An integrated approach for fractured basement characterization: the Lancaster Field, a case study in the UK

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Abstract: To date, naturally fractured crystalline basement reservoirs (‘basement’) in the UK Continental Shelf (UKCS) have been underexplored and underexploited. Over the last 12 years, Hurricane Energy have explored and evaluated the potential of the basement play, West of Shetland. Data acquired by Hurricane Energy through drilling and drill stem testing of five wells on the Lancaster Field has provided sufficient insight into the reservoir properties of the basement reservoir that Hurricane is now progressing Lancaster towards the first UK basement full-field development. The development is designed to be phased with production from the first phase achieved in 2019. Fractured basement reservoirs require a specific approach when acquiring and interpreting formation and well test data. A multi-disciplined team ethic, carefully integrating these data while avoiding a siloed approach, has proved essential to understanding the behaviour of the connected fracture network. Hurricane incorporates drilling and mudlogging data, high-resolution gas chromatography, logging while drilling (LWD) and wireline logs, drill stem test (DST) and production logging tool (PLT) data to analyse and model the reservoir. It is the combination of these disparate datasets which is key to Hurricane’s analysis and has led to the technical de-risking that has underpinned the final investment decisions leading to the first phase of the Lancaster development.

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The Lancaster Field is located West of Shetland (Fig. 1) in blocks 205/21a, 205/22a and 205/26b, licence P1368 Central, and is in relatively shallow water of c. 150 m. The Lancaster prospect was first drilled by Hurricane in 2009. The structure had already been drilled in 1974, by a previous operator, with well 205/21-1A, which was plugged and abandoned after retrieving a total depth (TD) core from the basement and undertaking two drill stem tests (DSTs). Slight oil seepage from the core is noted in the end of well report and small volumes of oil (c. 2%) were recovered from the tests, along with significant brine returns. A temperature anomaly confirmed that there was flow from the fractured basement, although a fluid sample a short distance above this influx point consisted entirely of water and so the end of well report concluded that it was probable that the small volumes of oil were being produced from the overlying sediments.

Ultimately, this well was abandoned and the structure left undrilled for 35 years. Hurricane reinterpreted the well data and considered that the evidence of oil within the core was significant enough to demonstrate oil presence at a specific depth. The lack of oil within the fluid sample was interpreted by Hurricane as circumstantial, a product of low oil volume being flowed. Hurricane’s interpretation of the recovered fluid was that it was consistent with drilling brine filtrate and, therefore, there was no evidence of formation water influx into the wellbore. Therefore, the temperature anomaly was most likely due to oil influx into a severely compromised wellbore, with complications arising from the invasion of the drilling fluid into the fracture system – a perennial issue which Hurricane has had to deal with many times since.

The reinterpretation of well 205/21-1A provided confidence that exploring the fractured basement reservoir at this location would prove fruitful. Hurricane’s first exploration well at Lancaster, 205/21a-4, was the first UK exploration well drilled specifically to evaluate basement as an exploration play (Trice 2014). Hurricane continued this success with a sidetrack (205/21a-4Z) in 2010 to further appraise the basement, and a subsequent horizontal production well (205/21a-6) in 2014 that demonstrated extremely high reservoir productivity. An extensive drilling campaign in 2016–17 included two further wells on Lancaster – another deep inclined well (205/21a-7) designed to investigate the depth of the oil column; and a second horizontal producer (205/21a-7Z), which confirmed the high productivity observed with well 205/21a-6.

Data from the Lancaster wells has been supported by the drilling of neighbouring assets in Hurricane’s acreage. Whirlwind (205/21a-5) was drilled in 2010, while Lincoln (205/26b-12) and Halifax (205/23-3A) were drilled during the 2016–17 drilling campaign. The drilling and testing results across Hurricane’s assets demonstrate the similarity of this reservoir on the Rona Ridge and present an exciting opportunity within the UK Continental Shelf (UKCS). The progress in unlocking this basement play, specifically related to Lancaster, was documented by Hurricane prior to the 2016–17 drilling campaign (Belaidi et al. 2016), and through this drilling campaign Hurricane moved the field closer to development and further de-risked the play.

Lancaster is the first basement reservoir to have been put onto production in the UK, with first oil achieved in May this year (2019). Current production comes from two horizontal wells that are tied back to the Aoka Mizu, a floating production, storage and offloading vessel (FPSO). This is termed an early production system (EPS) as it is the first phase of a full field development. The EPS is designed to obtain early, commercially-sustainable production from the Lancaster Field ahead of a full-scale development, while at the same time providing crucial information about reservoir behaviour. Lancaster has assigned 2P Reserves of 37 MMstb based on the planned EPS, and a further 486 MMstb of 2C Contingent Resources assigned to the full field. In total, this attributes a Base Case recoverable resource of 523 MMstb to the Lancaster Field (EPS Energy 2017). The acquisition of reservoir data during the EPS will allow these numbers to be revised over time.
Fractured basement considerations

‘Basement’ is defined as the crystalline igneous or metamorphic rock underlying the sedimentary cover. The Lancaster fractured basement is classified as a Type 1 naturally fractured reservoir (NFR), as it contains little to no intergranular matrix porosity or permeability and, as such, the reservoir behaviour is entirely dominated by the fracture network (Nelson 2001). Therefore, fracture identification and characterization is of the utmost importance when appraising this reservoir.

In terms of lithology, the Lancaster Field consists of c. 95% tonalite, based on the evaluation and integration of neutron and density data from wireline logging while drilling (LWD), combined with cuttings analysis through visual inspection and continuous X-ray fluorescence (XRF) scans. The remaining 5% is comprised of basalt, dolerite and quartz diorite lithologies, which have been characterized by analysis of thin sections derived from rotary sidewall cores. Sidewall core locations were chosen to investigate apparent variations in lithology, as determined from cuttings and wireline characteristics, so the relative abundance in core-derived lithology, as displayed in Figure 2a for the Lancaster wells, is a product of sampling bias. Figure 2b shows that, whilst the Lancaster lithologies so far encountered are confined to four types, incorporation of wells from neighbouring basement structures introduces a broader lithological suite that could be encountered with additional drilling on Lancaster.

As a Type 1 NFR, the conceptual reservoir model is focused on the fracture network rather than the lithology of the host rock. As shown in Figure 3, the reservoir is subdivided into two facies based on proximity to seismic-scale faults. Fault zones represent the gross rock volume (GRV) near to faults, where the tectonic activity has contributed to enhancing the porosity and permeability characteristics of the fracture network. The average width of these fault zones (from log analysis and outcrop analogues) is 40 m. GRV outside of these zones is referred to as ‘fractured basement’ and is demonstrably heavily fractured and productive. Although the fracture network is not as enhanced by tectonic activity outside of the identified seismic-scale fault zones, there are subseismic faults present in the reservoir that introduce additional deformation. A NE–SW regional joint system exists across both facies, consisting of long and deep, near-vertical features. Cross joints of varying orientations and dip angles are also present in both facies, aiding connectivity of the fracture network. Hurricane classifies joints based on orientation and dip angle as shown in Figure 4, with...
additional consideration given to joints that exhibit shear offset or particularly wide apertures (in excess of 2 cm). Underpinning the joint system and fault enhancement is a population of microfractures that are found pervasively throughout the reservoir, providing additional storage for reservoir fluid. 

It should be noted that, although being a new play for the UKCS, there are a number of fractured basement fields around the world which have been discovered and are on production, some of them for decades. Hurricane has evaluated the potential analogues and found that while there are several reservoirs that share certain qualities with the fractured basement at Lancaster, they all have idiosyncrasies that make direct comparisons extremely difficult. Therefore, the approach to modelling fractured basement reservoirs cannot necessarily be repeated between different fields and a more bespoke approach is required that is sensitive to the particular characteristics observed. The numerous examples of successful fractured basement developments demonstrate that a variety of formation evaluation and modelling techniques have proven effective. This paper describes the methodology that Hurricane has used and continues to develop for evaluating the fractured basement reservoir present in Lancaster and its surrounding Rona Ridge assets, which so far is yielding positive results. This is a continuous process and the methodology will continue to be improved as more data are gathered. 

**Formation evaluation**

The optimum approach to formation evaluation is to acquire as much high-quality data as possible, with the objective of reducing interpretation ambiguity through the provision of multiple measurement methods. This approach is particularly important in the analysis and quantification of resources within the fractured basement play where key measurements can be at the lowermost acceptable range of their signal-to-noise ratio. The formation evaluation challenge is further compounded by the paucity of relevant and detailed analytical case studies available in the public domain. Hurricane has struggled to find suitable field analogues for comparison with Lancaster; that stated, however, the data gathered to date from the field does demonstrate that Lancaster shares many similarities with certain characteristics of other fractured basement reservoirs globally, including:

- the trapping mechanism;
- porosity ranges;
- the significance of tectonic faulting to improve productivity of the fracture network;
- the positive effect of dissolution and subaerial exposure in enhancing the hydrodynamic fracture network;
- the value of horizontal wells targeted to seismically mapped targets in order to achieve high production rates.

Finding a suitable analogue to match all of the characteristics of the Lancaster Field has not been possible, due in large part to the extensive geological history that Lancaster has been subject to. The reservoir has been dated to c. 2.7 Ga, and that extremely long and varied geological history has resulted in a unique and well-connected hydrodynamic fracture network. This well-connected fracture network is reflected in the intense fracturing seen on image logs throughout the reservoir section, as well as the extremely high and consistent productivity index (PI) from two horizontal wells. No
matching fracture networks have been located from the literature or through access to commercially available databases. Consequently, the use of analogues is confined to the understanding of general fractured reservoir behaviour, the impact of applied reservoir management schemes and comparisons of formation evaluation techniques. These comparisons have helped Hurricane to develop its own formation evaluation programme, which is summarized in Table 1 in terms of the datasets acquired from the Lancaster wells.

There are a number of challenges when acquiring and interpreting well data in fractured basement reservoirs, many of which arose from the behaviour of using overbalanced drilling mud in highly permeable fractures. Hurricane has recently published, in cooperation with Schlumberger, some of the considerations that have been noted during the exploration and appraisal of Lancaster (Bonter et al. 2018).

Fracture identification from logs, core and drilling data forms the core work stream in evaluating the reservoir. Hurricane refer to all discrete fractures that can be interpreted from image logs as joints, and therefore have an associated depth, dip, azimuth and classification (Belaidi et al. 2016). Figure 5 shows an example of

Table 1. Hurricane well data acquisition for formation evaluation

<table>
<thead>
<tr>
<th>Well name</th>
<th>Asset name</th>
<th>Year drilled</th>
<th>Well type</th>
<th>LWD data</th>
<th>Mud gas</th>
<th>Wireline logs</th>
<th>Well test</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>205/21a-4</td>
<td>Lancaster</td>
<td>2009</td>
<td>Inclined</td>
<td>✓✓✓ ✓✓✓</td>
<td>✓✓✓ ✓✓✓</td>
<td>✓✓✓ ✓✓✓ ✓✓✓</td>
<td>✓✓✓ ✓✓✓</td>
<td>✓✓✓ ✓✓✓</td>
</tr>
<tr>
<td>205/21a-4Z</td>
<td>Lancaster</td>
<td>2010</td>
<td>Inclined</td>
<td>✓✓✓ ✓✓✓</td>
<td>✓✓✓ ✓✓✓</td>
<td>✓✓✓ ✓✓✓ ✓✓✓</td>
<td>✓✓✓ ✓✓✓</td>
<td>✓✓✓ ✓✓✓</td>
</tr>
<tr>
<td>205/21a-5</td>
<td>Whirlwind</td>
<td>2010</td>
<td>Inclined</td>
<td>✓✓✓ ✓✓✓</td>
<td>✓✓✓ ✓✓✓</td>
<td>✓✓✓ ✓✓✓ ✓✓✓</td>
<td>✓✓✓ ✓✓✓</td>
<td>✓✓✓ ✓✓✓</td>
</tr>
<tr>
<td>205/21a-6</td>
<td>Lancaster</td>
<td>2014</td>
<td>Horizontal</td>
<td>✓✓✓ ✓✓✓</td>
<td>✓✓✓ ✓✓✓</td>
<td>✓✓✓ ✓✓✓ ✓✓✓</td>
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</tr>
<tr>
<td>205/21a-7</td>
<td>Lancaster</td>
<td>2016</td>
<td>Inclined</td>
<td>✓✓✓ ✓✓✓</td>
<td>✓✓✓ ✓✓✓</td>
<td>✓✓✓ ✓✓✓ ✓✓✓</td>
<td>✓✓✓ ✓✓✓</td>
<td>✓✓✓ ✓✓✓</td>
</tr>
<tr>
<td>205/21a-7Z</td>
<td>Lancaster</td>
<td>2016</td>
<td>Horizontal</td>
<td>✓✓✓ ✓✓✓</td>
<td>✓✓✓ ✓✓✓</td>
<td>✓✓✓ ✓✓✓ ✓✓✓</td>
<td>✓✓✓ ✓✓✓</td>
<td>✓✓✓ ✓✓✓</td>
</tr>
<tr>
<td>205/26b-12</td>
<td>Lincoln</td>
<td>2016</td>
<td>Inclined</td>
<td>✓✓✓ ✓✓✓</td>
<td>✓✓✓ ✓✓✓</td>
<td>✓✓✓ ✓✓✓ ✓✓✓</td>
<td>✓✓✓ ✓✓✓</td>
<td>✓✓✓ ✓✓✓</td>
</tr>
<tr>
<td>205/23-3A</td>
<td>Halifax</td>
<td>2017</td>
<td>Inclined</td>
<td>✓✓✓ ✓✓✓</td>
<td>✓✓✓ ✓✓✓</td>
<td>✓✓✓ ✓✓✓ ✓✓✓</td>
<td>✓✓✓ ✓✓✓</td>
<td>✓✓✓ ✓✓✓</td>
</tr>
</tbody>
</table>

*Modular formation tester (MDT) run aborted for operational reasons.
Joint identification in well 205/21a-7 and representative associated conventional log responses. Conventional logs respond to joints, particularly those with wide apertures or in discrete intervals of relatively high frequency, although the resolution is insufficient to fully characterize them. Therefore, higher-resolution image logs are used to pick and characterize joints where they display a response indicative of drilling mud invasion. This ‘invasion response’ is typified by a reduction in resistivity as shown by the LWD AFR (azimuthally focused resistivity) tool and wireline FMI (formation micro-imager) log. It is also shown by a reduction in density on the LWD ALD (azimuthal litho-density) and acoustic amplitude or impedance typical of porosity on the UBI (ultrasonic borehole imaging) wireline log. High-resolution logs are processed such that low resistivity and porous responses produce a dark response on the images. The data portrayed in Figure 5 are from an inclined well, and so have both wireline and LWD image data from which comparative analysis can be undertaken. This comparison is particularly useful in guiding joint interpretation in horizontal wells, where only the lower-resolution LWD data are available.

Estimating effective fracture aperture from wireline and/or LWD data is a challenge that has faced the industry for many decades. While some published methods for estimating fracture aperture from electrical logs (Luthi & Souhaité 1990) do have practical application in many instances, the conclusion from work on Lancaster is that the technique is unreliable as the fracture aperture results are influenced by mud resistivity and tool effects. Attempts to use electrical logs to establish fracture aperture have been augmented by manual picking of joint apertures when the apparent aperture is sufficient to do so. The minimum aperture that can be reliably measured manually is 2 cm, so any joint with an aperture in excess of 2 cm is defined as a wide aperture joint.

Figure 6 shows three examples of wide aperture joints from well 205/21a-7. All of these wide aperture joints display sufficient expression to pick a top and base, allowing for manual measurement of the apparent aperture. These three examples are also associated with significant porosity responses, demonstrating that they are contributing to the poro-perm system. There are some differences between them, identified by comparing the FMI to the UBI images. In Figure 6a, a typical response is observed from drilling fluid invasion causing an FMI response which is mirrored by the UBI – indicating an open fracture. Figure 6b shows some clastic or mineral infill of a large fracture, as seen on the reduced UBI response, but the continuous high-porosity response indicates some dissolution control and does not indicate a completely closed feature. Figure 6c could represent clastic or cuttings infill within a wide aperture joint; the joint boundaries are sharp and there is only a slight occlusion of the open aperture visible on the UBI. Again, the porosity log responds to this large feature.

These wide aperture joints can be effectively measured and assessed for how open or closed they may be, but Figure 6 also highlights the problem with quantifying fracture porosity from image logs. This is an acknowledged industry challenge which can be seen in this case as being due to the difficulty in estimating how open these wide aperture joints are, as well as calculating the
apertures of the many subordinate joints that can be seen in these three images. However, as Lancaster is a Type 1 NFR, the view is taken that all of the porosity is associated with fractures. Consequently, bulk porosity measurements will reflect fracture porosity. This assumption has been corroborated by comparing bulk porosity measurements to core porosity, joint frequency plots, joint aperture estimates from electrical imaging logs and fracture frequency derived from drilling data (Bonter et al. 2018).

The preferred method of establishing bulk porosity is the Bateman–Konen technique, a density-neutron cross-plot methodology that simultaneously solves for matrix density and porosity, and thereby avoids problems caused by the mineralogical variation in the host rock (Bateman & Konen 1977). The technique has been compared between wireline and LWD datasets to confirm the validity of relying on LWD porosity alone in horizontal wells. Generally, the LWD and wireline porosity matches well—an example from well 205/21a-7 is shown in Figure 7 (note that the LWD was not run to TD in this well).

Bateman–Konen porosity has been compared with porosity derived from nuclear magnetic resonance (NMR) logs. The NMR has the advantage of being completely independent of lithology and mineralogy, and responds to effective porosity. However, within the high-salinity mud environment and relatively low porosity ranges of the Lancaster reservoir, the NMR is at the lower end of its effective operational limit. Despite these operational constraints, NMR porosity is generally supportive of Bateman–Konen, although tends to read slightly higher, presenting a potential upside porosity case (Fig. 7). Both the Bateman–Konen and NMR porosity logs can be observed to respond to the darker (more jointed) portions of the image log in this well (Fig. 7); thus demonstrating that porosity peaks are associated with those joints with wider apparent apertures, or with clusters of joints. However, there is also a background porosity calculated from the bulk porosity logs which is due to microfractures contributing to the overall storage system of the reservoir.

To provide lithological data and a control on the Bateman–Konen porosity calculation, Hurricane acquired a large number of rotary sidewall cores. The sidewall cores are purposely targeted away from discrete joints to maximize their recovery and provide grain density data. Despite this intention, numerous cores are associated with microfractures and thereby provide a data source to help quantify the porosity associated with microfractures; sidewall core porosity data for well 205/21a-7 are displayed in Figure 7. These sidewall core porosities provide a constraint on the downside from the bulk porosity logs, but do include some higher values that match the bulk porosity logs quite well—this is particularly evident towards the top of the basement section, but is also seen at depth in Figure 7 (e.g. a sidewall core porosity value of 12% at 1560 m measured depth (MD)). Some of these surprisingly large porosity values in sidewall cores may be caused by discrete joints that could not be avoided when running the coring tool. However, most of the porosity seen in thin sections from sidewall cores is associated with microfractures. These microfractures either do not cut the entire borehole or are below the resolution of the image logs, but the porosity contribution they provide demonstrates that even the smallest fractures are open features contributing to the bulk porosity of the reservoir.

In terms of characterizing the fractured basement reservoir as a whole, the conceptual model shown in Figure 3 focuses on the...
Interaction of regional and cross joints within fault zones and fractured basement. As seen from the bulk porosity logs and sidewall core analysis, microfractures are also present within the reservoir between these joints, contributing to the overall porosity. The significance of defining ‘fault zones’ is because porosity is enhanced within these damaged volumes of rock surrounding seismic-scale faults, shown by Figure 8 which includes generally higher average porosity within fault zone intervals (in yellow) and generally lower average porosity in fractured basement intervals (in green). Figure 8 includes both a horizontal well (205/21a-6) and an inclined well (205/21a-7), showing that the fault zone porosity enhancement is observed regardless of well angle and whether using LWD or wireline Bateman–Konen porosities.

The identification of seismic-scale faults has benefitted from third-party automated techniques based on coherency analysis (Emsley et al. 2012) combined with in-house manual interpretation. Faults interpreted on seismic are matched to fault zones interpreted from well logs, with the fault map evolving over time pre- and post-drilling (Slightam 2012). More recently, automated fault identification has been achieved using Ant Tracking in-house, providing assistance to the manual fault interpretation, particularly in terms of the connectivity of the fault network at top basement level. This technique does not provide a good image of the faults within the basement itself using the seismic vintage Hurricane has available, but a comparison between the Ant Tracking extracted at top basement level and the fault zone interpretation at depth from well

Fig. 7. Comparison of porosity methodology, well 205/21a-7.
logs shows that there is a good match between the two, so therefore the majority of the faults are near-vertical (Fig. 9).

Through an extensive formation evaluation programme, it is clear that porosity within the Lancaster reservoir is related both to discrete joints and background microfractures, and that porosity is enhanced by seismic-scale faulting. There is also a demonstrable link between the faults interpreted from the seismic data and the fault zones interpreted from well logs, allowing some prediction of porosity enhancement (within fault zones) away from well control.

**Well test interpretation**

Understanding the behaviour of a Type 1 NFR, such as Lancaster, requires an integrated approach to combine the dynamic data from well test interpretation with the static information from well log analysis. As in the case of formation evaluation from wireline and LWD data, the impact of drilling fluid invasion needs to be carefully considered in well test analysis. A summary of the well tests undertaken in the fractured basement reservoir of Lancaster and some of the surrounding assets is shown in Table 2. Each well test has benefitted from a learning process through analysis of previous wells. For example, the use of a mixed metal oxide (MMO) mud throughout the reservoir section of well 205/21a-4 was selected due to safety concerns related to anticipated high loss rates while drilling. This mud system proved to be excellent at preventing losses but severely compromised the well test due to operational constraints preventing the deployment of acid to break down the mud prior to testing. This well, however, flowed...
oil to surface and demonstrated that the reservoir was indeed productive.

Therefore, the following well (205/21a-4Z) was drilled with brine, with careful control on pressure at the bit to keep as close to balance as possible and limit losses. Again, this strategy was successful for drilling but, due to the lack of the lifting capacity of this brine, a large quantity of cuttings were left downhole which induced a significant skin in the near-wellbore environment, limiting the productivity that could be achieved. Later wells employed varying brine compositions including viscosifying agents to enhance the lifting capacity of the mud and avoid this skin issue.

The most productive well tests have been the two horizontal wells on Lancaster, 205/21a-6 and 205/21a-7Z, which had a PI of 160 and 147 stb/day/psi, respectively. The rates of these well tests were constrained by the surface equipment on the rig in both the ESP (electrical submersible pump) and natural flowing cases. A strategy of using brine with improved lifting capacity and a rigorously monitored hole-cleaning programme combined with the horizontal well path contributed to minimizing skin in both these wells. Losses while drilling were accepted but carefully monitored and controlled as much as possible to achieve an acceptable balance between safe drilling practice and a successful well test.

Data from the pressure build-ups following the natural flowing periods of these two productive horizontal wells has been used to interpret the behaviour of the fracture network away from well control and is shown in Figure 10. In each test, the early time (up to 1 h) is characterized by a complicated storage response. By analysing higher-resolution data around the shut-in on well 205/21a-7Z (Fig. 11), the true wellbore storage effect can be seen occurring within the first 3–4 s. The remaining storage effect is interpreted as being caused by large fractures connecting to the wellbore so well that they appear to increase the volume stored within the wellbore. Therefore, this early time response is seeing a very large volume of well-connected reservoir fluid.

After the early time storage effects, both horizontal wells display a period of increasing transmissivity away from the wellbore, followed by a dip and recovery (Fig. 10) that can be matched with a classic dual-porosity response (Warren & Root 1963). This is interpreted consistently between the wells as being caused by a highly productive medium, containing approximately one-third of the STOIP (stock tank oil-initially-in-place), which is supported by a second, less productive, medium containing the remaining two-thirds. In terms of relating this to the static reservoir model, as the reservoir is a Type 1 NFR, both mediums are subdivisions of the connected fracture network. The porosity evaluation shows that there is a continuum of fracture sizes contributing to the reservoir storage system, from microfractures up to wide joints with apparent open apertures of decimetre scale. Although the extremes of this continuum are easy to identify, it is difficult to make a distinction between fractures within the range that contribute to either the productive or supportive medium as the dynamic response may be due to a combination of factors such as aperture, orientation, fracture fill and connectivity with the rest of the network.

PLT (production logging tool) logging provides a method to link the well test data to the fracture interpretation, demonstrating which features flow under different conditions during a well test. Well 205/21a-4Z exhibited several interesting features during three PLT runs in 2010 (Fig. 12). The cumulative flow from these PLT runs shows a constant increase in contribution flowing into the wellbore, indicating that there are productive fractures throughout the entire

### Table 2. Summary of Hurricane well tests

<table>
<thead>
<tr>
<th>Well name</th>
<th>Asset name</th>
<th>Year</th>
<th>Well type</th>
<th>Mud system</th>
<th>Maximum stable rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>205/21a-4</td>
<td>Lancaster</td>
<td>2009</td>
<td>Inclined</td>
<td>Drilplex (MMO mud)</td>
<td>– 200 bopd</td>
</tr>
<tr>
<td>205/21a-4Z</td>
<td>Lancaster</td>
<td>2010</td>
<td>Inclined</td>
<td>NaCl brine (no viscosifier)</td>
<td>– 2399 bopd</td>
</tr>
<tr>
<td>205/21a-5</td>
<td>Whirlwind</td>
<td>2010</td>
<td>Inclined</td>
<td>CaCl/CaBr brine</td>
<td>– 2400 bopd</td>
</tr>
<tr>
<td>205/21a-6</td>
<td>Lancaster</td>
<td>2014</td>
<td>Horizontal</td>
<td>CaCl brine (viscosified)</td>
<td>9800 bopd 5300 bopd</td>
</tr>
<tr>
<td>205/21a-7</td>
<td>Lancaster</td>
<td>2016</td>
<td>Inclined</td>
<td>CaCl brine (viscosified)</td>
<td>10930 bopd 6300 bopd</td>
</tr>
<tr>
<td>205/21a-7Z</td>
<td>Lancaster</td>
<td>2016</td>
<td>Horizontal</td>
<td>CaCl brine (viscosified)</td>
<td>15375 bopd 6520 bopd</td>
</tr>
<tr>
<td>205/23-3A</td>
<td>Halifax</td>
<td>2017</td>
<td>Inclined</td>
<td>CaCl brine (viscosified)</td>
<td>– Minor flow</td>
</tr>
</tbody>
</table>
tested interval. However, there are certain points at which the flow increases more dramatically allowing for the assignment of specific flow zones, associated with particularly wide aperture joints. This is further demonstrated in Figure 13 where significant flow contribution was seen at the base of Fault Zone 1A, caused by a joint with a 45 cm open aperture. This aperture has been estimated from manual methods as described above and has been corrected for dip and borehole inclination. Similarly, the entire flow contribution for well 205/21a-7 (maximum stable rate of 10 930 bopd (barrels of oil per day) using an ESP) was provided by a series of wide aperture joints near the top of the wellbore, each having apertures of several centimetres.

A combination of PLT data and pressure build-up analysis demonstrates that flow in the fractured basement reservoir is dominated by highly productive joints and supported by other elements of the fracture network. This indicates an extremely well-connected hydrodynamic fracture network and is fully consistent with static observations from well logs.

Data integration and reservoir modelling

The static and dynamic data that Hurricane has gathered are integrated into a single reservoir model that honours the conceptual model described in Figure 3 and reflects the outcrop analogues that Hurricane has analysed. Hurricane produce a static model in-house which is designed for simulation, modelling faults vertically and stair-stepping them laterally so that the grid cells remain orthogonal. Grid cells are built with an areal extent of $10 \times 10$ m, and maintaining this geological grid scale required the use of a high-resolution simulator (Bonter 2015).

To summarize the modelling process, Hurricane utilizes the seismic interpretation, including the Ant Tracking as shown in Figure 9, to create a fault model within Petrel (Fig. 14). Note that this fault model remains work-in-progress and as such is under-populated towards the east of the field (away from the EPS development wells). There are currently some 740 faults within the...
model, which will increase as the modelling work progresses. A distance-to-fault property is created to allow for the creation of fault zones based on the proximity of cells to seismic-scale faults (Fig. 15); the fine grid resolution allows for uncertainty modelling regarding the fault zone widths (Fig. 16).

Figure 17 shows intersections along the two wells (with simplified trajectories for simulation purposes), which indicates the fault zone and fractured basement facies that have been identified from seismic and well log interpretation. These fault zones are observed to be generally vertical, or near-vertical, due to the correlation of seismically interpreted faults at the top basement surface to the log-interpreted fault zones at depth. Modelling these features vertically is therefore an acceptable approximation, supported by data, that enables the simulation grid to be modelled orthogonally to reduce errors in gridding.

With the facies model constructed, the grid cells can be populated with reservoir properties. These are applied as single values within each facies due to the lack of any guidance away from well control other than the presence or absence of fault zones. The porosity and permeability values used for the dual-porosity model are summarized in Table 3. Each grid cell within the model represents a block of basement that contains many joints and many more microfractures, so the bulk porosity methods described previously apply very well to this model. The permeability values are derived from the well test analysis where the primary permeability is provided by the highly conductive joint system. This permeability value is applied to the productive joint set in both facies. Through the Warren & Root dual-porosity interpretation, a secondary permeability value is calculated for a given block size of 10 m (matching the cell geometry) that represents the supportiveness of the secondary medium in the dual-porosity response and can be used for the supportive fracture set in this model. It should be noted that the values applied are bulk values, applicable to a representative elementary volume that matches the grid cell size, rather than being applicable to individual
Discrete fracture network (DFN) modelling is used to aid in constraining the geocellular grid. To this end, DFN modelling has been applied to model joint sets away from the near wellbore environment and to establish which of these joint sets are associated with the fluid flow recorded during a DST. The simulated joint network established from DFN modelling is validated by modelling pseudo-wells within the DFN modelled space at locations and orientations equivalent to the source well paths. Comparisons of joint populations from well data with the DFN simulated data give confidence that the DFN representation of joint distribution is consistent with measured data (Fig. 18a). Once calibrated, the DFN can be used to simulate the pressure response from a given well and thereby used to evaluate which joint sets are the primary contributors to flow. Figure 18b shows a map that demonstrates a plan view of a modelled pressure response around a single wellbore. The mapped pressure response indicates that fault zones and regional joints provide the primary conduits for fluid flow into the wellbore, with cross joints and microfractures providing secondary pressure support. The DFN model has also been used to construct pseudo-PLT responses that can be used to infer fracture apertures, which can be compared to measurements of wide aperture joints estimated from electrical image logs. Finally, DFN modelling has been used to constrain the size of representative elementary volumes (REV) which provides a mechanism of cross-checking the geological character of the reservoir that the geocellular grid is attempting to model. Further integration of the DFN and geocellular modelling work is ongoing to improve the inclusion of factors such as permeability anisotropy; however, the conclusion of this work requires data from the planned inter-well testing during the EPS, the results from which are not expected to be available until the latter part of 2019.

**Fig. 13.** Wide aperture joint control on flow, demonstrated by well 205/21a-4Z and 205/21a-7 PLT.

**Fig. 14.** Lancaster Field fault model.
The full-field simulation model constructed for Lancaster consists of a geocellular grid with approximately 80 million cells (Bonter 2017). This number of cells is a consequence of the desire to maintain a fine resolution to the model for robust fault-zone modelling, as described above. Building the static model with a view to simulation ensured that an appropriate level of geological complexity could be maintained throughout the process, avoiding common industry problems with upscaling and lack of integration between geological and reservoir engineering workflows. Acceptable compromises were introduced during the static model build, such as maintaining an orthogonal grid and including all faults as vertical, so that there was congruence between the static and dynamic models. In fact, there is no difference between the two and by using a high-resolution simulator the static model can be taken straight through to dynamic simulation with no alterations or upscaling.

Initially, the full-field simulation model was designed to establish base cases from which to evaluate the data that will be acquired from interference and long-term production during the EPS phase of the Lancaster Field development. Further to this, it has allowed several discrete uncertainty cases to be modelled. This began with a study on the three primary uncertainties of fracture porosity, oil–water contact (OWC) depth and aquifer strength. Those scenarios that did not match the well test data from well 205/21a-6 without requiring significant changes to other assumptions were immediately discounted – this included the cases with shallowest OWC and a lack of aquifer support. Other discrete cases that could be used to match the well test data were used to produce forecasts for single well production to evaluate reservoir behaviour as well as developing end-member predictions for the two-well EPS. As this work was...
... progressing concurrently with the 2016–17 drilling campaign, once these data were incorporated they reinforced the simulation methodology and the concepts that underpin the reservoir model while refining some of the input ranges. The initial results have provided confidence to continue with the simulation modelling approach. New data from the start-up of the Lancaster Field earlier this year will be gradually incorporated into the analysis, though this process takes time. This will include variable rate production and longer shut-in periods than previously acquired during well tests, in addition to long-term production data. The simulation work is therefore iterative and refinements will be ongoing as production and data continues to be acquired from the EPS.

The Lancaster EPS and the future of fractured basement

The Lancaster EPS consists of a two-well tieback to the Aoka Mizu FPSO, as outlined in Figure 19. Long-term dynamic data gathering is the primary technical objective of the EPS, to complement the well test data gathered to date. By producing from two wells, Hurricane will be able to investigate the connectivity of the fracture network with interference testing, enabling estimates of permeability anisotropy which will provide invaluable data to position future wells in the next phases of development. By taking this phased approach to development, Hurricane can ensure that the Lancaster Field is developed optimally to enhance ultimate recovery from the field. It also provides an economically viable solution with lower risk in the early phase of the development.

Real-time data from the FPSO is being streamed back to shore, for analysis and integration into the reservoir model. Hurricane should be able to begin eliminating the least likely cases from the uncertainty analysis and focus on improving the predictions from the simulation modelling. Individual flowlines from the two wells enables accurate attribution of the production, while high-resolution downhole gauges provide reservoir pressure and temperature both during production and during regular shut-in periods, which will be used for reservoir characterization and compared to those pressure build-ups shown in Figure 10.

A successful EPS on Lancaster has a significant impact for the rest of Hurricane’s portfolio, as the surrounding assets can be expected to behave in a similar way to Lancaster – unlocking the potential from Lancaster may enable Hurricane to repeat this success on the Lincoln, Warwick, Halifax and Whirlwind fields. This could have a dramatic impact not just on the West of Shetland region, but the UKCS as a whole. Fractured basement is underexplored in the UKCS and success in proving the play could be highly beneficial for the UK oil sector.

Table 3. Summary of dual-porosity model porosity and permeability values

<table>
<thead>
<tr>
<th>Facies</th>
<th>Fracture set</th>
<th>Porosity (%)</th>
<th>Permeability (mD)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fault zone</td>
<td>Highly conductive</td>
<td>2.3</td>
<td>796</td>
</tr>
<tr>
<td></td>
<td>joints</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Supportive fractures</td>
<td>2.9</td>
<td>0.06</td>
</tr>
<tr>
<td>Fractured</td>
<td>Highly conductive</td>
<td>0.7</td>
<td>796</td>
</tr>
<tr>
<td>basement</td>
<td>joints</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Supportive fractures</td>
<td>2.9</td>
<td>0.06</td>
</tr>
</tbody>
</table>

**Fig. 18.** Example of DFN model building and simulated pressure response from DST.
Integrated fractured basement characterization

Fig. 19. Schematic of the Lancaster EPS. MDT, modular formation tester; TVDSS, true vertical depth subsea.

Conclusions

Fractured basement is an underexplored and underexploited play within the UKCS. The next stage of materially de-risking this play will be provided from the analysis of data acquired from long-term production of the Lancaster Field. First oil was achieved in May 2019 and analysis of the data obtained to date is ongoing. Acknowledging that the play is poorly understood, the analytical approach has been to avoid interpretations from a single data source which could establish a negative interpretation bias. Such bias has been avoided by focusing on optimizing data quality and early integration across disciplines. This approach has been prioritized, both at the well site and during post-well evaluation. Static and dynamic interpretations of well data reinforce one another and underpin a reservoir interpretation that indicates a highly connected fracture network with tremendous production potential. Ultimately, however, it is the data and production from the EPS that determine the viability of the UKCS fractured basement play. Ongoing seismic and structural modelling, dynamic simulation, and an aggressive drilling and testing programme on the neighbouring Greater Warwick area will provide additional insight into the reservoir behaviour of the fractured basement play to complement the results from the Lancaster EPS.

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References


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 EPS objectives

1. To provide long term production data to enhance understanding of reservoir characteristics and associated full field development scenarios

2. Commence development of the resources in a phased manner with regard to managing uncertainties over reservoir characteristics and associated development risks

3. Deliver an acceptable return on investment

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