Real-time seismic hazard monitoring with PRM

The recent integration of automated real-time seismic hazard detection is the latest development furthering the argument for permanent reservoir monitoring. Aaron Smith, of PGS, sheds light.

Over the last two decades, time-lapse (4D) seismic has established itself as a valuable tool for offshore reservoir monitoring. Imaging production-induced changes has proven to increase the recovery rate and reduce uncertainty through a better understanding of the subsurface. But for operators who need to monitor reservoir conditions frequently, cost quickly becomes a factor.

Seismic receivers installed permanently on the seabed serve two purposes: significantly minimizing the cost of repeat seismic acquisitions and providing better image quality through higher repeatability and increased detectability. Commercial permanent reservoir monitoring (PRM) technology was first introduced in 2003 in the North Sea at Valhall, delivering significant value over the last decade (e.g., van Gestel et al., 2008), and has since steadily grown to a number of fields in the North Sea and Brazil. Recent examples include Ekofisk (Folstad et al., 2015), BC10 (Galaragga et al., 2015), and Jubarte (Thedy et al., 2015).

The ever-present push to maximize value from subsea assets has several operators looking to further leverage PRM technology beyond 3D acquisitions repeated at finite time intervals. Subsurface information at even shorter timescales can be extracted from passive seismic data, acquired continuously with PRM arrays. Rather than recording the reflected seismic energy produced from air-guns at surface, passive seismic records the energy produced directly from subsurface and seafloor activity in the absence of an artificial source. Already designed to continuously record active source data, PRM systems can easily record passive data as well. Recent developments in automation and remote operation have expanded PRM services into real-time passive event detection.

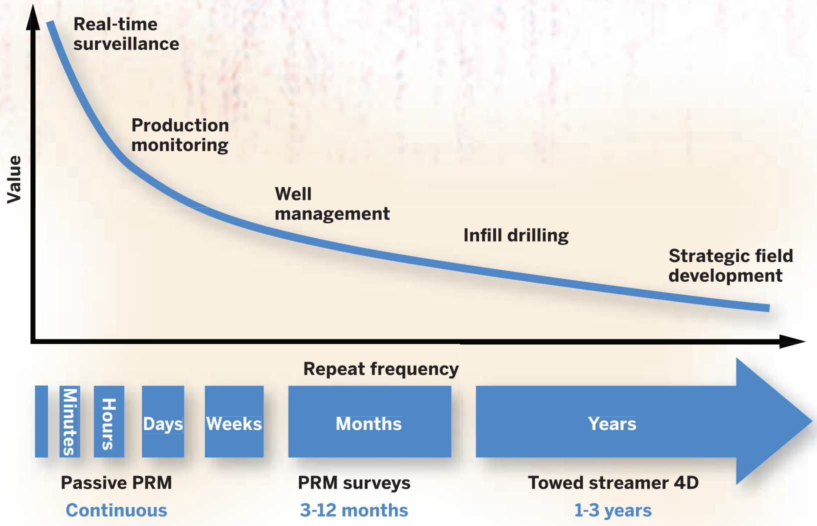

Fig. 1: Time scale of decision making in oilfield operations and associated relative value vs. different seismic monitoring techniques. The potential of utilizing passive monitoring for proactive production management and risk monitoring is so far largely untapped. Images from PGS.

Seismic events of specific magnitude, location, or both can be independently recorded based on client-identified parameters in order to monitor and optimize reservoir production. Examples include the optimization of injection patterns for directing production flow, or the identification of potential production hazards such as reservoir zone breaches, pump cavitation, flow line slugging, or choke failures. As many incident investigations have shown, early warning of these production risks is paramount to their safe mitigation. It has long been recognized that environmental hazards can be more effectively mitigated by better seismic monitoring. In the US, mandatory offshore monitoring systems for risk mitigation have been proposed in new legislation as a response to the *Deepwater Horizon* incident. Norwegian authorities have started to mandate provisions for seismic monitoring systems as well in conjunction with sanctioning big field development plans such as Johan Sverdrup.

Microseismicity induced by pressure changes in the reservoir or stress changes in the overburden are the main diagnostic for deformation. Larger seismic events that could impose a risk to installations or compromise reservoir integrity are typically preceded by many much smaller seismic events. If captured with a sufficiently sensitive seismic monitoring array, such small events can give ample warning. Mitigation measures can then be planned ahead of time, e.g., in the form of changing production – or injection plans to alter the pressure distribution in the reservoir. At the same time, the distribution of microseismicity in time and space characterize preferred fluid pathways and drainage patterns. The latter information is complementary to time-lapse images and can be used to update the reservoir model. Other potential uses of passive data include monitoring overburden velocity changes through passive interferometry (e.g., de Ridder et al., 2014). This can help to detect surface breaches, e.g., of oil or re-injected cuttings at an early stage.

In order to be useful for reservoir management and risk mitigation, information from passive data needs to be available within minutes of occurrence, hence requiring real-time acquisition and analysis. By their very nature, cabled PRM systems are already capable of doing that, and in mature regions such as the North Sea, broadband onshore connections for real-time data transfer are already in place. In the age of constant connectivity and on-demand remote system monitoring, PRM systems then become just another component of the digital oilfield. Prior to reaching wellhead and valve tree sensors monitoring production infrastructure, PRM delivers in-situ information of reservoir changes before they reach the borehole.

Having real-time subsurface information at your fingertips for decision making quickly changes the value proposition of PRM systems. Passive monitoring not only makes much better use of the PRM capital investment, but also opens up new applications for subsurface information in production monitoring and hazard surveillance that provide significant value (Figure 1). The goal of all PRM data, both active source and passive, must be to get updates into the hands of reservoir and production teams as early as possible to maximize the impact of available actions.

Similar technology is regularly used onshore for real-time monitoring of frac-induced seismicity. The goal is to verify that a shale gas frac operation is not causing a fault activation that could potentially trigger a much larger event in populated areas. If an event is detected, it needs to be located, its magnitude determined, and warnings issued within seconds of occurrence. Recent upticks of seismicity in Oklahoma (mainly believed to be correlated with prolonged wastewater injection) led many US states to mandate such real-time monitoring and warning systems around shale gas operations.

The key to applying microseismic monitoring technology offshore for reservoir characterization and risk mitigation is achieving a sufficiently low detection threshold with the seismic array. Capturing many low magnitude events allows forecasting the risk of larger, potentially damaging production-induced events to occur.

A fully fiber optic PRM system offers performance and reliability advantages over alternative systems for both, 4D imaging, and real-time passive monitoring. Using passive, pressure-balanced fiber optic sensors provides broader sensor bandwidth, better vector fidelity, superior cross feed isolation, and lower noise floor. The avoidance of any in-sea electronic components leads to superior longevity that ensures the system will perform over the lifetime of the field. The first such PRM system in deep water was installed by PGS in 2012 in Petrobras' Jubarte field, located in Brazil's Campos basin. This pilot array consists of 712 4C sensors installed at 1300m water depth. It has since provided three annual active source surveys and multiple passive monitoring campaigns. The technology has resulted in several reservoir model updates and influenced well position changes. The impact of this seismic analysis and production planning has been estimated by Petrobras to yield EOR improvement of 4% in the area of PRM illumination.

Passive monitoring at Jubarte detected several hundred tiny microseismic events that could be used for subsurface characterization. The key to achieving this low detection threshold was analysis of all four sensor components which included shear wave arrivals on the horizontal components. Figure 2 shows a 4C receiver gather of an example microseismic event before and after rotation of the accelerometer component, which highlights the excellent data quality and vector fidelity.

Clouds of microseismic events could be located with high accuracy and align with faults visible in 3D seismic images. Results from the next scheduled repeat acquisition, approximately six months after microseismicity recordings, revealed 4D changes of the seismic image that seemed spatially correlated with the microseismic events. This highlights the significant value that can be provided by passive monitoring; detected microseismicity revealed dynamic subsurface activity when it actually occurred, in this case half a year earlier than it would have been detected relying solely on scheduled active seismic repeat surveys. This gives operators a significant advantage in understanding the subsurface and with reservoir planning. In addition, pinpointing the location of dynamic changes with two independent datasets (passive and active) reduces ambiguity related to the interpretation of sometimes weak 4D signatures in time-lapse images.

An additional uplift from real-time event detection with PRM systems is the ability to pair it with rapid seismic source mobilization. Active-source vessel(s) of opportunity can be mobilized on-demand when significant microseismic activity warrants immediate validation. Rapid high density time-lapse (4D) seismic can also be acquired over a subset of the field or array and fast-track processed in days rather than weeks. A target-oriented 4D over the microseismic area can then quickly help to characterize the dynamics of the region in question.

Once installed, PRM systems remain the fastest, most reliable, seismic imaging tool available proving that new efforts to reduce production risks continue being developed. **OE**

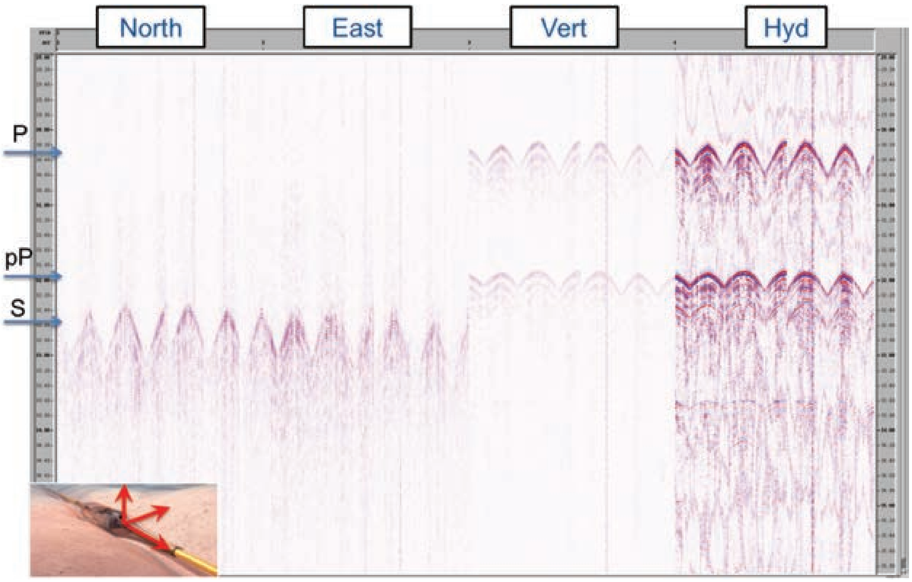

Fig. 2: Four-component gather of one microseismic event with good signal-to-noise ratio after component rotation. Note the clear separation of P- and S-arrivals between the horizontal and vertical components.