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SAGD Production Monitoring by Seismic Refraction

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Summary
Bitumen production monitoring is used to optimize production but a compromise has to be found between the cost of the monitoring techniques and the value of the added information. Different monitoring techniques exist from in-well monitoring to 4D-seismic and surface deformation monitoring. 4D seismic is unique as it gives a spatial view of the growth of the steam chamber but is quite expensive. Refraction seismic could be a cheaper alternative although less precise. Seismic modeling was performed to assess the possibility to detect a steam chamber using refraction. Modeling suggests that refraction seismic should allow detecting and locating a steam chamber and assessing its thickness with a fair accuracy. 3D real reflection seismic data were also reviewed to identify the presence of refracted energy.

Introduction
Alberta Oil Sands contain huge amount of hydrocarbons in the form of extra heavy oil or bitumen. Solid bitumen is produced by Steam Assisted Gravity Drainage (SAGD), whereby injected steam transfers its heat to the bitumen. The melted bitumen and condensed water are driven toward the producer by gravity. The injector and producer wells are horizontal and parallel. Ideally the steam is expanding homogeneously along and above the well pair.

Understanding how the steam chamber is expanding will help adjust the injection and production pressures and flow rates and ultimately optimize the production and run safer operations.

Different techniques may be used to monitor the production: well head and bottom hole pressure and temperature are commonly monitored. Temperature and sometimes pressure are permanently recorded in a limited number of vertical observation wells. Temperature logs will show when the steam chamber is closing or has reached the observation well. Wireline logs such as saturation logs may give a finer picture of what fluids are behind the casing. All these techniques give local however important informations.

Spatial extension of the steam chambers may be monitored by a variety of techniques: optic fibers in production wells, surface deformation measurement, and 4D seismic.
Optic fiber in production wells such as DTS may record temperature all along the reservoir and show producing zones. This is very useful information to improve conformance of the steam chamber. However most of the currently operationally available fibers resist only a few months to temperatures of 250°C and require work-over to be replaced.
Surface deformation monitoring may be performed either by conventional leveling measurements, remote controlled surface tilt measurement, or measurement by satellite radar interferometry (Dubucq *et al.,*2008). Surface deformation measurement may be very useful to detect steam excursion in the reservoir overburden and potentially prevent steam release to the

surface. Careful protocol and set-up is required to get reliable measurements and to filter noise. Surface deformation data may be used to infer the steam chamber location and geometry; this requires a geomechanical model of the subsurface and to be able to compute the reservoir strain from the surface deformation.
4D reflection seismic was used in a number of cases to monitor the steam chamber expansion (Nakayama *et al.* 2008, Byerley *et al.* 2009). Repeated seismic is the only technique that give a 3D view of the steam chamber expansion. It can be used to detect when and where a steam chamber is reaching a thief zone, where the steam chamber is, the coalescence of steam chambers, … 4D seismic is the best imaging technique but acquisition is often limited to winter when the ground is frozen; it requires careful set-up and processing and is quite expensive;. For these reasons 4D may not be envisaged for full field monitoring.

We therefore tried to find alternative approaches to detect, locate and assess the size of the steam chambers. Refraction seismic is a possible alternative. It will not give an image of the subsurface but will highlight the velocity variations related to the presence of underground steam.

Theory and/or Method

Refraction seismic is well known for the measurement of near surface seismic velocities. It is also used combined with surface resistivity measurements. In that case refraction seismic is used to define boundaries that will constrain the resistivity computation for the surface measurements. It was also used in the past to define at a large scale the main seismic boundaries.

Seismic refraction is generally applicable only where the seismic velocities of layers increase with depth (See Fig. 1). Seismic refraction involves measuring the travel time of the component of seismic energy which travels down to the top of a fast layer, is refracted along the top of that layer, and returns to the surface as a head wave. The waves which return from the top of rock are refracted waves, and for geophones at a distance from the shot point, always represent the first arrival of seismic energy.

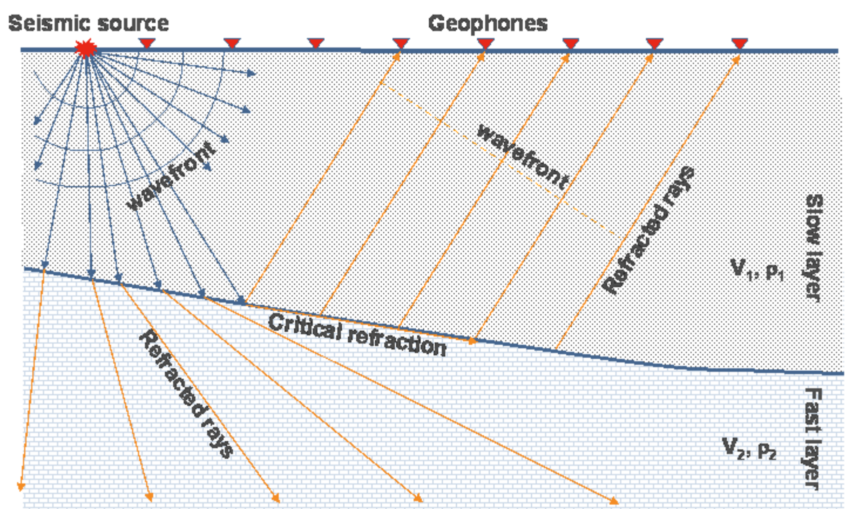

Fig. 1: Refraction principle. Wave velocity V_2 is greater than V_1. If the interface is flat and horizontal, the apparent velocity of the refracted wave is equal to V_2.

In the Athabasca region the MacMurray reservoir formation has velocity in the order of 2000 to 2500 m/s. This reservoir is underlain by Devonian carbonates with much faster velocities. This is a favorable condition to record refracted energy at the surface.

As our objective is to monitor underground steam injection we did some modeling with and without a steam chamber. The geological layers, velocities and densities are derived from our field data (See Fig.2). The Devonian Unconformity is at a depth of +/-400 meters. We then compared the shot point images to see if we could detect the steam chamber, and by comparison of the first break arrival times, if we could estimate the steam chamber thickness.

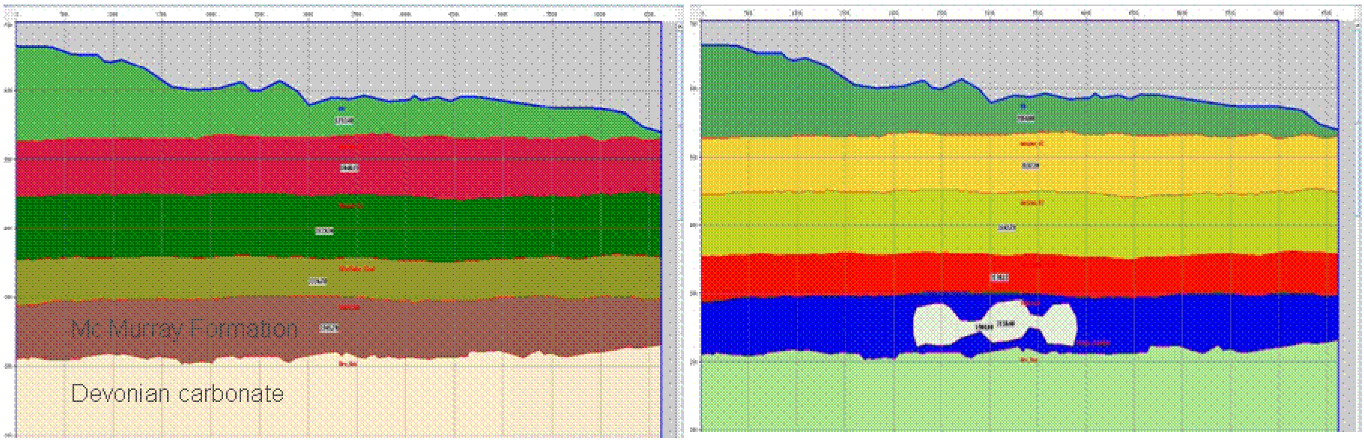

Fig.2: Geological model for refraction seismic modeling. Left base model; right steam chamber added in the Mc Murray interval.

Modeling is performed with a finite difference code. As we had no reliable shear velocity data, only the acoustic case was modeled.
Refracted energy is weak compared to reflected energy and high gain had to be applied to shot point images to see the head wave.

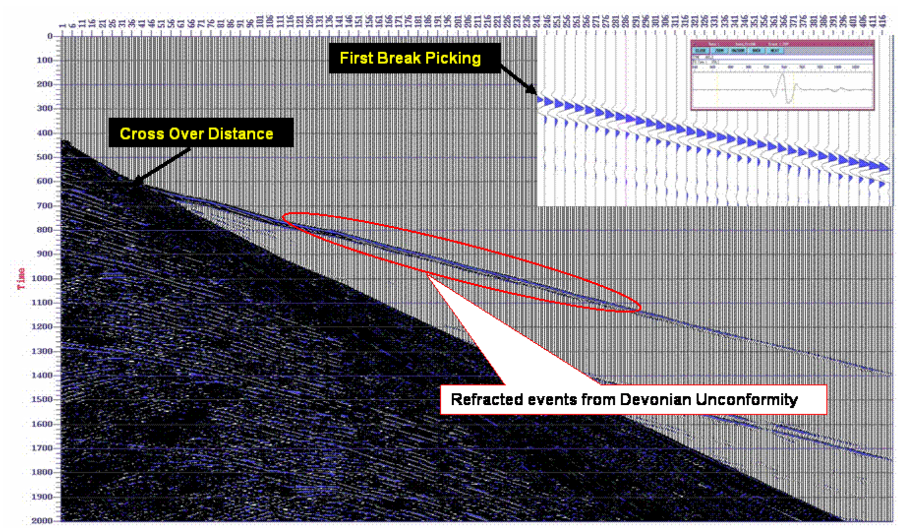

Fig. 3: Synthetic shot point.

Comparison of the first break arrival times of the base case and the monitor case show variations of a few milliseconds (See Fig. 4). Thickness derived from these variations is in the range of 90 to 100 % of the steam chamber thickness.
As the refracted wave is emerging with an angle, the apparent location of the steam chamber seems to be shifted in space relative to the true location. But this offset can be computed as the depth of the steam chamber multiplied by the tangent of the refraction angle. There is a slight uncertainty in the depth of the steam chamber, but the value is well constrained by the depth of the injection wells and of the Mac Murray formation.

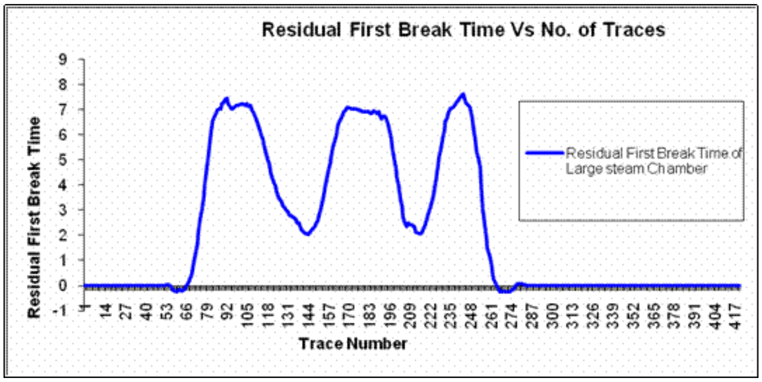

Fig. 4: Refracted time difference between base case and steam chamber case.

Existing 4D seismic data were examined in order to identify the presence of refracted energy by the Devonian unconformity. A problem with repeated 3D seismic is that surveys are generally limited to the extent of the monitored wells or pads. Maximum offsets are barely reaching 1000 meters, too short to identify the presence of refracted energy. The minimum source to receiver offset to see a refracted wave is the depth of the refractor multiplied by twice the tangent of the refraction angle; for a depth of 400 meters and a refraction angle of 30 degrees, refracted energy would appear at a minimum offset of 460 meters and as a first arrival for an offset of more than +/- 1385 meters. On real data, hints of refracted energy can be seen at the longest offsets. This need to be further investigated, either with exploration data with large acquisition offsets or data with a shallower Devonian unconformity.

Conclusions

Monitoring of Extra Heavy oil and bitumen in-situ production by reflection seismic is possible but expensive. Refraction seismic would be a cheaper alternative. Synthetic models show that we should be able to detect and locate the steam chambers, and get a good estimate of the chamber thickness. Real data suggest the presence of refracted energy from beneath the reservoir as required.

Practical difficulties might arise from the weak refracted wave amplitude and from incorrect estimation of the velocity in the steam chamber.

A possible set-up would be to have a grid of buried geophones above the producing pad, to avoid WZ annual velocity variations and a few sources, for each pad. These sources could be permanent sources such as piezo-electric sources (Forgues *et al*., 2006).

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