Breaking the seismic 4D 'image' paradigm of seismic monitoring

Habib Al Khatib[1*], Yessine Boubaker[1] and Elodie Morgan[1] present a focused 4D seismic monitoring method that predicts the optimal source and receivers' location for the monitoring of strategic areas.

Abstract

Seismic imaging techniques were designed for exploration. To better image the subsurface, the industry developed high-resolution 3D seismic monitoring methods which used systems able to record hundreds of thousands of channels simultaneously. In the 1990s when the need for reservoir monitoring appeared, repeating the seismic image over time was a natural progression and delivered high quality results. Later, to increase the detection threshold, expensive permanent systems have then been installed enabling world record detection threshold levels.

Yet, since then, improvements in seismic structural images combined with reservoir dynamic simulations provide more accurate predictions. With reduced uncertainty, lighter seismic monitoring approaches could be considered: focused seismic monitoring could provide more frequent observations at strategic subsurface locations to rapidly validate or invalidate flow simulations.

In this article we present a focused 4D seismic monitoring method that predicts the optimal source and receiver locations for the monitoring of strategic areas, capitalizing on existing 2D/3D seismic and reservoir knowledge. Such a light acquisition set-up using conventional equipment is agile enough to enable frequent detections of changes in several locations.

The method is illustrated using two field cases that show excellent correlation results with observation well data which illustrate a better reservoir understanding of dynamics arising from our approach.

Introduction: is repeated seismic 'image' a mirage?

Geophysicists are subsurface 'image' specialists: 2D lines, 3D images using time migration, depth migration, broadband data. From the 1990s to the 2020s, denser, wider and broader was – and still is – the 3D image moto as seismic exploration and development needs and values such precision.

Later, when geophysicists were challenged to catch the subsurface dynamics, 3D images repeated over time were provided, and here was the birth of 4D seismic. In the book *Petroleum Geoscience, from Sedimentary Environments to Rock Physics* (Bjorlykke & Landrø, 2010), M. Landrø accurately wrote that 'repeated seismic' was a more accurate term for 4D seismic. In this article 'repeated seismic images' or '4D seismic images' will be used as we believe that we can get around the image paradigm.

On the one hand, 4D repeated seismic images are a success. They are reliable and provide valuable information to better understand subsurface dynamics. On the other hand, the following question could be asked:

Why repeating a full 3D seismic image, when we know that only a tiny fraction of it will change over time?*

(*) Subsurface geological structures will not change over human time scale, and in most cases valuable information about fluid changes, compactions and fracs… are located within sedimentary layers only a few metres thick.

Is 4D seismic imaging overkill? Some may argue that 'most of the 4D seismic image value is to see changes where you aren't expecting any'. It was the case back in 1995 when the first full 4D survey was acquired over the Gullfaks field. Gullfaks 4D seismic images were made to identify unswept zones (Landrø et al., 1999) and drill new wells more accurately. Over time, 3D and 4D seismic resolution had been constantly improved.

The reservoir management had been also improved since 1995 and the subsurface landscape has changed drastically on several subjects that may 'challenge' the future of repeated seismic images:

1. Resolution: 3D images are accurate and reliable enough to a build consistent reservoir static model
2. Prediction: As resolution increases, flow simulation and predictions are more accurate.
3. Digitalization: Fields are now digitalized, and machine learning approaches are supporting better forecast and analysis of subsurface dynamics.
4. Environment: Environmental footprint and CO_2 emissions of 4D seismic are a growing concern.
5. Agility: More frequent updates of the subsurface are required to anticipate rather than react. These updates are 'feeding' flow simulations and digital twins to further optimize prediction.
6. Cost efficiency**:** The 2020 structural downturn is a push for developing affordable solutions that could also address

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emerging markets with lower economics like CCUS (decades of monitoring ahead), underground storage, and geothermal activities.

7. Experience: as we have been working on understanding subsurface behaviour for more than a century (as a science) and now have a much better understanding of it than 30 years ago.

If digitalization is the future, dynamic models will be more accurate for subsurface activities. In this vision, no big surprises are expected. To further build confidence in the model whilst improving them, they can be checked by focus detections at strategic locations (i.e., when/where needed). If predictions match detection, that is excellent news. If not, the model will be updated to match measurements and repeated seismic images can be generated when it is impossible to correct models without an image.

The 'Spot' concept

A 'strategic subsurface location' that could be monitored to validate or invalidate a dynamic model, a prediction or a hypothesis will be described here as a 'Spot'. The Spot concept could be illustrated using the Sleipner 4D images (Figure 1-A), that can be found in most of the 4D seismic illustrations (Chadwick, 2015).

Capitalizing on the Sleipner structural image (Solomon, 2007), a southwest-northeast CO_2 plume evolution following the anticlinal direction can be predicted. To validate this hypothesis and grasp the CO_2 plume extension velocity, five repeated seismic images were made. The result confirmed the structural hypothesis about the CO_2 plume expansion. To illustrate the focused monitoring approach, five spots of interest were located on structural isolines to validate or invalidate the above prediction. The evolution at each Spot location was modelled by taking an average value from the 4D seismic image changes.

Thanks to the above illustration, and assuming we could achieve the same detectability and reliability with focused seismic detection, it would have been possible to validate the structural CO_2 injection scenario and grasp the CO_2 plume dynamics. Moreover, with a focused seismic detection, it could be economically viable to perform more frequent detection than the repeated seismic images (here every 2.8 years) to better characterize CO_2 plume velocity.

Each model has its specific uncertainties, and each uncertainty requires monitoring of one or several spot monitoring locations to be reduced. The next paragraph will explain how seismic waves can be used to monitor a field as well as the limitation that needs to be considered when detection of subtle changes in detection are needed. These are the specifications for the development of focused seismic monitoring.

Repeated seismic images

The concept of repeating seismic images was first implemented onshore before offshore applications, where the seismic quality is generally better (Coléou, 2018). The original need of monitoring using 4D seismic images comes from the sparse disposal of observation wells. Indeed, observation wells provide accurate quantitative and frequent information around it, but not a significant understanding of the full area. Moreover, drilling is expensive. 4D seismic images can provide confidence to make expensive decisions such as drilling production wells. Therefore, it usually has an immediate business impact on reservoir management (Wang et al, 2017).

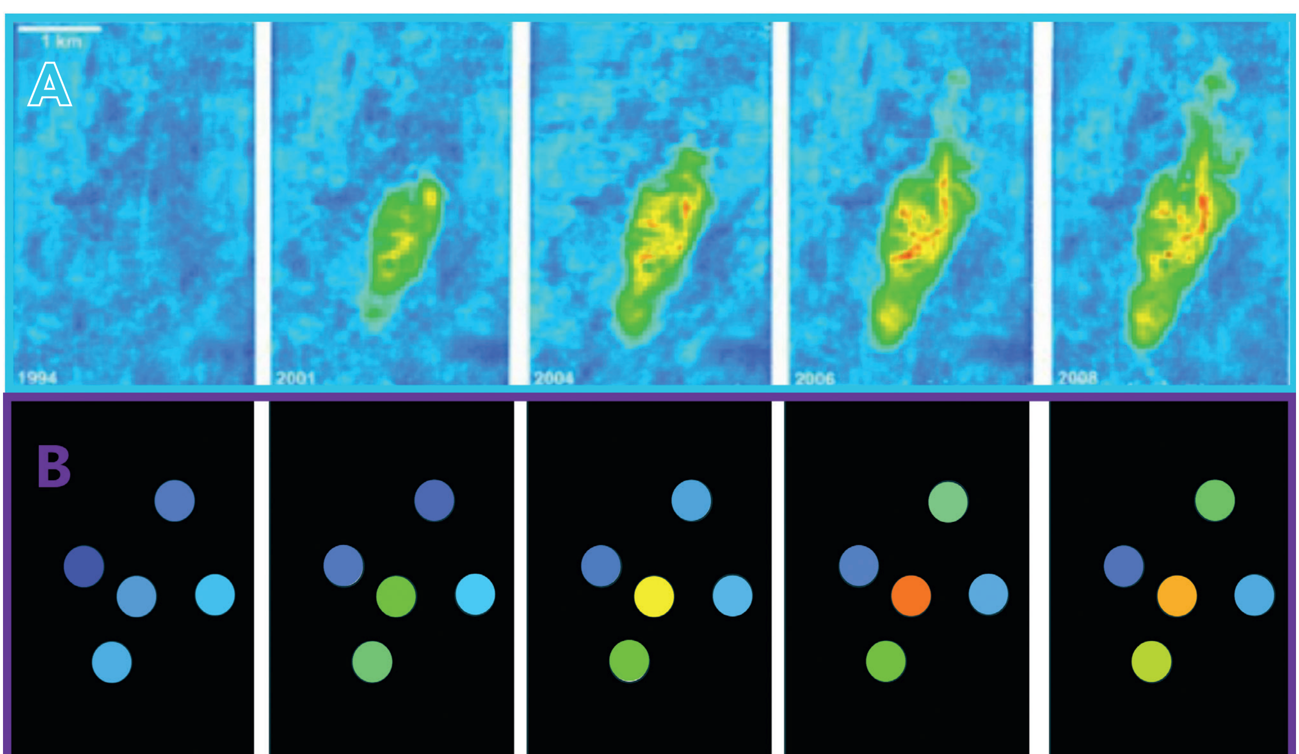

Figure 1 Modelling of spot monitoring concept. (A) timelapse seismic images showing CO2 detailed plume evolution (Chadwick, 2015). (B) Modelling of focused detection on five critical spots of interest, the average 4D value had been taken to model the spot seismic 4D response.

Timelapse seismic limitations

4D seismic image quality depends on geological and geophysical parameters. Overburden and reservoir complexity such as karsts, salt diapers, or gas chimneys have a negative impact on the seismic quality and therefore on the 4D seismic image quality. However, the most important issue that can be influenced is the repeatability of the seismic data. 4D seismic quality is directly related to how accurately the seismic measurement is repeated. The main issue affecting the 4D seismic repeatability for offshore and onshore surveys is the mispositioning of sources and receivers vs baseline (Jervis, 2012)

To completely solve the mispositioning problem, permanent receiver systems have been developed. Using a dense receiver network, Permanent Reservoir Monitoring (PRM) enables frequent and reliable 4D seismic images. However, the drawback of PRM remains its installation costs which are still too expensive for most fields. Also, the source effort remains high, as more than 30 days of shooting are required to cover the whole Ekofisk shooting area for instance (Buizard et al., 2013). With one acquisition every six months the one-month source effort per monitor is a limitation to further reduce the gap between each survey even if the seismic 4D response allows it.

Onshore, permanent or semi-permanent systems have been developed for SAGD monitoring, some with permanent sources reaching very high levels of repeatability that can even be compared to offshore ones with 1 to 3% NRMS (Postel et al., 2010).

Latest and lightest attempts for seismic monitoring

Driven by several downturns and more recently stronger environmental concerns, innovations shifted away from the 'bigger, denser' solutions towards more frugal solutions. Lighter innovative approaches are being developed to greatly reduce the number of sources and receivers used and to focus the measurement on key areas of the subsurface.

An example of very sparse seabed seismic acquisition for reservoir imaging (Lecerf et al., 2017) uses high order multiples to significantly increase the fold while using fewer receivers, thus reducing capital expenditure.

Another example is the instantaneous 4D (i4D) method that focuses the measurement around a critical area. A small 4D seismic image is obtained owing to a limited number of nodes (five times fewer than conventional 4D images) and a patch of shots using small marine sources (Wang et al., 2017). This technique is agile enough to be rapidly implemented in the field. However, compared to standard 4D seismic images data quality seems lower.

4D DAS Vertical Seismic Profiles (VSP) using optical fiber are also used for reservoir monitoring. This technique enables a penetration of up to 6-km deep with a small marine source and has shown a good repeatability. The monitoring is focused around the well and requires having an accessible well for instrumentation (Kiyashchenko et al., 2020).

Onshore, on a SAGD field using buried receiver locations, several single fold seismic images were performed (Forgues et al., 2006). The permanent source used was emitted continuously and buried below the weathering zone.

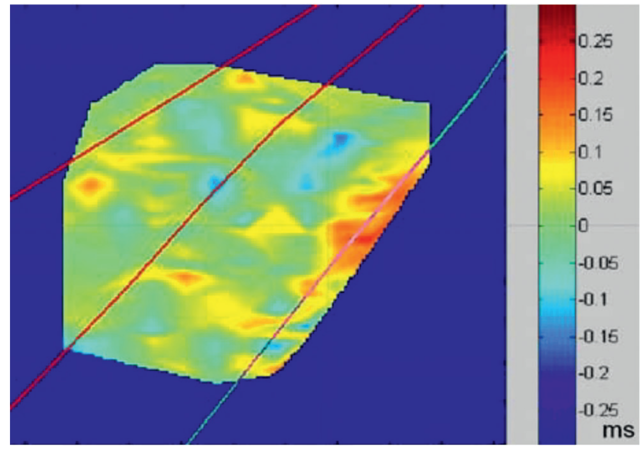

Figure 2 Time shift anomaly map (Forgue et al., 2006). Transit time variation through the reservoir measured over a period of one month.

The repeatability reached with this system was quite good. The processing sequence applied on the single fold is light (spherical divergence correction, NMO corrections, statics and seismic-to-well tie). The monitoring attributes, computed trace by trace highlight time shift anomalies, drawn on a map (Figure 2).

Since no migration is performed, the exact location of the anomaly is approximated to a Common Mid-Point (CMP). This can induce an error that is acceptable for shallow targets and uncomplicated overburdens. However, this cannot be duplicated similarly on a dipping reflector or for deeper targets.

Lighter seismic reservoir monitoring systems have demonstrated their appeal and value. However, the use of these frugal images remains limited compared to conventional 4D seismic images. Learning from the above, the use of permanent/semi-permanent source and receiver location to increase repeatability is paramount and if not permanent, they need to be relocated precisely. But to deliver a seismic 'image', the amount of equipment needed will increase the cost, even with frugal approaches.

Like a paradox, the way out of this image paradigm is precisely to use existing seismic images not just as baseline, but as a travel-map of all the wavefield within the subsurface that can be mined to find out the optimal traces to be repeated to detect changes without making an image.

The focused seismic monitoring approach

Demigration instead of migration

The migration process is made to reposition seismic events to their right XYZ location to build a subsurface image. To work properly and provide accurate images this process requires the use of many seismic 'traces' per seismic bin.

The first aim of the demigration is to overcome the error made with the CMP approximation when considering a single source-receiver pair for subsurface monitoring. The difference between the CMP position associated with an optimum source and receiver pair and the effective reflection point in the subsurface (calculated by the demigration process) is dependent on the local geological complexity of the overburden and the dip of the target's reflector.

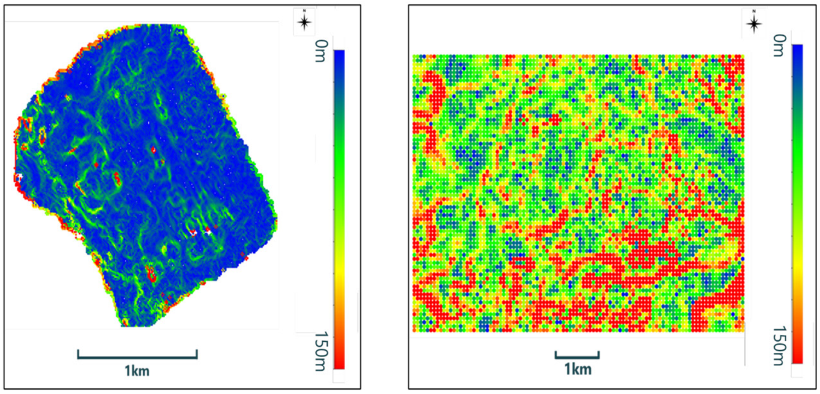

Figure 3 Mapping of the deviation between CMP approximation (zero offset) at reservoir level vs same source/receiver migrated points. Left panel is a shallow onshore reservoir, Right panel is an offshore deeper reservoir (Courtesy of Lundin).

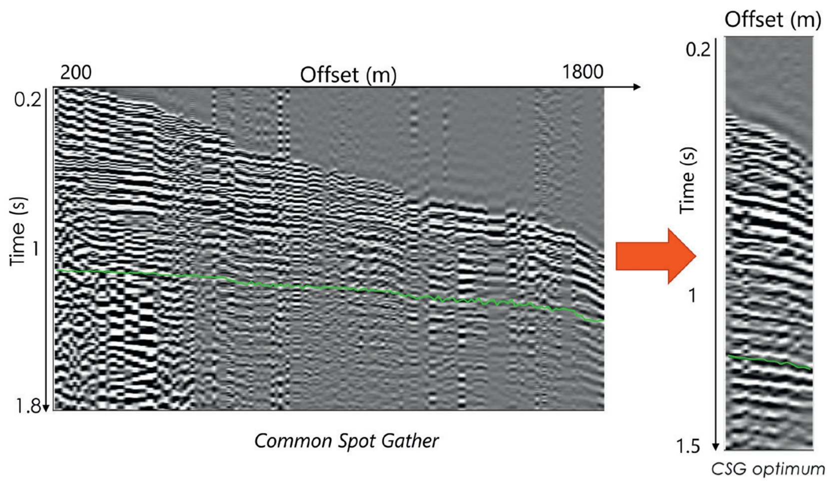

Figure 4 Common Spot gather (Morgan et al., 2020)
Left panel – CSG with all raw traces.
Right panel - Same CSG after selection of optimums. The green line shows the spot (reflector) of interest

For shallow targets with flat, horizontal reflectors and an uncomplicated overburden, the theoretical CMP position and the effective reflection point are very close to one another, at zero offset, 0 to 60m deviation could be observed (Figure 3 – left panel). For deeper targets with a more complex geology (Figure 3 – right panel), the difference between the CMP and the reflection point can reach hundreds of metres. This deviation between the CMP and the spot position is a function of the dip and the depth of the demigrated horizon plus velocity contrasts.

Such a CMP versus spot deviation highlights the importance of the demigration process to choose the correct location for the surface equipment to precisely monitor the right spot.

Common spot gather

The second aim of the demigration is to determine which of the raw traces contributed the most to the imaging of each spot. The demigration is a method developed to optimize ray tracing.

The demigration process first determines a theoretical design of source/receiver couples' positions imaging the spot, and then compares these positions with the raw traces from the first acquisition (Al Khatib, 2017). The raw traces matching the theoretical design are then extracted, creating a new kind of gather called Common Spot Gather (CSG).

In a CSG, the only common reflection between all the raw traces is the **targeted spot reflection** (Figure 4, left image, green picking). Unlike Common Depth Point (CDP) that is in the migration domain, a CSG is in the non-migration domain.

The next step is to determine which of the many CSG raw traces contributed the most to the illumination of each spot on the optimum selection phase.

Optimum selection

Once the CSG is obtained, the objective is to identify among these traces several optimal traces i.e., source and receivers' locations most suitable to detect a 4D change at target. Several geophysical criteria are used to avoid ground-roll, surface noise generator or artefacts such as guided waves, cavities, or gas clouds (Morgan et al., 2020). This selection process is critical to defining a source-receiver pair that

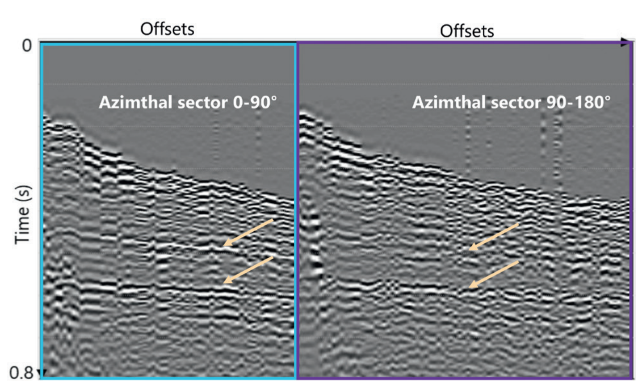

Figure 5 Azimuthal Common Spot Gather example. Traces have been separated in two azimuths sectors, between 0-90° (left panel) and 90-180° (right panel), to help visualize the data quality discrepancy. The left panel shows a much better signal to noise ratio than the right one. Optimums will be selected as part of this first azimuthal selection. (Brun et al. 2021 unpubl. results courtesy of ConocoPhillips).

provides a target detection as clean as possible (Figure 4, right side).

In most of the optimum selections performed to date, and as shown in Figure 6, preferential offset and azimuth for optimums were identified. Figure 5 – left panel shows a much better signal to noise ratio (azimuth sector 0-90°) than the Figure 5 – right panel (azimuth sector 90-180°). On both panels smaller offsets are affected by groundroll.

This selection process is critical. We need to provide a target reflection data with the best signal/noise ratio as possible to minimize the 4D processing of newly acquired data while increasing the detection threshold. Several optimums locations are usually defined per Spot in order to accommodate surface access and operational constraints. As an example, when it is possible the position of the receivers is selected away from noisy areas (roads, plants, rig) and the source positions close to a road to facilitate access.

Equipment selection, and acquisition parameters definition are the final part of the survey design.

Equipment and acquisition parameters

From an equipment point of view, the proposed methodology could be seen as contradictory to conventional seismic acquisition design for optimum imaging. The goal of the survey design is to reduce as much as possible the quantity of equipment needed on the field. The final acquisition design can also consider source and receiver reciprocity.

To illustrate the reduction of equipment needed compared to conventional seismic imaging, Figure 6 shows on the left image the initial 3D seismic image layout and on the right side the results of the optimum selection. The detection of three spots required a 1000 times less equipment than a full 4D image.

On the equipment side, to further reduce cost and environmental footprint, standard seismic equipment (sources & receivers) is used. Impulsive sources, such as dynamite or weight drop have been successfully tested as well as permanent piezoelectric sources and vibrators. Offshore, small airgun arrays are a good trade-off as well as marine vibrators or/and sparkers.

On the receiver side, buried geophones or hydrophones are used onshore. Offshore, nodes are the most convenient option. If microseismic networks or permanent receivers are installed, a subset of these could be used for focused monitoring.

Finally, existing seismic data are used again to define acquisition parameters using petro-elastic modelling.

This survey design capitalizes on expensive existing assets and knowledge to facilitate a frugal monitoring approach.

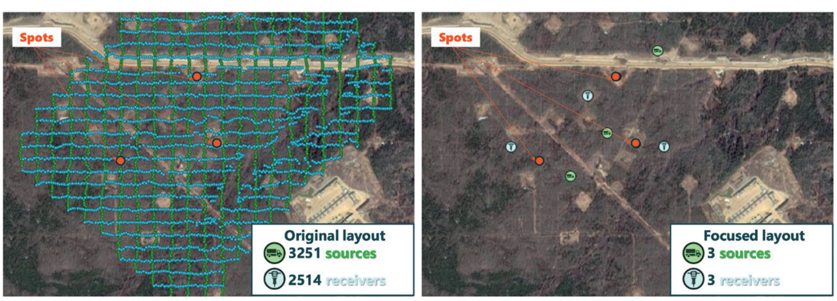

Figure 6 Optimum selection for focused detection (Brun et al, 2021 unpubl. results courtesy of ConocoPhillips). Left panel - Original 3D acquisition design. Right panel – Focused detection final design (1000 time less equipment used on the field).

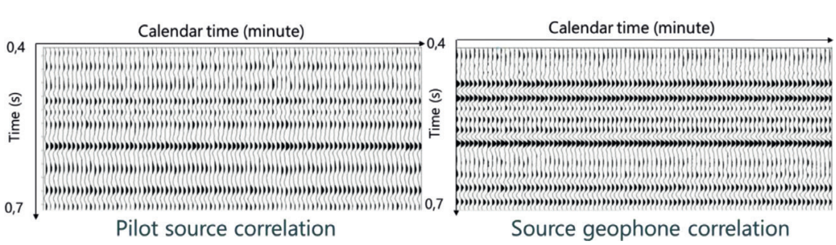

Figure 7 Bad source repeatability correction left: Raw traces over several hours (one trace per minute) using the pilot for correlation. Right: Same recording using the source geophone for the correlation improving the trace-by-trace repeatability.

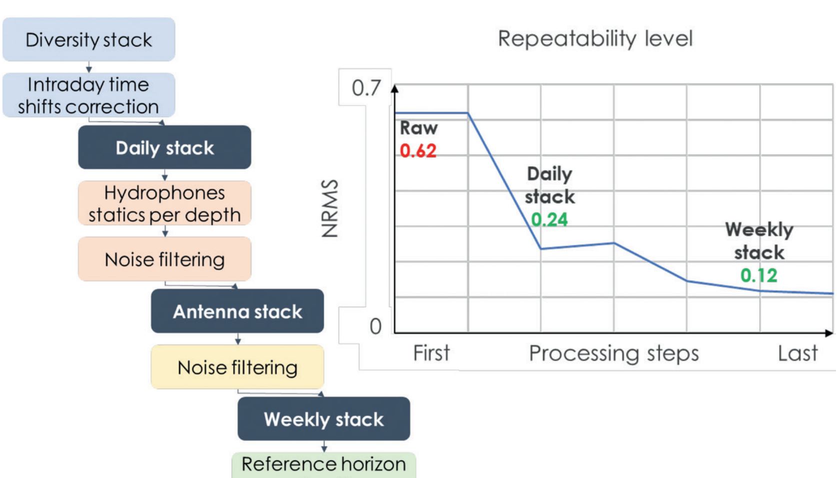

Figure 8 Processing sequence used in 2020 on an Austrian gas storage (Morgan, 2020).

Equipment and acquisition are usually made by local acquisition providers as standard equipment is specified.

The monitoring – tailor-made installation and time as an ally to improve the signal-to-noise ratio

Such an ultra-light acquisition system enables a tailor-made operational model to further increase the signal-to-noise ratio on the field compared to conventional seismic surveys.

Onshore – source and receiver locations can be carefully prepared during the equipment installation phase to ensure a stable coupling onshore (buried receivers).

Offshore – source and receiver mispositioning will be the main driver and extra operational care should be taken.

Source receivers can be installed next to every source location to compensate for possible source signature variations as shown in Figure 7.

Assuming they are repeatable enough, smaller sources could be used to take advantage of the temporal stacking to increase signal-to-noise ratio. In Austria (Morgan et al., 2020), 50 sweeps per source position per day were performed using a small vibroseis truck. Here the absence of spatial redundancy commonly used in seismic imaging is compensated by a strong temporal redundancy.

Non-migrated domain detection

The temporal focused raw traces acquired are processed to further increase the final detection threshold. A dedicated timelapse processing sequence had been detailed previously (Morgan et al., 2020) as shown in Figure 8.

The processing sequence performed on the seismic dataset increased the repeatability from 0.62 to 0.12 of Normalized Root Mean Square (NRMS). This repeatability level allows for a detection threshold of approximatively ~100µs on that specific use case.

Standard 4D seismic attributes such as time shifts, amplitudes, frequency spectrum changes and phase rotations can then be computed to detect changes. Sensitivity analysis can be performed to assess measurement uncertainties and ensure that they are lower than the detection threshold to avoid false positives.

Integration of the detection information

To get the most value from focused seismic detection, spot detection results need to be integrated with other field measurements (such as well information) and integrated into the dynamic modelling to check if the detection matches with the reservoir dynamics hypothesis.

Assuming the detection threshold is reached, frequent measurement enables us to precisely correlate a detection with, for example, the start or restart of an injection. Two focused detection examples are shown in (Figure 9). Time shifts obtained on both gas storage and steam example monitoring showed excellent correlation with associate observation well measurements (pressure and temperatures data). In these cases, the detection could have been used as a qualitative virtual observation well.

Conclusion

In this article we presented a frugal and agile method to focus the seismic monitoring only on strategic locations of the subsurface. Survey design using legacy data and existing knowledge enables seismic monitoring that employ up to a 1000 times less equipment than conventional 4D seismic methods. Acquisition is performed with standard equipment, and new operational models can be implemented to further enhance both repeatability and acquisition efficiency.

For increased acquisition efficiency, we can envisage mutualization of the Spot survey to be acquired using only a small crew (2-3 persons with related equipment) onshore or a small boat with 15-20 nodes plus a small airgun array offshore. Several fields within the same area could be monitored to perform spots monitoring. Such survey could be repeated every three months to feed reservoir dynamic models with frequent and focused updates away from existing well locations.

The presented results show more qualitative than quantitative information. Future developments are planned to provide more quantitative results such as saturation estimation where and when they will be needed.

For market perspective, the economics, its low environmental footprint and CO_2 emissions together with its agility and reliability for first gas detection should make the methodology particularly attractive for carbon capture underground storage (CCUS) monitoring.

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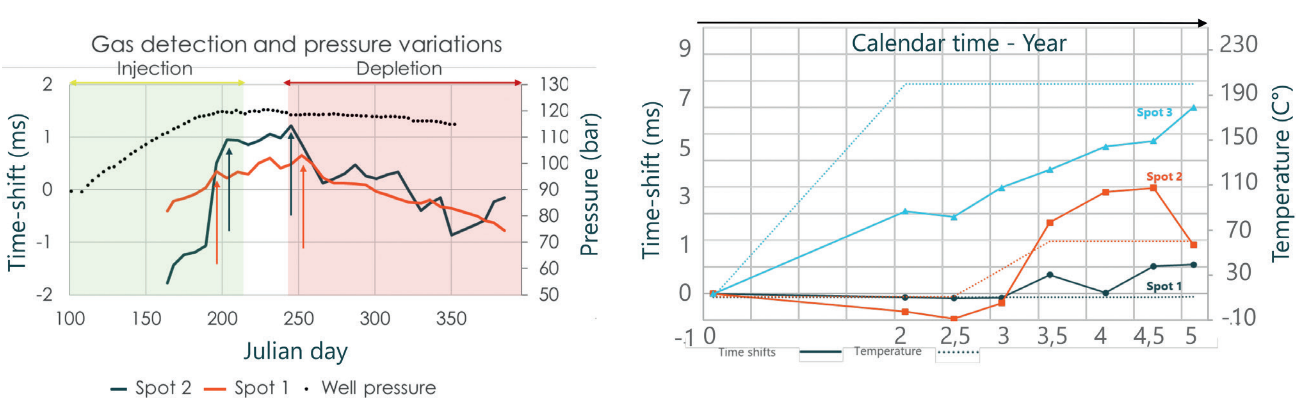

Figure 9 Two focused real data example. Right panel – detection of a gas storage in Austria (Morgan et al., 2020) showing excellent correlation with pressure measurements. Left panel - Time-shift plots (solid lines) for each spot & temperature data (dotted lines) from the observation wells in the vicinity of each spot showing again an excellent correlation (Brun et al., 2021 unpublished results courtesy of ConocoPhillips).

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