Seismic methods in heavy-oil reservoir monitoring

Duojun A. Zhang and Laurence R. Lines

ABSTRACT

Laboratory tests show that a significant decrease in acoustic velocity occurs as the result of heating rock samples saturated with heavy hydrocarbons. Therefore, it is possible for us to monitor reservoir characterization during the process of thermal recovery of heavy-oil resources by repeated reflection seismic surveys. To describe the reservoir characterizations, it is imperative that the field data have an extremely good signal-to-noise ratio over a broad frequency band. Specialized acquisition and processing techniques should be used in seismic baseline and monitoring surveys. Some effective seismological methods in monitoring the subsequent subsurface steam movement or injection effect, such as seismic velocity models, isochron analysis, amplitude analysis, frequency attenuation, time-lapse and converted-wave exploration, are summarized from the referenced published papers. All these technologies yield significant new insights about the reservoir parameters, thus leading to a better understanding of the patterns of the heat-front movement. The integration of these into the design and operation of steam injection projects should help in improving their future viability.

INTRODUCTION

Vast resources of untapped tar sands and heavy-oil reserves are waiting to be developed when the technology becomes available to mobilize this highly viscous hydrocarbon both efficiently and economically. A good deal of the ultimate success of heavy oil in-situ thermal recovery is necessarily related to preliminary knowledge of the reservoir's characteristics, together with reliable imaging of the subsequent subsurface heat movement throughout the life of the project. What kind of contributions can seismic techniques make in this process? Buyl et al. (1989) demonstrated optimum field development with seismic reflection data; Lines et al. (1990) introduced a method to make seismic velocity models for heat zones in Athabasca tar sand; Matthews (1992) described 3-D seismic monitoring of an in-situ thermal process; Eastwood (1993) made comparisons of theory and experiment on temperature-dependant propagation of P- and S-waves in Cold Lake oil sands; Eastwood et al. (1994) discussed seismic monitoring of steam-based recovery of bitumen; Isaac (1996) researched seismic methods for heavy oil reservoir monitoring; Watson et al. (2002) discussed heavy-oil reservoir characterization using elastic wave properties; Greaves (1987) analyzed the 3-D seismic monitoring of an enhanced oil recovery process. To play an important role in proceeding reservoir characterization and monitoring, high-resolution and high signal-to-noise-ratio 3-D seismic data is required. Pullin et al. (1987) presented techniques that they applied to obtaining very high-resolution 3-D seismic imaging at an Athabasca tar-sands thermal pilot.

DATA

In this summary, three monitoring projects in three different locations are referenced. One is on the Gregoire Lake In-situ Steam Pilot (GLISP) site, designed to test a steam stimulation process. The well configuration consists of a central injector, H-6, surrounded by three equidistant producers (H-3, 4, and 5), and three observation wells (HO-7, 8, and 9). The pilot location and well pattern are illustrated in Figure 1. Four high-resolution 3D seismic surveys were conducted. Figure 2 illustrates the well configuration and associated recording geometry. The survey area was 168 by 196 m with 4 m by 4 m CMP bins. Acquisition resulted in a minimum of 12-fold coverage except near the perimeter of the pilot area. The down-hole seismometer locations are designated by the symbol "+" and shot points by the symbol "X". Field acquisition of the baseline 3-D survey was conducted in April 1985. Monitoring survey 1 was acquired in January 1987 after a four-week steam and soak period at the three production wells, H-3, 4 and 5. At the conclusion of monitoring survey 1, the central injection well, H-6, underwent a short period of hot water injection before being converted to steam. By the time the second 3-D monitoring survey occurred in April, steam had been injected continuously into H-6 for 10 weeks. Monitoring survey 3, recorded in early November 1987, was completed after another period of continuous steam injection in the central well. The processing sequence employed was identical to that used for the baseline 3-D survey in order to minimize the creation of artificial differences not heat-related.

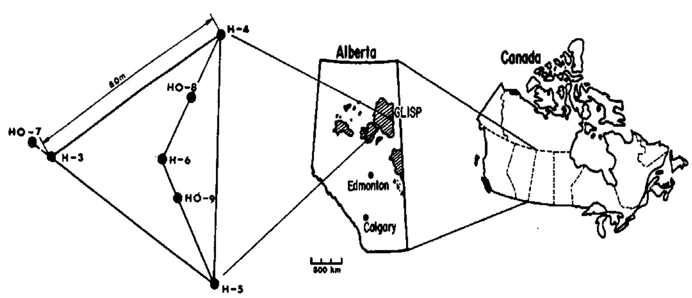


FIG. 1. GLISP pilot site location and well configuration (from Matthews, 1992).

The second monitor project was in the Cold Lake region of Alberta (Figure 3), where a recovery process, cyclic steam stimulation (CSS), was used to commercially produce bitumen from the Clearwater Formation. Figure 4 indicates the location of 15 CSS wells and six observation wells, and the area covered by the analyzed 3-D seismic data. The first survey was shot in April 1990, during the sixth CSS production cycle. During production, reservoir conditions are at a local minimum in terms of both temperature and fluid pressure while gas is present in the region immediately surrounding the well-bore due to phase equilibrium conditions. The second survey was shot in January 1992 during the eighth CSS steam injection cycle. During steam injection, reservoir conditions are at a local maximum in terms of both temperature and fluid pressure. During injection, the gas zone is smaller than during production due to the extremely high ambient pressure in the reservoir.

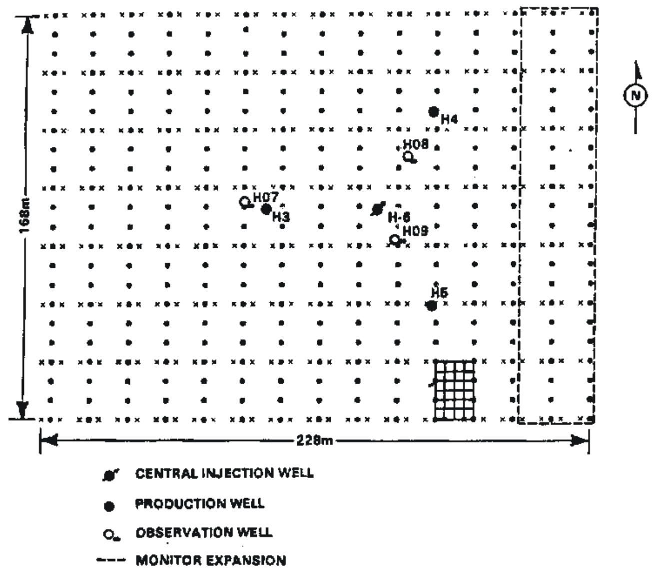


FIG. 2. Plan showing well configuration, source and receiver locations, and a portion of the stacking cell grid (from Matthews, 1992).

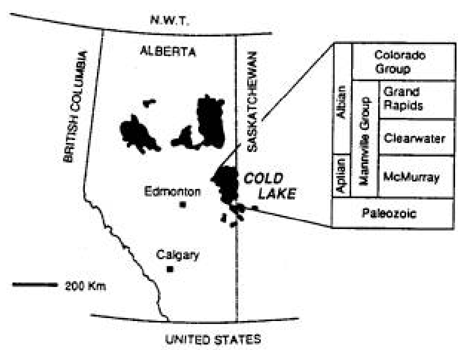


FIG. 3. The Cold Lake region of Alberta (from Eastwood et al., 1994).

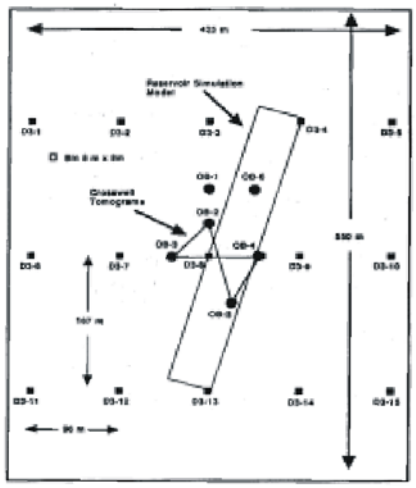


FIG. 4. Site map for the monitoring program (from Eastwood et al., 1994).

The third monitor project was at Pikes Peak Field, a prolific heavy-oil field just east of the Alberta-Saskatchewan border that has been operated by Husky Energy since 1981. Figure 5 shows a map of the field and 29 north-south seismic lines (100-m apart) that Husky acquired in a 2-D seismic swath survey in 1991. To investigate time-lapse effects, the University of Calgary, with AOSTRA funding, and Husky returned to the field in March 2000 to acquire a repeat line on the eastern side of the field. Four types of data were collected: P-wave, SV-wave, SH-wave, and experimental surface microphone data. The original and repeat seismic data were processed simultaneously using similar workflows. Both surveys were conducted in the winter, possibly minimizing ground-coupling differences. The time-lapse lines are referred to as H1991 and H2000. H2000 extends to the north beyond H1991.

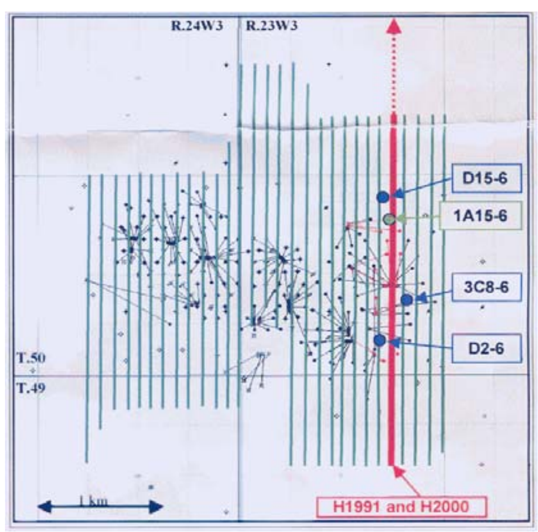


FIG. 5. Map of wells and seismic coverage at Pikes Peak (from Watson et al., 2002).

3-D SEISMIC ACQUISITION

In order to achieve the required seismic expression for describing the reservoir characterizations, it is imperative that the field data have an extremely good signal-to-noise ratio over a broad frequency band. A high-resolution, 3-D seismic base survey was conducted at Amoco's Gregoire Lake In-situ Steam Pilot (GLISP) located in northeastern Alberta, Canada. Field-test results demonstrated that by using buried seismometers and very light charges (both located beneath the muskeg), a dramatic improvement in overall quality and high-frequency content of the data was achievable when compared to standard recording techniques (Figures 6 and 7). Test results indicated that the most important field parameters were: (1) Seismometer depth: should be buried below the muskeg; (2) Charge size: should be small (1 to 50 g); (3) Recording offset: should be beyond the noise train. Based on this testing, a 3-D survey was designed and acquired which resulted in excellent high-resolution data. The following recording parameters for the 3-D survey were optimal:

- Seismometer depth — single SM-11 (30Hz) cemented at 13-metres depth;
- Charge size — 18 g in cement at 18-metres depth;
- Recording offset — 50–150 metres;
- CDP multiplicity — 6–12 fold.

The final processing flow was established after extensive parameter testing. The most significant steps were Q-compensation for attenuation losses caused by dispersion, surface-consistent deconvolution, 3-D post-stack migration, and bandpass frequency filtering. After diligent quality control and the use of advanced processing techniques, signal frequencies up to 220 Hz were recovered on the final stacked data (Figure 8).

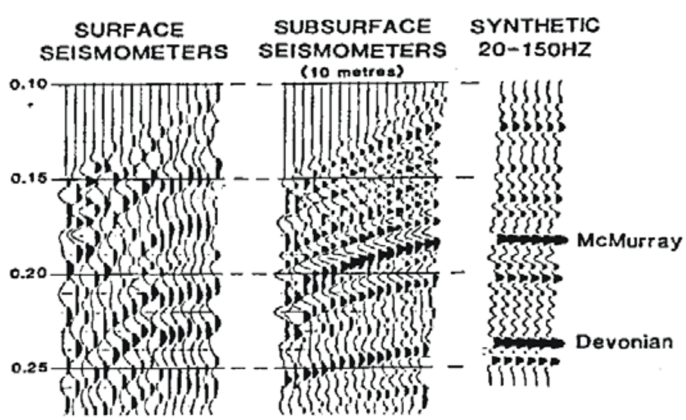


FIG. 6. Comparison of synthetic with surface and subsurface field profiles (from Pullin et al., 1987).

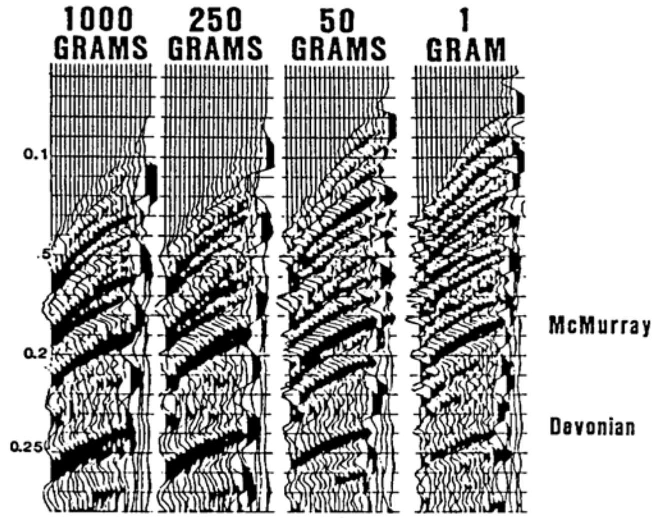


FIG. 7. Shot records (buried seismometers) for different charge sizes (from Pullin et al., 1987).

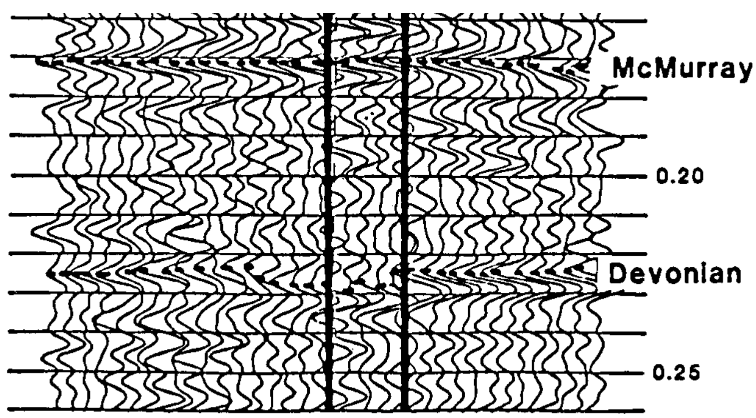


FIG. 8. Migrated section extracted from final processed 3-D data volume (from Pullin et al., 1987).

SEISMIC VELOCITY MODELS

The experiments indicated that observed velocities were most affected by changes in fluid properties due to temperature (Figure 9; Eastwood, 1992). Rock property measurements made on core samples from the GLISP site showed that tar sands can have a velocity of 2800 m/s at 25℃, and a velocity of 2000 m/s at 100℃ (Figure 10; de Buyl, 1989). So the velocity model can be used to delineate the effects of steam injection.

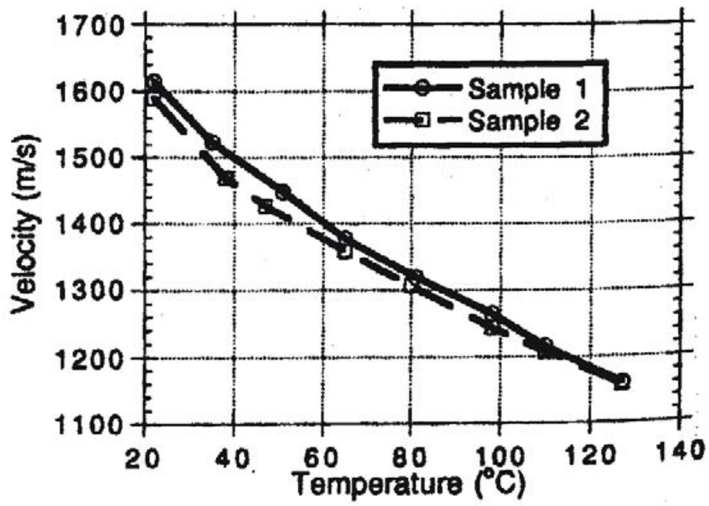


FIG. 9. Measured velocities in two Cold Lake bitumen samples (from Eastwood, 1993).

The updated velocity map (Figure 11) demonstrates that the velocity near injector wells (marked with dots) has been lowered by the temperature increase due to steaming (the reservoir layer velocity prior to steam injection is 2400 m/s). Following the injection of steam into the triangular pattern of wells in Figure 11, steam was then injected into a central injector well equidistant from the original three injector wells (Figure 12). A second seismic monitoring survey was completed, and the traveltime inversions for velocity were computed. The velocity decrease for this model exhibits an excellent correlation with the location of four injector wells. A general decrease in reservoir velocity in the area around all four injector wells suggests that there was a gradual heating of all reservoir sands in the survey area. The regions of lowest velocity show an excellent agreement with the locations of steam injection. These results suggest that repeated reflection seismic surveys can delineate lateral velocity variations due to steam injection.

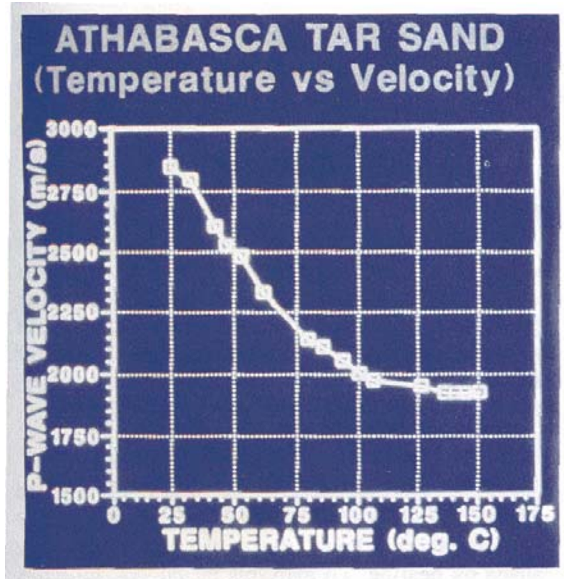


FIG. 10. Representative velocity-versus-temperature profile (from Matthews, 1992).

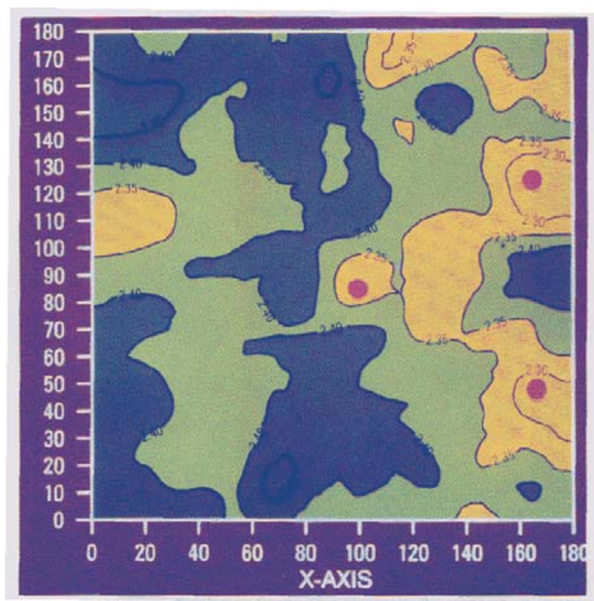


FIG. 11. Map of the tar-sands velocity model from monitoring survey 1 (from Lines et al., 1990).

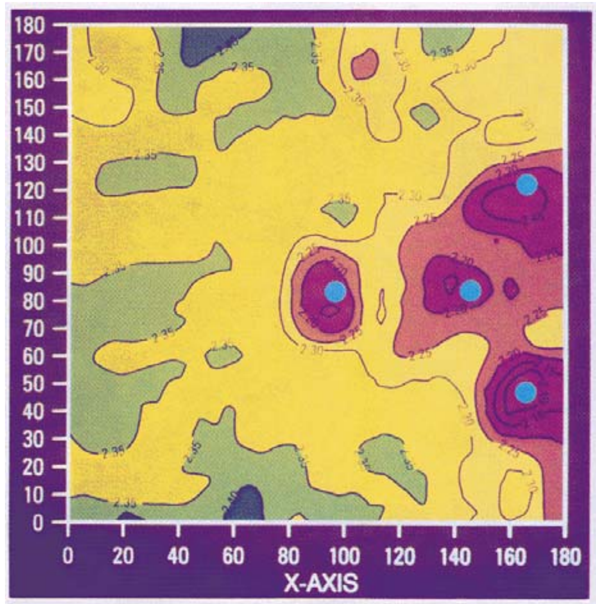


FIG. 12. Map of the tar-sands velocity model from monitoring survey 2 (from Lines et al., 1990).

ISOCHRON ANALYSIS (PUSHDOWN MAPPING)

If the seismic wavefront travels through a heated interval, then all the reflections from horizons below this interval are delayed, due to the velocity decrease caused by heating. Delay-time maps can be generated between the baseline survey and monitoring survey by mapping horizons above and below the reservoir on both surveys, and subtracting the isochron map of the baseline survey from the isochron map of the monitoring survey, as described above in the "Seismic velocity models" section.

Decreasing velocity in the reservoir formation will increase the ratio of the isochron map of the monitoring survey to the isochron map of baseline survey (Figure 13). The three wells on the left (1D10-6, 2B9-6, and 3B8-6) were drilled between the surveys; the ratio rises above unity in this section of the line. Conversely, the ratio drops below unity along the portion of the line where the older producers (3C1-6, 1D2-6, and 3B1-6) were more active in 1991 than in 2000. More heat and steam were present in this portion of the reservoir in 1991 and are responsible for the ratio reversal. These results suggest that compressional velocity is sensitive to more than just the steam zone radius around the well. The total area of the heated reservoir also affects V_p.

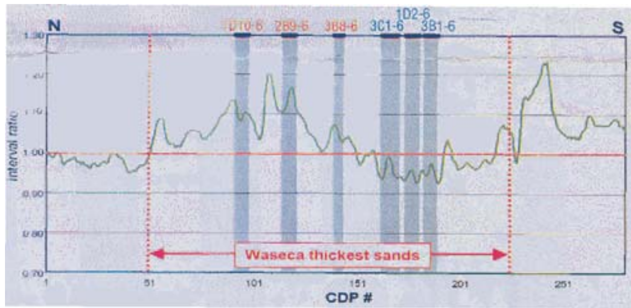


FIG. 13. H2000/H1991 ratio of Waseca interval traveltimes for P-wave arrivals (from Watson et al., 2002).

AMPLITUDE ANALYSIS

Seismic amplitude is directly proportional to the change in acoustic velocity and density at an interface. Further, as the reservoir sands are heated, the velocity decreases by an amount directly related to the magnitude of the temperature change. Taken together, these phenomena mean that a heated zone, if thick enough, should show a change in seismic amplitude when compared to the base pre-steam survey (Figure 14). The event at 0.2s on the monitor survey, postulated to be the result of steam injected into H-5, is not as pronounced on the base dataset.

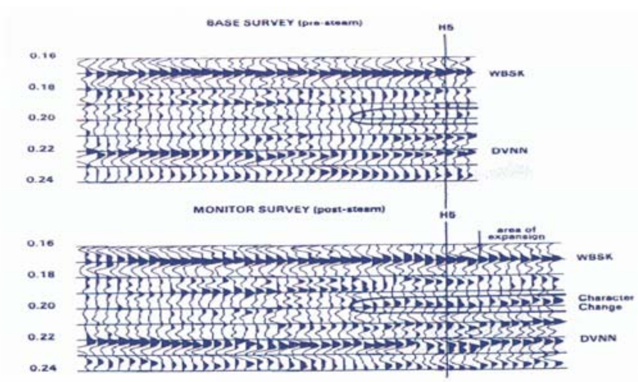


FIG. 14. Seismic amplitude change associated with pre- and post-steam surveys (from Matthews, 1992).

FREQUENCY ATTENUATION

Two time-windows were chosen, above the reservoir and below the reservoir, respectively. Analysis of the spectral data indicated that high-frequency energy surfaces provided the most pertinent information regarding the relative spectral changes between the baseline survey and the monitoring survey (Figure 15). The spectral image for the time window above the reservoir showed good repeatability between the baseline and monitoring survey, the spectral image for the time window below the reservoir showed attenuation for the higher frequencies.

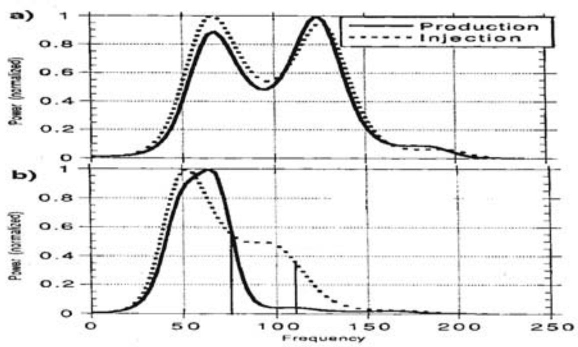


FIG. 15. The spectra above (a) and below (b) the reservoir (from Eastwood et al., 1994).

EFFECTS OF REFLECTIVITY AND IMPEDANCE

Injecting steam into the reservoir formation reduces acoustic velocities, thus increasing traveltime for waves through the reservoir formation, changing impedances of the reservoir formation, and reflectivity coefficients of the top and bottom horizons of the reservoir formation. Therefore, there are observable differences when these attributes are compared between the baseline and monitoring surveys. Figure 16 shows interpreted P-wave reflectivity sections of the baseline and monitoring surveys; Figure 17 shows inversed acoustic-impedance sections of the baseline and monitoring surveys with three impedance logs. Figures 18 and 19 are the difference sections of reflectivity and impedance. The most significant differences in Figure 18 are below the reservoir zone in the area of the production wells. The most significant impedance differences in Figure 19 are in the zone of interest where there is a lower impedance zone.

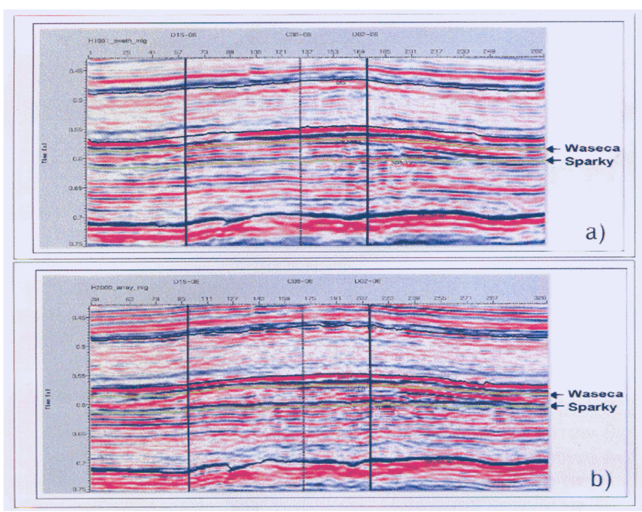


FIG. 16. (a) H1991 interpreted P-wave reflectivity section; and (b) H2000 reflectivity section (from Watson et al., 2002).

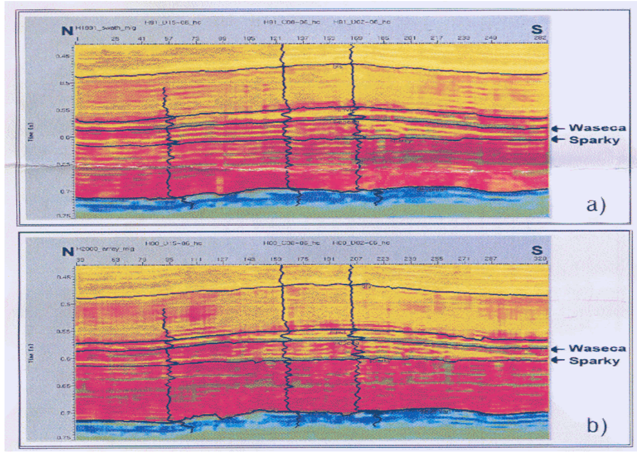


FIG. 17. (a) H1991 acoustic impedance section; and (b) H2000 acoustic impedance section (from Watson et al., 2002).

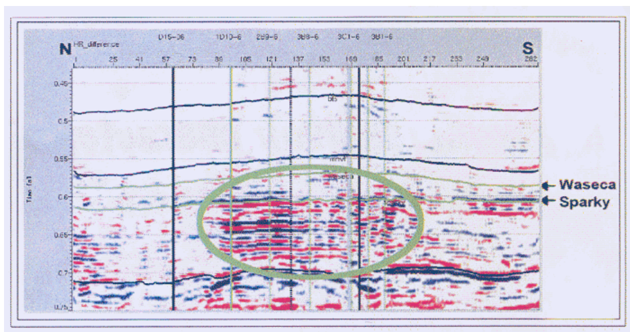


FIG. 18. Seismic reflectivity difference section (from Watson et al., 2002).

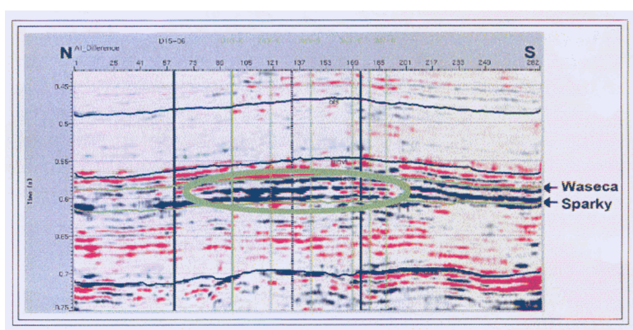
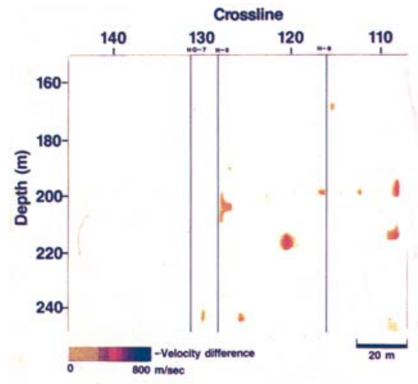
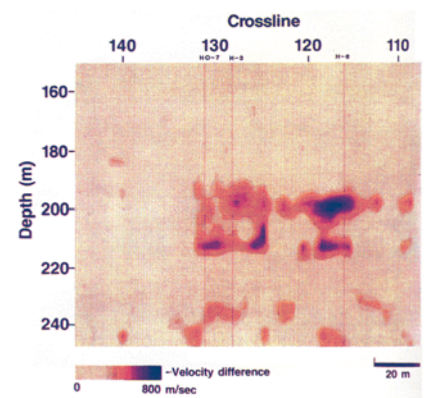


FIG. 19. Acoustic impedance difference section (from Watson et al., 2002).

If simplified assumptions were made about density, velocity can be separated from acoustic impedance. The inverted data volumes for each monitor survey were independently subtracted from the baseline survey. The resulting 3-D volumes of velocity-difference data were sliced by horizontal and vertical planes to reveal the distribution of heat in the subsurface. Figure 20 shows the cross-sections obtained by vertically slicing the velocity difference volumes for monitoring surveys 1 and 2 in an east-west direction, through wells H-3 and 6. The velocity difference section for monitor ing survey 1 indicates that a relatively small portion of the reservoir has been heated. The velocity-difference section for monitoring survey 2 indicates dramatic heating effects. Figure 21 shows the result obtained by slicing the velocity-difference volumes for monitoring surveys 1 and 2 horizontally. In both cases, the distributions of heat over the area correlate well with those obtained independently from pushdown measurements.



a)

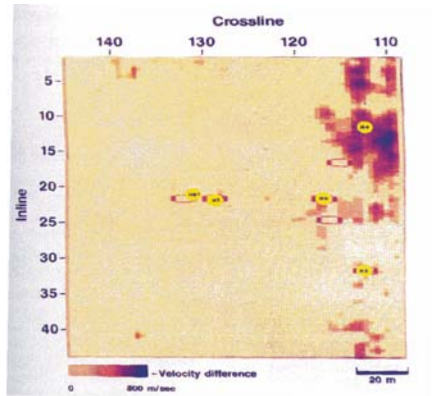


b)

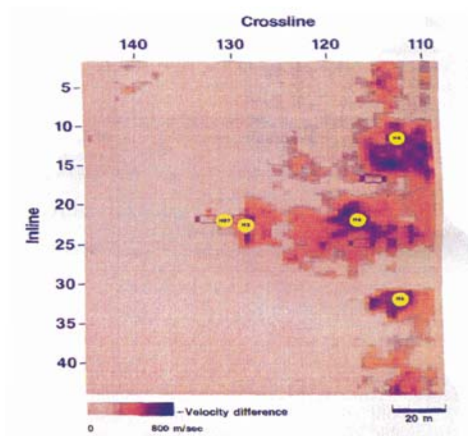
FIG. 20. a) Velocity-difference profile in depth after monitoring survey 1 (from Matthews, 1992); b) Velocity-difference profile in depth after monitoring survey 2 (from Matthews, 1992).

CONVERTED-WAVE EXPLORATION (V_P/V_S)

In the heavy-oil case at Pikes Peak, the addition of steam into the reservoir has the effect of decreasing both V_p and V_s. Core tests on samples from the Waseca interval investigated the effect of temperature on compressional and shear velocities. Figure 22 shows that both decrease with temperature but V_p decreases at a greater rate. Therefore, it is anticipated that steam injection into a sand unit would decrease V_p/V_s.



a)



b)

FIG. 21. a) Velocity-difference depth-slice after monitoring survey 1 (from Matthews, 1992); b) Velocity-difference depth-slice after monitoring survey 2 (from Matthews, 1992).

V_p/V_s analysis was also interpretation based but only used the multi-component data from H2000. The vertical (PP) and radial (PS) components were used and interpreted (Figures 23 and 24). V_p/V_s is calculated using interval traveltimes with

$$V_p / V_s = (2\Delta t_{ps} - \Delta t_{pp}) / \Delta t_{pp}\,, \tag{1}$$

where Δt_{pp} is the traveltime of an interval from the PP section, and Δt_{ps} is the traveltime of an interval from the PS section. Figure 25 is a V_p/V_s plot of the Mannville-Lower Mannville interval. Noise is present but some distinct anomalies can be seen around the wells with the most recent steam injection. In particular the response at 3B8-6 shows a pronounced drop in V_p/V_s. Steam injection was occurring in this well at the time of the 2000 seismic acquisition. The width of the anomaly fits very well with the predicted steam zone radius. At wells 1D10-6 and 2B9-6 there is a smaller response. It had been 12 and 26 months, respectively, since steam had been injected in these wells.

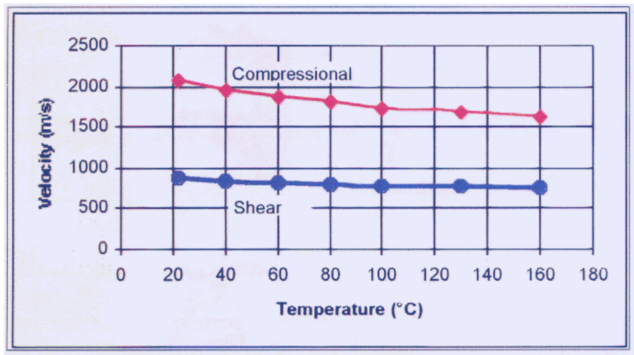


FIG. 22. Effect of temperature on V_p and V_s on a core sample from Pikes Peak (from Watson et al., 2002).

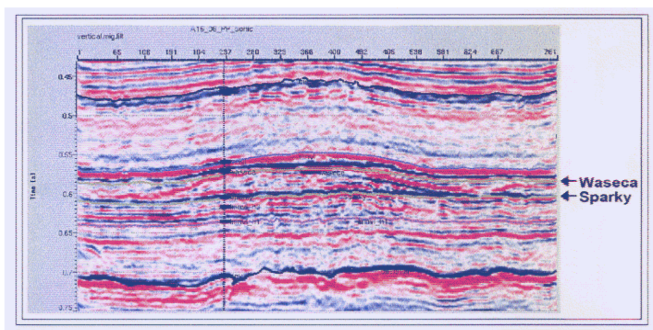


FIG. 23. H2000 interpreted PP section (from Watson et al., 2002).

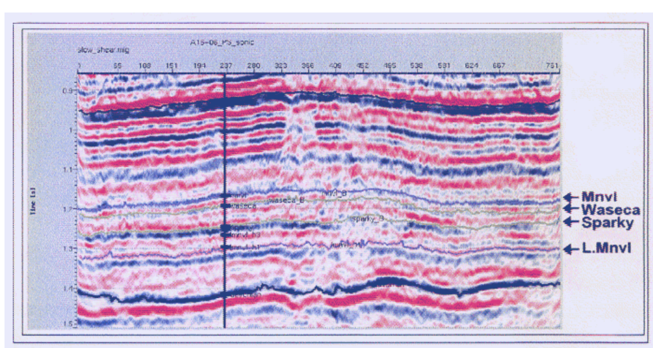


FIG. 24. H2000 interpreted PS section (from Watson et al., 2002).

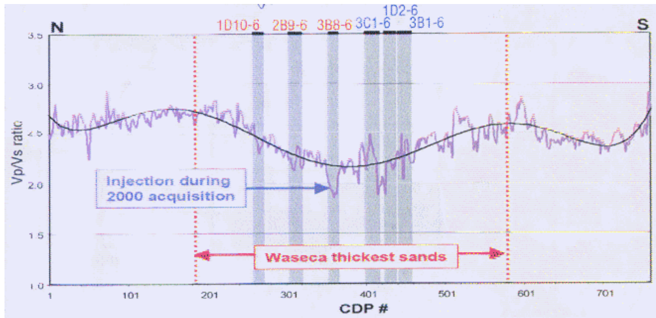


FIG. 25. V_p/V_s plot of reservoir interval (from Watson et al., 2002).

CONCLUSIONS

Laboratory tests shows that a significant decrease in acoustic velocity occurs as the result of heating rock samples saturated with heavy hydrocarbons. The magnitude of this decrease is sufficient to allow seismic monitoring of thermally enhanced oil recovery processes. With careful use of acquisition and processing parameters, repeat seismic surveys can provide valuable information about the effects of steaming operations at a reasonable cost. Velocity models obtained from seismic traveltimes proved to be useful in detecting steam-fronts in tar sands. Isochron analysis provided clues about the extent of the heated reservoir. Amplitude change is also related with the decrease in acoustic velocity, and is another expression of seismic character changes. High-frequency attenuation is the only seismic character change, which is not related with velocity during our discussion. The reflectivity difference shows the effect of increased traveltime of the seismic signal through the reservoir zone. The impedance difference indicates lower impedance in the reservoir zones. With interpreted seismic sections, the V_p/V_s isochron method provides further insight into the effect of steam injection for heavy oil reservoirs. All these technologies yield significant new insights about the reservoir parameters, thus leading to a better understanding of the patterns of the heat-front movement. The integration of this data into the design and operation of steam injection projects should help in improving their future viability in enhanced heavy oil recovery.

ACKNOWLEDGEMENTS

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