processors of a Myrias SPS3 parallel computer. The CPU time required for the migration (including I/O and FFT) of each data volume (90 x 73 CDPs and 1501 time samples) using 1500 depth steps and 250 frequencies was 9.16 hours.

SEISMIC ANALYSIS

Prior to any processing we analyzed the stacked data. Inline 12, from both stacked volumes (base 1987 and steam-monitor 1988), is shown in Figure 8. At the time of the monitor survey only two (16, 18) of the five wells along inline 12 were still steaming. We observe clearly the amplitude anomalies (bright spots) associated with the steam injection when the monitor inline 12 is compared with the base. Furthermore, time delays are easily observed on the monitor for the reflectors below the reservoir (Sparky Sands between 0.375 and 0.4 s). This delay is more evident for the Devonian reflector (at about 0.5 s) and it is about 6 ms. Also, this is clearly seen when time slices from both base and steam data volumes are compared (Figure 9).

Seismic analysis (differencing) of the Colony which is above the reservoir showed amplitude changes and time delays thus, indicating that effects other than the steaming ones exist. Therefore, the changes that are observed on the reflectors within and below the reservoir are due to the combined steaming effects with others such as source changes and variations in the water table. Therefore, it is necessary to energy balance, to correct for the effects not related to the steaming process. Instead of comparing travel time maps that are referenced to the surface we should compare isochron

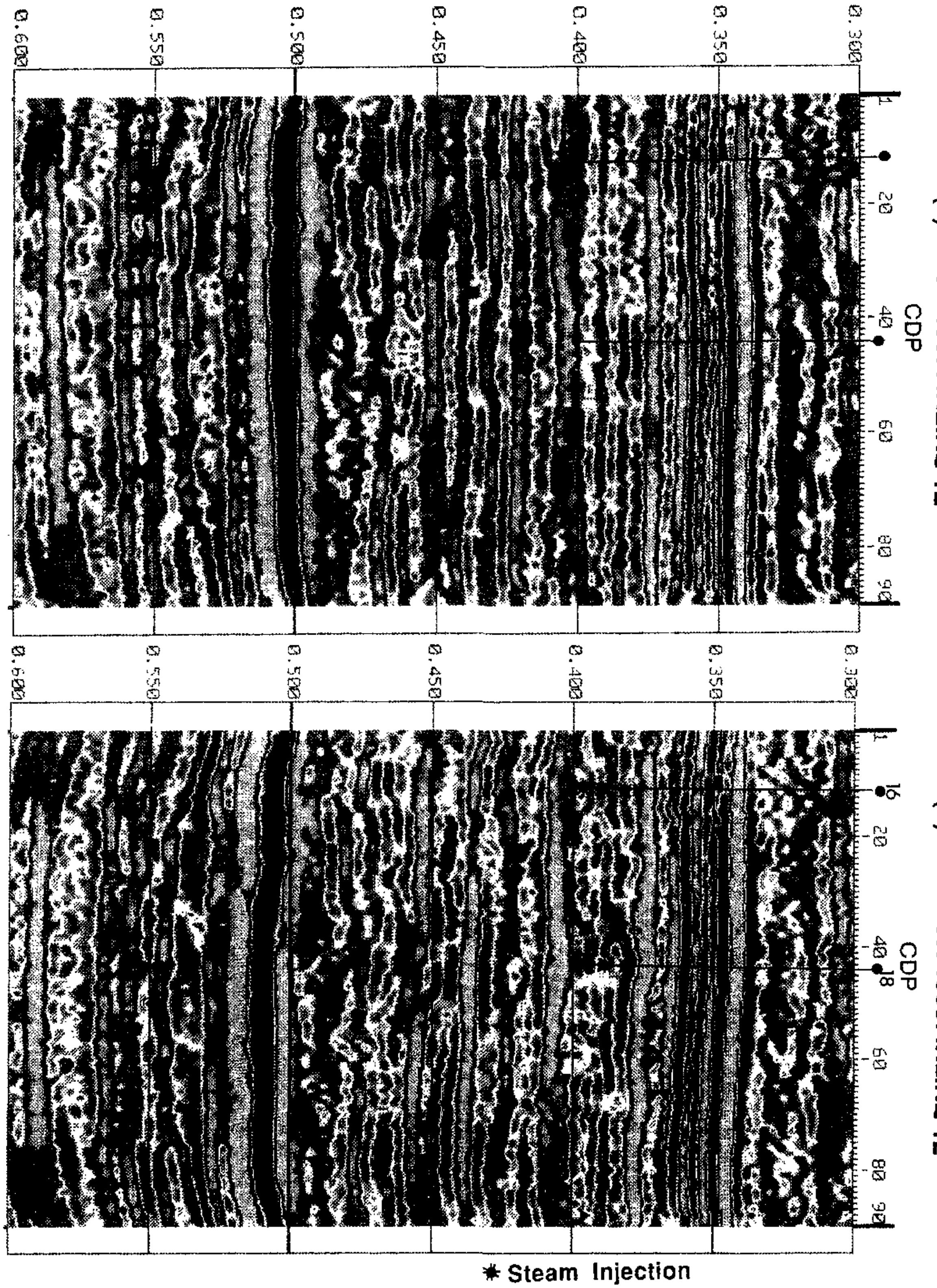


Fig. 8. The inline 12 from the stacked data sets: (a) base and (b) steam-monitor.

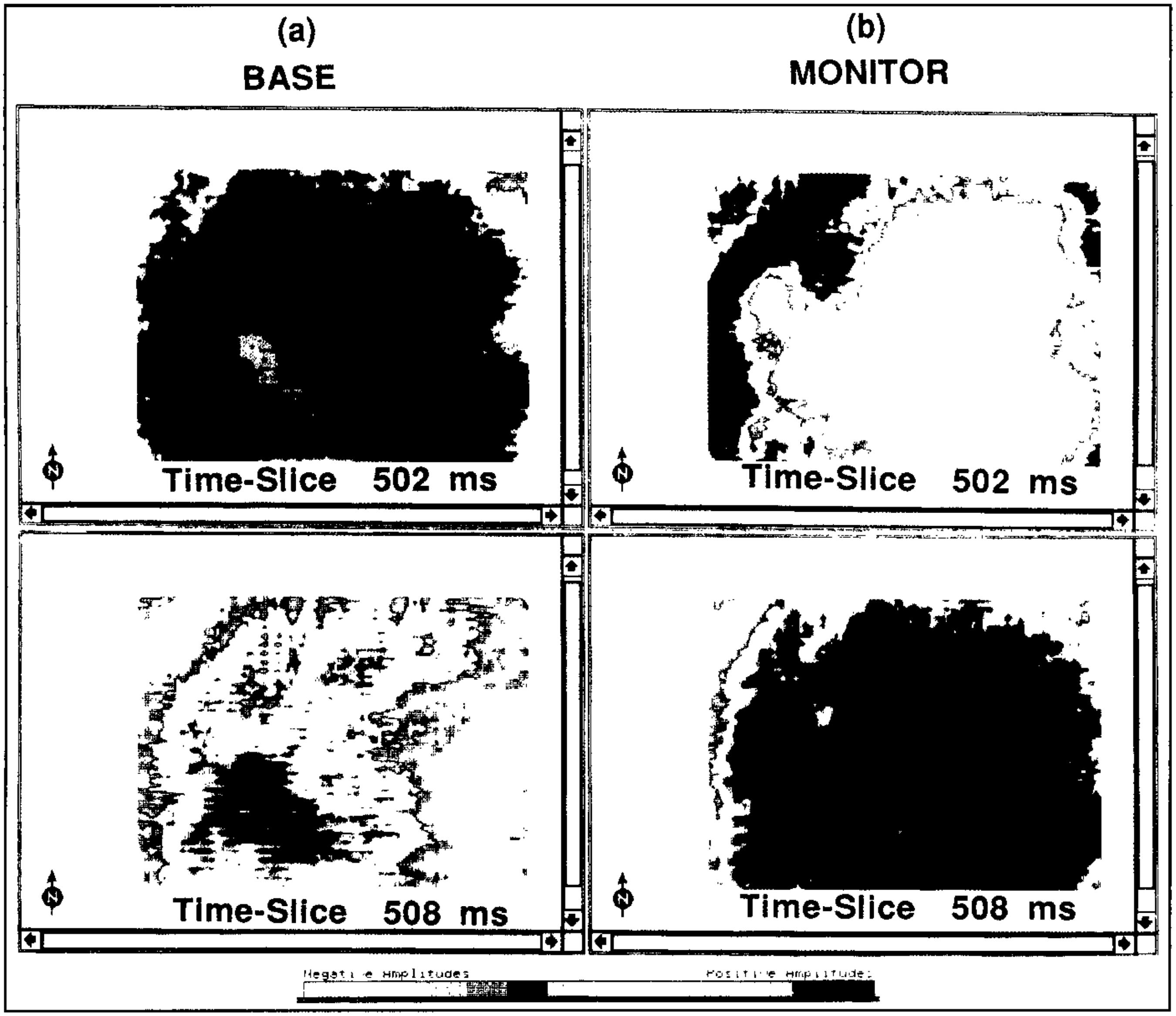


Fig. 9. Time slices from the stacked data volumes: (a) base and (b) steam-monitor.

maps which are referenced to the Colony, in order to remove time delays that are not due to the steaming effect.

The Devonian reflector was interpreted on both energy balanced stacked data volumes. The amplitude difference (Figure 10a) between the two horizon slices (monitor-base) show that the Devonian has dimmed during steaming. The main anomaly is in agreement with the stress field in this area thus suggesting that most of the steam is moving through preexisting fracturing paths. On the other hand, the difference between the Devonian isochron maps (taken with respect to the Colony as each survey) from the base and steam surveys show a large time delay (Figure 10b). This time delay correlates with the steaming wells at the time of the monitor survey (wells 16, 18, 13, 3, 6). However, the major time delay anomaly (blue colour, ~5 ms) does not correlate with the amplitude anomaly very well.

Next, we analyzed the depth migrated data volumes. In Figure 11 the inline 12 from both the base and steam migrated data is shown. The effect on the seismic reflections of the steam injection is present on the monitor inline 12 when compared to the base one. The amplitude of the reflectors within the Sparky reservoir in the vicinity of the steaming wells is increased, especially notice the bright spot around CDP 40. Furthermore, we observe changes in the seismic signature such as amplitude decreases and depth pushdowns. For example, the Devonian shows an apparent depth pushdown in the steam data.

The Upper Sparky (about 355 m) horizon was interpreted on both base and monitor-stream depth migrated data volumes. The isopach maps generated with respect to the Colony (above the reservoir) were differenced (Figure 12). The resultant apparent depth difference (pushdown) shows an anomaly that is mostly concentrated in the east side of the pad. However, pushdowns are observed in the vicinity of all steaming wells (16, 18, 13, 6, 3). Additionally, the difference

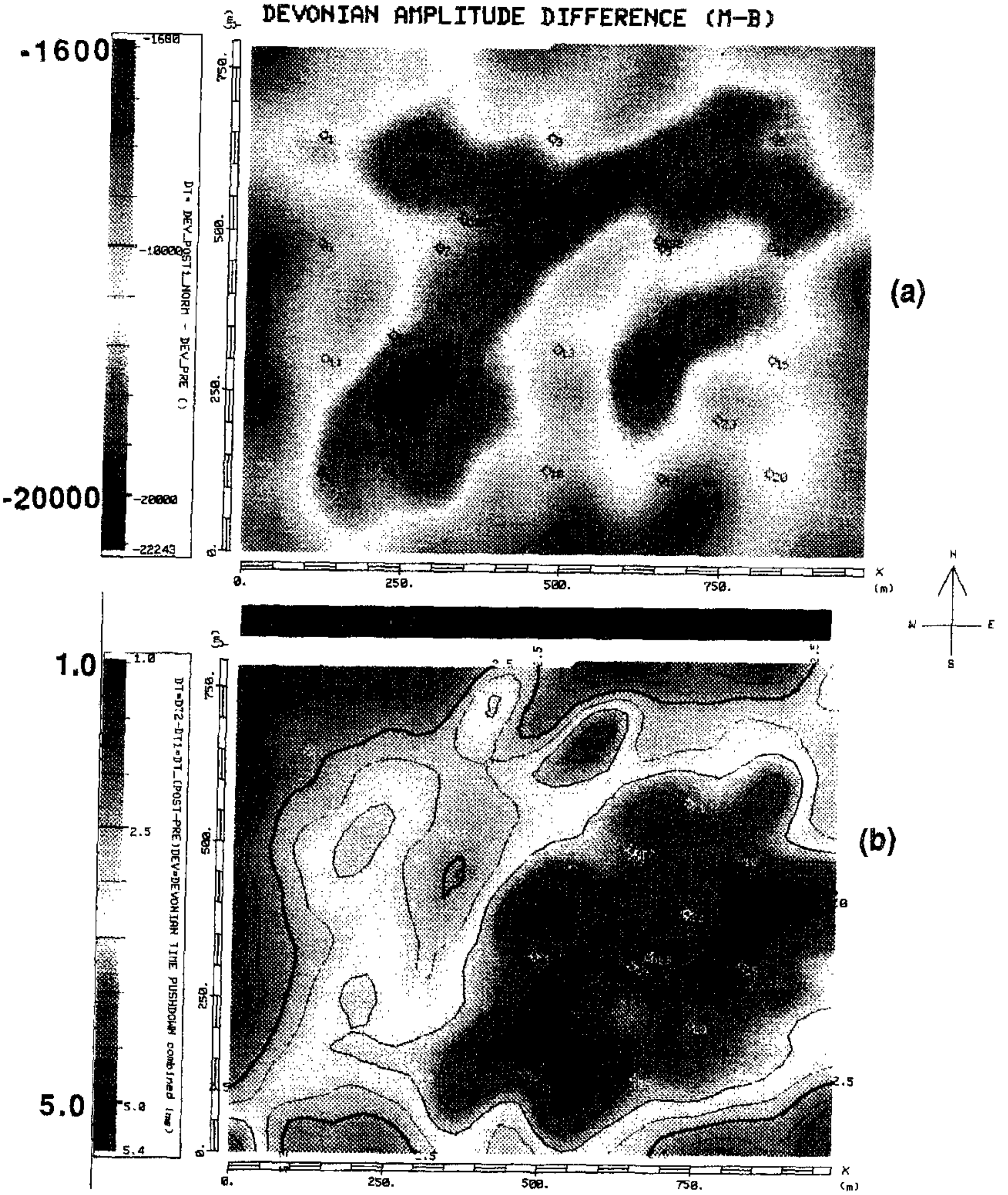


Fig. 10. The Devonian horizon from the stacked data after normalization: (a) the amplitude difference and (b) the time delay (pushdown) between monitor and base surveys.

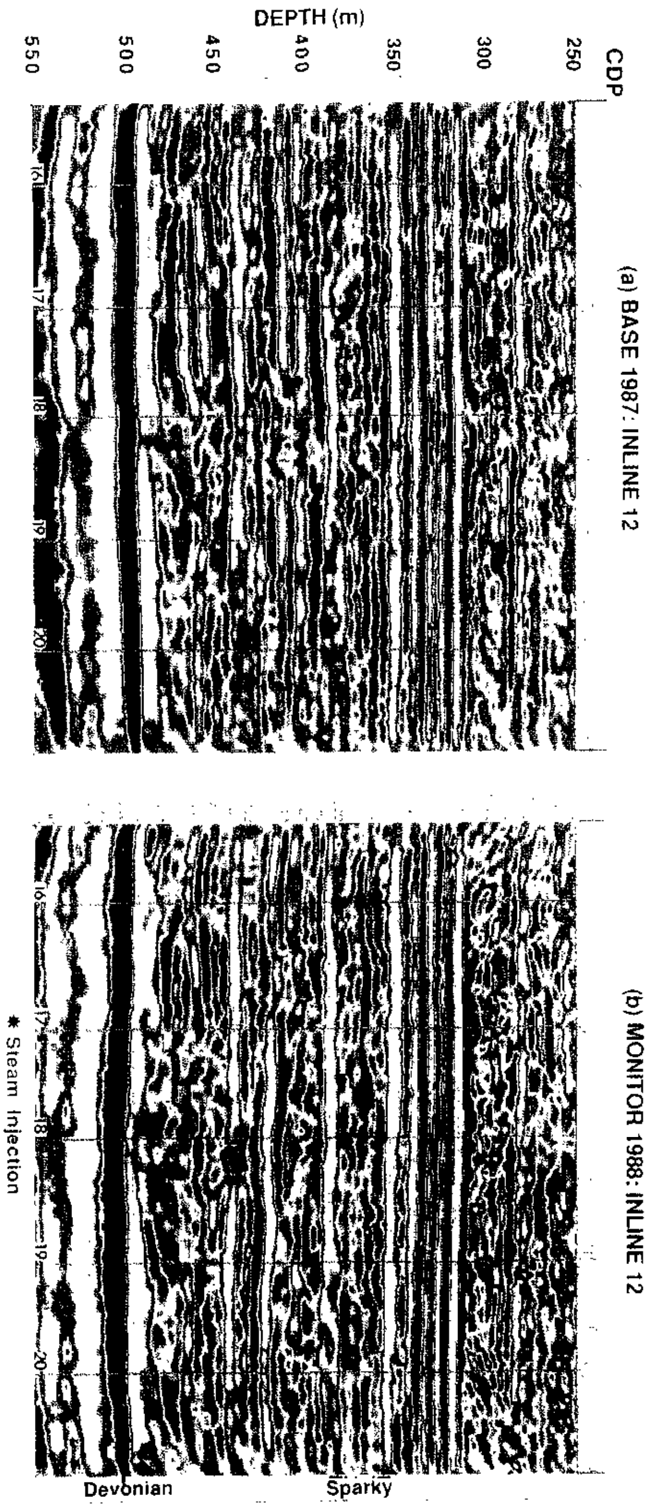


Fig. 11. The inline 12 from the depth migrated data: (a) base and (b) steam-monitor surveys.

between the base and steam horizon slices shows anomalies associated with the steaming wells. These semicircular anomalies only show up on our own balanced and migrated data sets and the tests we have performed do not indicate that they are 3-D migration artifacts. It is tempting to associate them with movement of an expanding steam front but additional field examples will need to be obtained to validate this hypothesis.

In addition to the above analysis, other horizons such as the Middle Sparky, the GP kick and the Clearwater were interpreted. Seismic attribute analysis, such as travel time and amplitude differencing, generated seismic images (not presented here) that show anomalies that correlated well to the pressure states of the wells and were in agreement with the anomalies discussed above.

DISCUSSION OF RESULTS AND CONCLUSIONS

High resolution realistic models (velocity, density) for Mobil Oil's vertical pilot site were generated before and after underwent cyclic steam stimulation for bitumen recovery for the Cold Lake oil sands. These models were generated by successfully integrating all available information such as sonic and density logs, 3-D seismic data, geologic data and reservoir engineering data from observation wells. 2-D acoustic and elastic wave simulations were carried out for these models. The generated synthetic seismic data resolved the geological structure and displayed calcified tight streaks in the oil sands reservoirs. These tight shales are of critical importance for the oil recovery process since they act as permeability barriers that impede vertical migration of the steam. Furthermore, the resultant realistic seismic sections show the effects on reflections within and below the Sparky reservoir due to the presence of an expanded steam-heated zone.

The analysis of the stacked data showed effects on the seismic attributes that were not related to the steam stimulation only thus dictating the need of the energy balancing between the base and monitor surveys. This processing was performed on the 3-D seismic data and it removed almost all the effects not associated with the steam stimulation. The high resolution images from the balanced stacked data and the depth migrated data showed seismic anomalies such as time delays, depth pushdowns, velocity decreases, and amplitude changes, that are associated with the expanding steam-heated zone during the steam injection phase and the gas presence during production. Also, these anomalies imaged the expanding steam front and suggested areal and vertical conformances. Furthermore, these anomalies were well correlated to the areal location of the pressure and temperature states of the wells on the pads. This suggests that the anomalies on the seismic signature, imaged from the seismic analysis of the monitoring data (base, monitor steam), are the combined result of a decrease in the effective stress, a temperature increase, and gas reduction during the steam phase with respect to the base.

Overall, the generated seismic images correlate well with the observed field performance behavior. However, a quantitative correlation is required in order to obtain estimates of

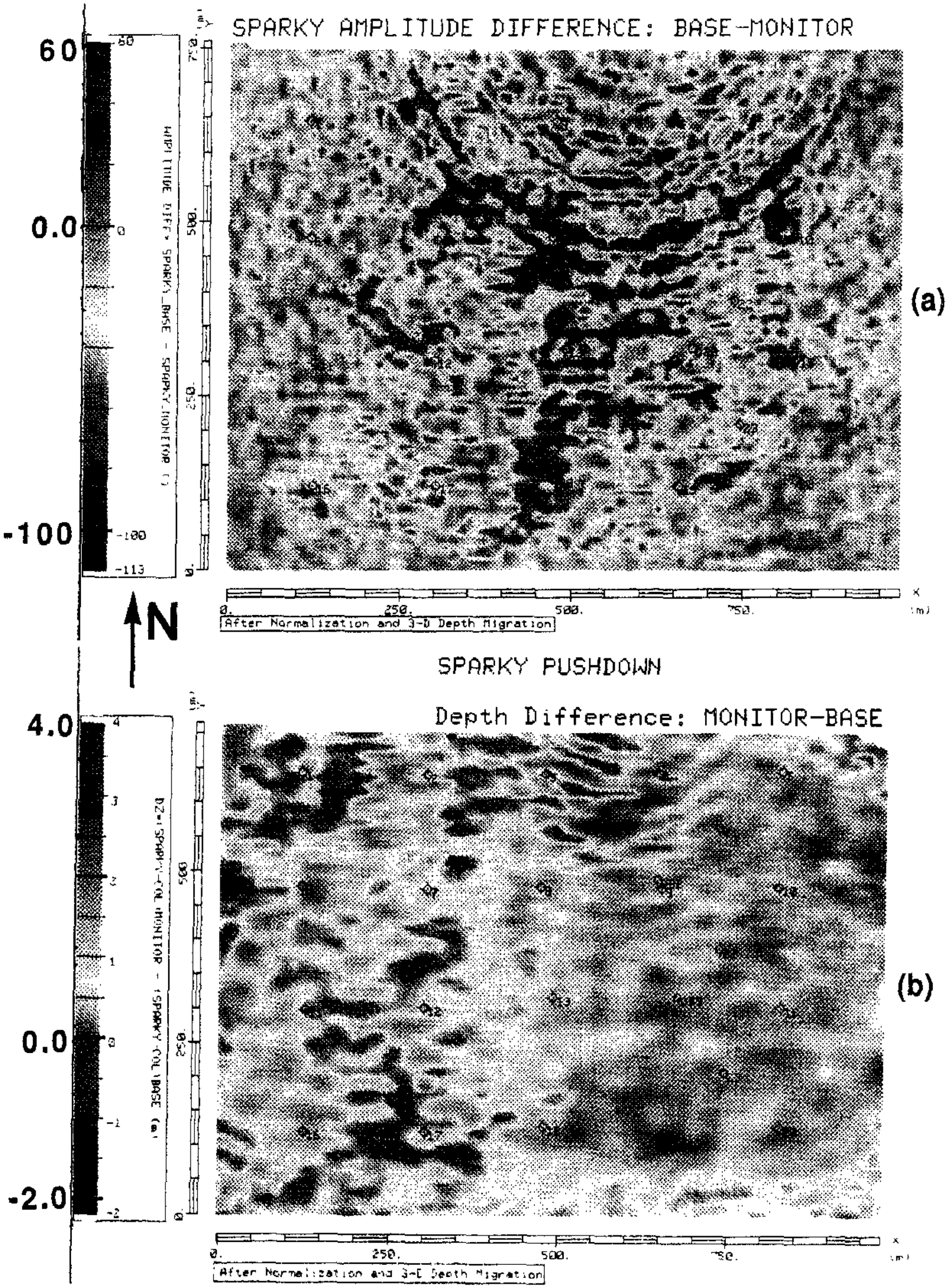


Fig. 12. The Sparky horizon from the depth migrated data: (a) the amplitude difference between base and monitor and (b) the apparent depth push-down between monitor and base.

reservoir properties such as saturation and permeability from the above seismic images. This may be possible with the utilization of geostatistical estimation methods such as co-kriging. Ideally, seismic surveys should have been conducted over shorter time intervals (e.g., 4 to 6 month intervals) to enable better forecasting of the steam front movement, and to assist in the balancing of reservoir voidage at the production wells in attempt to exercise some control over the reservoir sweep mechanism.

The reported results imply that reflection seismology may be used to map the spatial heterogeneity of porosity and permeability, detect anomalous pore pressure and its temporal variations, detect subsurface fractures, track thermal fronts, monitor the movement of gas caps and track the steam front in steam stimulation. 3-D high resolution surface seismic time-lapse monitoring is a feasible and potentially powerful technique that can be used for the design and efficient management of the thermally enhanced oil (EOR) recovery from the enormous reserves in the tar sands at Cold Lake, Alberta.

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