Gas to Europe: Exploring for Norwegian gas-richness in the Atlantic Margins

Adriana Citlali Ramírez[1]*, David Went[1], Bent Kjølhamar[1], and Reidun Myklebust[1] illustrate how exploration can be fast-tracked and risked through the use of modern multi-client seismic data.

Motivation

Less than two years ago, conversations about the need for oil and gas were almost frowned upon. That was the effect of the pandemic and a laudable worldwide focus on an accelerated path to Net Zero with a specific subset of technologies and energy solutions. This changed the global exploration outlook. It hugely reduced budgets, limited exploration to infrastructure-led targets within mature areas, enforced low-risk E&P strategies, pressed hard on geophysical contractors, and promoted personnel reductions worldwide. In short, the industry shrank, slowed down, and struggled.

Well before the end of 2021, the fact that Europe needs huge amounts of gas to pull through the winters, their increasing supply problem, and their strong reliance on Russian gas were all known, though not always acknowledged. According to the World Economic Forum, in 2021 all but two European countries included gas in their energy mix. However, the increased investment in alternative energy solutions was not enough to curtail Europe's increasing demand for gas that winter. This is due to their inherent intermittency, uncertain supply, volatile prices, and a very low power density. In addition to these facts, the geopolitics in early 2022 completely changed the world's focus when it comes to energy. The events leading to the ongoing war in Ukraine, have exacerbated Europe's need for gas, and refocused the energy conversation towards energy security. These events have highlighted the impact that a shortage of gas has, disrupting economies, supply chains, the sovereignty, and security of countries. They have also led to a recognition of gas as a key fuel for the energy transition. Furthermore, outside Europe, the LNG demands from China and India are also increasing, while a consistent supply from Russia remains uncertain.

Norway is well positioned to further rescue Europe and fuel the energy transition. For starters, the Norwegian Petroleum Directorate estimates that more than 20 billion barrels of oil equivalent remain to be found within their borders. A year after the geopolitical turmoil highlighted above, with a worldwide agenda of energy security and higher gas prices, oil companies are refocusing their exploration target areas, and their appetite for higher risk and higher rewards outside mature prolific basins. This includes the hugely underexplored Møre and Vøring basins in the Norwegian Sea's Atlantic Margin. To our knowledge, there are no basins as under-explored and as proximal to major energy markets as these basins. Thus, they are not full-frontier, isolated basins. They already contain huge producing gas fields (Aasta Hansteen and Ormen Lange). Today, it is possible to obtain a second opinion of relinquished gas discoveries and identify new drillable targets adding critically needed volumes from these deep-water terrains. The purpose of this article is to illustrate how exploration can be fast-tracked and risked through the use of modern multi-client seismic data.

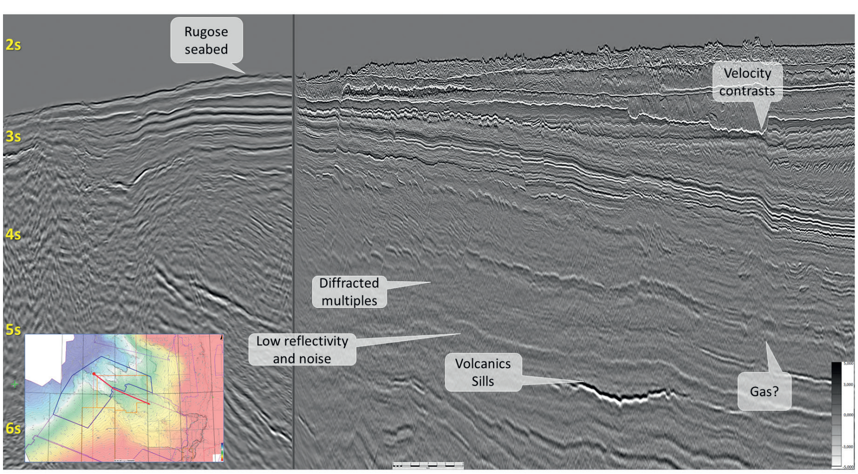

Figure 1 shows some of the processing challenges encountered in the Atlantic Margin, with 2D seismic on the left, and triple source, 3D seismic with original time processing on the right.

[1] TGS
* Corresponding author, E-mail: Adriana.Citlali.Ramirez@tgs.com
DOI: xxx

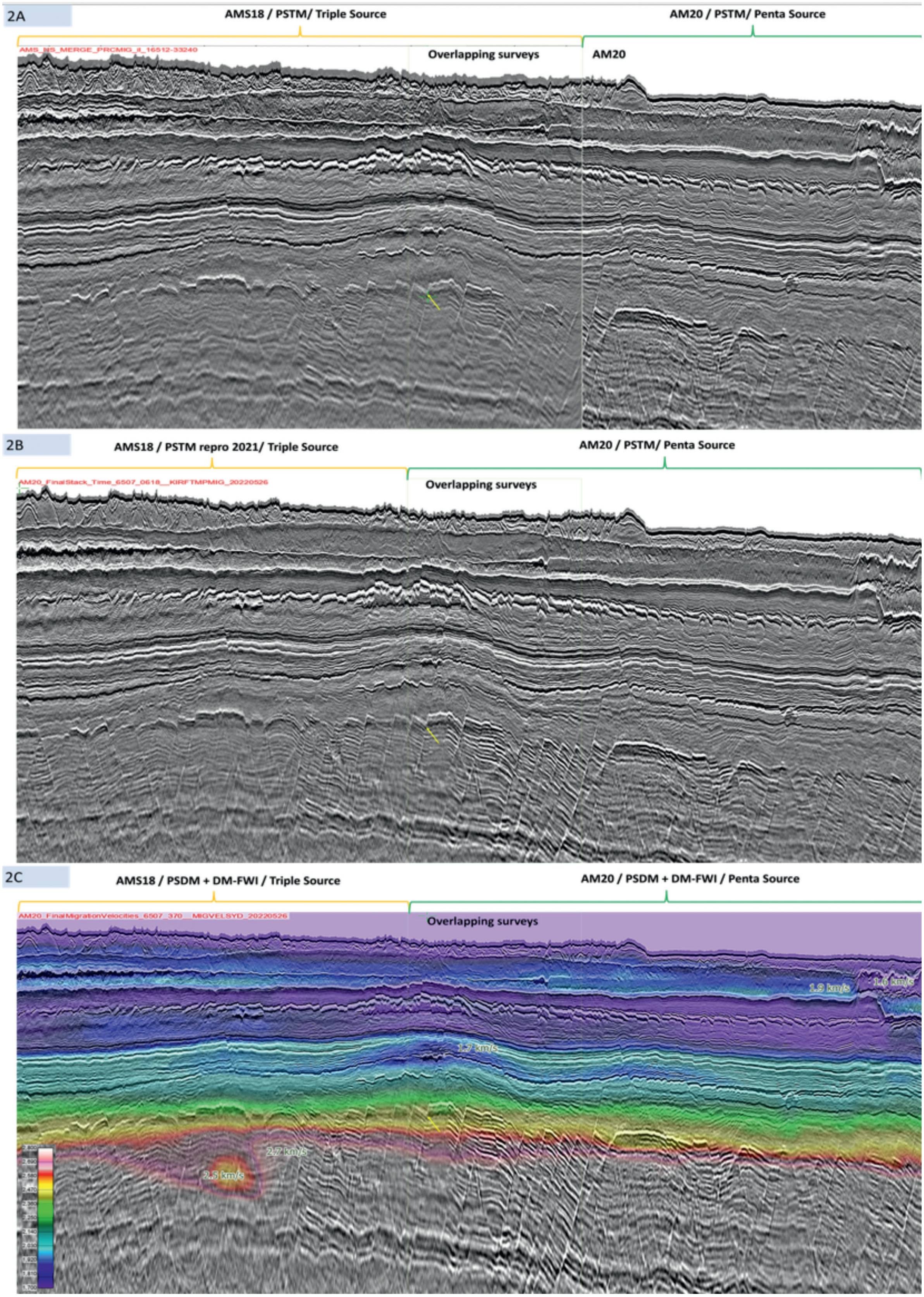

Figure 2 On the leftmost of Figure 2a, PSTM legacy data is displayed vs. AM20 PSTM. The same AM20 PSTM is displayed on the right of 2b, extending it to the overlapping area in the middle, the data on the left is the reprocessed AMS18 PSTM. The arrow highlights the depth location from which most differences can be observed. In the original processing, leftmost 2a, the illumination is severely affected, due to multiples, scattering, and noise. The reprocessing, leftmost 2b, shows improved illumination and fault definition, while the overlap highlights the further benefits of improved sampling leading to even better illumination at depth in addition to faulting, sharpness, and signal penetration. Figure 2c displays the AMS PSDM on the left vs. AM20 PSDM on the right, overlain by the DM FWI velocity, which has been clipped to highlight the interpretability of the velocity values.

Developments in modern multiclient data

Exploration in this area was traditionally hampered by a lack of geological understanding mostly from 2D seismic. Very few wells have been drilled to date. This deep-water area, between 2 and 3 km occasionally has a rugose seabed, like at the Holocene Storegga sub-aquatic slide. Shallow mud diapers also create complexity. This generates strong multiples which are difficult to remove, and which diminish the reflectivity at the target level. A portion of the area is affected by volcanic rocks which are hard to image with 2D seismic and legacy processing. The complexity of the glacial overburden characterised by high velocity contrasts related to evacuation craters and remobilised oozes is another challenge. Low reflectivity is due to nonlinear scattering, attenuation due to gas, hydrothermal vents, and the presence of sills. As opposed to other regions nearby, where most fields were discovered with 2D seismic, this area was not to be unlocked without investment in modern technology.

Between 2017 and 2020, over 59000 km^2 of modern 3D streamer seismic data were acquired by TGS. The regional dataset comprises four surveys, one per year. AM17 was among the first 3D large scale surveys acquired with triple source, with the goal of increasing quality (sampling with natural bin size of 6.25 x 18.75 m., offsets up to 8km) and reducing cost (time in the field). AM18 and AM19 used the same configuration, achieving an improved PSTM characterisation of the subsurface compared to legacy 2D as seen in Figure 1. The improvement brought up by moving to 3D in time processing is significant, but not enough. Therefore, from 2018 to 2020 TGS's Sub-basalt Imaging and Research program focused on testing and developing advanced depth imaging workflows specific for the Atlantic Margins using wave equation-based techniques inspired by the advances in subsalt imaging over 625 km2 of AM18 data. The key findings from these first tests were that the velocity model driven by Full Waveform inversion started to be interpretable alongside the depth-imaged seismic, a good correlation with gravity highs was obtained, and faults and strata below the basalts could be interpreted with more confidence. In parallel, the progress in acquisition and deblending technology matured in this time to enable wide source towing with penta-source shooting (6.25 x 12.5 m. bin size). This way, AM20 became a penta source survey, maintaining the 8km maximum offset and extending two cables to 11 km for advanced velocity model building with Dynamic Matching Full Waveform Inversion (DM FWI).

The AM20 survey overlapped a portion of AMS18 (where S stands for the southern portion of the survey acquired in 2018). The processed AM20 volume included this overlap and a small extension into AMS18 which was reprocessed. With these volumes, the following comparisons were readily available to demonstrate the improvements of reprocessing in time, vs. depth imaging with DM FWI model building, and some of the benefits of improved sampling with penta source:

1. AMS18 PSTM vs. reprocessed PSTM –leftmost areas of Figure s 2a and 2b.
2. AMS18 PSTM vs. AM20 PSTM –middle areas (Overlapping surveys) of Figure 2a and 2b.
3. AMS18 reprocessed PSTM vs. AM20 PSTM, i.e., triple vs. penta source sampling –Figure 2b.
4. AMS18 PSTM vs. AM20 PSDM –middle areas (Overlapping surveys) of Figure 2a and 3c.
5. AMS18 PSTM and AM20 PSTM vs. AMS18 PSDM and AM20 PSDM –Figure 2b and 3c.

In the following, we present the use of high-end imaging, elastic inversion, and model building with DM FWI to interpret the geology and gas anomalies. New data and technology are revealing secrets in a formerly elusive deep-water basin explored for more than 25 years. We may soon answer if indeed the gas itself is generated from the heat when volcanic sill intruded organic-rich Cretaceous shales. We hope the following information inspires you to do more frontier exploration in the middle of Europe.

Beyond imaging: screening for prospect opportunities using elastic inversion

The integrity of the pre stack seismic signal is such that when the geological conditions are suitable, the data can be inverted to screen for hydrocarbons directly using elastic inversion. The geology of the Atlantic Margin is dominated by post-rift, siliciclastic sediments (sands and shales) locally intruded by volcanic sills and dykes. Whilst the intrusions can pose a challenge for imaging teams, the siliciclastic sediments are well suited to yielding information regarding their lithology and fluid properties through elastic inversion.

A study of global trends in the velocity (Vp, Vs) and density (rho) of siliciclastic lithologies suggest that in normally compacting basins, over a wide range of depths, lithology, and fluid (brine versus oil and gas) can be discriminated using intercept and gradient data projected to an incidence angle (θ) of around 45° (Went 2021). When viewed on an intercept-gradient cross-plot this equates to a rotation angle (χ) of 27°. Petrophysical analysis of the few well penetrations in the area can be used to corroborate this trend.

TGS uses the attribute termed relative extended elastic impedance (rEEIχ27) to screen for fluid anomalies. As the name suggests, this is a band-limited elastic inversion derived entirely from the seismic data and uses differences in intercept-gradient relationships to discriminate lithology and fluid at a chi(χ)-angle of 27°. In this sense it builds on AVO concepts relating to the fluid factor (Smith and Gidlow 1992, Gidlow et al 1993, Fatti et al 1994) and extended elastic impedance (Whitcombe et al 2004). The method uses relative impedance inversion of angle stacks then calculates intercept and gradient impedance to generate rEEI at any angle (Went 2021). The process is robust and relatively quick to employ since no wells or horizons are used in the process. Well data still has a vital role, however, since every well in the inverted volume acts as a true blind test of the efficacy of the method. In this way, confidence is built in the ability of the seismic data alone, to truly discriminate lithology and fluid.

Example results are illustrated from the survey AM19 in Figure 3. The line shows a prominent rEEI anomaly over wells containing gas in the Springar Sandstone, a discovery called Gro. It also shows an anomaly at the level of the Tare Formation on the high above the Rån volcanics. The Gro gas accumulation is proved by two wells and the extent of the REEI anomaly combined with the pay present in the wells suggests it contains more than 10TCF gas in place (nearly 2 billion BOE). The Tare lead is smaller but could be indicative of hydrocarbon-bearing sands containing more than 1 TCF of gas (or oil equivalent) in place. The efficacy of the rEEI technology is proved at the level of the Springar Sandstone by the successful prediction of the results of the two Gro wells (Figure 3c). In addition to the anomalies mentioned, there are several other rEEI anomalies present at Tang- and Tare-Formation levels, which are also prognosed to be indicative of the presence of hydrocarbons. The multiple rEEI anomalies together with the wells proving the presence of gas, suggest the region has the potential to yield many very large discoveries and to become a large gas producing province. Reservoir intervals are scarce. However, the strong AVO contrasts of gas sand, brine sand and shale mean the rEEI technology is well suited to both identifying and delimiting the extent of sand fairways and hydrocarbon accumulations.

Volcanic rocks might be beneficial for the hydrocarbon systems

During the first two decades of this century, there was an ambition to understand how to best acquire seismic data, process, and image it in volcanic areas. Early 2D and 3D sub basalt imaging was beyond difficult. The volcanic rocks with high velocities, layering and high-density contrast challenged conventional workflows and signal penetration, their rugosity and heterogeneity created massive noise challenges, strong nonlinear scattering that completely masked intra basalt and sub basalt targets. As an example, the development of the Rosebank intra volcanic oil discovery was delayed more than a decade, due to subpar imaging of the hydrocarbon reservoirs in seismic data. Better and more densely spaced measurements in acquisition, longer offsets, and modern processing workflows (using key resource-heavy algorithms like SRME, IME, RTM, and FWI) was necessary not only to the development of Rosebank but to contribute to solving the puzzle of hydrocarbon systems in the Atlantic Margin's volcanic areas. Rosebank, now better understood, suggests a continental crust under the Western Atlantic margin. Three wells crossed a section indicative of weathered granites on the Kolga High (the dating is ongoing, so it is not yet conclusive the type of granite). Before this, the Kolga High was assumed to have exhumed mantle rocks as root or core. Similar outcropping granites have been identified on the conjugate Greenlandic side, modelled to be less than 80 km from Kolga High (see Figure 4) pre-continental breakup. Granites are sources for quartz-rich sands that can uphold much of their initial porosity to

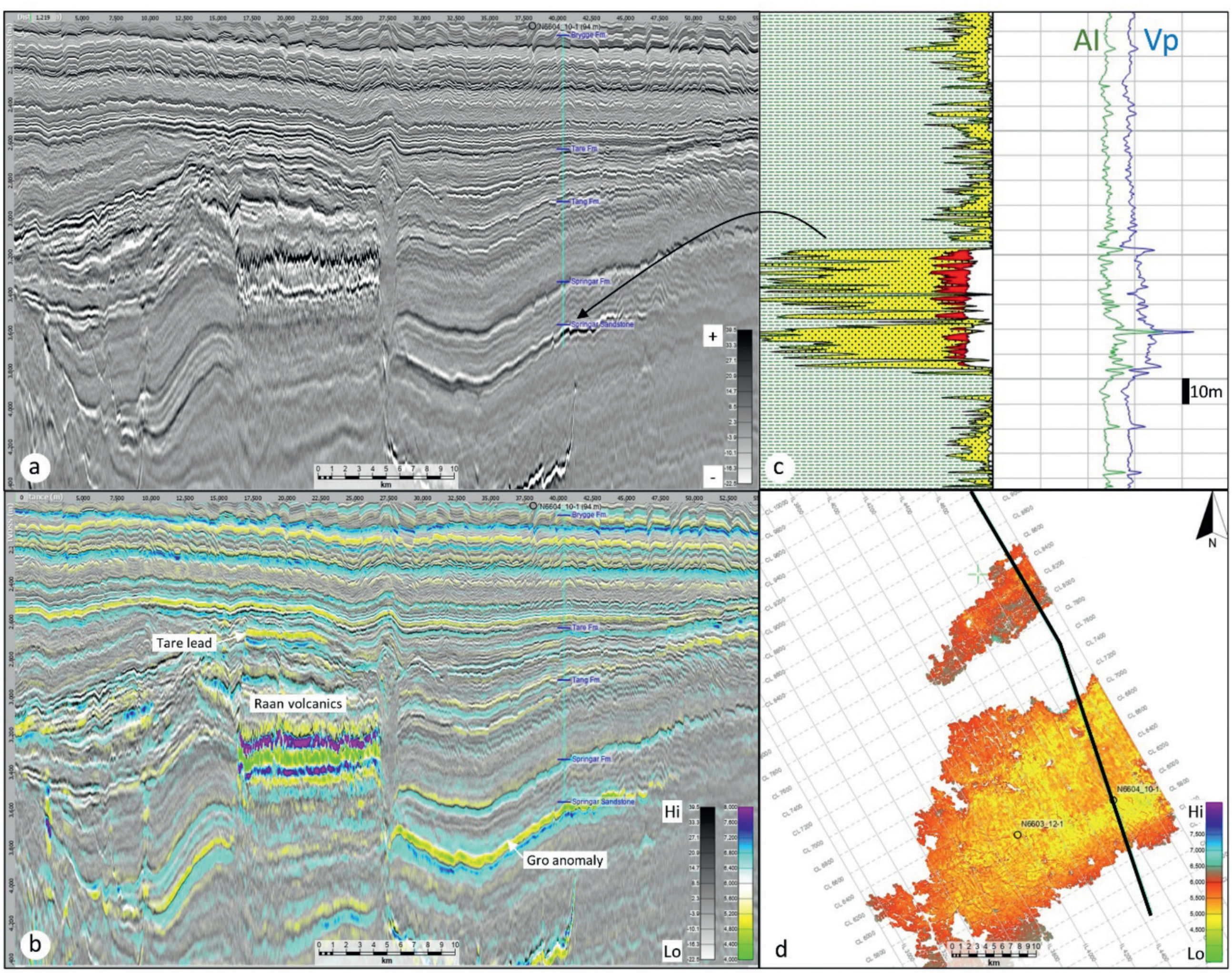

Figure 3 a) NNW-SSE seismic stack section intersecting well N6604/10-1, b) rEEIχ27 inversion showing the Gro rEEI anomaly and an rEEI generated lead in the Tare Formation above the Rån volcanics, c) petrophysical interpretation from the N6604/10-1 well showing gas in the Cretaceous age, Springar Sandstone and the p-wave velocity and acoustic impedance characteristics of the seal and reservoir, d) extent of visible Springar Sand gas anomaly (yellow) and line of section.

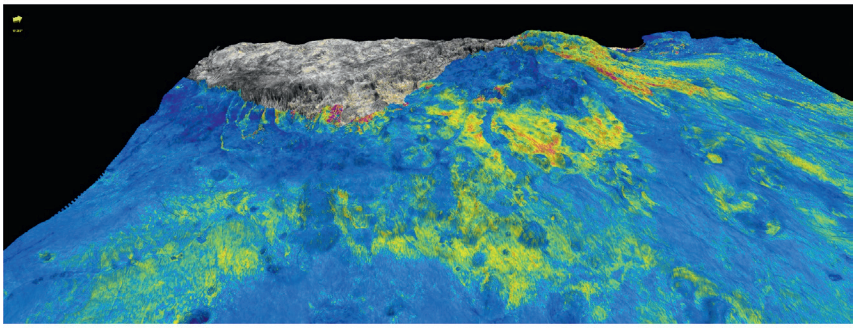

Figure 4 shows the top basalt and outcropping Kolga High granites within the grey area and, in warm colours, the rms amplitude anomalies of deltas, presumed quartz-rich sands coming from Kolga High. There are no wells yet in this 15000 km2 3D area covered by seismic.

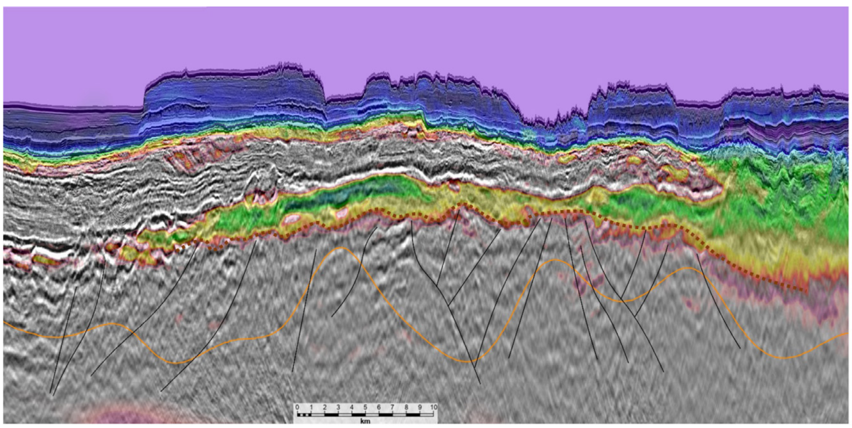

Figure 5 New 3D data processing approaches on the western flank of the Atlantic margin, including DM FWI velocity modelling, has changed interpretability of intra and sub basalt targets. The Figure has the velocity field overlayed, and this helps the interpreter assess hardness of the underlying rifted terrain including basement horsts. The dotted blown line is near the top of an older fast velocity high with interpretable faults and the orange line is Bougher gravity. Isolated slower velocity layers in green blue, between flood basalt above and fast velocity, rifted terrain below indicate sediments with preserved reservoir quality, potentially containing hydrocarbons.

become reservoirs. Furthermore, any long reaching turbidites from the Greenland side might have been decapitated leaving coarse grained sediments exposed when passing these elevated rugged terrains. As such the marginal highs, areas of about 100-km wide plateau with limited Cretaceous and Paleogene overburden, may have locally derived quartz-rich sands between the highs in the basins in the east of Greenland.

In the 2021 IODP #369 cruise, 21 boreholes at 10 sites were drilled around and within the Vøring Basin. Eight of these boreholes were wireline logged (Planke et al. 2023). The wells were drilled into basalts, retrieving 2 km of core, sampling igneous and sedimentary rocks. Among the current findings are interbedded sands encountered between flood basalts. Thus, there is increasing evidence of highly porous and permeable vesicular flood basalts, with preserved intra basalt sand reservoir or even sub basalt reservoir quality with strong implications for sub basalt prospectivity in the Atlantic Margin. To make these observations in the 59000 km^2 of 3D AM seismic and enable the interpretation of sub basalt geology, dedicated work on demultiple was necessary as well as denoising to prepare gathers for tomographic and anisotropic updates in between passes of DM FWI, during model building, and for a cleaner image of the subsurface. In particular, the DM FWI velocity field has provided added value aiding the interpreter to identify slow velocity layers where porosity in reservoirs could be preserved and fast trends indicative of basement or hard old sedimentary rocks. Figure 5 provides an example. In this seismic image, under 500-1000 m. of flood basalts, penetration of low frequency signal is observed. In addition, older rifted terrains or Cretaceous basins below these thick volcanics can be interpreted. The low frequency character of the sub basalt signal is mostly due to extrinsic attenuation related to scattering, and it is the signal that in the past was elusive, buried in noise and multiples. Alternative migration algorithms like RTM and LS RTM have proved beneficial to use in these cases, bringing out layering not seen in the sub basalt Kirchhoff migration –this is the subject of ongoing work and future publications.

As is frequently observed in the volcanic sill intruded Cretaceous basin, the presence of volcanic rocks often helps the hydrocarbon migration and trapping in an else flat mud-dominated basin. One example of this, imaged recently is the Rån flow, a massive volcanic body in the Vigrid synclinal in the Vøring Basin (Figure 6). The joint interpretation of the DM FWI velocities and the imaged seismic support the theory that it was emplaced in the initial stages of the breakup, about 55 ma. Push ridges in the top indicate that it was moving from west to east in an existing Paleogene sedimentary fairway. A heavy 200-300m thick volcanic body is likely to sink into soft sediments. As seen in the seismic (Figure 6), three bright soft events, possibly sands, must have been controlled by this sinking body and the available accommodation space above it. Later inversion then pushed the whole system in an anticlinal structure. Furthermore, this heavy body seems to have static faults on its sides. A distinct slow velocity anomaly below can be interpreted as trapped fluids or gas. Stated succinctly, the volcanic body has focused later reservoirs above and potentially created a trap below – all that can be tested with one exploration well. Risked volumes should be within the commercial range.

Conclusions: What's next?

Until a few years ago vast areas of the deep-water Norwegian Sea lacked a basic 3D data coverage. In 2021, the IODP drilling program drilled two shallow wells penetrating granite basement

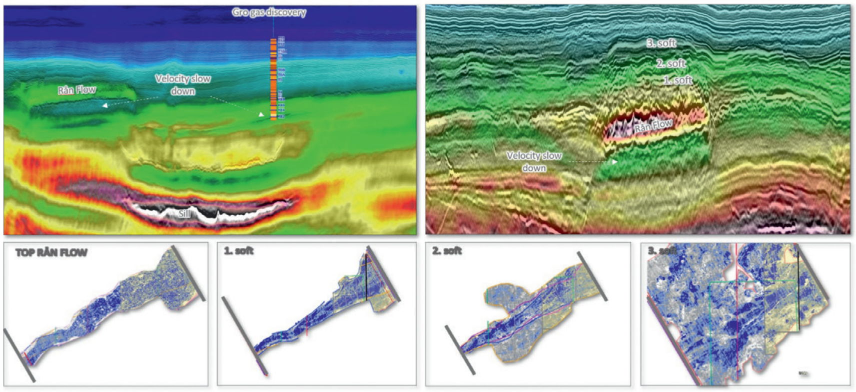

Figure 6 The Rån volcanic flow may have created traps above and below by sinking into soft Paleogene sediments north in the Vøring Basin. Four potentially prospective levels have been identified based on DM_FWI velocity (top left) and seismic amplitudes (four boxes below). The slower velocity observed under the Rån Flow is like the slow velocity anomaly in the Gro gas discovery beside.

and interbedded quartz-rich sands. These facts together with bright fan systems off the highs has changed the perception of the Atlantic margin areas in the Norwegian Sea.

Better geophysical tools and imaging are unlocking new play models close to, in between, and under volcanic rocks. Latest PSDM technology utilising DM FWI velocities has yielded a new indicative tool that can be used in combination with relative elastic impedance and the seismic image itself to, e.g., identify anomalies associated with hydrocarbons in the Atlantic Margin region and allowing to us to distinguish between thin volcanic and siliciclastic layers. More importantly, sedimentary details are becoming interpretable beneath sections of thick and complex basalts. This is an immature area regarding exploration drilling, but close to existing infrastructure and a demanding energy market.

The technical drilling successes, so far, have identified hydrocarbons in Upper Cretaceous and Paleocene sections. Our extensive interpretation of these datasets, a collaboration between VBER and TGS, has revealed details about the untapped potential of the region, and illustrates an opportunity for more active exploration and drilling activity. There are enormous sub basalt closures all along the Atlantic Margin, with significant catchment areas for any migrating hydrocarbons. The likely pre-Cretaceous highs are at present located within the oil window. In fact, recent seafloor sampling has detected gas and oil seeps related to the inner flows in the Northern Vøring Basin. Our expectation is that announcements of drilling activity in this potentially highly prolific margin are imminent.

References

Fatti, J.L., Smith, G.C., Vail, P.J., Strauss, P.J. and Levitt, P.R. [1994]. Detection of gas in sandstone reservoirs using AVO analysis: A 3-D seismic case history using the Geostack technique. *Geophysics*, **59**(9), 1362-1376.

Gidlow, P.M., Smith, G.C. and Vail, P. [1993, April]. Hydrocarbon detection using fluid factor traces: a case study. In *3rd SAGA Biennial Conference and Exhibition* (pp. cp-224). EAGE Publications BV.

Planke, S., Berndt, C., Alvarez Zarikian, C.A. and the Expedition 396 Scientists 2023. Mid-Norwegian Margin Magmatism and Paleoclimate Implications-Expedition 396, Sites U1565–U1574, *Proceedings of the International Ocean Discovery Program*, College Station, Texas, 10.14379/iodp.proc.396.2023.

Smith, G.C. and Gidlow, P.M. [1987]. Weighted stacking for rock property estimation and detection of gas. *Geophysical prospecting*, **35**(9), 993-1014.

Whitcombe, D.N., Connolly, P.A., Reagan, R.L. and Redshaw, T.C. [2002]. Extended elastic impedance for fluid and lithology prediction: *Geophysics*, **67**(1), 63-67, https://doi.org/10.1190/1.1451337.

Went, D.J. [2021]. Practical application of global siliciclastic rock-property trends to AVA interpretation in frontier basins. *The Leading Edge*, **40**(6), 454-459.