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***Abstract*—To extract all the oil from a well, petroleum engineers pump hot reactive chemicals into the well. These Enhanced Oil Recovery (EOR) processes need to be thoroughly monitored, since the injected fluids can seep out of the production oil wells and, if unchecked, eventually pollute sources of drinking water. There is a need to measure the corresponding effects. One way to measure these underground effects is by observing seismic waves resulting from hot fluids-induced fracturing. Seismic waves generated by this fracturing are, however, weak in comparison with the background noise. Thus, the accuracy with which we can locate the spreading liquids based on these weak signals is low. Hence, we get only an approximate understanding of how those liquid propagate in the reservoir. To get a more accurate picture of the propagation of these fluids, we propose to use active seismic analysis: namely, we propose to generate strong seismic waves and use a large-N array of sensors to observe their propagation.**

I. Introduction

What is enhanced oil recovery process. Traditional oil and gas industry mostly rely on locations where oil and gas are stored under high pressure. Because of this pressure, oil and gas flow out of the well on their own.

As the pressure decreases, production decreases accordingly. Hence, higher pressure pumping is needed to recover physical push to enhance mobility of oil and gas to the surface; this is performed by water, nitrogen, or CO_2 injection.

Alternatively, instead of pumping high-pressure fluids, we can pump chemicals that convert difficult-to-extract heavy carbohydrates into easier-to-extract lighter ones. This is known as *enhanced oil recovery process*; see, e.g., [1], [7], [8] and references therein.

The resulting chemical reaction must be as efficient as possible. It is known that the speed of chemical processes exponentially grows with temperature. Hence, to speed up the corresponding processes, chemical at high temperatures – between 200° C and 350° C – are injected into the well. This leads to a better extraction of oil from the production wells which are near the injection well.

Enhanced oil recovery process: successes and problems. The enhanced oil recovery process has enabled us to extract a large amount of remaining oil – up to 75% of the remaining oil [8].

However, the problem is that the chemically aggressive hot liquids seep out, and the corresponding chemicals can eventually pollute the sources of drinking water.

Need to monitor the enhanced oil recovery process. To avoid unnecessary pollution, it is important to monitor how the pumped liquids propagate at the corresponding depths. Also, we need to monitor the location of the injected liquids after the injection process is over.

How the enhanced oil recovery process is monitored now. When the liquid propagates, it fractures the minerals and thus, causes minor earthquakes. Just like major earthquakes, the location of these minor earthquakes can be detected by the seismic waves that they generate; see, e.g., [2]. This passive seismic approach is indeed used for the desired monitoring.

Limitations of passive seismic monitoring. In contrast to major earthquakes, disturbances caused the pumped liquid are small. As a result, the generated seismic waves are very weak (they are imperceptible to human senses), the signal-to-noise ratio is very low, and hence, the accuracy with which we can trace the spreading of the pumped liquid is very low – we only get a very crude approximate understanding of how and where the hot liquids propagate.

What we do in this paper. In this paper, we propose an alternative, *active* seismic technique, that enables us to provide a more accurate picture:

- of liquid propagation and
- of the resulting location of the liquids.

Future plans. At this stage, we only have a theoretical idea, an idea supported by computer simulations. However, we are already planning real-life tests on a location in Mexico.

Need to take into account uncertainty, in particular, fuzzy uncertainty. How is all this related to fuzzy and soft computing? The relation is straightforward: we do not know the exact characteristics describing the propagation of the corresponding seismic waves. Instead, we need to reply on expert understanding of this process – and this understanding is often described in terms of imprecise ("fuzzy") words from natural language. To describe this knowledge in precise terms, it is reasonable to use techniques specifically developed for processing such expert statements – namely, the technique of fuzzy logic; see, e.g., [4], [6], [9], [10], [12], [13], [16].

II. Our Main Idea and the Corresponding Physics

Main idea. The low accuracy of the existing techniques is caused by the fact that the micro-quakes generated by enhanced oil recovery process are very *weak*. Thus, to improve this accuracy, a natural idea is to generate *stronger* seismic waves and to see how these waves propagate – by measuring the signals detected by the seismic sensor located on the Earth's surface. Such techniques, when we actively generate seismic waves, is known as *active seismic analysis*.

To describe this idea in detail, we need to describe:

- what kind of seismic signals we can generate,
- how the generated signals propagate, and
- how we can determine the location of the liquid based on the measurement results.

Let us consider these topics one by one.

What seismic signals can be generated. To generate an active seismic signal, we have basically two main options:

- we can use all the available energy at once, thus producing an explosion, or
- we can spread this energy over time, thus generating a periodic seismic signal; this is done by using especially equipped truck called a *vibroseis*.

In this paper, we consider both options.

How seismic waves propagate: a brief reminder. When the medium is reasonably homogeneous, with some inhomogeneities whose size is much larger than the wavelength of the corresponding seismic wave, then the waves propagate geometrically, by following paths. Specifically, the path between points A and B followed by a wave is the path for which the propagation time is the smallest possible; see, e.g., [2], [3], [4], [5]. This shortest-time idea leads to the known Snell's Law of propagation, according to which, when a wave crosses the border between the two layers with different wave propagation speeds v_1 and v_2, then the angles α_1 and α_2 between the paths in both areas and the direction orthogonal to the border between the layers are related by the following formula:

$$\frac{\sin(\alpha_1)}{v_1} = \frac{\sin(\alpha_2)}{v_2}.$$

In such homogeneous situations, waves behave as if they were particles.

The situation changes drastically if we have inhomogeneities whose size is smaller than the wavelength. In this case, in the analysis of the wave propagation, we can no longer view the wave as a single whole, we need to take into account that different parts of the wave encounter areas with different wave propagation velocity and thus, get reflected differently. As a result, instead of the wave simply changing its direction and continuing as a single ray, we get a *scattering* phenomenon, when the wave that was initially a single ray starts going in several different directions.

How pumped liquid affects the propagation of seismic signals. The liquid spreads via the cracks – both the existing cracks and the cracks it generates. So, its trajectories are composed on linear paths whose width is definitely much smaller than the wavelengths of the seismic waves. Thus, the pumped liquid produced scattering.

In relative terms, the amount of liquid is small in comparison with the amount of surrounding minerals. Thus, the angle of the resulting scattering is mostly also small.

What we know before we start the enhanced oil recovery process. Usually, for an oilfield or a gas field, we know the velocities at different locations and different depths. Indeed, this is one of the main techniques based on which we decide that there is oil and/or gas in a given location – by:

- analyzing the seismic data,
- extracting the velocities from this data, and
- looking for patterns of the corresponding 3-D velocities model that are typical for oil and gas fields.

In this case, in the pre-pumping stage, if we use an explosion at some location E to generate a pulse wave, and we use a 2-D grid of surface sensors to monitor the resulting waves, then for each sensor location S, we also observe a single pulse. The time delay of this pulse is affected by the velocities along the smallest-time path that connects the explosion location E and the sensor location S.

Comment. In some locations, we may have small inhomogeneities. In this case, at the corresponding sensor, instead of a single instantaneous pulse, we observe a longer signal, a signal that combines the original pulse and the signals scattered by this inhomogeneity.

How we can determine the location of the liquid based on the measurement results: general idea. On the surface, we have a 2-D array of sensors that detect the signals on all possible surface locations.

Based on the previously obtained description of seismic velocities v at different depths, for each sensor S, we know the 1-D path following which the seismic signal propagates to reach this sensor S.

When in some underground location, the liquid appears, this liquid scatters the original seismic wave. Due to this scattering, the duration of the observed seismic wave becomes longer that it was before we started injecting the liquid.

So:

- if for some sensor, after the injection of the liquid, the observed seismic signal becomes wider that before,
- this means that somewhere along the corresponding 1-D path, there was the injected liquid.

How we can determine the location of the liquid based on the measurement results: first approximate idea. We know that the liquid is somewhere along the path, but based simply on the fact that the signal has become wider, we do not know where exactly on this path is the location of the liquid.

One way to find this location is it take into account that since, in geological terms, the amount of injected liquid is reasonably small in comparison to the the amount of the surrounding minerals, the scattering angle α is small. How does this affect the duration of the observed signal?

Let D be the original distance from the source of the seismic wave to the sensor. Let us assume that at distance d from the sensor, the path changes the angle by α. Now, the overall path consists of two segments:

- the first segment of length $D - d$, and
- the second segment of length d at the angle α with the first segment.

Because of the angle, the length of the second segment in the original direction is no longer d, but the hypothenuse of the triangle in which d is one of the sides, i.e., the length is

$$d' = \frac{d}{\cos(\alpha)}.$$

For small α, we have

$$\cos(\alpha) \approx 1 - \frac{\alpha^2}{2},$$

thus

$$d' = \frac{d}{\cos(\alpha)} \approx \frac{d}{1 - \frac{1}{2} \cdot \alpha^2} \approx d + \frac{1}{2} \cdot \alpha^2 \cdot d^2.$$

The increase in path is proportional to d^2, thus the increase Δt in the duration of the observed signal is also proportional to d^2:

$$\Delta t \approx c \cdot d^2,$$

for some constant c.

So, based on the increase Δt in the duration of the observed signal:

- we can not only find the 1-D path along which the liquid is located,
- we can also find the location of the liquid along this path:

Namely, the liquid is located at a distance d from the sensor, where

$$d \approx \sqrt{\frac{\Delta t}{c}}.$$

Case of the periodic active seismic signal. For the sinusoid (periodic) signal, scattering appears as smoothing of the signal, with amplitude decreasing as

$$\exp(-d^2 \cdot \alpha^2) \approx 1 - \alpha^2 \cdot d^2,$$

i.e., with a change in amplitude proportional to d^2.

In this case, we can similarly estimate d based on the observed decrease in the amplitude of the observed signal.

This location is still approximate. While the 1-D path can be determined reasonably accurately, the exact distance d on this path is determined only approximately – since:

- the constant c depends on the scattering angle, and
- this angle may be somewhat different for different locations of the liquid.

How can we get a more accurate location of the liquid?

How we can determine the location of the liquid based on the measurement results: second idea that leads to much more accurate location. The above analysis shows that:

- if we have only one source of active seismic signals,
- then we cannot find the distance between the liquid and the sensor very accurately.

Thus, to make a more accurate location, a natural idea is to use *two* different sources of the active seismic waves.

Based on each source, we find the 1-D paths that contain the desired liquid locations. We can find the actual location of each liquid mass as the intersection of the two corresponding 1-D paths.

As we have mentioned earlier, the paths are determined very accurately, as a result we can find the location of the liquid very accurately.

This way, we can determine the size of the liquid, not just its location. As we have mentioned earlier, the scattering effect occurs only when the size of the obstacle starts being commeasurable with the wavelength. The generated seismic wave is usually a combination of waves of several wavelengths. The corresponding frequencies range from 1 Hz to 475 Hz, with:

- the smallest frequency 1 Hz corresponding to the longest wavelength, and
- the largest frequency of 475 Hz corresponding to the smallest wavelength.

Thus:

- on the shortest wavelengths, which are much smaller than the size of the liquid mass, we will not see any scattering,
- on the other hand, on the longest wavelengths, we will see an increase in the duration of the observed seismic signal – which is an indication of scattering.

Thus, by comparing the signals on different wavelengths, we can find the wavelength at which the scattering starts – and thus, find:

- not only the location of the liquid mass,
- but also its size.

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