Programme Area: Carbon Capture and Storage

Project: Storage Appraisal

Title: Security of Storage Appendices

Abstract:

This document is a supporting document to deliverable MS6.1 UK Storage Appraisal Final Report.

Context:

This £4m project produced the UK's first carbon dioxide storage appraisal database enabling more informed decisions on the economics of CO2 storage opportunities. It was delivered by a consortium of partners from across academia and industry - LR Senergy Limited, BGS, the Scottish Centre for Carbon Storage (University of Edinburgh, Heriot-Watt University), Durham University, GeoPressure Technology Ltd, Geospatial Research Ltd, Imperial College London, RPS Energy and Element Energy Ltd. The outputs were licensed to The Crown Estate and the British Geological Survey (BGS) who have hosted and further developed an online database of mapped UK offshore carbon dioxide storage capacity. This is publically available under the name CO2 Stored. It can be accessed via www.co2stored.co.uk.

UKSAP

Appendix A6.2

Security of Storage (Appendices)

Conducted for

The Energy Technologies Institute

By

Senergy Alternative Energy

British Geological Survey

Geospatial Research Limited

GeoPressure Technology Limited

University of Edinburgh

List of Appendices

Appendix 1 Guidance: Likelihood of Occurrence– Definitions

Containment Risk - Seal

Fracture Pressure Capacity

Low: maximum column height 2 x estimated max relief
Med: max column height 1.5-2 x estimated max relief
High: max column height < 1.5 x estimated max relief
V high: undefined

Seal Chemical Reactivity

Low: evaporites (halite, sulfates etc.)
Med: dominated by fine - very fine grained silicates (mineralogically sub mature-mature)
High: seal includes carbonates, feldspar, ferromagnesian silicates and/or mineralogically immature
V high: undefined

Seal Degradation

Low: no evidence of seal lateral pinchout, erosion, injection structures, leakage, base seal integrity if relevant e.g. strat trapping component (comment on resolution based on data source)
Med: one of the following: seal lateral pinchout, erosion, base seal degraded if relevant i.e. with strat trapping component
High: one of the following: injection structures, evidence of overburden surface hc/gas leakage (pock marks, seeps, gas chimneys etc.), or more than one of the following: seal lateral pinchout, erosion, base seal degraded if relevant e.g. strat trapping component
V high: undefined

Containment Risk - Faults

Density

Low: none recorded (comment on resolution based on data source)
Med: < 10 resolved faults per Unit
High: > 10 resolved fault per Unit
V high: undefined

Throw and Fault Seal

Low: none (comment on resolution based on data source)
Med: estimated offset less than caprock/inter-reservoir shale thickness (note timing of faulting versus expected consolidation)
High: estimated offset greater than caprock thickness/potential for clay smear (cf. published work on UKCS fault seal)
V high: undefined

Vertical Extent

Low: resolved fault displacement limited to reservoir and seal (comment on resolution based on data source)
Med: resolved fault terminates in overburden reservoir deeper than 800 m
High: resolved fault displacement/conduit to shallower than 800 m
V high: undefined

Containment Risk - Lateral Migration

Structural Trend

Low: no dominant directionality
Med: mild tectonic fabric e.g. local trend superimposed on regional
High: intense tectonic fabric e.g. multiple elements parallel to regional trend (graben axis)
V high: undefined

Depositional/Diagenetic Fabric

Low: isotropic
Med: multiple fabric/migration directions, none dominant
High: dominant migration direction controlled by poroperm distribution (e.g. channels)
V high: undefined

Dip Direction

Low: dominant dip direction will lead to primary trap
Med: dominant dip direction will lead to migration to secondary containment
High: dominant dip direction towards surface\shallower than 800m
V high: undefined

Dip

Low: < 1 degree
Med: 1-5 degrees
High: > 5 degrees
V high: undefined

Rugosity

Low: estimated max relief/average thickness > 1
Med: estimated max relief/average thickness = 0.5 - 1.0
High: estimated max relief/average thickness < 0.5
V high: undefined

Hydrodynamics

Low: no aquifer influx during production
Med: significant pressure support from aquifer (only really tells us aquifer is very big or gassy not long distance mobility)
High: active discharge at surface and/or tilted oil water contacts (but note varying OWC with rock quality)
V high: undefined

Pressure Sinks in Storage Unit

Low: none recorded within mapped Unit (but comment on resolution based on data source)

Med: single small-medium oil or aquifer drive gas/condensate reservoir < 100mmbbl STOIIP with water injection
High: single pressure depleted gas or condensate reservoir or multiple small-medium or single large > 100mmbbl oil reservoir (or equivalent)
V high: undefined

Transnational Migration

Low: mapped storage Unit boundary > 10km from international boundary
Med: mapped storage Unit boundary 1- 10km from boundary
High: mapped storage Unit boundary < 1km from international boundary
V high: undefined

Operational Risk - Formation Damage

Mineralogy of Grains and Cements

Low: quartz dominant pore forming and cementing phase
Med: matrix carbonate (if carbonate cements rank as high severity), abundant feldspar, mineralogically immature
High: carbonate cements, feldspar and pore throat filling clays
V high: undefined

Mechanical Integrity

Low: consolidated formation
Med: poorly/partially consolidated
High: unconsolidated formation
V high: undefined

Salinity

Low: < 50g/L
Med: 50-150g/L
High: > 150g/L
V high: undefined

Operational Risk – Dynamic Capacity/Compartmentalisation

Stratigraphic Compartmentalisation Vertical

Low: stacked channels, massive sands etc.
Med: limited vertical connectivity between channels sand bodies lack of erosive stacking,
High: laterally extensive shales/salts
V high: undefined

Stratigraphic Compartmentalisation Horizontal

Low: laterally continuous sands/reservoir
Med: laterally discontinuous sands/reservoir
High: isolated channels/clinoforms, salt walls etc.
V high: undefined

Structural/Fault Compartmentalisation

Low: none recorded (but comment on resolution based on data source)

Med: faults allow wetting fluid transmission, risk fault may provide capillary seal
High: Evidence of risk of fault seal on sub compartment scale
V high: undefined

Diagenesis

Low: No evidence of diagenetic affects/none expected
Med: Evidence or expectation of limited diagenetic overprint reducing reservoir quality
High: Evidence or expectation of severely reduced reservoir quality due to diagenesis i.e. pressure isolation e.g. Upper Bunter
V high: undefined

Pressure Isolation

Low: Production operations/geological evidence suggests pressure compartment larger than defined storage Unit (particularly relevant where Units have been defined in the absence of direct pressure data)
Med: Production operations/geological evidence that defined Unit is single dynamic compartment with hard boundaries (i.e. supporting interpretation based on GPT pressure data)
High: Production operations/geological evidence of pressure compartments within defined Unit (i.e. there might not be measured pressure compartments, but operations suggest dynamically isolated volumes of subsurface contribute to flow cf. Geol Soc 25 yr Commemorative Volume etc.)
V high: undefined

Appendix 2 Participant Reports

1 Participant Reports

1.1 British Geological Survey

1.1.1 Introduction

BGS were primarily involved in filling fields on the CarbonStore website for:

1. Faults
2. Lateral Migration
3. Dynamic Capacity/compartmentalisation

1.1.2 Review of Data Sources, Data Entry, Issues and Recommendations

1.1.2.1 Faults

The PGS Megamerge was utilised for fault assessment of Units in the Southern North Sea and the Northern and Central North Sea. The resolution of the seismic data in the Megamerge used for the fault analysis was at 100 m line spacing.

Seismic data were not available for the Channel and East Irish Sea areas in this study. In the absence of project seismic data, publically available references were used.

Fault Density

The density of the faulting in the storage Unit was categorised as low medium or high based on the guidance on the UKSAP CarbonStore website. A representative seismic section provided by Senergy was also used for guidance.

In the Southern North Sea each storage Unit was identified using the PGS Megamerge seismic data. For each storage Unit several in-lines and cross-lines were assessed for general fault trend, style and density. Screenshots were captured from sections of seismic for each storage Unit which demonstrated the most representative structural style. The fault density was classified as low, medium or high risk using the categories described on the CarbonStore website. An example of a storage Unit classified as high risk (greater than 10 resolved faults per Unit) is shown in **Figure A2.1**.

Faulting was assessed in the large open regional Cenozoic storage Units in the Northern and Central North Sea using key regional seismic reflection profiles. These were obtained from PGS in the form of partly interpreted, illustrative seismic panels. Small Cenozoic faults are widespread. Since most Cenozoic storage Units are areally extensive, the development of more than 10 faults in a single Unit was classed as highly likely. An example of the seismic sections as provided by PGS for the assessment of the faulting in the Northern and Central North Sea is shown in **Figure A2.2**. The data provided did not include accurate maps for locating the seismic lines, but for the regional assessment of faulting in a storage Unit were sufficient.

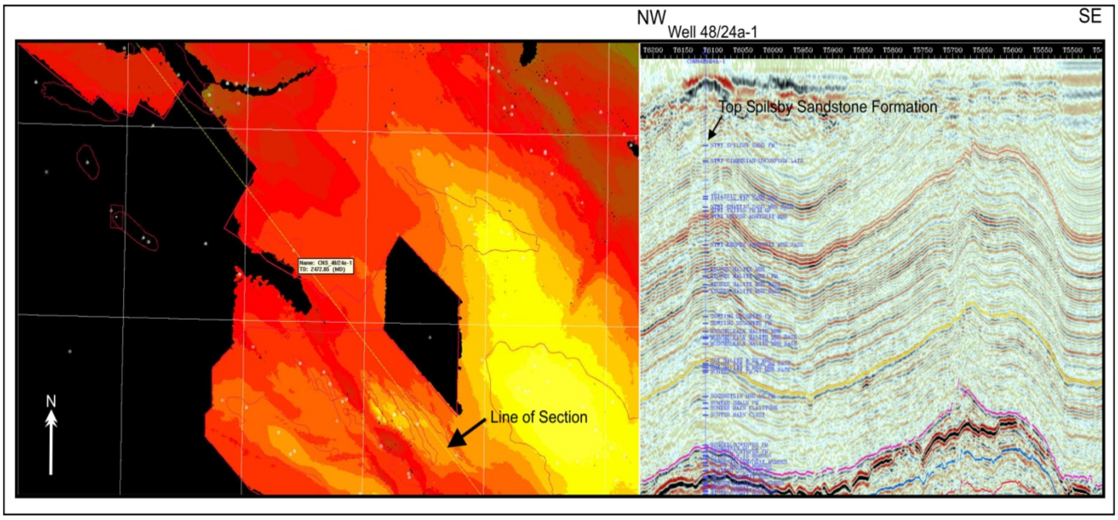


Figure A2.1: Screenshots of PGS Data used for Fault Analysis, showing Storage Unit 140.000 (Spilsby Sandstone Formation)

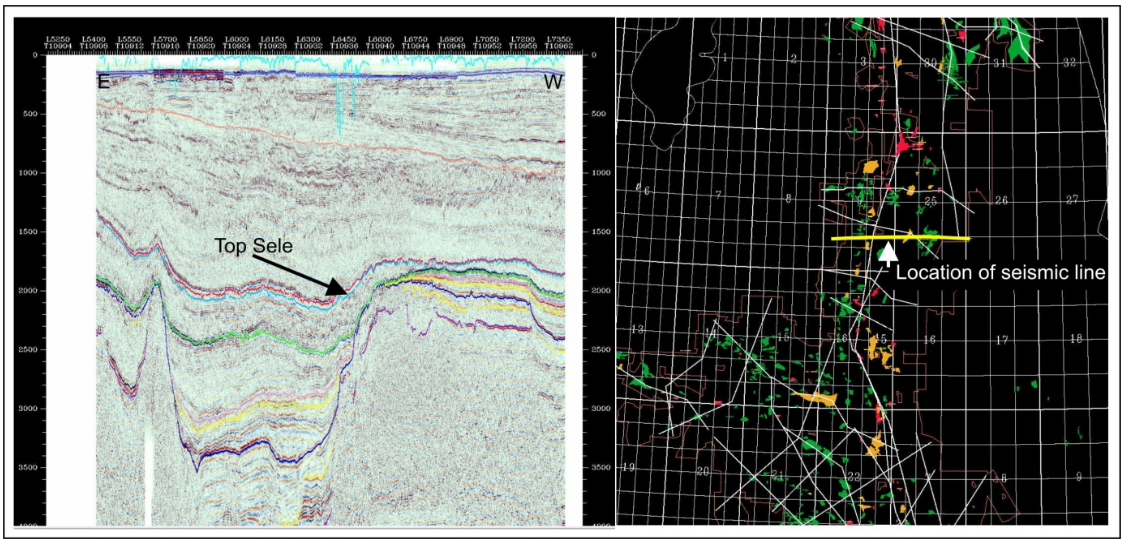


Figure A2.2: Example of PGS Data Provided for Fault Analysis in the Northern and Central North Sea

In the East Irish Sea Basin and the Bristol Channel Basin, published maps and references were used to give a qualitative description of the faulting in storage Units.

For storage Units where structural data were not available for this study, the fields were populated as unknown.

Where storage Units were covered by PGS seismic the confidence in the assessment was usually classified as high, unless poor resolution or quality of the seismic data lowered the confidence in the assessment. For storage Units which relied on 2D seismic data or secondary data, such as published maps and papers, data confidence was classified as medium to low.

Throw, Seal and Vertical Extent

The throw and the vertical extent of faults for each storage Unit were identified in areas where seismic data was available (PGS mega merge). Each storage Unit was assessed visually based on the guidance provided on the CarbonStore website and screenshots were captured. **Figure A2.3** shows an example for three storage Units within the Bunter Sandstone Formation which were all classified differently with respect to risk of leakage due to fault throw.

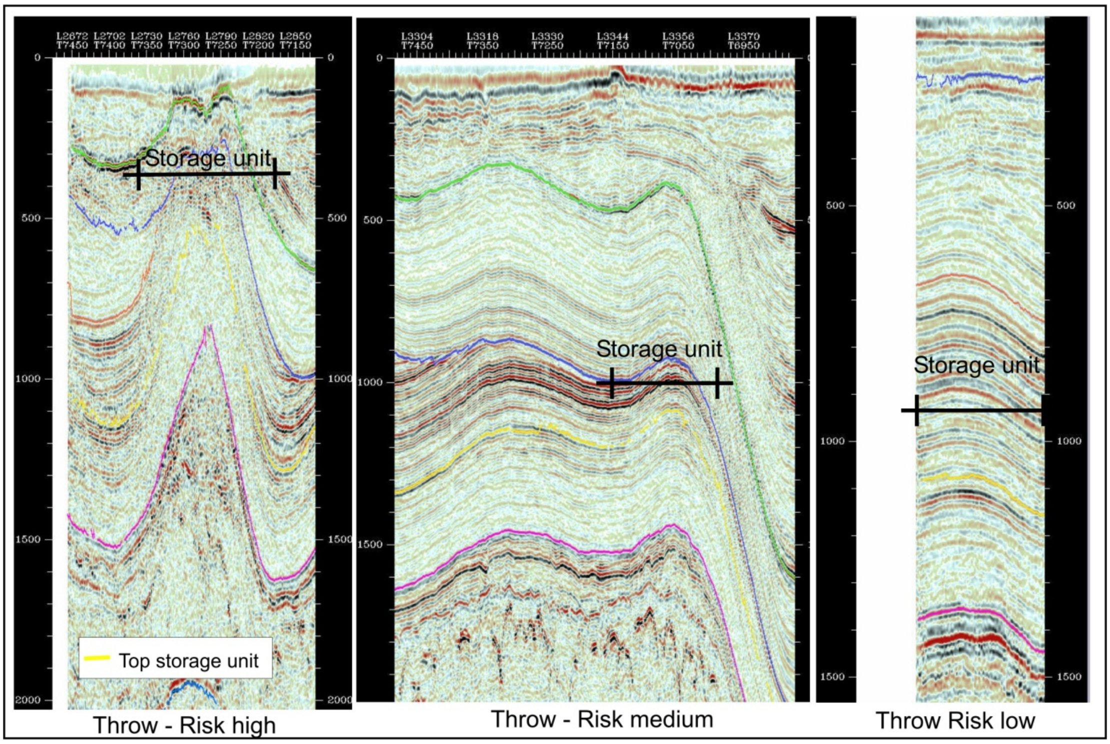


Figure A2.3: Classification of Risk with Respect to Throw
(top of each storage Unit is indicated by the yellow line).
Classified as high, medium and low risk with respect to throw

For storage Units where no seismic data were available BGS relied on published data. Storage Units with no structural data available were classified as unknown.

1.1.2.2 Lateral Migration

Structural Trend (Degrees)

Depth maps were created in Petrel using interpreted depth surfaces derived from seismic data (from PGS) and/or IHS well data. No structural/fault interpretation of the seismic was available for this project. In storage Units where structural data could be located (for example, existing maps) these were incorporated into the depth maps. Using ArcGIS the structural trends were picked by eye on the maps. The mean structural trend was calculated using the 'Linear Directional Mean' tool within the spatial statics toolbox in ArcGIS.

Depositional/Diagenetic Fabric (Degrees)

These data were taken from papers and published information where available.

Dip Direction (Degrees)

The dip direction was calculated for storage Units with Petrel:

'Dip azimuth: Calculate the dip azimuth at each node in the grid. Dip azimuth is the downhill direction along the maximum dip angle. The value is from 0 to 360, clockwise from north.'

Storage Units without Petrel generated surfaces dip angle were measured using contour maps of the stratigraphic tops produced from IHS well tops.

Dip (Degrees)

For storage Units in the Southern North Sea and the East Irish Sea Basin the dip direction was calculated using Petrel on the generated surfaces for each storage Unit. Petrel calculated the dip direction as follows:

'Dip angle: Calculate the dip angle at each node in the grid. Dip Angle is the steepest angle between the surface and the horizontal plane. The value is 0 horizontal, 90 vertical, measured in degrees.'

For the Cenozoic storage Units in the Northern and Central North Sea this was calculated using trigonometry: the measured length of the dip section of the storage Unit and the height difference between its minimum and maximum depths.

The dip was then classified as low, medium or high using the guidance on the CarbonStore website.

Rugosity

Thickness and depth maps for the storage Units were created using a combination of existing interpreted seismic horizons of the storage Units (from PGS) and/or well data from IHS. Rugosity was then estimated from Petrel using the following calculation in MS Excel:

Rugosity = Estimated relief / Mean thickness

Where: Estimated relief = Max depth of top surface - most likely shallowest depth

1.1.2.3 Operational Risk – Dynamic Capacity/Compartmentalisation

Compartmentalisation Vertical, Horizontal and Structural

Stratigraphic and structural compartmentalisation was assessed using the PGS seismic data (where available). The storage Units were assessed visually at the PGS offices using the PGS Megamerge. The connectivity between storage Units or geological formations was assessed and classified using the guidance on the CarbonStore website. In the Northern and Central North Sea UKOOA volumes were also utilised in conjunction with IHS well data to assess vertical and horizontal connectivity.

Seismic data were not available for the East Irish Sea storage Units, therefore the vertical connectivity was assessed using wells and published stratigraphic data.

Diagenesis

Very little data could be located for this field. In most cases diagenesis was classified as unknown.

Transnational Migration

The shapefile of each storage Unit was overlain on a map of the UK offshore transnational boundaries in ArcGIS. The distance of a storage Unit from the transnational boundary was measured in ArcGIS.

1.1.2.4 Key Challenges and Recommendations for Future Work

Faulting

Problems concerning scale – large regional aquifers could be classified as high density faulting (high risk) even though they only have 10 faults over 10's km. Whereas small storage Units (often children) having one major fault in a structure could be classed as low density (low risk) faulting.

The resolution of the seismic data in the PGS Megamerge used for the risk assessment was sometimes poor. It was difficult to tell the difference between a fault, tiling of the seismic (joins at the edges of surveys) and the poor resolution. It is recommended that in critical storage areas the faulting should be assessed in detail on high resolution 3D seismic data.

Structural interpretation of high resolution seismic data should be undertaken for each of the most promising storage Units.

It is recommended that seismic data in the East Irish Sea should be acquired in order to better assess risk in this area.

Dip

Average dip does not reflect the architecture of the Unit and should be the up-dip angle relative to the injection point.

Diagenesis

Further work could be carried out as there are very little publically available data for this field.

1.2 GeoPressure Technology Limited

1.2.1 Introduction

GeoPressure Technology Limited's (GPT) commitment to Work Package 2 was three-fold:

- Work Package 1 algorithms supplied by GPT included aquifer seal capacity, hydrostatic pressure and CO_2 column height, for use within the web-enabled database and GIS application. The results were used to inform the seal risking in Work Package 2.

- Source information on primary and secondary seals and update the web-enabled database and GIS application (WDG).

- Input low, medium or high categories for likelihood and severity for fracture pressure capacity, seal chemical reactivity and seal degradation. List the source of the data and assign confidences.

1.2.2 Comments

Algorithms to determine Aquifer Seal Capacity and CO_2 column height were supplied, which contributed to both Work Packages 1 and 2. The hydrostatic pressure was based on an average gradient of 0.445 psi/ft (0.1 bar/m) from sea level to depth. Overburden and fracture pressures were calculated for each specific Unit in turn at the point of shallowest depth.

Horizons directly in vertical contact with the Unit reservoir were taken as primary seals. The secondary seal was assumed to be the first horizon with which CO_2 will come into contact, on exiting the reservoir, penetrating the primary seal and continue to migrate vertically. Sourcing information on potential seals demanded a thorough literature review to establish an understanding of the local stratigraphy. IHS stratigraphic data from the pressure database were used and websites from governing bodies such as Department of Energy and Climate Change (DECC) and United Kingdom Offshore Operators Association (UKOOA) were consulted to affirm assumptions and source missing horizons. GeoPressure Technology also used its standard stratigraphic column for areas covered by regional studies, constructed specifically for use with the pressure data on a regional scale.

Categories for the likelihood and severity of seal chemical reactivity and seal degradation were informed from a host of information sources. These included established publications such as the Millennium Atlas, Geological Society Memoir 20 and Proceedings from the Petroleum Geological Conferences. Published peer review papers focused on the area under investigation were also consulted. In most cases, data were not available to confidently assess seal degradation. For this reason most Units were assigned a 'medium' category and 'medium' confidence, together with associated comments for each Unit to explain the thought processes and assumptions. Where information was available, confidences were determined based on the source; the more reliable the information the higher the confidence.

Inputting low, medium and high categories for likelihood for the fracture pressure was based on a numerical comparison of the maximum column height and the estimated maximum relief of the structure. When divided, if the resulting value was less than 1.5, the likelihood category would be <u>high</u>. If the result was between 1.5 and 2 the likelihood would be considered <u>medium</u>, and values greater than 2 would be assigned <u>low</u> likelihood.

1.2.3 Challenges

Assessing the 'severity' of the fracture pressure at this stage of the project was challenging due to the scale at which the Units were being assessed. Understanding the likelihood of a Unit with the shallowest depth greater than 800 m would require a more detailed understanding of the structural and lithostratigraphic relationships than is currently available. On this basis, categories were often based on evidence sourced from literature, such as The Millennium Atlas. Again, confidence was based on the standing of the publication used in determining the Unit relationship with adjacent Units. Where the shallowest depth was less than 800 m the task was much easier, as surface communication is assumed and therefore hydrostatic pressure is applied.

Challenges identifying primary and secondary seals were directly related to the stratigraphic description of the Unit assigned by the principal contributor; British Geological Survey and Edinburgh University. Units were sometimes not delineated beyond group level, which made pin-pointing a probable seal near impossible. A Unit described as Zechstein, for instance, is too broad a term as there are too many alternative sub-horizons (some porous with reasonable permeability, others not) within the Zechstein to be specific as to the first horizon the CO2 will come into contact with on exiting the 'Zechstein' saline aquifer. For that reason, the named seal matched the stratigraphic level of the description of the Unit.

Seal chemical reactivity and seal degradation raised similar concerns as those of the primary and secondary seals, and for the same reason. Not clearly understanding the stratigraphic horizon brings into question the lithology of both the saline aquifer and the adjacent or vertical barrier. This leaves a number of open-ended questions with regard to how differing lithologies will react or interact with CO_2, if exposed.

1.2.4 Uncertainties

The uncertainty associated with the categories and confidence levels assigned to the severity of the fracture pressure capacity, the likelihood and severity of both the seal chemical reactivity and the seal degradation and the choices made for primary and secondary seals are, in most cases, significant and controlled, proportionally, to the accuracy with which the stratigraphic description of the Unit was defined.

To reduce this uncertainty and increase the usability of the data, comments were included on each Unit page within CarbonStore. Where necessary, the comments were written at length and tried to include all the relative information for the end user.

1.2.5 Critical Comments on Risking Methodology

We identified two points worth considering:

- Controlling the order with which contributors enter data into, and extract data from, the WDG. On many occasions, data were input, changed or corrected and re-input repeatedly directly due to results affecting results. This was largely Work Package 1 affecting Work Package 2 activities.

- Better definition of the stratigraphic and areal extent of the Units to allow for more detailed assessment of the requested parameters, i.e. interaction with adjacent Units and lithologies and basement and ceiling barriers.

At this stage, ensuring the data can be used to maximum effectiveness is based largely on the comments entered with the numerical data. This will allow the user to determine the probable margin of error with the input data, and therefore gauge the degree of detail they themselves should aim to achieve.

1.3 University of Edinburgh

1.3.1 Introduction

University of Edinburgh's contribution to risk assessment was limited to the consideration of faulting, lateral migration and dynamic capacity/compartmentalisation. All sub Tertiary Units in the Northern and Central North Sea were evaluated.

1.3.2 Containment Risk

1.3.2.1 Faulting

Most of the data inputted into this part of the data loader were extracted from the PGS database. In order to reveal structures, seismic lines were chosen through each storage assessment Unit (as close to perpendicular to the main structural trend as was practical) in the areas covered by the North and Central North Sea 3D Megamerge. The sections were interpreted by PGS, with as many horizons as possible and fault sticks. Note that the quality of the picks, especially for the deeper (pre-Jurassic), appeared to be variable. The majority of the 'leakage containment' section was completed by analysing screenshots of interpreted sections. Note that not all of the storage assessment area was covered by the available seismic data.

Fault Density

The location map of seismic lines (**Figure A2.4**) was scanned and imported into ArcGIS. The shapefile of the 'storage assessment Unit' to be analysed was then superimposed on the location map. This allowed the correct seismic line to be selected for each Unit, to give the best possible representation of the subsurface structure.

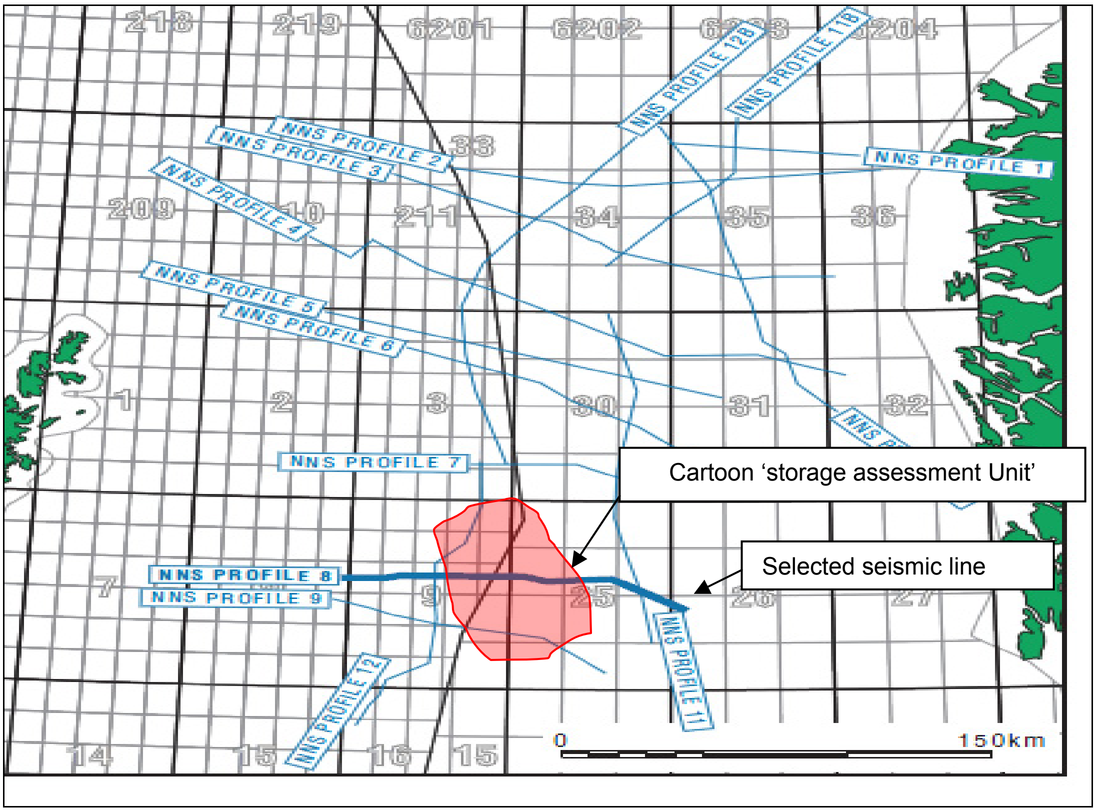


Figure A2.4: Location Map Portraying Position of Seismic Profile (8) in Relation to a Selected 'storage assessment Unit'

An example of a sample seismic line is displayed in **Figure A2.5** below. The fault density was estimated by counting and summing the interpreted fault sticks which intersect the horizon or formation being considered. The data loader was populated following the instructions given, .i.e. 'Low' fault density when no fault stick was interpreted (sometimes due to the low quality of the seismic data, especially for deeper Units), 'Medium' where the sum of the interpreted faults intersecting the formation of interest was below 10 and 'High' when greater than 10 faults were present.

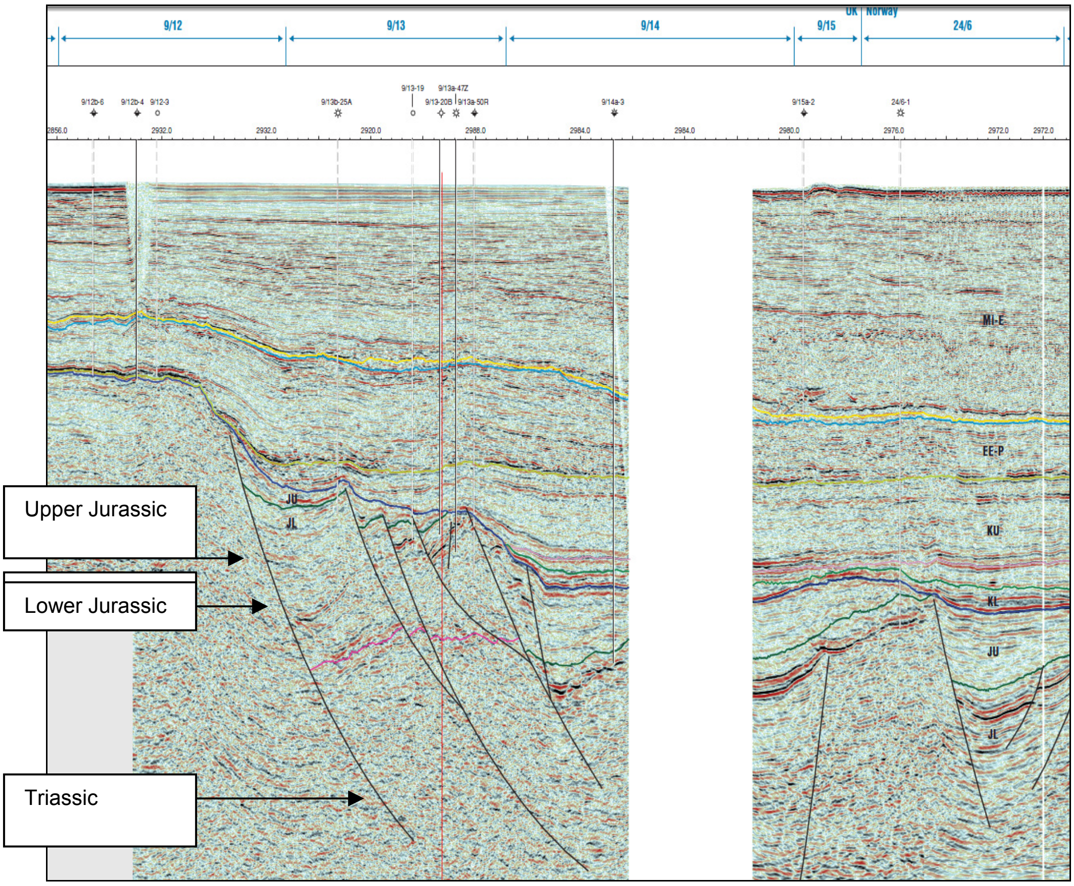


Figure A2.5: Seismic Section showing the Fault Sticks and the Horizon Picks for Unit

Confidence level was allocated mainly based on data quality. Confidence was set at 'Low' when the seismic data were poor or chaotic. 'Medium' was selected if some un-interpreted, relatively small faults were visible. 'High' confidence was selected when clear seismic sections, which allowed for a comprehensive interpretation, were available. An example of a high confidence section is shown in **Figure A2.5** above.

Issues with Method: the faults sticks were drawn manually on the seismic sections. Due to the varying quality of seismic data it is likely that a number of small faults may have been missed. In any case, there will be sub-seismic faults present wherever there are faults that are sufficiently large to be visible. The resolution of seismic data inevitably decreases as depth increases, so that smaller faults may be visible in a shallow Unit that are not visible in a more deeply buried Unit. Hence there is bias in the results.

Recommended Approach: using seismic interpretation software the horizons could be auto-tracked. This would allow faults with smaller displacements to be automatically picked, at a higher resolution than can be done with the human eye. If portrayed on geo-referenced maps, this would give a better representation of the density of faulting for a given area.

Throw and Fault Seal

The throw was estimated by calculating the displacement on faults sticks from the same representative seismic sections used for estimating fault density (**Figure A2.5**). The majority of available interpreted seismic lines were already converted to depth from 'two-way time'. Where the cap rock was mapped adequately, the thickness was deduced from the seismic.

Where this was not possible the thickness was derived from the literature. Fault seal was then estimated by comparing the throw on the fault to the thickness of the cap rock. The slots on the data loader were completed using the instructions provided. When the throw was minimal, 'Low' was selected. 'Medium' was selected when offset was less than the thickness of the cap rock and 'High' where the estimated offset was greater than the thickness of the cap rock.

Issues with Method: again errors may arise due to the resolution of data, and the method used to pick faults within the interpreted sections. Faults with small throws, below the resolution of the picking process, may have been missed. Another error may arise due to the assumed constant thickness of the cap rock. Although a constant thickness was assumed for the purpose of this exercise, it is recognised that in reality, this thickness may vary significantly, especially a region with growth faulting.

Recommended Approach: re-interpretation of seismic data is recommended.

Fault Vertical Extent

The available seismic sections were depth converted. This allowed the vertical extent of faults to be calculated by noting the depth at which the interpreted fault stick terminated. The guide provided for 'Vertical Extent' was used i.e. 'Low' for no fault in Unit, 'Medium' was selected when the resolved fault terminated in the overburden reservoir deeper than 800 m and 'High' when the resolved fault displacement/conduit extended to shallower than 800 m. The 'Severity' risking was completed following the guidelines in the data loader. This was often completed using the best judgement of the analyst. 'Low' confidence was selected for poor quality seismic. Confidence was set at 'Medium' where there was scanty seismic interpretation and the exact formation (reservoir or seal) in which the fault truncated was unclear. 'High' confidence was selected where seismic quality was good and the formation being analysed was directly underlying or overlying interpreted tops.

Issues with Method: whether or not to include the relatively small faults that are visible but not picked was a major challenge. Some of the 3D seismic dataset showed a noisy character that made it difficult to interpret the target horizons with confidence, especially along complex fault zones or in areas with multiple reflectors of uncertain age. This created difficulty in predicting the throw on the fault as the throw on a fault varies both vertically and laterally.

Issues also arose because some beds of interest were relatively thin and below seismic resolution. This led to the analyst making an 'educated guess' as to where the Unit should intersect the chosen fault.

Recommended Approach: better well control (well tie where possible) and reduced noise through the re-interpretation of the seismic data. The faults and horizons therefore must be picked with the highest possible precision and confidence.

1.3.2.2 Containment Risk – Lateral Migration

Structural Trend

Details of structural trend, of a given formation, are rarely given in the literature. For the most part structural maps of the major tops (Cretaceous, Jurassic, Triassic and Palaeozoic) from the Millennium Atlas were imported into ArcGIS and superimposed on the Unit of interest. A representative line is taken and the azimuth computed automatically. For instance in **Figure A2.6** below, the predominant structural trend in the Unit (outlined in red) was set at 118°.

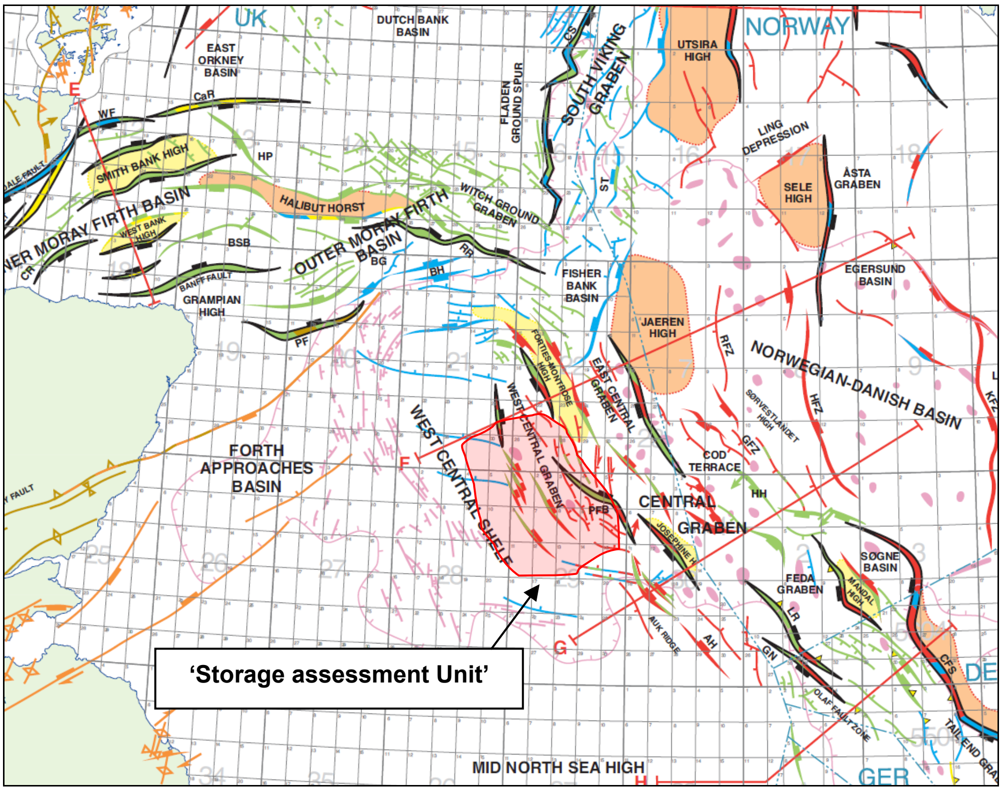


Figure A2.6: Map showing Location of Hypothetical Unit (red shading and the NW-SE structural trend)

The likelihood was set at 'Low' where there was no distinct structural trend (faults in Unit are 'anisotropic'). A 'Medium' likelihood was selected where there was an obvious trend close to the Unit but not directly in the Unit. A 'High' likelihood for structural trend was set when the Unit is trending in one direction and faults are directly within the Unit.

Confidence in this method is mostly 'Low' as only a general (major tops) structural trend map was available. A major assumption was that the structural trend on the individual formations is the same as the closest overlying or underlying available surface. A 'Medium' confidence was selected when the formation is close to but not directly below or above a major surface. A 'High' confidence was picked when a formation was directly above or below the main surface.

Issues with Method: ability to decide a representative value to the structural trend for large Units was the main challenge.

Recommended Approach: edge or curvature maps of the different formation tops would give a more accurate structural trend estimate.

1.3.2.3 Depositional/Diagenetic Fabric

Most commonly, papers written about a chosen hydrocarbon field gave details of depositional and diagenetic fabric. Confidence is 'Low' where there was no field close to Unit. A 'Medium' confidence was selected where there is a field relatively close to the Unit and 'High' where there was a hydrocarbon field within the Unit that intercepted/sampled the formation. Diagenetic fabrics are not commonly described, and even if mentioned (e.g. concretions), then any direction is not specified.

Dip Direction

To determine 'Dip direction' depth contours were overlain on the storage assessment Unit shapefiles. A line of transect (A-B) was then drawn through each Unit, as close to perpendicular to the depth contours as could be assessed. Dip direction was computed automatically for the line of transect using the azimuth calculator function in ArcGIS (**Figure A2.7**). The figure shown has a 'Dip direction' of 90 degrees. The likelihood was completed based on the analyst's 'best judgement' following the guidelines given in CarbonStore.

Confidence was set at 'High' when the Unit has a simple, planar structure so that the entered value was representative of the majority of the Unit. 'Medium' was selected where there was a more complex structure and difficulty was experienced when choosing an appropriate representative direction. 'Low' confidence was chosen when there were few or no contours in the Unit and an educated guess was made to extrapolate between contour lines.

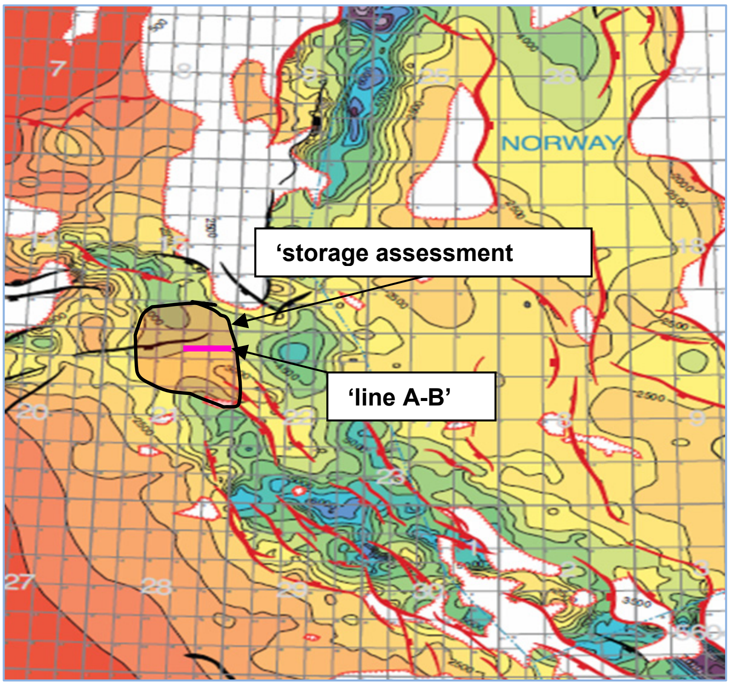


Figure A2.7: Example of a 'storage assessment Unit' and the Line used for Computation of Dip and Dip Direction

Issues with Method: the analyst must use 'best judgement' when selecting the orientation of the dip, so that the method may not be repeatable, and be at least partly operator-dependent. The more complex the structure, the more judgement required, and the less repeatable the result.

Recommended Approach: contour maps can be generated from interpreted surfaces, where available and dips measured automatically using software. Where interpreted surfaces are not available (i.e. the majority of cases), then there is no obvious way to improve on the method.

Dip

The same line described above is used for calculation of dip (**Figure A2.7**). The dip is calculated using simpler trigonometry using the difference in height of contours (vertical separation) along the line and the horizontal distance. Likelihoods were completed following the recommendations in the data loader. Error in the method may have arisen when a depth map for a specific formation was not available. In this case a depth map for the closest formation was utilised and the confidence set to ‘Low’. A ‘Medium’ confidence was selected where the line was not representative of the entire dip of the Unit (either because of complexity of structure or ‘wiggly’ shape of Unit). Confidence was marked as ‘High’ in a number of cases where there were complete depth data, simple structures and the shape of the Unit was consistent.

Recommended Approach: average dip angles could be computed using suitable software where digital surfaces are available. This applies to only a minority of surfaces in this study.

Rugosity

The rugosity of a Unit was calculated using the recommended formula of ‘estimated maximum relief / average thickness. The maximum relief of a Unit was taken as the depth between the shallowest and deepest part of the top surface, derived from the EDIN GIS database. The ‘Most Likely’ thickness for the Unit was utilised for calculating the rugosity. Confidence levels were based primarily on the concentration of top depth data points. Confidence was set to ‘low’, where there were no relevant well penetrations within the Unit and analogue data were used to calculate the relief. Confidence was set to ‘medium’ where direct well data were available, but the number of data points was limited. Confidence was set to ‘high’ where the maximum relief could be calculated from a plentiful supply of data points spread geographically throughout the Unit.

Issues with Method: depths are derived from well logs that are likely to have been drilled through structural highs and therefore the relief of a Unit may be underestimated.

Hydrodynamics

The ‘hydrodynamics’ of a Unit was often difficult to assess. Most commonly, papers written about a chosen hydrocarbon field will give details of the level of aquifer drive in the reservoir during production. The reservoir Units within the chosen hydrocarbon field were used as analogues for aquifer Units derived from the same formation. The hydrodynamics of an aquifer Unit were predominantly associated to two groups. ‘Low’ likelihood was selected when there was limited aquifer drive and water/gas injection was needed to aid production. ‘Medium’ likelihood was selected where natural aquifer influx aided production. There were very limited data available on the angle of Oil-Water contacts and discharge at the surface, and therefore ‘High’ likelihood was not often selected. Confidence was based predominantly on the location of the data source relative to the aquifer Unit. ‘High’ confidence was selected when the chosen hydrocarbon field lay within the Unit. ‘Medium’ confidence was selected when the chosen hydrocarbon field lay out with the Unit but within the same formation. ‘Low’ confidence was selected when an analogue formation was utilised to predict hydrodynamics.

The hydrodynamics field was left uncompleted where there was no data source and a analogue data source could not be justified.

Pressure Sinks in Storage Unit

The location of pressure sinks (hydrocarbon fields) within the study area was derived from published DECC offshore hydrocarbon shapefiles. The likelihood selection was completed as instructed in the data loader. Only fields with reservoirs directly within the formation member of the aquifer Unit were included. Values for STOIIP were derived from literature. Confidence was based predominantly on the location of the pressure sinks both stratigraphically and geographically. A ‘High’ confidence was selected when a field with a single reservoir lay distinctly within the formation/member of the aquifer Unit. A ‘Medium’ confidence was selected when a reservoir extended out with the boundaries of the aquifer Unit, or drew reserves from a number of different formations/members. A ‘Low’ confidence was selected when the conditions as described in the ‘medium scenario’ combined with an undefined value for STOIIP for the chosen field.

Issues with Method Pressure depletion will extent beyond the OWC (or GWC) of a reservoir to an unknown extent.

1.3.3 Operational Risk

Dynamic Capacity/Compartmentalisation

Stratigraphic Compartmentalisation Vertical

Formation compartmentalisation assessment was based on descriptions of reservoir architecture from fields that had reservoirs producing from the relevant formations / members. Where relevant papers could not be found for a formation, data was derived from lithological descriptions within the BGS Reference Atlas. ‘Low’, ‘Medium’ and ‘High’ likelihoods were selected based on the recommended characteristics. Where a Unit contains significantly different lithofacies associations, then the risking was completed in a conservative manner, i.e. the risking was set for the highest risk lithofacies present. For example, if it was known that a Unit was comprised of both sand-filled fluvial channels and interbedded mud and sand crevasse splays, a ‘Medium’ likelihood was selected to represent the highest risk lithology of the Unit. Confidences were selected to represent the uncertainty caused by the variability in the composition of a Unit.

Issues with Method: it is difficult to allow for heterogeneity within a Unit. The degree of compartmentalisation is impossible to infer from a sedimentological description unless specifically described. For example, fluvial channels may (or may not) be in contact, allowing effective communication vertically. Hydrocarbon fields may not be representative of the remainder of a Unit.

Stratigraphic Compartmentalisation Horizontal

Formation compartmentalisation assessment was based on descriptions of reservoir architecture from fields that had reservoirs producing from the relevant formations / members. Where relevant papers could not be found for a formation, data were derived from lithological descriptions within the BGS Reference Atlas. ‘Low’, ‘Medium’ and ‘High’ likelihoods were selected based on the recommended characteristics. The greatest uncertainty was due to the full lateral extent of a reservoir Unit not being known. Where data were sourced from a hydrocarbon field paper it was difficult to determine whether a reservoir Unit was laterally extensive within a storage assessment Unit. Confidences were predominantly based on this uncertainty.

Issues with Method: hydrocarbon fields may not be representative of the remainder of a Unit.

Structural/Fault Compartmentalisation

Both the location of faults and their capacity to seal was based on descriptions of hydrocarbon fields. Confidence was based on the location of the hydrocarbon fields in relation to the storage assessment Unit.

Issues with Method: hydrocarbon fields may not be representative of the remainder of a Unit. Inevitably, hydrocarbon fields are structural culminations and as such are atypical.

Diagenesis

Information on the extent of diagenesis within a storage assessment Unit was derived primarily from the literature, often based on studies of hydrocarbon fields. Likelihood of compartmentalisation was completed based on the recommendations in the data loader.

Issues with Method: there is a substantial literature concerning whether the diagenesis of hydrocarbon fields is the same as the diagenesis of the enclosing aquifer. While the question is unresolved, there is good reason for questioning the application of data from fields to regional aquifers. Difficulties also arose when selecting likelihood for diagenesis when varying extents of diagenesis were present within a single storage assessment Unit. Likelihoods were predominantly selected based on the most severe form of diagenetic effect within a single storage assessment Unit. This was reflected in the selection of confidence for the Unit alongside a comment justifying the decision. Again a large uncertainty arose when data were derived from a hydrocarbon field that may have been geographically distant from the storage assessment Unit.

Transnational Migration

Distances from the Norwegian-UK border were calculated in ArcGIS. Distances were calculated from the most easterly edge of the assessment Unit to the closest point on the border. A ‘High’ likelihood was selected for those storage assessment Units that had boundaries that lie along the UK-Norwegian border.

Issues with Method: one of the simplest risk elements to assess.

Pressure Isolation

The ‘pressure isolation’ of a storage assessment Unit was based predominantly on GeoPressure Technology’s ‘Upper Jurassic Overpressure Compartment’ maps. A ‘Low’ likelihood was selected when the lateral extent of a storage assessment Unit fell within the boundaries of a ‘pressure compartment. ’A ‘Medium’ likelihood was selected when the lateral extent of a storage assessment Unit is equal to the boundaries of a ‘pressure compartment’. A ‘High’ likelihood was selected if the lateral extent of the storage assessment Unit went beyond the boundaries of a single ‘pressure compartment’. Where possible data were also extracted from the scientific literature where details of compartmentalisation within a reservoir were given. If a fields reservoir was known to be compartmentalised at a sub-storage Unit scale, ‘High’ likelihood was selected for the given storage assessment Unit.

Issues with Method: the utilisation of two data sources means that the resolution of input data may vary. This will be highlighted however in both the confidence and source selections in the data loader. Uncertainty arose where pressure isolation within a hydrocarbon field was extrapolated to represent the pressure relationship for an entire storage assessment Unit.

1.4 Geospatial Research Limited

1.4.1 Introduction

Geospatial Research Limited completed two sections within the risking section of UKSAP; the operational risk caused by formation damage including both mineralogy and mechanical integrity; and the containment risk associated with well integrity.

1.4.2 Operational Risk – Formation Damage

1.4.2.1 Methodology – Formation Damage through Mineralogy

All of the saline aquifers have been risked for formation damage by mineralogy (of grains and cements) and mechanical integrity.

1.4.2.2 Data Used

The shapefiles supplied by the BGS and University of Edinburgh which define each saline aquifer were used alongside the relevant CarbonStore entry to define the geographic extent and formation or member to be risked. Public domain literature was then searched to find relevant information to assign a likelihood and confidence for each entry, according to the definitions in CarbonStore. The assigned values were then entered in the CarbonStore database. All sources were entered in the database. Where no direct data have been available then an analogue has been used. The confidence of results reflects the data source. As there is only room to enter one data source, any further sources are listed in the comments box.

1.4.2.3 The Approach

Operational risk has been assessed as follows (**Figure A2.8**):

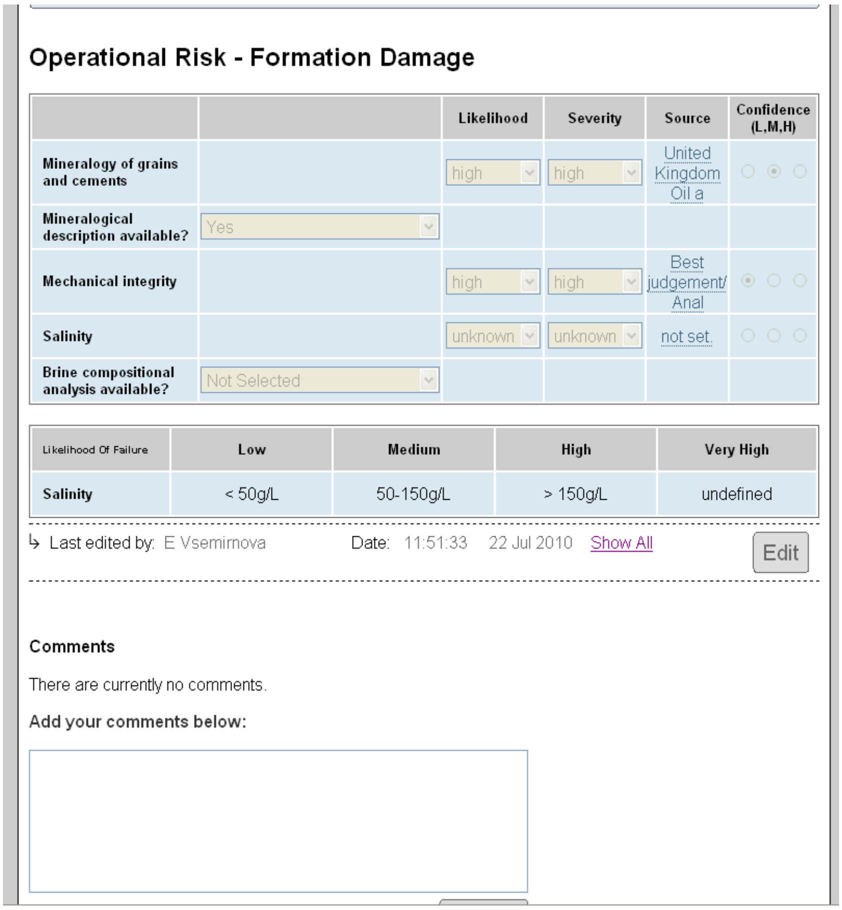


Figure A2.8: Data Entry Screen for Formation Damage in CarbonStore

The mineralogy of grains and cements were rated (low, medium or high) to assess their likelihood of 'failing' – causing an injectivity problem. A confidence was assigned to the assessment depending on proximity of information and certainty in judgement. For all risks, if there is no information, an 'unknown' entry has been entered. In practice, it has often been possible to find a distant field representative or an age-equivalent Unit to base an assessment on; this has been accompanied by low confidence in the data and a comment reflecting data source.

Likelihood of Failure

Likelihood Of Failure	Low	Medium	High	Very High
Mineralogy of grains and cements	quartz dominant pore forming and cementing phase	matrix carbonate (if carbonate cements rank as high severity), abundant feldspar, mineralogically immature	carbonate cements, feldspar and pore throat filling clays	undefined

Figure A2.9: Categories of Likelihood of Occurrence for Mineralogy of Grains and Cement

Specific diagnostic details are below:

Mineralogy	Likelihood	Severity
Quartz cement	L	L
Quartz uncemented	H	M
Lithic clays	H	H
Feldspars	M	L
Carbonates	Detailed below	

Table A2.1: Diagnostic Minerals and Cements

Carbonates

Units with a carbonate matrix have been assigned a medium likelihood of failure. Units which have carbonate cements and a siliciclastic matrix are assigned a high likelihood of failure. The logic behind this is as follows.

- The impact of minor carbonate dissolution in a carbonate-cemented sandstone typically has a bigger and more negative impact on flow properties than for a Unit with a carbonate matrix. In a carbonate-cemented sandstone cements can be removed allowing grains to collapse, fines to release, etc.

- The response of a carbonate reservoir to CO2 injection is typically limited to minor matrix dissolution, with the system buffered by excess HCO3- production (both CO2 dissolution and carbonate dissolution produce HCO3-). Permeability is sometimes improved.

- Evidence for this comes from CO2 EOR monitoring in carbonate reservoirs (Weyburn, Midale, Sacroc etc.) and carbonate-cemented siliciclastics (e.g. Pembina Cardium) where the former records minor carbonate dissolution during CO2 injection (a few mmoles/litre) and the latter, though also recording minor carbonate dissolution led to significant formation damage and injectivity issues as cements dissolve and fines block pores (Sayegh et al 1990).

Thus, matrix carbonates like Zechstein Argyll carbonate (Unit ID 146) are less likely to be damaged by CO2 injection than carbonate-cemented sandstones such as Cormorant Formation (Unit ID 001). The Cormorant Fm has a high likelihood of injectivity failure and the Zechstein Argyll carbonate has been assigned a medium likelihood of failure, reflecting minor carbonate dissolution and the risk of some unexpected changes to permeability (e.g. excess Ca^{2+} driving $CaSO_4$ precipitation).

Assumptions

- Most data come from hydrocarbon legs of the storage formation – which might as a result of this charge have differing diagenetic history to the saline aquifer leg

- Clay minerals identified in Units with permeabilities less than 1 mD have been ignored as these would not have sufficient injectivity

- Local variations in mineralogy and permeability are not taken into account

- The source material is representative of the whole Unit

Confidence

The confidence of the likelihood of occurrence was assigned according to the following criteria:

- LOW - data from an analogue formation
- MEDIUM -data offset from the Unit; or Units without any direct comments on cements within the reference
- HIGH -direct data from within that Unit
- VERY HIGH - not used

Methodology – Formation Damage through Mechanical Failure

Likelihood Of Failure	Low	Medium	High	Very High
Mechanical integrity	consolidated formation	poorly/partially consolidated	unconsolidated formation	undefined

Figure A2.10: Categories of Likelihood of Occurrence for Mechanical Integrity

If mechanical integrity is lost there may be mobility of individual grains which may represent a loss of injectivity. The presence of reactive cements is risked in the mineralogy of grains and cements section (and hence loss of integrity in this way is also risked in the preceding section); this section specifically deals with mechanical issues. For example, published material has been scoured for anecdotal evidence of sand production, special completion screens, etc. There are little public data pertaining to mechanical integrity. In cases where there is information on the reservoir from a petroleum production perspective **and** there is no mention of consolidation or sand production having been an issue, we can assume that no news is good news and have assigned a low risk with low confidence. Any evidence stating an issue with consolidation will invoke a high likelihood assessment with high confidence.

Severity\impact	Low	Medium	High	Very High
Mechanical integrity	formation damage localised and temporary (work over to recover well)	reduction in permability and injection rate	injection well may fail permanently	undefined

Figure A2.11: Categories of Severity Associated with Mechanical Integrity Occurrence

Although within the same section, salinity data were entered by GPT.

Worked Example

The following example (**Figure A2.12)** is from Unit ID 198, Louise 012/22 Mid-Upper Jurassic saline aquifer, which contains the Beatrice oilfield, in the Inner Moray Firth Basin, Northern North Sea.

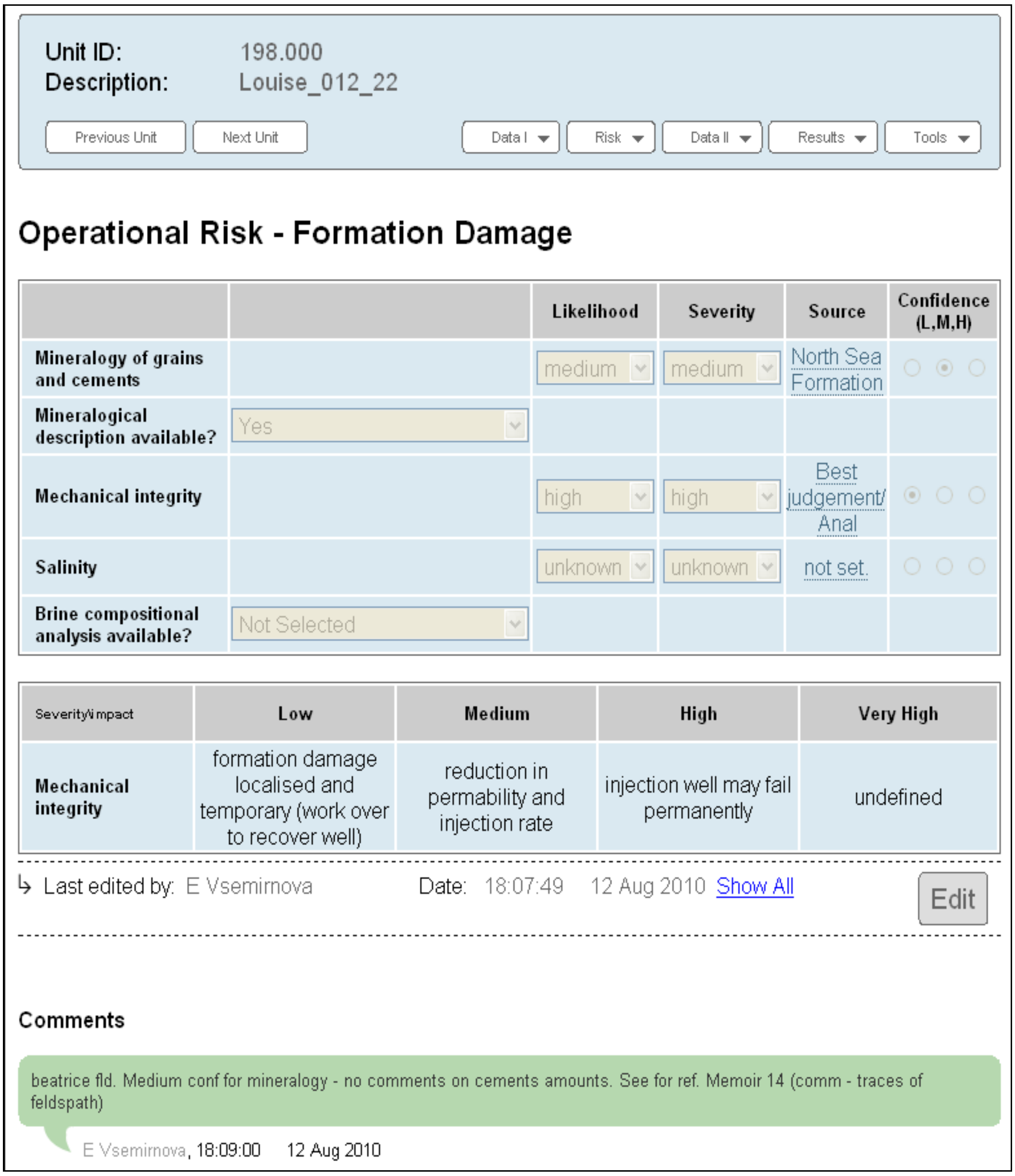


Figure A2.12: Data Entry Screen for Mechanical Integrity in CarbonStore

The **likelihood** of failure due to the mineralogy of the grains and cements is rated as medium. The critical comments from Abbots 1991 are 'the sandstones are fine to coarse grained quartzose sandstones, with traces (<1%) of feldspar....Quartz overgrowths are common'. This has thus been assigned a medium likelihood (feldspar is present but not in high volumes and only mentioned in one sand, quartz cement and quartz grains; there is no mention of carbonates being present in either cement or matrix).

The **confidence** also has a medium assignation. This reflects the fact that there are data from an oil field within the saline aquifer; however this is limited data, a very general description of the zones, with little mineralogical information.

The data sources were the North Sea Formation Waters Atlas, 1994, GSL Memoir 15, Editors Warren & Smalley; and United Kingdom Oil and Gas Fields 25 Years Commemorative Volume, Abbots 1991, GSL Volume 14 – only one reference can be given in the source column so the second is given in the comments box.

A lack of information about mechanical integrity has resulted in the assignation of 'unknown' likelihood and severity.

Challenges

- Some hydrocarbon fields (and hence storage Units) have much published data – there is then a challenge to choose representative results. Some fields (and hence storage Units) have a paucity of data requiring the use of offset or age-equivalent Units.

- Despite rigorous definitions of prescriptive criteria to determine risk of formation damage the assessed saline aquifer Units often have more than one permeable horizon (zone or member). These horizons do not necessarily have the same mineralogy or mechanical properties as each other, so a judgement call is necessary to determine how much influence the presence of a diagnostic mineral in one zone should have on the overall formation damage risk for the whole Unit. Extremely minor quantities of, for example, feldspars might not warrant raising the risk category to high for the whole Unit.

- All of the assessments were made by the same GRL staff member, so that all of the formation damage risk assessments are internally consistent. This does not entirely remove the subjective nature of comparing very different source references.

- With low confidence data it can be challenging to decide on likelihood and severity – the assessment becomes more subjective under such data circumstances.

Recommendations for Future Work

- A few well-placed industry contacts could add significant knowledge to the mechanical integrity issue – this could significantly reduce uncertainty within the database.

- A more detailed study using industry composite logs and core studies from wells would allow an absolute rating and comparison of sites for formation damage risks. This would be a labour-intensive study compared with the work to date in this project and is perhaps beyond the scope of this project.

- Further studies are necessary to understand the impact of injection of CO2 into unconsolidated Units. There is debate as to whether injection into an unconsolidated permeable Unit would have a significant negative impact on injection rates. Injection can be viewed as a push, rather than the pull which is experienced when producing hydrocarbons, so might not result in mobilising grains to the same extent.

1.4.3 Containment Risk – Wells

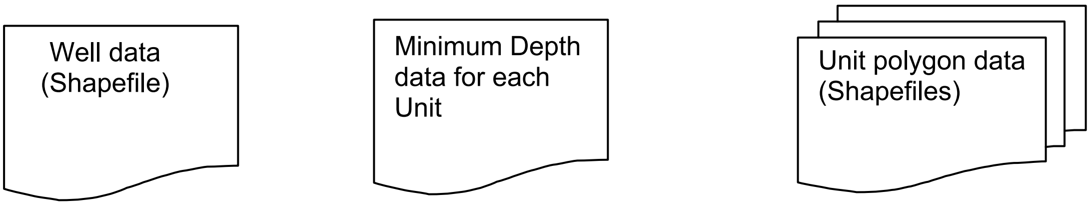
1.4.3.1 Methodology

Data Used

The containment risk of wells was risked using (**Figure A2.13**):

1. Well data from IHS EDIN-GIS database, downloaded on 23/11/2010.
2. The minimum depth of these storage Units and fields were taken from the CarbonStore database (23/11/2010) as generated within this project.
3. The storage Units and hydrocarbon fields were taken from shapefiles generated by University of Edinburgh and BGS within this project and downloaded from the project SharePoint site 23/11/2010. Each storage Unit and hydrocarbon field has its own shapefile.

Updates to these databases made after 23/11/2010 are not yet incorporated.



1. ArcMap shapefile showing locations of boreholes (also has attribute data for each well, such as TD, age, status etc.) n = 13570

2. ASCII file with list of Unit_ID and matching values of minimum depth for each Unit. Currently n = 472. Note – if depth values are missing, a value of -999 has been inserted prior to analysis.

3. Set of ArcMap shapefiles with the extents of each Unit. Must identify each Unit by its unique Unit_ID

Figure A2.13: Data used for Well Risking

The Approach

These three sources (**Figure A2.13**) were used to identify which wells lie within a particular storage Unit (or hydrocarbon field) and penetrate that Unit.

The wells were then risked according to density (using number of penetrations divided by areal extent as calculated from the shapefiles) and vintage, using the header data from IHS.

The shapefiles and well data were displayed using ArcGIS. An algorithm was run to determine which wells intersected each saline aquifer Unit (see the final part of this report). Wells were determined to penetrate a saline aquifer Unit if:

1. They lay within the polygon depicting the extent of that Unit
2. The TD (total depth) was greater than the minimum depth for the Unit (as entered in CarbonStore) or if there was no TD information

If the TD of the well is less than the minimum depth of the Unit, the well does not penetrate the Unit and does not present a containment risk for injection into the Unit. As the depths are not adjusted for the drilling reference table (e.g. Kelly Bushing or equivalent) total depth in a vertical well may be less than total depth subsea as the measurements begin on the drilling rig which may be 50m or more above mean sea level. For non vertical wells the use of TD might lead to an assessment of higher well density as total vertical depth subsea may be significantly less than the total distance along the well path (the definition of TD).

Error values were generated if either the shapefile for the Unit did not have a Unit_ID attributed; in these cases there was no way to correlate the map data with the depth data for the Unit. If there was no TD entered for the well it was assumed to penetrate the Unit.

The shallowest depth of closure (‘minimum depth’ in CarbonStore) has been used to identify Units which penetrate a storage Unit. Any uncertainty in the value for minimum depth is not captured.

Well Density Risk

Once a definitive group of wells for each Unit or hydrocarbon field was generated, the average density of wells per Unit area of storage Unit was calculated. The area of the storage Unit was calculated from the shapefile (as not all shapefiles contained information on the area). The risk was assigned to the density as low, medium or high, such that there is an equal number of each.

The well density risks per storage Unit assigned as follows:

- 0.01 to 0.034 wells/km^2 - **low**
- 0.034 to 0.11 wells/km^2 - **medium**
- 0.11 to 1.85 wells/km^2 - **high**

There are 20 Units with no well penetrations, these have zero risk.

Vintage Risk

Vintage risks were assigned per individual well:

- 1986 or older risked as '3' high – oil price collapsed in 1986

- 1987-1995 risked as '2' medium, based on the assumption that a lower oil price led to better quality completions (e.g. Watson and Bachu 2007)

- 1996 or younger risked as '1' low. In 1996 the Offshore Installations and Wells (Design and Construction, etc.) Regulations were passed, regulating offshore development

- There are 42 wells in the IHS database which have an 'unknown' technical status, TD and age –these have been assigned a '3' high risk

These were then averaged to encompass all the wells in each storage Unit to yield an average vintage risk per storage Unit which has been assigned low/medium or high risk based on average numerical value such that there is an equal number of each.

The vintage risks per storage Unit are assigned as follows:

- 0 - 1.7145 - **low**

- 1.7145 – 2.11 - **medium**

- 2.11 - 3.0 - **high**

There are 20 Units with no recorded well penetrations. These are assumed to have zero risk of failure.

Worked Example

Unit ID 198, Louise 012/22 Mid - Upper Jurassic saline aquifer, which contains the Beatrice oil field, in the Inner Moray Firth Basin, Northern North Sea.

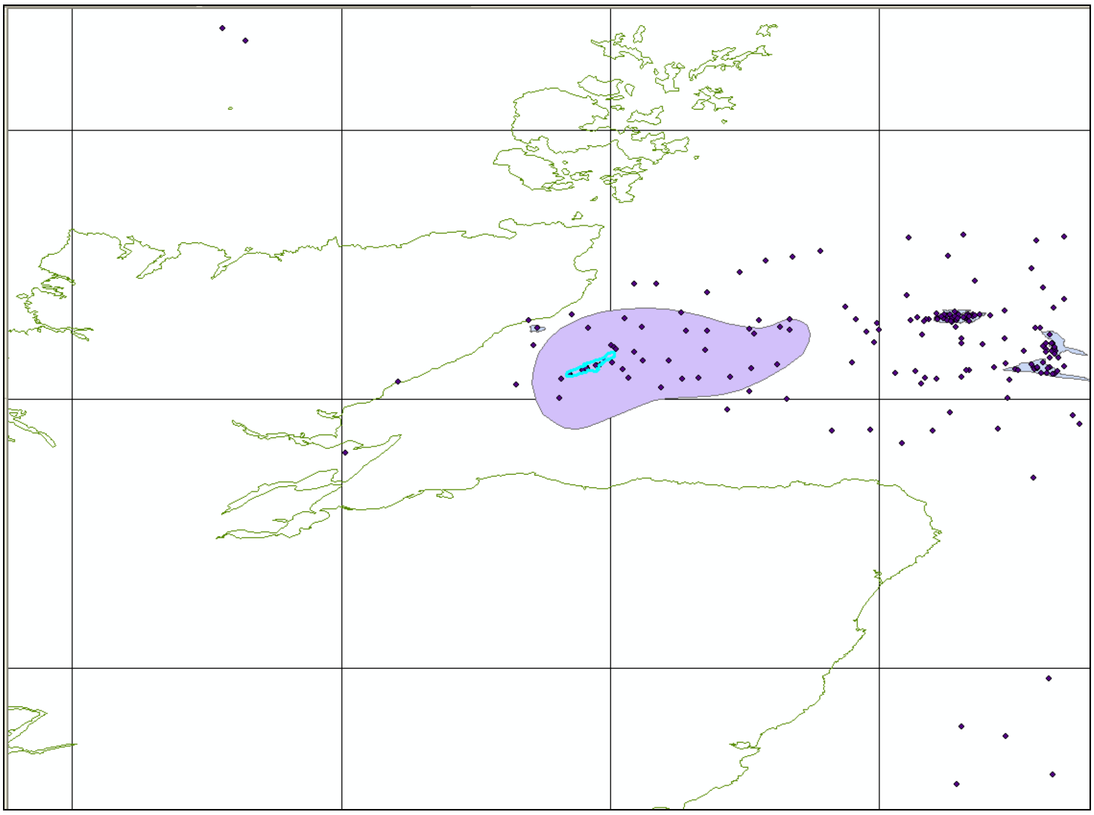


Figure A2.14: Storage Unit 198, Louise Fm Saline Aquifer

In **Figure A2.14** the wells are shown as burgundy dots and the purple polygon is the shapefile for the Unit ID 198. The outline of the Beatrice oil field is shown in light blue.

Ninety-two wells are found to penetrate this Unit. Clearly there are fewer wells shown to intersect the polygon in the preceding figure. The image from ArcGIS is slightly misleading as wells drilled from a platform will only have one well head (and hence one representative burgundy dot).

For Unit ID 198 (Louise member) the area of this Unit is derived from the polygon and is found to be 1988.57 km^2. The area given with the shapefile as an attribute is actually 1988.59 km^2. This minor discrepancy is an artefact of having used different projections for the data.

The well density for Unit ID 198 is 92 wells /1988.57 km^2 = 0.04626 per km^2, which is a medium likelihood (0.034 to 0.11 wells/ km^2 = medium).

The vintage risk for Unit ID 198 is 2.6, which is between 2.11and 3.0, is therefore a high likelihood of failure.

Challenges

Inconsistencies in Unit-ID naming and data entry proved time consuming (without manual correction these inconsistencies would have rendered the computer algorithm ineffective).

- The BGS data Unit_ID was labelled as Storage_ID and represented as a six digit number with no decimal place
- The University of Edinburgh Unit_ID was labelled as such and formatted as a one to three digit number with no decimal place
- The CarbonStore Unit_ID was labelled up to 6 digits with a decimal point and always 3 places after the decimal point
- Projections: not all data sources used the same projection. The University of Edinburgh data were projected in both GCS_European_1950 and GCS_ETRS_1989 and ED_1950_UTM_Zone_31N; BGS data were projected in GCS_European_1950; the wells were downloaded in latitude and longitude, and the project created to perform these analyses was in GCS_European_1950. Ideally all projects would have used the same projection. The projection used has an impact on the exact calculation of the area, and perhaps the exact representation of the boundaries of a Unit polygon (which in turn could impact whether wells which lie along the boundary penetrate the Unit).

This can lead to accumulated errors in display – wells that are along the boundary of a storage Unit may move relative to the storage Unit, and the area of the storage Unit as calculated from the project built in ArcGIS have a small difference to those given as attributes with the shapefiles.

Further Work

If the project was to be repeated, it is strongly advised that the data should all be in the same geographical projection to eliminate any potential error.

Usability of the Data

Wells are mostly concentrated in hydrocarbon fields. A high density for well penetrations might reflect wells which are localised in one part of the Unit only. Depending on development strategy, such a distribution might not present such as high a risk for CO_2 injection at a first glance as the figures might suggest.

Appendix 3 Severity of Impact Assessment

Data Collection Form - Risk Register

Name, Organisation	
Domains of Expertise	

Please complete the attached form for severity of impact for each risk mechanism using the severity scale shown below.

Complete all 3 columns where:

Lower-bound is the minimum impact that might be expected for a UK offshore saline aquifer.
Best-guess is the impact you expect for a 'typical' UK offshore saline aquifer.
Upper-bound is the maximum impact possible for a saline aquifer in the offshore UK.

When completing the assessment, please carefully consider the range of Units included in the Carbon Store database. The lower and upper bounds should represent the full range of possible impacts for this range for Units. The best-guess should represent your judgement of the most likely impact for these Units.

Severity Scale

Severity of Impact	Project Values
Low (L)	No or negligible negative impact to project
Medium (M)	Negative impact, but within acceptable costs to mitigate/repair
High (H)	Negative impact sufficient to end project

Negative impact can include financial, environmental, health and safety and industrial viability.

Refer to CarbonStore for definitions of the failure mechanisms. For access to CarbonStore please contact Duncan Anderson at Senergy; Duncan.Anderson@senergyworld.com

DO NOT COMPLETE ITEMS IN BOLD
Complete in the order: lower bound, upper bound, best guess.

		Lower bound (L, M, H)	Best-guess (L, M, H)	Upper bound (L, M, H)
containment	***Seal failure (leakage/containment)***			
	Fracture pressure capacity			
	Seal chemical reactivity			
	Seal degradation			
	Faults (leakage/containment)			
	Density (relative to defined Unit size)			
	Throw (is estimated offset greater than effective seal thickness, including fracture density if applicable)			
	Vertical extent (do faults terminate >800m depth etc.)			
	Lateral Migration (leakage/containment)			
	Structural trend			
	Depositional/diagenetic fabric			
	Dip Direction			
	Dip			
	Rugosity			
	Hydrodynamics			
	Pressure sinks in storage Unit			
	Transnational migration			
	Wells (leakage/containment)			
	Density			
	Vintage			
Operational	***Formation damage (injectivity i.e. operational risk)***			
	mineralogy of reservoir: grains and cements			
	mechanical integrity of reservoir			
	salinity			
	Dynamic Capacity (compartmentalisation i.e. operational risk)			
	stratigraphic compartmentalization vertical			
	stratigraphic compartmentalization horizontal			
	diagenetic compartmentalisation			
	structural/Fault compartmentalization			
	Pressure isolation			

	Risk mechanism	Can be mitigated	Method	Cost (% of total project)
containment	***Seal failure (leakage/containment)***			
	Fracture pressure capacity			
	Seal chemical reactivity			
	Seal degradation			
	Faults (leakage/containment)			
	Density (relative to defined Unit size)			
	Throw (is estimated offset greater than effective seal thickness, including fracture density if applicable)			
	Vertical extent (do faults terminate >800m depth etc.)			
	Lateral Migration (leakage/containment)			
	Structural trend			
	Depositional/diagenetic fabric			
	Dip Direction			
	Dip			
	Rugosity			
	Hydrodynamics			
	Pressure sinks in storage Unit			
	Transnational migration			
	Wells (leakage/containment)			
	Density			
	Vintage			
Operational	***Formation damage (injectivity i.e. operational risk)***			
	mineralogy of reservoir: grains and cements			
	mechanical integrity of reservoir			
	salinity			
	Dynamic Capacity (compartmentalisation i.e. operational risk)			
	stratigraphic compartmentalization vertical			
	stratigraphic compartmentalization horizontal			
	diagenetic compartmentalisation			
	structural/Fault compartmentalization			
	Pressure isolation			

Refer to carbonstore for definitions of the risk mechanisms. For access to carbonstore please contact Duncan Anderson at Senergy; Duncan.Anderson@senergyworld.com

Do not complete the items in bold

Mitigation Proforma

		Can be mitigated	How	Cost (% of project)
containment	***Seal failure (leakage/containment)***			
	Fracture pressure capacity			
	Seal chemical reactivity			
	Seal degradation			
	Faults (leakage/containment)			
	Density (relative to defined unit size)			
	Throw (is estimated offset greater than effective seal thickness, including fracture density if applicable)			
	Vertical extent (do faults terminate >800m depth etc.)			
	Lateral Migration (leakage/containment)			
	Structural trend			
	Depositional/diagenetic fabric			
	Dip Direction			
	Dip			
	Rugosity			
	Hydrodynamics			
	Pressure sinks in storage unit			
	Transnational migration			
	Wells (leakage/containment)			
	Density			
	Vintage			
Operational	***Formation damage (injectivity i.e. operational risk)***			
	mineralogy of reservoir: grains and cements			
	mechanical integrity of reservoir			
	salinity			
	Dynamic Capacity (compartmentalisation i.e. operational risk)			
	stratigraphic compartmentalization vertical			
	stratigraphic compartmentalization horizontal			
	diagenetic compartmentalisation			
	structural/Fault compartmentalization			
	Pressure isolation			

Appendix 4 Logical Routine Applied to Well Data

Logical Steps 1: Which Boreholes Penetrate the Unit

For each shapefile containing Unit polygons

For each unit)

If the Unit does not seem to have a Unit_ID, then

Flag an error (and then continue). Unit_ID set to -999 or -998, MinUnitDepth set to -999 or -998

Else if there is no Min Depth Data list available, or the Unit has a Unit_ID which does not appear in the Min Depth Data list, then

MinUnitDepth set to -999.9 (and then continue). [All boreholes within the polygon will assume to penetrate – see below]

For each borehole in the Well Data Shapefile …

For hydrocarbon fields only: merge bottom hole location data with IHS well header data, matching on well nameIf the lat/long of the borehole top hole location (or bottom hole for hydrocarbon fields) lies within the extent of the Unit's polygon, then

If the MinUnitDepth less than Zero (i.e. a proper value can't be found), then

Assume the borehole penetrates

Else if the TD of the well is Zero, then

Assume there is no proper TD value available, so assume the borehole penetrates

Else if the TD of the well is greater than the MinUnitDepth, then

Assume the borehole penetrates

Else If the TD of the well is greater than Zero but less than the MinUnitDepth, then

Assume the borehole is too shallow to penetrate the Unit

If the borehole is assumed to penetrate the Unit, then

Increment the stats for the Unit with the Risk that this well penetration represents (See below)

Normalise the Risk stats

Logical Steps 2: Defining the Risk Represented by each Penetration

Risking according to vintage:

- Pre-1986 wells were given high risk (‘3’ value)
- 1987-1995 wells give medium risk (‘2’ value)
- 1996 or younger risked as ‘1’ low
- These are then averaged to encompass all the wells in each storage Unit to yield an average vintage risk per storage Unit which has been assigned low/medium or high risk based on average numerical value, such that there is an equal number of each)

There are also 20 zero risk Units which have no well penetrations.

QC Issues Highlighted

Upon running the algorithm some further issues were highlighted.Units in the “Hydrocarbon_Fields_UoE” shapefile all have “storageid” (i.e. Unit_ID) values of zero (and hence, no Min Depth Data are available for these. Therefore all boreholes that lie within their polygon extents will be assumed to penetrate the Unit).

Unit_ID = 264.001 (Otter_Sst) [Min_Depth = -999.9] appears in the shapefiles but not in the Excel file with Units/Depths

The following Units do not have Min_Depth_Data in the carbonstore data we received from Grahame Smith (23.11.2010). The Min_Depth values were set manually to -999 before the analysis was carried out:

Unit_ID = 128 (Bunter_Sst_Fm)	[Min_Depth = -999]
Unit_ID = 141.057 (HydrocarbonFields BGS)	[Min_Depth = -999]
Unit_ID = 233.002 (HydrocarbonFields BGS)	[Min_Depth = -999]
Unit_ID = 267 (HydrocarbonFields BGS)	[Min_Depth = -999]
Unit_ID = 326 (HydrocarbonFields BGS)	[Min_Depth = -999]
Unit_ID = 327 (HydrocarbonFields BGS)	[Min_Depth = -999]

The following have Min_Depth_Data of zero in the carbonstore data we received from Grahame Smith (23.11.2010).

Unit_ID = 140 (Spilsby_Sst_Fm_all)	[Min_Depth = 0]
Unit_ID = 248 (Ormskirk_Sst_Fm)	[Min_Depth = 0]
Unit_ID = 256 (Ormskirk_Sst_Fm)	[Min_Depth = 0]
Unit_ID = 257 (Ormskirk_Sst_Fm)	[Min_Depth = 0]

NOTE – GRL do NOT carry out a check to see whether any the Units listed in the carbonstore have a corresponding geographical extent defined in a ShapeFile (e.g. see Units 308 and 314).