INTRODUCTION
The permanent reservoir monitoring (PRM) arrays installed in the seabed at the Grane, Snorre, and Johan Sverdrup fields offshore Norway are primarily used for periodic 4D seismic monitoring of the overburden and reservoir. But these arrays also provide a continuous stream of background noise recordings, amounting to tens of Terabytes of passive seismic data every day. During the past few years, a system has been developed to use passive seismic data for detecting and locating microseismic events induced by injection (Bussat et al., 2016, Bussat et al., 2018). This system is currently installed at all our PRM-equipped fields to support safe operations and prevent out-of-zone injection.

Passive data can also be used for seismic while drilling, using the drill bit as a source (Poletto and Miranda, 2004). Indeed, during microseismic injection monitoring at Grane, noise from a nearby drilling operation was detected (Bussat et al., 2018). The microseismic event detection technology was subsequently adapted to also enable monitoring of drilling operations in real time. The aim is not only to provide additional insight in case of sudden drilling issues such as liner failure (Bussat et al, 2018), but also to support better well placement by reducing the position uncertainty while drilling, and hence reduce the risk of e.g. drilling infill wells too close to already existing producers. Especially long horizontal wells have a large lateral position uncertainty since the error from the magnetic and gyro measurements accumulates with measured depth; at Grane, the lateral position uncertainty can be as large as ±60 m at 6000 m measured depth. Reducing this uncertainty becomes important when infill wells are drilled at 50-75 m lateral distance from existing wells, as is the case for some Grane wells.

METHOD FOR LOCALIZING DRILLING-RELATED NOISE
Our microseismic event detection method is based on computing the semblance and stack of passive seismic data along traveltime curves from each grid point in a subsurface volume to selected geophones at the seabed. The method can also be used for detecting sudden, transient drilling-induced events close to the well path. However, to localize the noise generated by the drilling assembly, the method must be adapted slightly. Since the drilling operation is expected to produce a continuous signal, a longer semblance window is used compared to what is used for microseismic monitoring. The window must be sufficiently long to be able to pick up the continuous, yet rather weak drilling noise, but sufficiently short such that the drill bit does not move substantially, and the image of the noise source would be blurred. We use a semblance window of 90 seconds and no overlap to scan through the passive data.

For each period of 90 seconds, the position of the drill bit is fetched from the database with real-time drilling parameters. A processing grid that covers a limited volume around the current drill bit position is then defined, see Figure 1. The volume must be large enough to cover possible revisions of the planned well path. For example, the extension of the volume is ±200 m along the well path (MD axis) with 20 m grid spacing, and ±80 m laterally (R axis) and 140 m vertically (Z axis) away from the well path with 20 and 35 m grid spacing, respectively. For a given drill bit position, a subset of the PRM nodes is selected, typically all nodes within a radius equal to the depth of bit. P-wave traveltimes between these receivers and all points on the processing grid are used to travelt ime-correct the seismic data (the vertical component of the geophone) and compute a semblance volume. This procedure is repeated every 90 seconds with a new optimal subset of receivers.

The passive seismic data also contain noise from a range of different sources that are not of interest for the drilling monitoring, like interference from nearby seismic acquisitions, noise from the platform, noise from vessels in the neighbourhood etc. To be able to track the drilling noise, some preprocessing of the passive data is necessary. We use a bandpass filter, an FX median filter, PZ-summation, and a subspace filter (Jones and Levy, 1987, Bussat et al, 2018) prior to computing the
semblance. Apart from the bandpass filter, the applied filters are data-driven, that is, filter parameters are computed on the fly, and optimized for the noise at any time present in the data. Figure 2 shows the effect of the PZ-summation and subspace filter, respectively, on some passive data. A lot of noise has been removed from the data, yet we will demonstrate that the drilling noise is preserved. In fact, without these filters, one would detect the drilling noise less clearly, or not at all.

Figure 2. Passive data after bandpass (BP) and FX median filter (left), after PZ-summation (middle), and after subspace filtering (right). The bottom panels show the Fourier transform after each processing step, respectively.

Figure 3 shows an example of the semblance volume for a 90 seconds period of data; each panel is a depth slice of this volume. The semblance has a maximum close to the location of the drill bit, which is approximately at (0,0,0) in the local coordinate system of the semblance volume. To obtain sub-grid resolution, the exact location of the maximum semblance and its value are estimated by fitting a second-degree polynomial in 3D through the 3x3x3 grid points around the grid maximum. These estimates are stored in a database together with the median semblance value on the grid, representing the background noise level. When the estimated location in any direction is farther than one grid point away from the grid point with maximum semblance, it is a sign of low-quality data without a clear maximum in the semblance volume. These observations are flagged as ‘bad data’ and replaced with their original maximum value and location on the grid. Note that one could have used a finer gridding instead of curve-fitting, but the coarse grid in combination with 3D fitting gives very similar results, and is much faster to compute, which is important for a real-time implementation.

RESULTS
The method described above is currently being applied to all drilling operations at Grane. Results for three wells (Well A, B, and C) are displayed in Figures 4-6. Each of these figures shows a map view and a vertical section of the drilled well path (black line) and corresponding 95% uncertainty ellipse (shaded pink) from gyro measurements. The (fitted) location of the maximum semblance for the 90 seconds intervals of data are plotted and coloured by time. Threshold values for the semblance and SNR (represented by maximum divided by median semblance) and the ‘bad data’-flag are used to filter measurements before plotting them in the map view and vertical section. For reference, the grid points at which the semblance is computed are indicated with grey dots. In addition, the PRM nodes (black triangles) are plotted. The three wells all cover a 700-800 m range of the well path, but at different measured depth levels around 1500, 3500, and 6500 m, respectively. The lateral extent of the error ellipse increases from less than 10-15 m for the measured depth range for Well A to over 60 m...
for Well C, while the vertical error ellipse is about 10 m for all wells. The lower right panels in Figures 4-6 show the value of the maximum semblance over time (here all semblance observations are included) and the rate of penetration (ROP) and rotations per minute (RPM) from drilling. Several observations can be made:

- The observed maximum semblance correlates well with the drilling parameters ROP and RPM. When drilling is ongoing (ROP > 0), the semblance is high, while the semblance is low when drilling is paused. This proves that the detected noise is coming from the drilling operation.
- For all three wells, the strength of the semblance signal from the drill bit varies when drilling is ongoing (ROP > 0), e.g. for the two drilling periods of Well C. Moreover, the overall level can be rather low, as for Well B. The cause of these variations needs further investigation, but proper pre-processing is crucial to be able to detect and locate the drilling noise for Well B.
- In the map views, the position of the (filtered) maximum semblance is close to the drilled well path, well inside the uncertainty ellipse from the gyro measurements. With time the observations are located at increasing measured depth, following the progress of the drilling. The lateral spread of the observations is smaller than the width of the error ellipse of Well A, and independent of measured depth. This indicates that the passive data can be used to reduce the lateral well positioning uncertainty significantly, with about a factor 4 at the largest MD, compared to the gyro measurements, and possibly even more during favourable (quiet) ambient noise conditions.
- The depth sections show that the vertical position of the maximum semblance is not estimated accurately; they are not inside the error ellipse of the gyroscope measurements. Depth estimates are influenced by possible errors in the velocity model, via the traveltimes. But more important for the lower vertical accuracy is the sensor geometry with stations at the seabed. Depth estimates can probably be improved by including passive data from sensors or DAS systems in wells, but the current method should not be used for vertical well path positioning.
- The spatial extent of the monitoring volume around the drill bit ensures that the drilling noise can be tracked even when a significant revision of the well path is made, see Figure 4. Here the actual drilled well path is relatively far from the monitored well path.

**CONCLUSION**

We have demonstrated that we can track noise from drilling operations on passive seismic data from the Grane PRM system and use this to laterally localize the well path with a higher accuracy than can be obtained with gyroscope measurements. For PRM-equipped fields, the method provides accurate, complementary information on the lateral well position; the aim is to use this information for real-time decision making while drilling. When working only with seabed sensors, the method is less suitable for localizing the well path in depth.

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**REFERENCES**

Figure 4. Maximum semblance position and value over time for Well A.

Figure 5. Maximum semblance position and value over time for Well B.

Figure 6. Maximum semblance position and value over time for Well C.