Faulting and fault sealing in production simulation models: Brent Province, northern North Sea


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ABSTRACT: Faults can severely compartmentalize pressures and fluids in producing reservoirs, and it is therefore important to take these effects into account when modelling field production characteristics. The Brent Group fields, northern North Sea, contain a complex arrangement of fault juxtapositions of a well-layered sand-shale reservoir stratigraphy, and fault zones containing a variety of fluid flow-retarding fault rock products. It has been our experience that these fault juxtapositions impact the ‘plumbing’ of the faulted layering system in the reservoirs and the models that are built to mimic them – and are, in fact, a first-order sensitivity on compartmentalization of pressures and fluid flow during production simulation. It is important, therefore, to capture and validate the geological feasibility of fault-horizon geometries, from the seismic interpretation through to the static geocellular model, by model building in conjunction with the interpretation. It is then equally important to preserve this geometrical information during geocellular transfer to the simulation model, where it is critical input data used for calculation of fault zone properties and fault transmissibility multipliers, used to mimic the flow-retarding effects of faults. Application of these multipliers to geometrically weak models tends to produce ambiguous or otherwise potentially misleading simulation results. We have systematically modelled transmissibility multipliers from the upscaled cellular structure and property grids of geometrically robust models – with reference to data on clay content and permeability of fault rocks present within drill core from the particular reservoir under study, or from similar nearby reservoirs within the same stratigraphy. Where these transmissibility multipliers have been incorporated into the production simulation models, the resulting history matches are far better and quicker than had been achieved previously. The results are particularly enhanced where the fault rock data are drawn from rocks that have experienced a similar burial–strain history to the reservoir under study.

KEYWORDS: fault model, fault geometry, fault seal, transmissibility multipliers, compartmentalization, Brent Group

INTRODUCTION

In general terms, a static hydrocarbon column held across a fault is caused by aquifer and buoyancy pressure of fluids (applied against the capillary entry pressure of fault rocks and juxtaposed stratigraphies) reaching equilibrium across the fault over geological time (Fisher et al. 2001). This equilibrium is achieved at infinitesimally slow rates of flow, and often results in a common static hydrocarbon contact level across intra-reservoir faults. However, under production conditions, pressure gradients between wells induce flow rates within the reservoir sands that can be much faster than the rates achieved across these (much lower permeability) fault zones. Thus, pressures and the hydrocarbon saturations and contacts begin to separate into compartments across the faults, and between individual sand units flowing at different rates from each other across the faults (e.g. Childs et al. 2002). Fault seal analysis under production conditions therefore attempts to define the oil, gas and water rate of flow across the faults in order to quantify: (a) the ‘effective’ connected volumes that can be accessed at economic rates by any given well; and (b) the related rate interaction between a group of wells.

The tool used for these assessments is the flow simulation or ‘dynamic’ model, which is used in ‘prediction mode’ to guide business forecasts, field development, production management and well planning decisions (e.g. Dake 2001). The validity of the ‘prediction mode’ of a model is tested by comparing the match
Fig. 1. Diagram showing the impact of an intra-reservoir fault on fluid flow. (a) and (b) show a potentially unswept compartment, identified in 4D seismic sections and maps (red polygon). (c) Re-examination of the 3D seismic data revealed a previously uninterpreted fault, which mapped out along the curved eastern edge of the 4D signal. This coincidence suggested that the fault retarded flow sufficiently to act as a sweep barrier in the reservoir. (d) The fault was incorporated into the simulation model for the field to examine its effect on fluid production in three crestal producers, being supported by a downflank water injector. Inclusion of the fault dramatically altered the sweep pattern. (e) The production simulation was improved greatly by inclusion of the fault – with the simulated oil and water rates in the three wells now matching the actual data.
between actual historical production data and the simulated production history, increasingly in recent years in conjunction with use of 4D seismic data (e.g. Fig. 1; Staples et al. 2002, 2005; Lygren et al. 2003; Waggoner et al. 2003). The stratigraphic controls on field compartmentalization are addressed within generally accepted subsurface tools and workflows. However, it has been an industry-wide experience that surprisingly little time and technology is set aside to capture, quantify and integrate the effect of faults on reservoir connectivity and flow behaviour into a typical simulation model. Thus, whilst a ‘model’ history match can be achieved by incorporating unrealistic faults and fault properties, this may be an artificial compensation for other hidden inadequacies in the model (Fisher & Jolley 2007). Hence, the distribution of fluids connected across the faults in a field, as controlled by the juxtaposition arrangement and fluid flow properties of the faults, has remained one of the largest uncertainties in the subsurface assessment. This impacts prediction of a field’s production efficacy, and the planning of drilling to optimize hydrocarbon sweep (e.g. Corrigan 1993; Lia et al. 1997).

The flow of fluids between adjacent cells in a simulation model is controlled by the cell–cell transmissibility (a function of the geometry and properties of the cells). However, the reduced permeability characteristics of an intervening fault should retard the flow across sand–sand juxtapositions. This effect is accounted for by correcting the cell–cell transmissibility with a fault transmissibility multiplier (a function of fault rock thickness, permeability and cell properties; Fig. 2). Traditionally, these flow-retarding effects of faults are addressed late in the workflow by the reservoir engineer, who imposes transmissibility multipliers on the faults, in some cases adding or removing faults from the model. However, this is essentially educated guesswork, which manually steers pressures and fluid flow within the model and frequently results in unrealistic ‘special’ treatment of some faults in the model. This treatment would imply that these faults were developed under radically different physical-chemical conditions to their neighbours. Clearly, this approach does not mimic the complex, three-dimensionality of faulted sand juxtapositions or the systematic porosity–permeability variations that characterize natural faults. Given that flow within a simulation model is a function of its input geocellular grids and that it is sensitive to the various \( \text{Ad_boc} \) parameter amendments applied by the engineer to achieve a history match, no simulation is a unique model solution for the field. Thus, the more amendments there are in a model, the less likely it becomes that the simulated flow approximates to reality (despite the production history match). Consequently, the forecast mode of the model becomes increasingly unreliable.

This paper describes how this uncertainty can be reduced greatly, through the constraints that are imposed on the model by inclusion of geologically realistic faults, integrated with systematically calculated fault zone properties (e.g. reduced porosity and permeability). The first step in ensuring that this takes place is the provision of a geometrically ‘realistic’ horizon–fault interpretation of the seismic data as a basis to build a structurally valid geological static model. Following this, the accurate import and preservation of the geocellular information from the static model into the simulation model ensures validity of fault architectures and juxtapositions. This is, in fact, a basic prior requirement for effective calculation and integration of fault transmissibility multipliers in the simulator – since most fault seal-related algorithms are based on fault displacement and the properties of the near-fault stratigraphy (see below). We then integrate these geologically valid fault geometries with geologically reasoned fault transmissibilities in the simulator – as calculated from the upscaled geocellular grid – to produce unique transmissibility multipliers for each across-fault cell–cell connection in the model (in the Manzocchi et al. 1999, 2002).

In this paper, we describe the application of an approach that has been found to be successful under the ‘battle conditions’ of live asset projects, and which is rooted in the pragmatic experience of the authors. Several case examples are used to illustrate the effectiveness of these methods in capturing the fluid flow properties of faults and faulted reservoir connectivity. It is shown that this is capable of generating a step-change improvement in history match without requiring iterative ad\( \text{boc} \) edits to model parameters – thus improving confidence in the model’s forecast mode. The examples come from mature Brent Group fields in the northern North Sea, where the method can be tested unambiguously with the production history match in several fields that each have 20–30 years’ production data from 2–300 wells (Fig. 3). Finally, the role and validity of the single-phase transmissibility multiplier method described here is discussed within the wider context of more recent developments in faulted multi-phase flow concepts and methodologies.

**GEOLOGICAL CONTEXT OF THE BRENT GROUP FIELDS, NORTHERN NORTH SEA**

This section of the paper outlines the reservoir geology, with emphasis on the geometry and timing of movement on the fault arrays. This information is important as input to understanding the nature of the basic fault juxtaposition of sand flow units, and the prevailing physical-chemical conditions that control the development of various types of flow-retarding fault rocks.

**Stratigraphy**

The Middle Jurassic Brent Group stratigraphy is subdivided into five major lithostratigraphic units (the Broom, Rannoch, Etive, Ness and Tarbert formations, Deegan & Scull 1977), which were deposited in a variety of shallow-marine to coastalplain environments (Hampson et al. 2004, and references therein). The sequence “motif” can be subdivided into three parts: a lower panel composed of a variety of bioturbated to clean fine–medium-grained laterally persistent sands, silts and shales, overlain by more massive sands; a mid section composed of shales; and an upper package composed of a depositionally complex suite of laterally persistent shales, silts, sands and locally developed coals, which become coarser and more bioturbated towards the top (Fig. 3). The detailed depositional content of the sequence and erosive quality of intra-Brent...
unconformities at any given point vary with respect to the position of the palaeo-shoreline, although the overall depositional thickness of the sequence remains fairly constant. The general exception to this is the uppermost part of the Ness and Tarbert formations, which have been shown locally to contain growth against normal faults, which were beginning to develop at the outset of the widespread late Jurassic–early Cretaceous rifting in the North Sea (e.g. Ziegler 1990; Thomson & Underhill 1993; McLeod et al. 2000, 2002).

Structure

The Brent Province oil fields lie within the footwalls of major half-graben of this age, which form regional terraces along the margins of the Viking graben system. The Brent Group thickens very gradually to the east regionally and across individual fields, and there are locally developed fault-growth sequences in the Tarbert Formation, in particular. However, the upper part of the Brent is often thinned by erosion and/or non-deposition towards the crestal areas of the fields, beneath the Heather shales, where footwall uplift on the margins of the local graben would have been most active, perhaps causing subaerial exposure at the time. The late Jurassic–early Cretaceous faults overprint and rework an earlier, equally significant rift system that had developed during the Triassic and even older Variscan structures and Caledonian-age lineaments and fabrics within the basement (e.g. Yielding et al. 1992; Roberts et al. 1995; Faerseh 1996). The Jurassic–Cretaceous fault arrays formed by a combination of new segment propagation and selective reactivation of pre-existing faults. Thus, some old normal faults became reactivated and incorporated within the plane of the main trend graben, whilst others became re-utilized as displacement-relaying cross-faults and strike-slip faults, to form a rhomboidal fault pattern across the region. The trend, spacing and throw variation of fault arrays are also seen to be partitioned by a combination of hard- and soft-linkage across Triassic structures and older basement lineaments. This reworking of faults to perform new kinematic functions is a common structural process (e.g. Peacock & Shepherd 1997; Jolley et al. 2007), as is the selective reactivation of basement fabrics and fault arrays to form rhomboidal fault patterns during oblique rifting (e.g. Khalil & McClay 2001; Younes & McClay 2002; Morley et al. 2004; Bellahsen & Daniela 2005).

The late Jurassic–early Cretaceous fault arrays in the region can be subdivided into two kinematically and geometrically distinct groups: a thick-skinned (basement-attached) fault system of major graben and smaller cross-faults, as described above; and thin-skinned fault arrays that form contemporary slope instability (landslide) complexes (Welbon et al. 2007), parochially referred to as ‘slumps’. For example, the famous Brent Field dips to the west in the footwall to a major easterly dipping normal fault. It is confined at its northern and southern ends by smaller, broadly E–W to WNW–ESE-trending normal cross-faults, which appear to reactivate older faults in the underlying basement. The immediate footwall to the field’s eastern boundary fault is disaggregated by an easterly transporting slump complex (Fig. 4). The economic value of understanding the relative volumes and fluid connectivity between these groups of structures is shown by total ultimate production, estimated in 2003 at approximately 2000 MMBL oil and 6000 BCF gas, with approximately 10% coming from the slumps (Taylor et al. 2003). The slumps are internally complex, comprising linked arrays of N–S-trending normal faults which detach into shale packages within and beneath the Brent Group reservoir sequence. These structures subdivide the reservoir into an array of blocks (ranging from 50 × 500 m to 200 × 1700 m in map area), but lose coherence and degrade into a rubble or slurry zone downslope. These slumps are underlain by a later, second tier of slumping which disaggregates the Statfjord reservoir zone. This lower slump complex is composed of arrays of larger, listric faults and rotated blocks which

Fig. 3. (a) Location map and fields in the Brent Province northern North Sea; fields involved in this study are indicated in red (modified from Underhill et al. 1997). (b) Stratigraphy, Brent Group. (c) A typical Brent Group well, showing gamma ray (GR), sonic (Son), Neutron (Neut) and density (Dens) geophysical log responses. This combination of logs can be used to differentiate the distribution of clay content within the sequence from locally developed coals and ‘dogger’ cement zones.
are less confined or influenced by stratigraphic detachments – appearing instead to ‘flatten’ towards the foot of the contemporary free surface, exposed by the downward movement of the hanging wall to the field-bounding normal fault. They, therefore, take the geometrical form of large-scale ‘rotational failures’, more commonly described as instability hazards within civil engineering and open-pit mining operations. This pattern of stacked slump complexes is also seen in the Statfjord Field, which lies along-strike immediately to the north (Hesthammer & Fossen 1999; Welbon et al. 2007) and is repeated in general terms within most of the fields in the region (e.g. Underhill et al. 1997; Berger & Roberts 1999). The thin-skinned slump arrays are linked spatially and kinematically to the thick-skinned faulting, via a combination of hard- and soft-linked fault geometries. Thus, the geometry, spacing and displacement variations within the arrays of faults in the slump complexes on some fields are clearly seen to be partitioned across the line of thick-skinned cross-faults and basement lineaments (Fig. 5). There are variations on this general theme, ranging from some fields having very narrow, steep extensional imbricate arrays linked to the main graben fault, grading into broad detached imbricate arrays and slurry zones, and to major footwall rotational failure zones spanning the entire width of a field (e.g. Gullfaks, Welbon et al. 2007; North Cormorant).

The Heather and Kimmeridge shales onlap these Brent/Statfjord slump complexes. However, a further panel of slumping is often developed within the Upper Heather and Kimmeridge shales, in particular. In the Pelican and Cormorant fields, these younger slump structures appear to detach somewhere within the middle of the Heather shales, whereas the Lower Heather is displaced by the thick-skinned faults, which rapidly tip-out at this level (Fig. 6). The Heather–Kimmeridge slump structures transport eastwards into the hanging wall of the field-bounding faults, occasionally truncating the crestal area, and also form broad arrays of faults which transport westwards and down local palaeo-slope above the field flanks,
Fluid flow and pressure in an oil field is compartmentalized by a combination of stratigraphic and structural architectures. Current subsurface tools and workflows routinely include detailed characterization of the depositional architecture of a given reservoir, its lithofacies and associated mineralogical and porosity–permeability property variations. These variations are captured at geological scale within the ‘static’ geocellular reservoir model, and upscaled to become the flow simulation model for the field. Thus, in siliciclastic reservoirs, stratigraphic barriers and baffles to vertical flow are captured explicitly by the relatively shale-rich layers in the model and lateral barriers and baffles by the intra-layer architectures, such as channels and pinchouts. However, assessment and account of lateral flow barriers and baffles at faults is often incomplete. Frequently, it is assumed that this is entirely due to fault juxtaposition of reservoir sands with non-reservoir stratigraphy. Even if time and effort are given to accurate modelling of valid fault geometries, the true effect of juxtapositions on flow connectivity is complicated by the fact that there are no ‘clean’ juxtapositions in nature. In detail, a fault plane interpreted from seismic data is not a discrete surface — but rather a ‘fault zone’ within which the well-ordered host stratigraphy is smeared, disarranged and re-aggregated (e.g. Fig. 7; Childs et al. 1997; Foxford et al. 1998; Aydin & Eyal 2002; Rykkelid & Fossen 2002; van der Zee et al. 2003; Davatzes & Aydin 2005; Kristensen 2005). Fault zones are generally composed of a hierarchical assemblage of meso-scale faults and halos of smaller-scale faults and fractures, which host a variety of fault-rock types and mineral fills (e.g. Fig. 7; Caine et al. 1996; Fisher & Knipe 1998; Beach et al. 1999; Odling et al. 2004; Berg & Skar 2005; Shipton et al. 2005). The disruption to flow caused by the complex juxtaposition of flow baffles and conduits across and within the faults is, therefore, compounded by the retardation effects of the fault rocks, and related tortuosities imposed on the flow pattern by the fault zone architecture.

The exact suite of fault rocks that form within the fault zone varies systematically with the prevailing physical-chemical micro-scale deformation mechanisms. In turn, these are controlled by factors such as the clay content and grain size of the protolith as well as the pre-, syn- and post-deformation stress and temperature history (e.g. Fisher & Knipe 1998, 2001; Fisher et al. 2000; Sperrevik et al. 2002). For example, where faulting occurs in high net-to-gross sands near to the surface, the dominant micro-scale deformation mechanism is particulate flow. Individual sand grains pop out of their packing order and revert back to a similar packing order once the fault has stopped moving, without significant grain fracturing, to form fault rocks called ‘disaggregation’ zones. The resultant permeability is, therefore, little different to that in the undeformed host sands (Fig. 8). However, if the same sands were deformed at greater burial depth (>1 km), there would be sufficient stress for fracturing and crushing of individual grains to occur — resulting in overall grain-size reduction to form ‘cataclasites’ with permanent porosity–permeability collapse (Fig. 8). Microstructural observation of fault rocks obtained from Brent Group drill core indicates that faulting deformation generally occurred with negligible grain fracturing (Fisher & Knipe 2001). This is consistent with seismic and drilling data (described above), which indicate that faulting in the Brent fields took place under shallow burial conditions.

Impure sands (15–40% clay) deform during shallow burial to produce ‘phyllosilicate-framework’ fault rocks. Deformation-induced influx of clay particles from the surrounding matrix
and mixing of these particles with the framework grains in the fault, results in a rapid decrease in porosity and permeability (Fisher & Knipe 1998, 2001). Faulting of discrete shale beds often results in the formation of clay smears in the faults (Fig. 7, Fig. 8), which often have permeabilities under 0.1 µD, below that of the source shale beds (Fisher & Knipe 2001; Eichhubl et al. 2005). The moderate to severe porosity–permeability reduction that occurs due to the deformation of impure sands and clay-rich layers may continue during burial, long after faulting has taken place, since the presence of clay minerals enhances grain-contact quartz dissolution in the fault zone (Fig. 8; Sverdrup & Bjørlykke 1992; Fisher & Knipe 1998, 2001; Sperrevik et al. 2002).

Thus, in general terms, the permeability of fault rocks is related to their clay content and the syn-kinematic and post-deformation stress–temperature history. This can have a profound effect on the variability of sealing/baffling behaviour of faults within a reservoir under production conditions (e.g. Hesthammer et al. 2002). The majority of faults in the Brent Group reservoirs experienced a single movement phase, causing syn-kinematic permeability collapse at relatively shallow (0–500 m) depths; and then further permeability collapse of the clay-rich fault rocks, in particular, during the subsequent relatively simple passive burial. Thus the present-day depth of a specimen taken from drill core, can be considered as a crude proxy for this later stress–temperature-driven permeability collapse. This is illustrated by the fault rock data measured in drill cores from Brent Group reservoirs shown in Figure 9. The data show basic clustering of the fault rock permeability (reduction) as a function of fault rock type, clay content and burial depth. As a general rule, cataclasites are not a common fault rock type in Brent Group faults (though included in Fig. 9) and tend to be associated with those particular faults that have experienced later reactivation under greater burial depths and temperatures.

In summary, it is therefore possible to quantify broadly the variation of flow-retarding effects of the faults in the reservoirs discussed in this paper, where the distribution of clay can be determined within the model-scale fault planes. This modelled clay content can be compared with measured data on fault rock clay content and permeability, with some refinement possible by filtering of the data based on syn- and post-kinematic burial history (see below).

INTERPRETING AND PRESERVING VALID FAULT GEOMETRIES

As mentioned above, the primary structural influence on flow in the reservoir is the geometrical arrangement of sandy juxtapositions across the faults. Therefore, structural assurance of a simulation begins with capturing a valid fault-horizon interpretation from the seismic data, and then preserving this geometry through the static geocellular model and into the simulation model. Since seismic interpretation files form the skeletal frame for a structure model build, it is critical to: (1) ensure that these data form a geometrically valid entity in their own right; and (2) then avoid discrepancies arising between these geometries interpreted in the seismic data, and the static and simulation model builds (cf. Fig. 10).

Structure-seismic interpretation, framework and static modelling

Seismic reflection energy is disrupted by faults to produce a number of diagnostic signatures, which – depending upon the geology, the type of data in use and the scale and geometry of a fault – are present in various combinations (e.g. two-way-time offsets, changes in reflection character and dip, amplitude dimming, diffractions, fault-plane reflections, coherency edges). Faults picked from a combination of these diagnostic criteria can be subdivided loosely into those that are large enough to offset the two-way-time arrivals of reflections (enabling them to be identified on traditional section and time-slice data displays) and those with smaller throws close to the detection limits of the seismic survey (which can be imaged only by data ‘attribute’ variations) (cf. Fig. 11). One theoretical rule-of-thumb suggests
that the smallest fault throws that can be imaged by seismic amplitudes are equivalent to 1/4 of the dominant seismic wavelength (see Townsend et al. 1998, for discussion). However, direct comparison of seismic data with underground structural mapping in deep mine workings indicates that seismic throw resolution is often closer to 1/8 of the dominant wavelength of the data (e.g. Jolley et al. 2007; Fig. 11). Most interpretation and modelling exercises import the larger structures to the static model, supplemented by the smaller fault populations as appropriate.

In almost all cases of manual or automated interpretation, the horizon picks will not extend exactly to the local fault

Fig. 8. Schematic cartoons of micro-structural processes within fault rocks, leading to permanent collapse of the host rock porosity–permeability structure, as a function of host clay content and burial depth. PFFR, phyllosilicate framework fault rock.

Fig. 9. Fault rock permeability data: (a) an example of an amalgamated dataset (after Manzocchi et al. 1999); (b–d) data measured from drill cores in Brent Group reservoirs within the study region (derived from Fisher & Knipe 2001, together with extra data gathered during this study). (b) Permeability (reduction) of different fault rock types compared to undeformed host rock permeability. Disaggregation faults show negligible permeability change, whereas clay smears show the most extreme reduction. Cataclasites and phyllosilicate framework faults show greatest scatter. (c) Fault permeability as a function of host clay content. Despite natural scatter, the data show some trend clustering as a function of burial depth range of the samples. (d) Brent Group fault permeability as a function of clay content and (burial) depth of sampled cores. The red curves represent the upper and lower bounds of the range of relations that can be derived from these data, whilst the black curve represents the whole dataset, and the green and blue curves are derived from sub-sets of the sample depth range equivalent to particular study reservoirs (see text for details).
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This produces fault surfaces and horizon surfaces that form a structurally valid, interlocking horizon-fault framework. Within this framework, the line of intersection between a horizon and a fault plane that displaces it, is separated into a hanging-wall cut-off and a footwall cut-off. These cut-offs taper towards closure at the geological tip line of the fault, where there is no displacement (Fig. 11). It follows that the fault throw in the model should not be less than the throw resolution of the seismic data adjacent to fault picks imported from the seismic interpretation. The zero-throw geological tips (and topologically valid fault–fault and horizon–fault intersections) are constructed within the structure framework model by various projection methods inherent within the framework-building software, guided by analogue structural data.

Within a seismic interpretation and the related framework model, the horizon cut-off lines are defined by ‘fault polygons’ on the fault surfaces. These polygons can be used as input data for static modelling, since they lie within the plane of the fault and, therefore, cleanly define the dip and geometry of the fault planes where they pass through the reservoir. The polygons, together with a closely-spaced \( x-y-z \) point-set up-sampled from the horizon surfaces in the framework model, effectively define a consistent structural geometry in their own right (Fig. 12). Since the horizon point-set data fit seamlessly into all corners of the fault model, use of this type of data constrains the gridding instabilities in most modelling situations. Thus, the structure framework model is re-generated reliably and quickly as the geometrical envelope within the static model, thereby ensuring geometrical validity and equivalence between the seismic interpretation and the static model (Fig. 12).

**Preservation of geometries in transfer from static model to dynamic model**

Accurate preservation of this geometrical equivalence during transfer from the static model to the dynamic simulation model is critical to maintain the appropriate connectivity of reservoir sands across the faults. However, the transfer often requires some degree of ‘upscaling’ to simplify the cellular dimensions and properties in the model in order to reduce the complexity.

![Image of bad practice examples](https://example.com/bad_practice_example.png)

**Fig. 10.** Examples of bad practice (a) The \( x-y-z \) horizon data cloud imported to the static model from the seismic interpretation is excessively rugose, with common loop skips and spikes, and is geometrically invalid (inconsistent throws and interpolations across faults). A surface has been made from the data cloud and this surface was then used as the ‘input data’ for the horizon modelling. (b) This has resulted in a fault-horizon model, which is geometrically invalid. For example, fault throws diminish to near-zero in many places (ringed by dotted ellipses) and most of the faults hinge/scissor throw direction along-strike (arrowed). For clarity, only those errors in the foreground are highlighted. To generate the variation of movement vectors required on all the faults in this model, the fault blocks would have to undergo significant, unfeasibly complex independent motion and internal shape-change to stretch, compress and twist into position without opening holes or overlapping at the corners across the fault planes. Furthermore, faults are not imaged by seismic reflection data where throws are less than equivalent to 1/8 to 1/4 the dominant seismic wavelength (see Fig. 11). Thus, the faults in the model should have coherent, consistent throw senses and should not be less than \( c. 10 \) m where they coincide with seismic fault picks. (c) An example of a disconnection between the fault-horizon geometries within the production simulation model and the original structure-seismic interpretation. In this case the top Etive (surface with zig-zag tears), has been exported from the simulation model into the static model for visualization in the same 3D space as the seismic interpretation of faults at the equivalent level (red fault polygons). There are radical differences between the two sets of faults and fault throws. The static model faults – not shown here for clarity – have an intermediate geometry.
of pressure and saturation-flow calculations and, therefore, the overall run-time of a production simulation. Thus, there is a tension between the two key aims of upscaling: to satisfy the practical needs of the simulation by reducing the geological complexity of a model to its salient characteristics; and to ensure that these key elements of the geology are preserved during the upscale. This is, therefore, a process that requires sensitive handling in order to avoid damage to the plumbing/flow characteristics of the model. Lateral \((x\times y)\) upscaling to increase cell size and/or discretize the cells to form orthogonal grids can cause severe damage to the fault geometries and reservoir juxtapositions across them, since it causes widespread changes to the fault positions, lengths, linkages, throws and surface areas. This is a particular problem where branching fault arrays may become disconnected and some faults ‘loop’ around the upscaled model. In severe cases, the reservoir engineer may have omitted ‘problem’ faults from the final model altogether. The impact of accepting incomplete fault arrays in a simulation model is illustrated in Figure 1.

However, if the static model is built to honour the framework fault geometries – at a cell size that is at or close to the size to be used in the simulation model – the model geometry can be transferred to the simulator with little or no lateral upsacle. This method preserves the geometry of the static geocellular fault model. The benefits of preserving the geologically valid fault geometries from seismic interpretation to static model to simulation model in this way, are illustrated by the example shown in Figure 13. This compares the attempts to history match two simulation models that were based on the same basic static model. The only difference between the simulation models is that one was laterally upscaled (damaging the geometry), whereas the other was transferred as a ‘realistic’ model without geometrical upscale. The static model is shown with the top layers removed to reveal the relative position of the faults in the static model with respect to: the seismic structure framework faults that were used as input data (red polygons); and the position of the simulation model fault planes (black ‘blades’).

These models were run ‘traditionally’, starting with simple global fault transmissibility multipliers, which allowed an unambiguous test of the effects of fault array and juxtaposition geometry on the flow simulation. Simulation model 1 (Fig. 13a) was upscaled laterally from the static model by a factor of four \((i.e. \frac{25}{100} \times \frac{25}{100} m \to 100 \times 100 m)\) and discretized, causing widespread damage to the fault geometries. The reservoir engineer had a ‘traditional’ iterative struggle with the model variables, which evolved into a long list of significant \(ad \ hoc\) edits, including a five-fold multiplier on stratigraphic permeability, adding extra fault lengths, deleting fault segments and applying unique local fault transmissibility multipliers. After more than 225 runs, the engineer was unable to bring the model close to achieving a history match and the excessive level of \(ad \ hoc\) edits had undermined confidence in the model to measure or forecast production realistically. Simulation model 2 (Fig. 13b) was derived from a static model built at the required \(100 \times 100 m\) cell size to honour the geometrically valid structural framework faults that were used as input data (red polygons); and the position of the simulation model fault planes (black ‘blades’).

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Accurate rendering of fault juxtapositions within Brent Group reservoir models is critical to understanding the brute connectivity of flow units. The permeability of fault zones should also be modelled, using algorithms based on the clay content of fault rocks, as a basis for calculating the transmissibility of faults within simulation models.

Fault clay content and permeability

Given the relationship between clay content and permeability of fault rocks in Brent reservoirs (Fig. 9), it is clear that an understanding of the clay distribution within the faults is critical to modelling flow-retarding effects of the faults in the flow simulator. There are several published and proprietary algorithms available, which calculate the clay content of model-scale fault planes in siliciclastic rocks (see Yielding et al. 1997, for discussion). These are based on the entrainment of clay into faults from discrete shale layers and upscaled clay content within the adjacent model layering. Therefore, these algorithms are sensitive to the accuracy of modelled fault displacement and to the petrophysical calculation, upscaling and gridding of $V_{\text{shale}}$ (used as a proxy for clay percent); and are effectively reliant upon a geologically feasible upsacle of a valid structural-stratigraphic model as described above. The algorithms each focus on the effects of several key physical processes that operate within fault zones (e.g. Figs 7, 8) and are therefore best used in combination to capture the full range of clay entrainment mechanisms active within the faults being modelled. A full discussion of the advantages and disadvantages of each method is outside the scope of this paper, since all have their merits when used within the geological settings for which they were designed (e.g. Fisher & Jolley 2007). Instead, the algorithms used in the context of the work described in this paper are summarized.

The most accessible algorithm is the ‘Shale Gouge Ratio’ (SGR; Fristad et al. 1997; Yielding et al. 1997), which focuses on the process of abrasion of relatively soft shale layers and the consequent admixture of collective stratigraphic clay content in the fault plane. This appeals to the redistribution of clay within fault rocks (cf. Fisher & Knipe 1998), the key assumption being that the volume-percent of clay entrained into the collective fault plane at any point along its surface is equivalent to the proportion of shale within the stratigraphy that has slipped past that point (Fig. 14). This may be a fair approximation, since recent comparison of a range of algorithm predictions with geological mapping/logging of surface exposures has shown that SGR gives a reasonable overall match to the average clay content of natural faults (Doughty 2003; van der Zee & Urai 2005).

However, ‘shale smear’ is another key deformation process that occurs within faults active at relatively shallow burial depths in well-bedded sand–shale sequences (Figs 7 & 8). This process shears the discrete sand and shale layers to form continuous smears within the fault planes. There is often a degree of local complexity in the fault zone around a shale
There is a great deal of complexity involved in the ratio of sand versus shale smears, their relative lengths with respect to source-bed thickness, and their lateral continuity (e.g. van der Zee et al. 2003; van der Zee & Urai 2005; Childs et al. 2007). Thus, in section view, the shale layers are seen to tongue into the fault and nip-out some distance away from the source bed as the tensile coherency of the material is exceeded by the displacement. Sand beds deformed under shallow burial conditions are also seen to be smeared.

There is a great deal of complexity involved in the ratio of sand versus shale smears, their relative lengths with respect to source-bed thickness, and their lateral continuity (e.g. van der Zee et al. 2003; Kristensen 2005). These features are captured for the static and dynamic models by a number of public and proprietary algorithms. For example, the ‘Clay Smear Potential’ (CSP) algorithm relates the downthrow continuity (length) of a shale smear as a function of the shale source-bed thickness (Fig. 14; Bouvier et al. 1989; Fulljames et al. 1997; Yielding et al. 1997). A related algorithm, the ‘Shale Smear Factor’ (SSF), calculates smear thickness as a function of fault throw and source layer thickness in order to estimate the continuity of smears caused by abrasion of shales and coals against more resistive sandstones during fault movement under deeper (>2 km burial) conditions (Fig. 14; Lindsay et al. 1993; Yielding et al. 1997). If a cut-off value is applied as a threshold between ‘seal’ and ‘no-seal’, CSP and SSF produce a ‘binary’ arrangement of totally sealed and ‘totally open to flow’ bands across the fault planes in a model, based on the ratio of fault throw to thickness distribution of discretely modelled shale source layers. Therefore, these algorithms are extremely sensitive to the validity and accuracy of the modelled layering scheme and fault throw variations.

Once displacement becomes large enough to disengage smears from their source layers, they become entrained wholly or partially within the fault to be randomly parked as sand and clay ‘slugs’ within the fault plane. However, some outcrop observations do not show a systematic arrangement of clay smears in relation to their source beds, and so a stochastic approach is used to ‘place’ the smear distributions along the fault planes (Childs et al. 2007). In situations such as this, and where the shales are thin within dominantly sand stratigraphy (or vice versa), or sand–shale layering is relatively fine (cm–m scale), it can be argued that the smear and slug lengths will be up to orders of magnitude less than fault throw values and are thus accounted for within the SGR algorithm once stratigraphy is upscaled. This implies that SGR can be used under the right circumstances as a catch-all algorithm for estimating fault permeability (e.g. Childs et al. 2007). However, in the case of decametre (>10 m scale) thickness sand–shale units deformed by meso-scale to relatively small seismic-scale fault throws, the fault throw to thickness ratio is within 4 or 5, so that sand and shale smears are generally continuous features (cf. Færseth 2006). Under these circumstances, the fault plane is scaled completely across the shale smears and stratigraphic continuity.

Fig. 13. Static model surface (Top Etive), together with framework model faults derived from the seismic interpretation (red fault polygon lines) that were used to build the static model faults, plus the equivalent fault surfaces from the simulation model (black ‘blades’) that were derived from them, all loaded into the static model for 3D visualization. This figure illustrates the benefits of preserving structural geometries from seismic interpretation and framework model to static model to simulation model. (a) Case 1: The static model was upscaled into the simulator, compromising the integrity of the static horizon-fault model and, therefore, the arrangement of juxtapositions in the model. This is particularly well illustrated in the dotted circles, where simulation model faults either link or open inappropriately across framework fault polygons. No production history match could be achieved in more than 225 runs with this model. This was despite the reservoir engineer amending fault geometries and treating their transmissibility multipliers separately to steer flow around the model and applying a long list of ad hoc amendments – many of which exceeded geologically reasonable limits (e.g. 5 × permeability multiplier on all layers in the model to get it to flow). (b) Case 2: The static model was built to honour the fault geometries at the cell size used in the simulation model (no lateral upscaling). Note that the simulator faults directly overly the original geometrically valid framework fault polygons. Almost none of the previous ad hoc amendments were required in the simulator. For example, model layer permeability multipliers were not needed, and only one fault required ad hoc treatment. Each simulation run was about 50% faster than the previous model and the model came close to history match in 70 runs, which included testing various sensitivities, before the exercise was terminated.

**Note:** The diagrams (a) and (b) illustrate the difference between upscaled and unupscaled models. Diagram (a) shows a scenario where the static model was upscaled into the simulator, leading to an inaccurate representation of the fault geometries and a poor history match. Diagram (b) shows a scenario where the static model was built to honor the fault geometries at the cell size used in the simulation model, resulting in a more accurate representation and a better history match.

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225+ runs but no History Match

70 runs for History match
Gouge Ratio (SGR, Yielding et al. 1999) and Fault Seal Factor (SSF, Lindsay et al. 1999). To do this, the method first compares CSP/SSF, SGR and fault permeability values for each faulted cell face in the model. These values are then used as a proxy for clay percent in order to assign fault permeability values derived from measured data (e.g. Fig. 9). The SGR and related fault permeability values are combined with fault rock thickness to calculate unique fault transmissibility multiplier values for each faulted cell connection in the model (Figs 2, 15; as per Manzocchi et al. 1999, 2002). Then clay smears can be plotted as/ if appropriate on the fault planes to define basic flow/no-flow zones, thus blanking-off certain areas of the fault to flow. This produces a systematic, geologically reasoned and calculated variation of fault transmissibilities within the model, which are then included in the simulation run of that model.

We have applied systematically modelled fault transmissibility multipliers to geometrically valid models (as defined above). To avoid ambiguity in describing the impact of these methods on flow simulations, in this paper we have: (1) included examples from fields with extensive well and production data control (e.g. the Brent Field, with >30 years of production and over 320 wells, and over 8000 well picks in the reservoir model); and (2) concentrated on the early simulation results – at a stage in the history matching process that has few, if any, model edits. In particular, the effects of applying multipliers derived from SGR were examined, since this is a simpler calculation and not as sensitive as CSP or SSF to the choice and upscaling of a modelled $V_{shale}$ layering scheme or to minor fault throw uncertainties. By focusing on SGR in this way, the study has also avoided additional ambiguities arising from the uncertainty associated with stochastic modelling required to cl]oy smear ‘slugs’ within fault throw windows (e.g. Childs et al. 2007; Manzocchi et al. 2007).

Results were compared between models simulated with systematically modelled multipliers derived from ‘amalgamation’ case fault permeability data and locally derived fault permeability data (e.g. Fig. 9, cf. Fig. 15). In both cases, fault rock thickness ($t_f$) is assumed to be a linear function of fault throw ($D$). Following the discussion provided by Manzocchi et al. (1999), several $t_f$ scenarios were modelled using the relationships $t_f = D/66$, $D/100$ and $D/170$. It was found that these differences had very little effect on the simulation results compared to the more profound impacts caused by perturbing model geometries and choosing different fault permeability relations. In the amalgamation data case (Fig. 9a), fault permeability ($k_f$) was given by (Manzocchi et al. 1999):

$$\log(k_f) = 0.4 - 4.3 SGR - 0.25\log(D)(1 - SGR)^2.$$  

(1)

In the case of fault permeability data collected from ‘local’ drill cores in Brent Group rocks, as discussed above, there is a basic relationship between $k_f$ and clay % of the samples, and also a crude relationship to the depth that the specimens were collected from the wells (Fig. 9b–d). Thus, in this case, fault permeability in mD, is given by:

$$k_f = a \times SGR^{-b},$$

(2)
power-law relations between $k_f$ and $a$ dataset, a function of the burial depth-range of the data (Fig. 9d). The coefficients which SGR calculated from the simulation corner-point model are the position and curvature coefficients of the flow restrictive fault planes. The faults at this scale clearly are not complete barriers to flow, but rather act as flow-retarding ‘baffles’ within the individual reservoir layers.

Simulation results

It is a general observation from production data that fluids and pressures within flow units in the upper Ness and Tarbert sands are often compartmentalized from flow units in the lower Ness and Etive sands. While depletion is often experienced within a flow unit over a wider area than individual small fault blocks, compartments arise during production that are bound within the larger fault blocks in the field (e.g. Fig. 16). This preservation of stratigraphic compartmentalization is explained most logically by clay smear processes on the smaller fault population (as described above). The faults at this scale clearly are not complete barriers to flow, but rather act as flow-retarding ‘baffles’ within the individual reservoir layers.

Initial simulation runs using a ‘traditional’ manual application of a fault transmissibility multiplier of 0.01 or 0.02 to all faults in the model will often help provide a starting point for the engineer to gain a certain level of overall pressure match. This is more useful in fields with a fairly homogeneous reservoir stratigraphy, but less successful where the reservoir stratigraphy is more heterogeneous. The results often indicate that the pressures within flow units in the models are too close by comparison with the true ‘layered’ and larger (km-scale) fault block-bounded pressure compartmentalization seen in the fields. This homogeneous pressure results from faults being too ‘open’ and thus allowing potential flow paths through the fault systems where they should be sealed. Therefore, fault transmissibility reduction is required to achieve a pressure match between the model and the historical data. However, it is clear that this also induces errors in the ‘plumbing’ of flow units across the faults, with some faults becoming sealed too much in some areas and left too open to flow in other areas. Moreover – and as pointed out by Manzocchi et al. (1999) – a constant transmissibility multiplier applied to a heterogeneous reservoir sequence does not, as generally assumed by the engineer, imply a homogeneous fault. In fact, it implies implicitly that the fault is heterogeneous, but that this heterogeneity has no geological basis and is simply a reflection of the permeabilities of the juxtaposed cells.

The general conclusions that can be drawn from these points are that the flow-retarding effects of faults depend on the particular intra-Brent juxtapositions present; and that the multipliers calculated according to the ‘traditional’ approach can never come close to honouring natural (yet, in a broad sense,
predictable) distributions of the sealed portions of faults, or the permeability and thickness of the open but baffling portions. That is best achieved through a ‘systematic’ approach similar to the one described in this paper (and elsewhere, e.g. Manzocchi et al. 1999).

Simulations run on models with application of the systematic fault transmissibility multipliers typically show a more realistic rate distribution of pressure depletion than is achieved by ‘traditional’ methods (e.g. Fig. 17). The match between the simulated and measured data is enhanced much further where these multipliers are calculated from fault permeability data derived from this and nearby Brent reservoirs. The improvement is especially enhanced where these data come from reservoirs that have experienced similar burial–strain histories. The multipliers produce a clear variability of fluid production across the faults in Brent reservoirs, with more heterogeneous distributions generated in the fault-dominated areas of the fields, and focusing of flow where previously the sweep was more unrealistically uniform.

Following this stage of applying field- and platform-scale adjustments (including the systematic fault transmissibilities described here), the history matches we have illustrated were improved upon further with relatively minor adjustments to the models (Table 1). For example, some well locations and perforation depths are found to be in error, such that too much water is injected into the inappropriate layers in the model. This issue is exacerbated where fracturing during water injection acts to re-connect and equilibrate depletion of local fault/layer compartments in the subsurface but not in the model (see Fig. 18). These issues are addressed by pragmatic adjustment to well locations and perforations, for example, to replicate the locally anomalous pressure/flow sweep patterns in the model.

**DISCUSSION**

The mature nature of the fields has provided us with a wealth of structural, stratigraphic and production data, sufficient to test...
the sensitivity of the dynamic models to a variety of subsurface influences. Stratigraphic architectures and properties and fault juxtaposition architectures are the first line of sensitivity in the simulation, since they impact the fundamental ‘plumbing’ of the reservoir and also form the basis for fault-seal calculations. Variation in these parameters, therefore, strongly influences the flow baffling-sealing behaviour of the faults.

We have described how geologically reasoned single-phase fault transmissibility multipliers can be calculated from the upscaled corner-point geocellular grid (cf. Manzocchi et al. 1999). The positive results described are unambiguous in the main part because effort was put into capturing, validating and preserving the detail of the structural-stratigraphic architecture from the seismic and well data into the static model; and because the subsequent upscaling process was sensitive to the validated fault architectures, thus preserving the arrangement of fault juxtapositions from the seismic interpretation into the static model and through to the simulator (Fig. 21). It follows that aggressive upscaling of a static model erodes the structural coherency of the model geometries and property layering system that the fault seal implementation technique – described here – uses as input data. Thus, although outside the scope of this paper to describe in detail, it is important to note that there is little improvement in history match with this technique when applied to a simulation model that is a poor reflection of the validated structural static model. For integration of fault seal into a simulator to succeed, it is therefore a prior requirement that a geometrically robust structural static model is translated accurately through the upscaling process.

Calculation of multipliers from the upscaled corner-point geocellular grid results in a unique multiplier per faulted cell connection in the model. As such this provides a mimic for the ‘texture’ of variation in cross-fault flow baffling effects that are likely to characterize the surface of geological faults – as suggested by the complex distribution of sub-structures and fault rock products within natural fault zones. The overall severity of the baffling and the degree of homogenization or granularity in the spatial variation between neighbouring multiplier values in this ‘texture’ is a function of the SGR–fault permeability ($k_f$) data relation applied to the SGR values on the faults.

Of the various scenarios tested, those that compare SGR with published amalgamated fault permeability data are capable of improving the production history match. However, a step-change improvement in the match is achieved by SGR comparison with fault permeability data derived from sources local to the reservoir/field under study (in this case, data collected from faults in nearby Brent Group reservoirs). The improvement is particularly enhanced when the data included are derived from fault rocks formed under similar burial depths and which experienced similar burial (stress–temperature) histories to the study reservoir (cf. Figs 9, 20).

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The intuitive explanation for this is that the Brent fault rock data came from reservoir rocks and deformation features that
have similar host mineralogies and physical attributes, and which had experienced essentially the same burial, diagenetic and strain histories and produced the same suite of deformation mechanisms to the faults in the reservoir being modelled. Following this logic, one can expect that the $SGR - k_f$ relation should vary between basins and host stratigraphies in response to variation in this suite of factors. The ‘global’ amalgamated datasets thus bring together a myriad of different mineralogies, geological conditions, strain–burial histories and physical-chemical mechanisms and different data collection and processing methods (e.g. Fig. 20, cf. Manzocchi et al. 1999, fig. 2). The resulting $SGR - k_f$ relation indicates what ideal ‘hybrid’ faults would be like if lots of different basin types, stratigraphies and strain–burial histories were combined together. Taken in isolation, the motif of each dataset in an amalgamated data cloud is unique to the local situation, with only some being similar to the ‘amalgamation case’. Therefore, as discussed by Manzocchi et al. (1999), while the amalgamation case might be a pragmatic approach with accepted uncertainties in relatively unknown reservoirs or otherwise sparse data situations, it is clearly preferable to use locally derived data, if available.

Several recent studies have suggested that it may sometimes be necessary to take into account the multi-phase flow properties of fault rocks during production simulation modelling (e.g. Manzocchi et al. 1998, 2002; Manzocchi 1999; Fisher & Knipe 2001; Rivenes & Dart 2002; Al-Busafi et al. 2005). History matches were obtained rapidly within the present study using transmissibility multipliers based on single-phase measures of fault rock permeability, without taking into account either their capillary pressure or relative permeability characteristics. The results of this study should not, however, be taken as providing justification for discounting the importance of multi-phase flow properties of faults in all production simulation models. Simple models, in which injector–producer well pairs are situated on either side of faults, with low permeabilities and high capillary entry pressures, also indicate that taking into account the multi-phase flow properties of faults is less important than fault rock thickness and absolute permeability (Al-Busafi et al. 2005). However, in other situations, such as reservoirs with little/no shale content and/or where reservoirs are produced by aquifer support or gas expansion, taking into account multi-phase flow is far more important (e.g. Zijlstra et al. 2007). The difference between these situations is that where injector–producer pairs are present, flow rates are sufficiently high that viscous forces dominate flow. Where lower flow rates are present, capillary forces will dominate and, in such situations, it is far more important to take into account the multi-phase flow behaviour of the faults (Manzocchi et al. 1998, 2002).

**CONCLUSIONS**

From a theoretical standpoint and by comparison with historical production data, results indicate that systematic modelling of single-phase fault transmissibility multipliers from the cellular model enables rapid application of fault seal to simulation models. Compared with ‘traditional’ methods, this allows superior production history match results to be achieved with far less manual intervention, and at a fraction of the normal workflow speed. Given the improvement in technical product and speed to achieve history match, this leads to improved confidence and quality of field development and management decisions based on running the models in predictive mode.

The Brent Group fields contain a complex arrangement of fault juxtapositions of the well-layered sand–shale reservoir stratigraphy. These juxtapositions are a first-order sensitivity on compartmentalization of pressures and fluid flow within production simulation models of the reservoirs. The detail of fault-horizon geometries should, therefore, be captured and geologically validated from the seismic interpretation through to the static geocellular model by framework model building in conjunction with the interpretation. This geometrical information should be preserved through the upscaling process into the simulation model because it captures the ‘plumbing’ of the faulted layering system in the model. It is also critical input data used for calculating fault zone clay content and subsequent fault transmissibility multipliers from the upscaled grid for use in the production simulation. Application of these multipliers to
geometrically weak models tends to produce ambiguous or otherwise potentially misleading simulation results.

Several case examples of mature Brent Group fields were used to illustrate: (a) the effectiveness of systematic modelling of fault transmissibility multipliers in capturing the essential fluid flow properties of faults and faulted reservoir connectivity for simulation models; and (b) that this is capable of generating a step-change improvement in production history match without requiring for further significant iterative ad hoc edits to model parameters. Specifically, single-phase fault transmissibility multipliers were incorporated that had been calculated systematically from fault throw/thickness ratios and the SGR derived from the upscaled geocellular grid, by comparing the SGR with data that correlate fault permeability with clay content.

In summary, a step-change improvement in the speed and quality of a history match is achieved where:

- geometrical coherence is ensured and preserved between the seismic interpretation, static geocellular model and the production simulation model by model building and validation in conjunction with seismic interpretation, and by sensitive upscaling to preserve these geometries for input to the simulator;
- fluid flow properties of the faults are accounted for in the simulator by systematic modelling of fault transmissibility multipliers from the upscaled geocellular geometry/property grids in the model, to produce unique multiplier values for each faulted cell face;
- multipliers calculated on ‘amalgamation’ datasets, based on global correlations between fault permeability and clay content improved the history match. However, the history match was far better when these multipliers were calculated with reference to fault rock permeability–clay content data,

Ensure structural validity and geometrical consistency throughout interpretation & modelling process

Fig. 20. Production history match measured by water production for one of the platforms on the Brent Field. Note that incorporating systematically modelled fault transmissibilities in the simulation improves the match to actual production data (compared to the result from the ‘traditional’ approach). Of the systematic approaches, use of amalgamated fault rock permeability data (cf. Figs 9a, 15a) improves the match, whereas use of fault rock permeability data measured directly from Brent Group reservoir cores (cf. Figs 9d, 15b) results in a step-change improvement in the match.

Fig. 21. Achieving geometrical validity in seismic interpretation of horizons and faults and preserving this geometry through the static geocellular model and into the simulator. This is the key structural sensitivity in achieving a production history match since it directly impacts the ‘plumbing’ of flow unit juxtapositions and the fault seal calculation in the simulation model.

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<th>Table 1. Basic simulation model adjustments applied at three broad scales and stages</th>
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<td><strong>Field-scale (early)</strong></td>
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measured from faults present in drill cores within the study reservoir, and/or from similar reservoirs within the same stratigraphy in nearby fields in the region. The results are particularly enhanced where these data are measured from rocks that have experienced a similar burial–stratigraphic history to the study reservoir.

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