

## Integrated workflow to unlock Near-Field Opportunities in a North Sea Injectite Paleogene play

### Introduction

The Norwegian North Sea is a mature hydrocarbon province that continues to attract sustained exploration and development activity, with increasing emphasis in recent years on near-field exploration strategies. Numerous discoveries within remobilized Paleocene and Eocene sand systems have confirmed the viability of this hydrocarbon play. Large-scale sandstone intrusions have been actively explored in the South Viking Graben since the discovery in the Balder Field in 1967. In the North Viking Graben (NVG), the play has been further de-risked by discoveries such as Kveikje (2022), Heisenberg (2023), and Kjøttkake (2025), all within the Paleogene section (Figure 1). This is particularly attractive from an economic perspective, given the presence of producing reservoirs in the underlying Jurassic section.

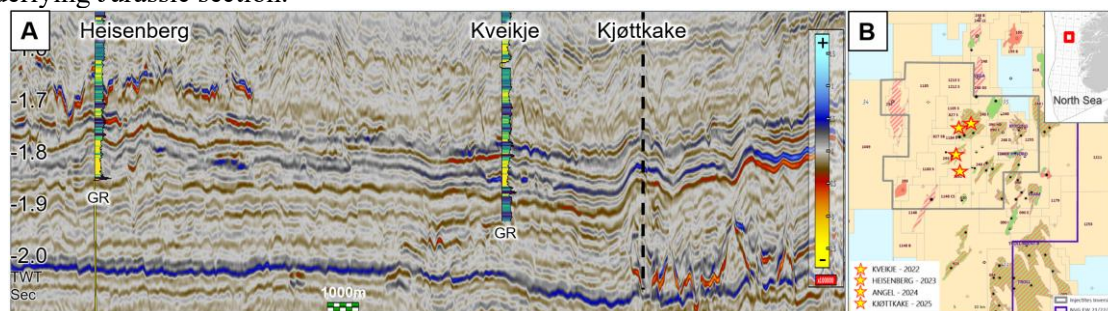


**Figure 1** - (A) DAZ Seismic section with Gamma ray logs (GR), where yellow is sands and blue is shales, through Heisenberg, Kveikje and Kjøttkake injectite discoveries; (B) map showing the locations of these discoveries.

This paper demonstrates how detailed understanding of these subsurface reservoirs across a 1,000 km<sup>2</sup> area can be achieved through an integrated workflow combining depositional system interpretation, and seismic attribute analysis with machine-learning (ML) techniques, rock physics analysis, and seismic inversion (Figure 2).

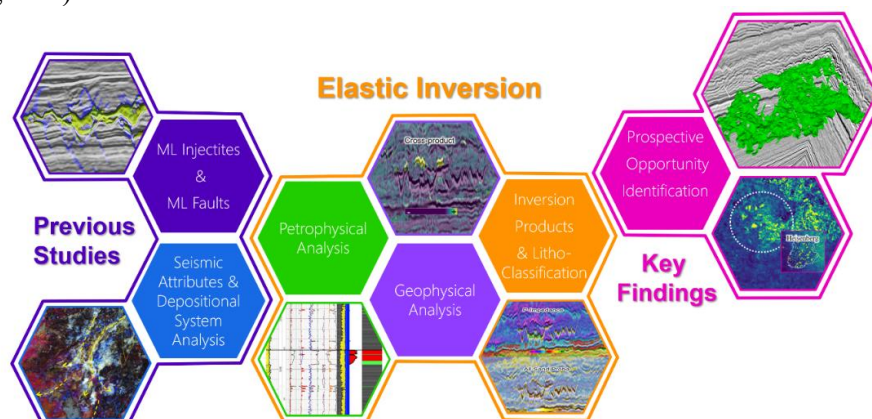


**Figure 2** An integrated G&G workflow that incorporates previous studies, including machine learning and seismic attribute analysis, and inversion facilitates the identification of potential injectite opportunities, where inversion is critical for differentiating between water-filled sands and hydrocarbon-filled sands.

### Sand Injectites: Geological Setting and Data Challenges

In the North Sea, sand intrusions are widespread within deep-water Late Paleocene to Early Eocene successions, typically encased in fine-grained, polygonal faulted mudstones (Huuse et al., 2007). Their

elastic response varies significantly, as a function of host lithology, burial depth, and fluid content. As a result, preservation of the AVO response, together with a robust petro-elastic understanding, is essential for accurate reservoir characterization.

To address these challenges, we developed an integrated workflow (Figure 2) spanning seismic processing to geological interpretation, specifically tailored to injectite play analysis. Injectites imaging has been improved through advanced pre-processing and velocity model building workflows, including high-resolution full-waveform inversion (FWI), as seen in Figure 3. The integration of two azimuths significantly enhanced subsurface illumination, resolution, signal-to-noise ratio, and AVO preservation relative to legacy single-azimuth data (Buriola et al., 2023).

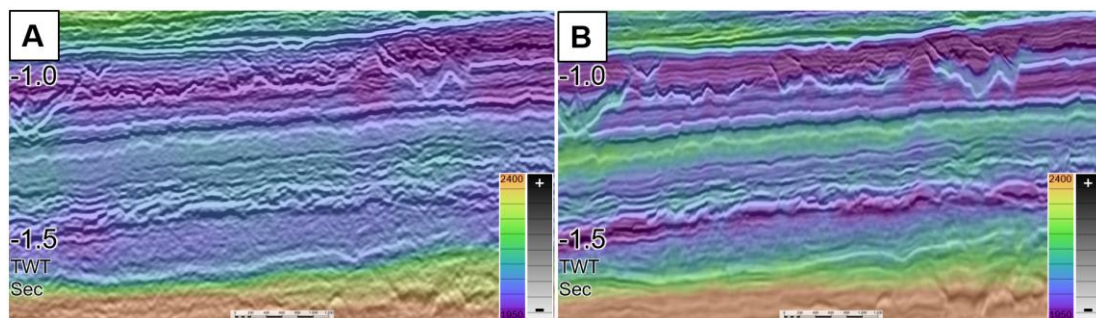


**Figure 3** Seismic sections with overlaid velocity models: (A) 2018 legacy and (B) DAZ. The DAZ seismic image is significantly enhanced, and the updated velocity model demonstrates improved lateral and vertical resolution.

Subsequently, depositional systems were investigated using RGB frequency decomposition, while the complex injectite network was delineated using machine-learning-based (ML) workflows, specifically designed to detect injectite bodies associated with polygonal faulting (Rumyantseva et al., 2024). For a more quantitative interpretation, elastic inversion and litho-fluid classification were then applied to discriminate hydrocarbon-filled sands from water-filled sands within the Hordaland and Rogaland groups.

### AVO Inversion and Litho-Fluid Classification

This study applies an elastic inversion workflow supported by a carefully conditioned well database. Well-logs of the Hordaland and Rogaland groups were available for 11 wells, while fluid-calibration was limited to two wells with hydrocarbon-bearing intervals. Petrophysical analysis indicate the elastic log data are generally of good quality. However, log coverage across the Rogaland and Hordaland groups is uneven between wells. To address this limitation, a multi-linear regression (MLR) model was developed to reconstruct missing elastic logs from the available raw data.

3D AVO inversion was performed on the NVG DAZ seismic using four angle stacks (from 5° to 39°) (Coulon et al., 2006). Results show close agreement of inversion-derived P-impedance ( $I_p$ ) and Poisson's ratio (PR) and the corresponding well-logs (Figure 4-B), which increase the confidence in their application for robust lithology and fluid discrimination. A Bayesian lithology and fluid classification workflow (Coulon et al., 2006) was then applied to generate litho-fluid probability volumes based on separability in the  $I_p$ -PR domain. Good agreement is observed between the resulting hydrocarbon sand probability, brine sand probability, and fluid interpretations from wireline logs (Figure 4-B). Elastic properties, notably P-impedance ( $I_p$ ) and Poisson's ratio (PR), were used as direct hydrocarbon indicators (DHIs) for lithology and fluid discrimination (Figure 4-A). Their effectiveness varies depending on the geological context, but rock physics analysis of the well data is encouraging. In the relative  $I_p$ -PR domain, good separation is observed between water-bearing sands and shales, and hydrocarbon-bearing sands are differentiated from water-bearing sands (Figure 4-A). Use of the relative

elastic domain helps mitigate the effect of compaction trends and improves litho-fluid discrimination. These observations highlight the importance of generating robust Ip and PR volumes through AVO inversion to ensure discrimination consistently across the study area.

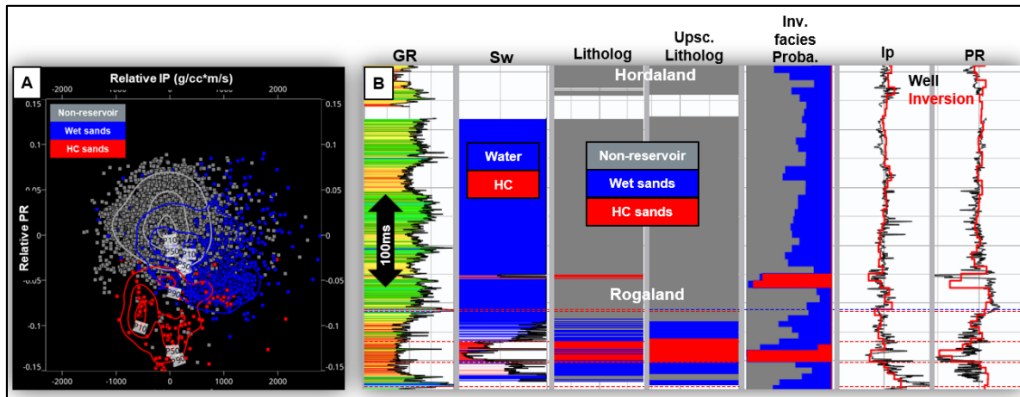


**Figure 4** – (A) Ip–PR relative domain, where a good separation between water-bearing sands and shales, and a clear discrimination between HC-bearing sands and water-bearing sands is observed and (B) comparison between well data, inversion and classification results for well 1.

### Integrated Geological Interpretation Approach

A detailed analysis of the subsurface reservoirs was previously conducted through the integration of seismic attribute analysis and machine learning techniques. This provided insight into the depositional system, which is essential for understanding the later processes that led to sand remobilization. The incorporation of elastic inversion and rock physics analysis into the integrated workflow (Figure 2) enables differentiation between remobilized injected sands and in-situ depositional sands, as well as between hydrocarbon- and water-filled sands (Figure 5). This shifts the interpretation from a largely qualitative description toward a more quantitative assessment of sand distribution, reservoir quality, and system architecture.

The inversion results have identified most of the injectite bodies as sand-prone features with good spatial resolution (Figure 5 – A, D). In addition to the injectites, other sand intervals are clearly defined, particularly within the upper Rogaland Group. The continuity of the inversion-derived properties improves the delineation of injectite geometry and connectivity, thereby supporting interpretation of potential migration pathways between parent sands and injected networks. The ML-derived mask did not capture some sand intervals, as that ML workflow was specifically designed to detect strong discordant amplitude characteristics of injectite complex geometries, rather than more in-situ depositional sand bodies. In contrast, the inversion properties enhance the detection of low-amplitude injectite features that may not be resolved by seismic amplitude-based or ML approaches. This is illustrated in Figure 5, where the most probable sands from the inversion results are shown in brown (Figure 5 - A, D), whereas injectite sands identified by ML are highlighted in yellow (Figure 5 - C, F).

The inversion workflow also provides a clear distinction between hydrocarbon-filled and water-filled sands (Figure 5 – A, B, D, E). The hydrocarbon-filled (HC) sand facies probability result, with green arrows indicate possible HC migration along the injectite wing and polygonal fault (Figure 5-B). These observations are consistent with known accumulations and highlight additional near-field prospective opportunity within the study area.

### Conclusions

In this paper we presented a large-scale case study from a 1,000 km<sup>2</sup> area in the Norwegian North Sea targeting a thin clastic hydrocarbon-bearing system comprising both remobilized and in-situ

depositional sands. The high-quality, AVO-preserving DAZ seismic data enabled robust elastic inversion, yielding reliable P-impedance and Poisson's ratio volumes. Integration of AVO inversion results with established geological concepts improves the understanding of subsurface reservoir architecture, including injectites geometry, connectivity, and parent-sand depositional systems. The workflow also enables discrimination between hydrocarbon-filled and water-filled sands. Overall, the integrated approach reduces uncertainty through hydrocarbon - sand probability attributes and supports near-field exploration of the Paleogene injectite play.

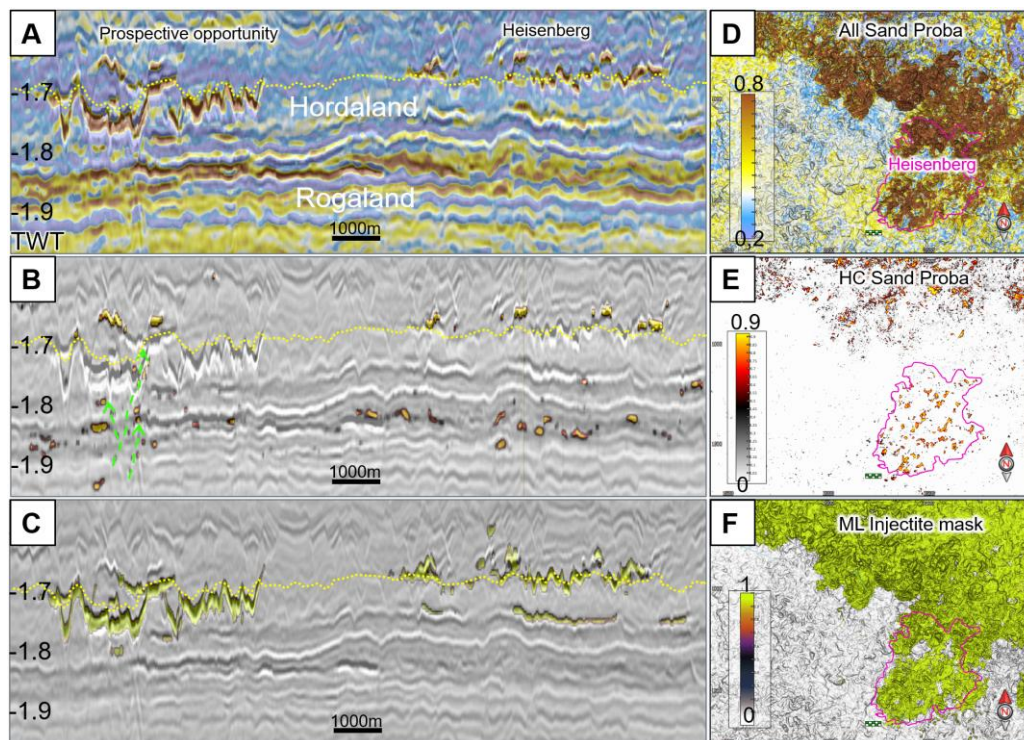


**Figure 5** DAZ seismic section with overlaid (A) probability of all sand facies across the Heisenberg discovery and an injectite prospective opportunity within the Lower part of the Hordaland Group; (B) hydrocarbon-bearing (HC) sand facies probability; (C) ML 3D injectite mask prediction; In the map view: (D) Maximum probability of all sand facies, (E) Maximum HC sand facies probability; (F) Maximum ML injectite mask prediction - extracted along yellow horizon within a 100 msec window.

## References

- Buriola, F., Mann-Kalil, J., Latter, T., Kjølraug, I. and Rummyantseva, A. [2023]. How technological advances in seismic acquisition, processing and imaging can bring new insights to near-field exploration. *First Break*, **41**, 63-70.
- Coulon, J.-P., Lafet, Y., Deschizeaux, B., Doyen, P. M. and Duboz, P. [2006] Stratigraphic Elastic Inversion for Seismic Lithology Discrimination in a Turbiditic Reservoir. SEG 76th Annual Meeting.
- Huuse, M., Cartwright, J., Hurst, A. and Steinsland, N. [2007]. Seismic Characterization of Large-scale Sandstone Intrusions. Sand injectites: Implications for hydrocarbon exploration and production: AAPG Memoir, **87**, 21-35, <https://doi.org/10.1306/1209847M873253>.
- Rummyantseva, A., Mann-Kalil, J., Mitchell, S., Macaulay, D. and Triki, A. [2024]. Norwegian North Sea: Detailed mapping of sand injectites integrating seismic attribute analysis and machine learning techniques. *First Break*, **42**.