Revitalizing seismic data with new imaging solutions to positively impact field development

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Abstract

Evaluating, planning, and forecasting are integral parts of asset development and continue throughout the life cycle of a producing field. The right decisions are required to lower risk and maximize economic recovery in challenging environments. The Claymore Complex is located in the North Sea and was discovered in 1977. A number of geologic challenges affect the imaging and hence field development including a system of shallow interweaving Quaternary channels, numerous high-contrast layers of varying composition, overburden structural complexity, and a sequence of tilted fault blocks containing the main reservoir systems. Historically, seismic processing over the area has not fully solved these challenges, resulting in significant imaging uncertainty. The Claymore Complex has an abundance of data including a large population of well information and interpretation. As part of a data revitalization process, geostatistical integration of these auxiliary data into a velocity model building sequence using full-waveform inversion and wavelet shift tomography enabled the generation of an accurate high-resolution velocity model. Access to a recent 3D survey acquired obliquely to existing data improved subsurface illumination for both the model building and imaging phases. Near-surface imaging effects and their impact on reservoir positioning and clarity were improved using the upgraded velocity model and dual-azimuth data. Shallow imaging challenges were mitigated by utilizing the additional illumination and angular diversity contained within the multiple reverberations. The revitalization of the Claymore area seismic data has challenged the current understanding of the geologic framework. Confidence has been improved by solving depth conversion problems and increasing the understanding of fault positioning and reservoir connectivity, which are invaluable for future field development.

Introduction

The North Sea has been an active site for petroleum exploration for more than 50 years and plays a vital role in satisfying the United Kingdom's energy requirements. In 2016, oil and gas provided 76% of the United Kingdom's primary energy of which 60% was indigenously sourced (Oil and Gas UK, 2017). Despite the policy shift toward renewables and nuclear energy, this trend is set to continue, and it is forecasted that by 2035 oil and gas will contribute two-thirds of total primary energy (Oil and Gas UK, 2017). Furthermore, the last half decade has been a turbulent time as the price of Brent crude oil has declined, which has affected all aspects of the upstream industry. This is well illustrated by both the reduction of capital expenditure for the U.K. Continental Shelf (UKCS), which has gone from £15 billion in 2014 to £5.6 billion in 2017 (Oil and Gas UK, 2018), and the number of people directly employed in the oil and gas sector, which has decreased by approximately 31% from 41,300 in 2014 to 28,300 in 2017.

Throughout the downturn, demand has not faltered, but companies have looked to improve the efficiencies of producing fields to maximize their economic return. Field development continues throughout the asset life cycle, and being able to analyze and forecast production accurately are essential ingredients to success. One key source of information used in the decision-making process is seismic data, which is readily available in the North Sea. These data can provide crucial information about a reservoir's geologic framework and are a vital tool in production planning to help maximize field potential. Seismic acquisition and processing solutions have continued to develop at a fast rate, and this coupled with an exponential growth in compute power has led to a step change in the quality of seismic imaging in recent years as we incorporate more of the wavefield into imaging flows. We demonstrate that a cost-effective approach to maximizing the value of seismic data for ongoing field development can be achieved through the application of leading-edge integrated imaging solutions in conjunction with the use of auxiliary information such as wells and interpretation to revitalize existing seismic data. The rationale for this reprocessing is that uncertainty in the seismic image is largely dependent on the precision of the imaging models and therefore the methodology used to generate them. By implementing an integrated workflow using different algorithms and data, we can mitigate existing limitations to technologies that exist in any one of the methods used, thus producing more accurate models and images in shallow waters with complex overburdens (Rønholt et al., 2014).

We present an example from the Claymore Field Complex in the Outer Moray Firth of the North Sea. Two previously acquired and processed seismic data sets were used jointly in a velocity model building and depth-imaging exercise using leading-edge integrated imaging solutions in conjunction with wells and interpretation data to revitalize and maximize the value of the seismic data over a producing field. The two data sets, shot in 2001 and 2012, were acquired obliquely to each other offering the opportunity to perform a dual-azimuth velocity model build and final image. The Claymore Complex reservoirs contain low gas-oil ratio (GOR) and relatively dense oil. Despite significant production and 11 years between the data acquisitions, no time-lapse effects have been detected in the acoustically hard reservoirs. We present the area and associated challenges and a technical description of the flow used along with data examples. Finally, we discuss the impact of the revitalized image and how it has influenced future target assessment as part of the ongoing field development. Comparisons are made with

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images provided by legacy prestack depth migration (PSDM) and prestack time migration (PSTM).

Geologic background and challenges for field development

The Claymore Complex is situated in UKCS block 14/19n in the Central North Sea approximately 160 km northeast of Aberdeen on the southwest margin of the Witch Ground Graben. It is a mature multireservoir system that began production in November 1977. Stock-tank original oil in place (STOIIP) for the entire Claymore Complex was estimated at more than 2 billion barrels of which more than 700 million barrels have been produced since extraction began.

There are several plays that make up the Claymore Complex consisting of turbidite sands in the Lower Cretaceous and Upper Jurassic as well as Carboniferous fluviodeltaic stacked channels and Permian carbonate reservoirs. These reservoirs vary in depth and range between 2100 and 3300 m. The area is subdivided into Main Area Claymore (MAC), Western Main Area Claymore, Northern Area Claymore (NAC), and Central Area Claymore (CAC), as shown in Figure 1. MAC is a triangular south-dipping truncated fault block lying on a dip slope dipping away from the Witch Ground Graben (Chen et al., 1989).

The Claymore area is situated in shallow water (100–140 m) and is characterized by small-scale heterogeneities in the overburden, which include Quaternary canyons and thin coal layers. In addition, the high-contrast chalk layer contains a number of different lithological units and reworked highly variable carbonates of the Maureen Formation. Together these result in significant imaging distortions and depth conversion challenges. Furthermore, the imaging of the fields is impacted by multiple contamination and aliased noise generated within the complex overburden. This results in noise contamination at the reservoir level.

Strong lateral and vertical velocity gradients require a robust earth model and an appropriate imaging algorithm. Legacy PSDM did not capture the overburden sufficiently, and PSTM is not optimal for imaging in such environments. Previous processing exercises in this geologic setting resulted in an incomplete understanding and characterization of the poorly resolved reservoirs particularly with regard to their connectivity and thickness. Structural definition and placement of the main faults has also been very challenging on the available data. Resolving these key issues is of great importance to the effective management and development of the field.

To tackle these challenges, leading-edge integrated workflows for optimizing the velocity model and final image were implemented and supplemented by the available auxiliary data. The aim of the model build was to generate an accurate development-grade velocity model, which was calibrated to the well data and resolved the short-scale velocity variations within the Tertiary with particular attention to the shallow channels and the reworked chalk at the Maureen/Tor formations. An additional challenge included accurately capturing the velocity inversion at the base of the chalk and producing a geologically conformable model in the prechalk where local structural dip increased leading to greater uncertainties in the image.

Solutions for a mature basin

The velocity model building and imaging workflow was designed to tackle the specific challenges recognized during previous reprocessing exercises and to incorporate all the auxiliary data available over the mature producing field. A complete wavefield imaging solution was implemented whereby reflections, refractions, and multiples were all used at various stages through the model evolution and also contributed to the final migrated image. The integrated workflow consisted of three main elements: full-waveform inversion (FWI) (Ramos-Martinez et al., 2016), wavelet shift tomography (Sherwood et al., 2011), and separated wavefield imaging (Lu et al., 2015). The final imaging was a combined separated wavefield and Kirchhoff image.

An abundance of auxiliary information meant that the initial model build could be constrained to produce a velocity profile with a high level of geologic consistency. Kriging was used in conjunction with data from 25 wells and horizon interpretations to create the starting point for each geologic unit. Kriging produced a robust and highly geologically conformable model, capturing the vertical velocity profile and the low wavenumber component of the lateral velocity variation in the interwell space. This in turn produced a stable well tie and a robust basis from which to compute the initial anisotropy parameters.

The integrated imaging workflow implemented wavelet shift tomography in conjunction with FWI to build upon and add the higher wavenumber spatial detail to the initial model. The model was built and then iteratively updated following a top-down layer-stripping strategy within the following macrointervals: (1) Tertiary (seabed to top chalk); (2) Cretaceous chalk layer; and (3) Lower Cretaceous, Jurassic, and Triassic (to top Permian). The top Permian defined a basement, and below that the model was populated with a well-derived velocity gradient. The main horizons were reinterpreted after each velocity update and the TTI anisotropy was adjusted accordingly.

Separated wavefield imaging provided quality control (QC) in the shallow overburden. The production migrations included a Kirchhoff PSDM and an ultra-high-resolution near-surface image from the separated wavefield image merged to produce the final imaged volumes.

Kriging the initial model

The kriging algorithm utilized two trends from the wells to generate the model: a global trend extracted from all of the available data and a residual from each well. The sum of these trends matched the well data input at a single location. The residual was kriged between all data points using a distance-weighted interpolation. Following an extensive screening process based on log quality,

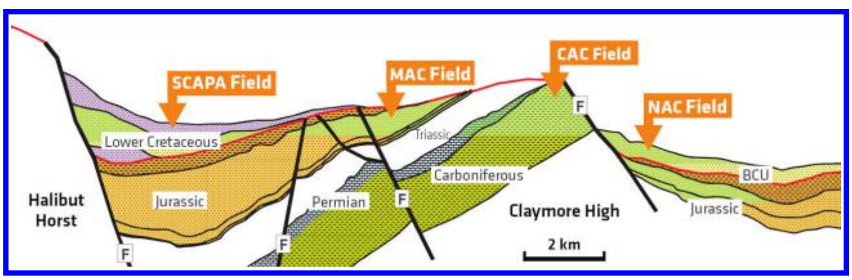

Figure 1. Schematic showing the structural setting of the Claymore Field reservoir.

depth range, and spatial coverage, a total of 25 wells were selected and used for kriging the initial model. Prior to kriging, the wells were conditioned. Horizons were used to guide and constrain the process within the various intervals. This stage involved close collaboration between the model builders, interpreters, and geologists, as several variations of the model were created at each stage to analyze the effects of horizon selection, kriging, and interpolation parameters. PSDM analysis was performed on each model scenario, and the best initial model was selected based upon the image results.

The success of the kriging exercise relied on the large number of wells and redundancy of data available over the Claymore Field. Figure 2 shows an example of the initial kriged model compared with the legacy PSTM alternative initial model. The dense well population provided a kriged initial model that accurately tied the wells and captured the velocity variation with high geologic consistency.

Full-waveform inversion

The Claymore Field is overlaid by a complex network of shallow Quaternary channels, which result in velocity-related artifacts in the legacy imaging (pull-ups and push-downs from both fast and slow velocity fill). FWI was used to capture these short-wavelength velocity features. More traditional reflection tomography techniques struggle due to offset limitations to constrain the curve fitting. To mitigate cycle skipping, a multiscale approach was implemented in three passes starting with a maximum frequency of 6 Hz for the first pass and stopping at a maximum frequency of 10 Hz for the final pass. Each successive pass added resolution to the model. The inversion was primarily driven by transmission energy. To maximize depth penetration from FWI, the full-offset range of the shot data was used. No limit to the number of iterations for each pass of FWI was set. Instead a user-defined convergence criterion was used. The inversion was terminated when the relative change in the objective function was less than the defined criterion between successive iterations. The resultant FWI velocity model effectively captured the local variation in the shallow section (Figure 3). Regionally, the model conformed geologically and the smaller scale velocity features were resolved with the appropriate channel fill added to the model. The effect of the updated model on the imaging is shown in Figures 4 and 5 illustrating how the pull-up observed beneath the channel in the initial migration was resolved. The continuity of events improved at reservoir depths, and the wave fronting present on legacy images associated with the near-surface velocity features was addressed. Solving these shallow anomalies is of great importance for field development as it provides confidence that imaging over the reservoir is not directly impacted by unresolved velocity features in the overburden, mitigating top-down error accumulation.

Wavelet shift tomography

Wavelet shift tomography was implemented to update each layer in the model in a top-down fashion, adding detail between the kriged locations. Tight constraints were implemented in the

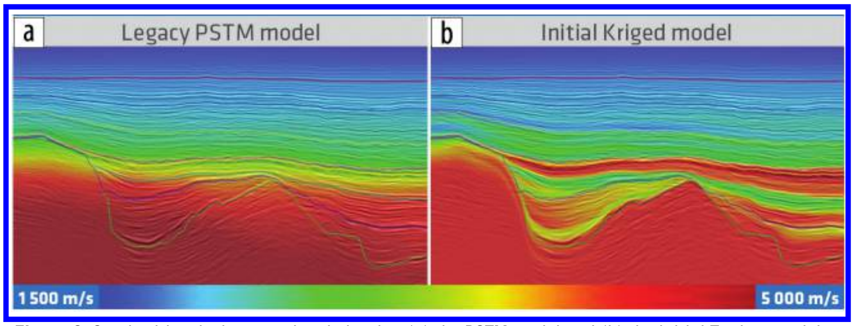

Figure 2. Stack with velocity corendered showing (a) the PSTM model and (b) the initial Tertiary model.

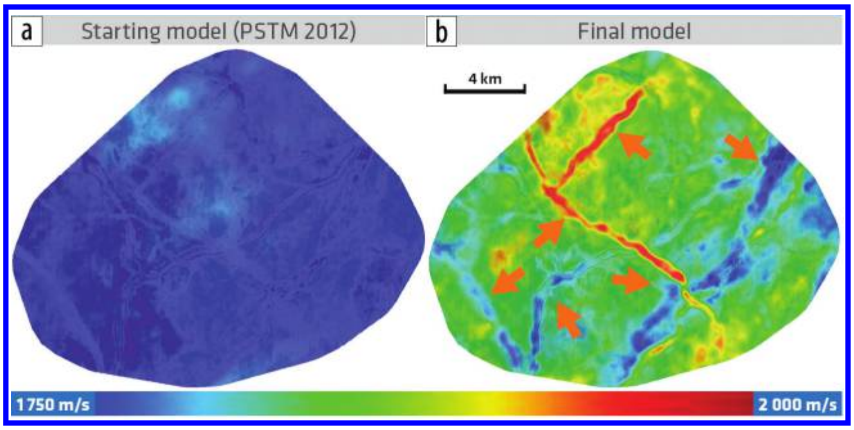

Figure 3. Shallow depth slice through the seismic velocity models (z = 280 m) with the seismic corendered. The Quaternary channel systems are characterized by fill velocities both fast and slow relative to the background and were captured through combinations of shallow tomography and FWI updates (up to 12 Hz) without prior interpretative input.

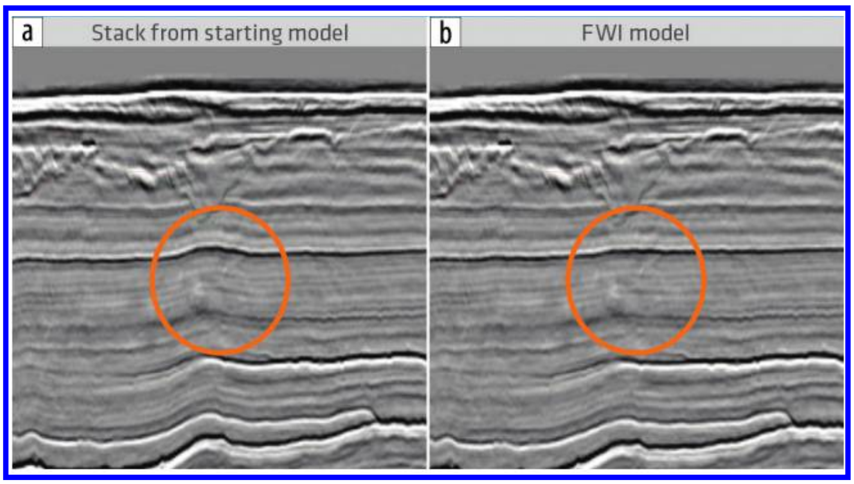

Figure 4. Kirchhoff stack QC from FWI. Stack migrated with (a) the initial model and (b) the model from FWI. The velocity field after FWI has a correct channel fill resolving the pull-up associated with the slow channel velocity.

initial passes to ensure stable results and a controlled evolution of the solution. The constraints were relaxed on successive passes.

Updating the Cretaceous chalk layer is particularly challenging in the North Sea geologic setting because the sharp velocity increase at the top of the interval results in a lack of offset diversity within it. The interval is also very thin, is affected by multiples, and contains intrachalk velocity inversions, all of which make optimizing the constraints for tomography challenging. Kriging of the well data for the initial model was guided using the top and base chalk and the intrachalk Flounder horizons (Figure 6). A strong partnership between model builders and interpreters helped to optimize the kriging process, as several interpretations of the chalk and intrachalk horizons were undertaken and numerous scenarios were tested. The initial model captured the velocity trend within the chalk and included the expected velocity inversion at the Flounder (Figure 6a). The wavelet attributes (Sherwood et al., 2009) from wavelet shift tomography enabled a discrimination of multiple from primary energy allowing for dense vertical and lateral picking of the data, which stabilized the update. Successive passes of tomography produced a detailed geologically conformable model (Figure 6b) slightly decreasing the gradient observed in the chalk over the Flounder horizon and improving the imaging of the pre- and intrachalk intervals (Figures 8 and 9).

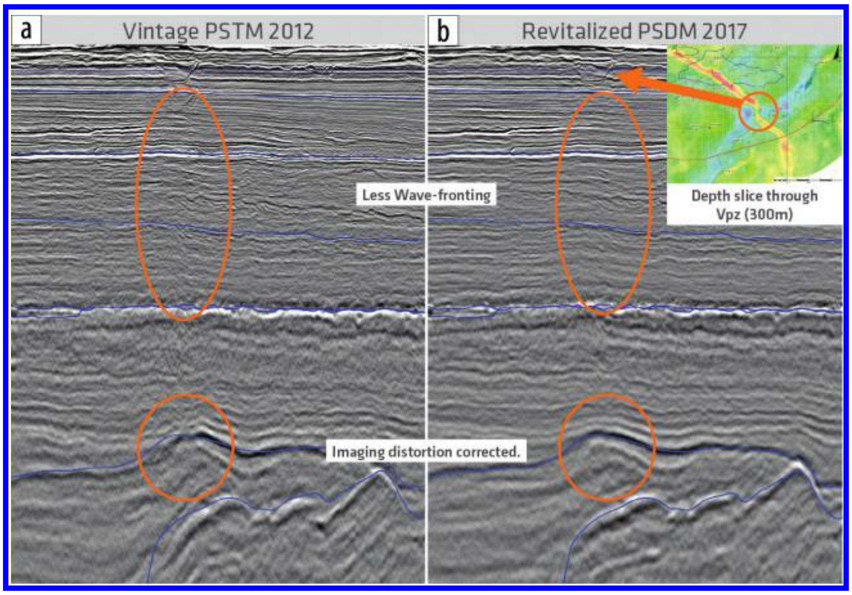

Figure 5. Kirchhoff stack QC from vintage PSTM and reprocessed PSDM. Stack time migrated with (a) the PSTM model and (b) the model from the PSDM model. The velocity field, derived using FWI and wavelet shift tomography, has improved the imaging below the channel both in event continuity and a reduction in wave fronting.

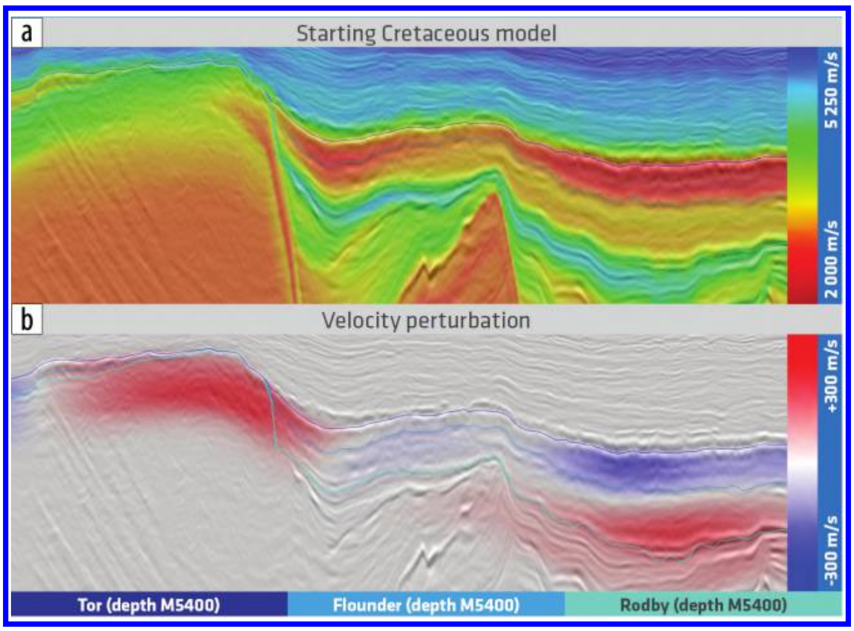

Figure 6. Beam-migrated stack with (a) the initial Cretaceous velocity model generated by kriging the well velocities, illustrating the intrachalk velocity inversion. (b) The velocity perturbation provided by wavelet shift tomography, adding further detail.

Separated wavefield imaging

Separated wavefield imaging uses the extended illumination and angular diversity of energy from multiples. Figure 7 shows a shallow depth slice at 140 m from the Claymore data and compares conventional primary-only imaging with that using the multiples. The near-surface Quaternary channel system is better defined when utilizing the benefits of the multiple energy, while the primary-only imaging suffers from an acquisition-related illumination footprint. On the Claymore Complex data, it was used twice, initially providing QC of the FWI model generation using the shallow stack image to examine the impact of velocity perturbations and to understand the structural conformity of the model with the seismic data. Secondly, it was used to augment the shallow image of the final migrations by combining a processed stack with the final Kirchhoff PSDM.

Seismic revitalization summary

An integrated imaging solution was applied to previously acquired and preprocessed data over the Claymore Complex of producing fields and provided significantly improved models and images of the subsurface. The scope of work incorporated multiple workflows, which use different parts of the seismic wavefield coupled with the extensive coverage of auxiliary data, including wells and horizons, to produce a high-resolution earth model.

Creating the initial model directly from the auxiliary data provided a geologically consistent long-wavelength starting point, which tied closely to the wells from the outset. The subsequent updates added the heterogeneity of the multiple scale-length velocity features observed throughout the overburden from the near-surface Quaternary canyons to the Maureen carbonates and the intralayer variability within the Cretaceous chalk. FWI resolved the high-wavenumber component of the shallow model identifying the channel locations and adjusting the velocities to remove associated pull-ups and push-downs in the migrated data. Wavelet shift tomography allowed for additional updates, adding more detail from the mid-Tertiary to basement.

The final Kirchhoff PSDM resolved the imaging distortions and depth conversion issues introduced at reservoir level associated with the challenging overburden features. When merged with the separated wavefield image, the final volumes allowed for a high-resolution image to be produced, which did not suffer from illumination issues in the shallow, positively impacting the interpretation of the Claymore Field area.

Dual-azimuth imaging helped mitigate the illumination limitations inherent within each individual seismic data set through dual-azimuth velocity model updating and the intelligent combination of the two surveys.

The results provided a step change in the seismic image quality (Figures 8 and 9). The improvements in signal to noise, event continuity, and signal fidelity have provided the basis for further reservoir characterization, providing a better understanding of the lateral variations in reservoir quality, connectivity, and thickness definition. The improved image focus provided an updated structural definition, and the localization of the faults has assisted the understanding of reservoir compartmentalization. A thorough understanding of the geologic environment and the challenges involved required a targeted approach to problem solving throughout the work. The close collaboration between the larger project team was essential to the successful outcome of the project. This was achieved primarily through geologic input and feedback to the model builders but also through successive reinterpretations of the data as model revisions progressed.

Reservoir-specific impact

Production from the Claymore Complex started in 1977. The STOIIP for MAC alone is just over 1.0 Bstb with a cumulative production to date of approximately 415 MMstb. As with many aging giants, the goal is to maximize economic recovery recognizing that marginal increases in recovery factor before end-of-field life are materially significant. Seismic data can impact the MAC recovery factor in two ways: (1) improved structural imaging as input to static and dynamic models within areas of well control and (2) better definition of the reservoir extent outside of well control to derisk step-out drilling.

The MAC reservoir is a massive stacked turbidite accumulation divided into discrete zones based on dynamic and petrophysical data. The aquifer is effectively inert, and water injection is required for pressure support and sweep. Mobility ratios are high, and oil/water displacement is far from piston-like — sweeping and producing one volume of oil requires many volumes of injected water. There is no Claymore direct hydrocarbon indicator — these are old hard rocks with relatively dense low GOR oil.

The top of the reservoir is characterized by structural uplift and erosion followed by deposition of the relatively soft Kimmeridge shales and silts at the base of the Cretaceous. The juxtaposition of this package above the acoustically higher impedance Jurassic sandstones in the MAC reservoir results in the characteristic base Cretaceous unconformity (BCU) seismic event. Overall, the reservoir is an extremely high net-gross package; however, the relatively homogeneous nature of this interval above an underburden sequence with similar acoustic properties means that production-level stratigraphic and structural mapping is extremely challenging. There is a thin coal sequence below the base of the Claymore sands, but this was

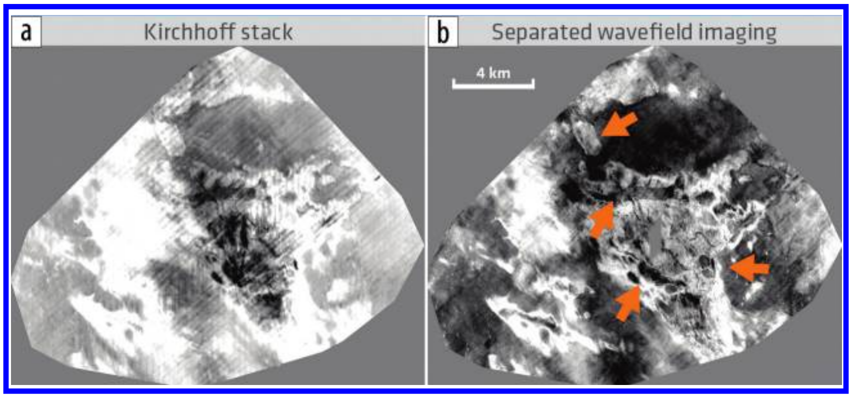

Figure 7. Final dual-azimuth Kirchhoff stack comparison with separated wavefield imaging. Images show depth slices (140 m) through (a) the Kirchhoff stack and (b) separated wavefield image. The primary-only imaging suffers from an acquisition-related illumination footprint, while the separated wavefield image shows a clear image of the Quaternary channel system (arrows).

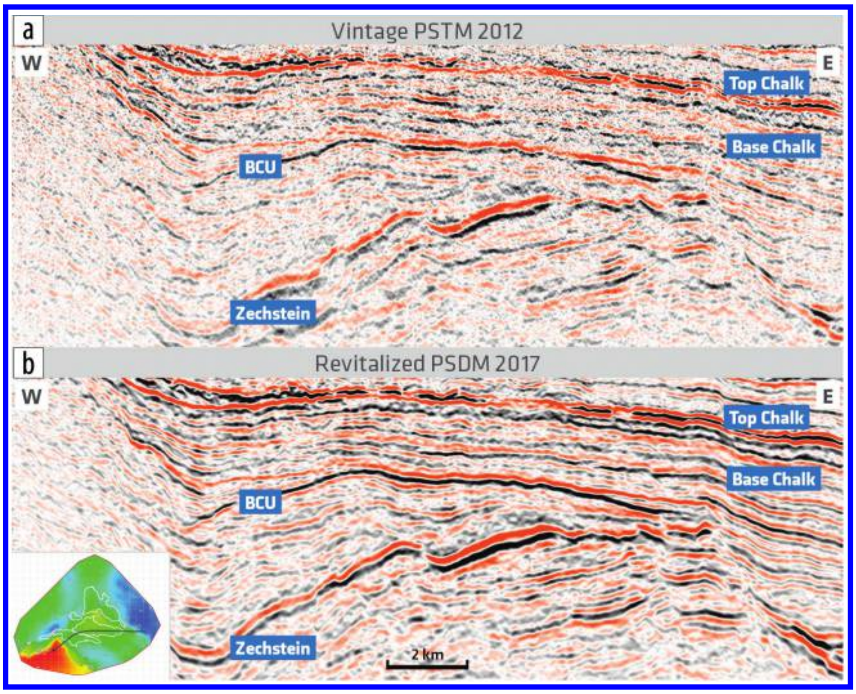

Figure 8. Comparison of 2012/13 data migrated with (a) a PSTM workflow with the (b) revitalized PSDM data. Both are registered in depth using vertical velocity from the PSDM velocity model.

extremely difficult to map on previous data sets. Extensive use was (and is) made of well data and geologic inference (isopachs and fault extrapolations from the deeper top Zechstein reflector) to define the structural framework.

Figure 10 clearly illustrates the impact of reprocessing on the data quality and interpretability. The revitalized PSDM data exhibit superior imaging and depth registration — depth errors away from well control should be significantly reduced — and superior fault delineation at the Zechstein and through the CAC Permian/Carboniferous interval. This significantly improves our regional structural understanding including the relationship between different phases of faulting. A better understanding of this structural history helps build the fault framework. Importantly, it is now possible to map the decrease in acoustic impedance associated with the coal sequence at the base of the reservoir with much more confidence. Geologic extrapolation (for example, isopachs) is used to estimate reservoir presence in the updip limits of the field. There is now sufficient confidence in the data to interrogate the BCU reflection using stochastic inversion to assess the impact of erosion at the top of the Jurassic, which further defines the reservoir extent.

Similar statements can be made about the impact of the data on the NAC and Scapa fields. Stratigraphic mapping in CAC is still not feasible due to the limitations imposed by the rock physics, but a lot more structural insight has been gained from the revitalized seismic data. The work on MAC, Scapa, and NAC has resulted in updated static and dynamic models used in day-to-day field management and to assess production-adding opportunities. In terms of MAC step-out drilling, one previously defined target area has been better quantified, one target area has been reinterpreted as extremely high risk, and one new potential target has been identified.

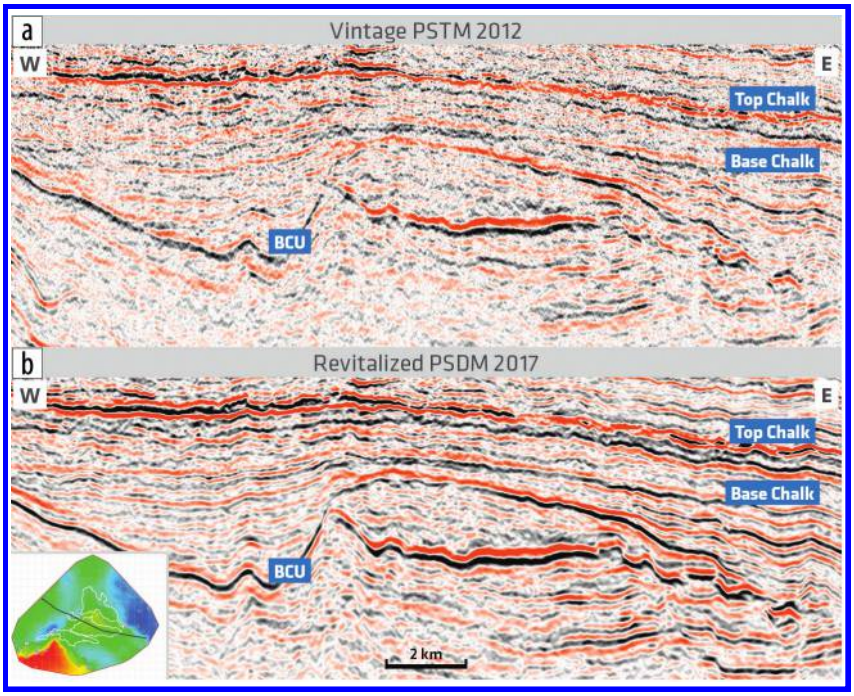

Figure 9. Comparison of 2012/13 data migrated with (a) a PSTM workflow with (b) the revitalized PSDM data. Both are registered in depth using vertical velocity from the PSDM velocity model.

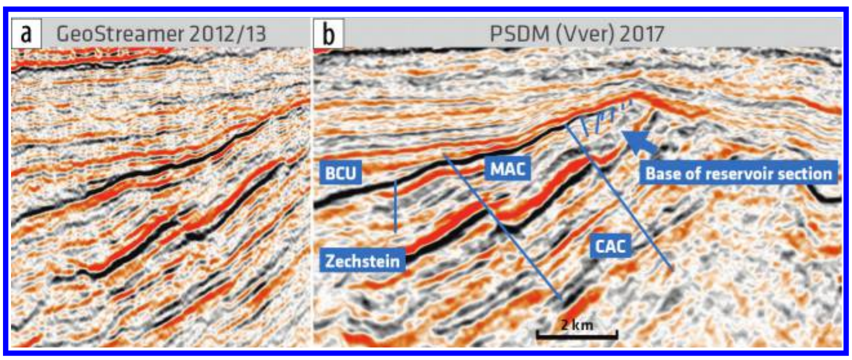

Figure 10. Comparison of 2012/13 data migrated with (a) a PSTM workflow with (b) the revitalized PSDM data. Both are registered in depth using vertical velocity from the PSDM velocity model. The base of reservoir coincides with the coal seam, and key faults are delineated by the blue lines. The data spectra are very similar — the higher frequency component of the PSDM data is much more coherent than the time product.

Summary and conclusions

Despite the downturn in the industry, the high demand for oil and gas is forecasted to remain for the foreseeable future. The last five years have refocused the requirement to maximize the economic recovery of existing fields. Seismic data are an integral part of the asset-management process, setting the geologic framework and aiding decision making on a producing field. Correspondingly, seismic data are readily available over large areas of mature basins like the Claymore Complex in the North Sea. Revitalizing existing data using leading-edge and integrated imaging solutions can offer new insights to help with field development. This is especially the case when there is close collaboration between the seismic contractor and operator. These data are being used to aid the planning of a development drilling program by reducing the risks and uncertainty associated with legacy imaging. Results show a step-change improvement in data quality, facilitating updated static and dynamic models, which are being used in day-to-day field management. TLE

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Data and materials availability

Data associated with this research are confidential and cannot be released.

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