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Energy Procedia 37 (2013) 4894 – 4901

Energy Procedia

GHGT-11

Development of key performance indicators for CO_2 storage operability and efficiency assessment: Application to the Southern North Sea Rotliegend Group

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Abstract

This paper outlines the development of a methodology which can be used to produce key performance indicators for operability and efficiency of a CO_2 storage site. The methodology is based on the premise that individual geological formations and their characteristics can be assessed on the basis of their depositional and tectonic setting and more recent reservoir/site history using hydrocarbon exploration and development data. The methodology is illustrated for a candidate storage reservoir in the Rotliegend Leman Sandstone Formation of the UK Southern North Sea.

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Keywords: Key performance indicators; dynamic modelling, CO_2 storage, Southern North Sea Rotliegend Group

1. Introduction

Implementation of large scale carbon capture and storage requires substantial capital investment in CO_2 capture, transport systems and storage complex management. So far, significant efforts have been focussed on improving our understanding and ability to characterise and predict CO_2 storage site evolution during the life time of an operation and after its closure. However, little effort has been devoted to assessing the operability and efficiency of managing CO_2 storage sites.

This paper outlines the development of a methodology which can be used to produce key performance metrics for operability and efficiency of a CO_2 storage site. The methodology is based on the premise that

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Selection and/or peer-review under responsibility of GHGT
doi:10.1016/j.egypro.2013.06.400

individual geological formations and their characteristics can be assessed on the basis of their depositional and tectonic setting and more recent reservoir/site history using hydrocarbon exploration and/or production data. Although reservoir properties of potential storage formations exhibit large spatial and temporal heterogeneity, there is some structure to this variability which can be characterised using spatial modelling methods. Combining this with stochastic reservoir modelling and injection scenario analysis provides the opportunity to develop key performance indicators (KPI) specific to the storage formation considered. The methodology developed to define these KPIs is illustrated for a candidate storage reservoir in the Rotliegend Leman Sandstone Formation of the UK Southern North Sea.

2. Methodology

A specific gas field, namely Ravenspurn North and South, within the Leman Sandstone reservoir was selected as the template model for detailed analysis and simulations to develop the methodology (Fig. 1a). Available reservoir data and information on the geology of the whole Leman Sandstone Formation were used to establish a correlation between porosity and formation depth. The range of formation depths exhibited by the Leman Sandstone Formation, and its corresponding thickness combinations provided five distinct area type scenarios which were modelled to establish its specific key performance indicators.

The correlation between porosity and formation depth was used to stochastically assign porosity to the template model for each of the storage area type scenarios using available well log and core data (Fig. 1b). Corresponding permeability distributions were estimated stochastically in relation to depth and from relationships deduced from core data. Other petrophysical properties such as initial reservoir pressure, net-to-gross ratio and gas saturations were also populated based on information available from well logs and published hydrocarbon field information. Additional structural features and characteristics such as closure and presence of sealing versus transmissive faults were tested and assigned to the structures present in the template model. The template model is located within the deep, moderate thickness area type scenario and includes 72 gas production wells for which cumulative gas production data are known. Prior to simulation of CO_2 injection, gas production from these wells was modelled until the field cumulative production was reached.

a)

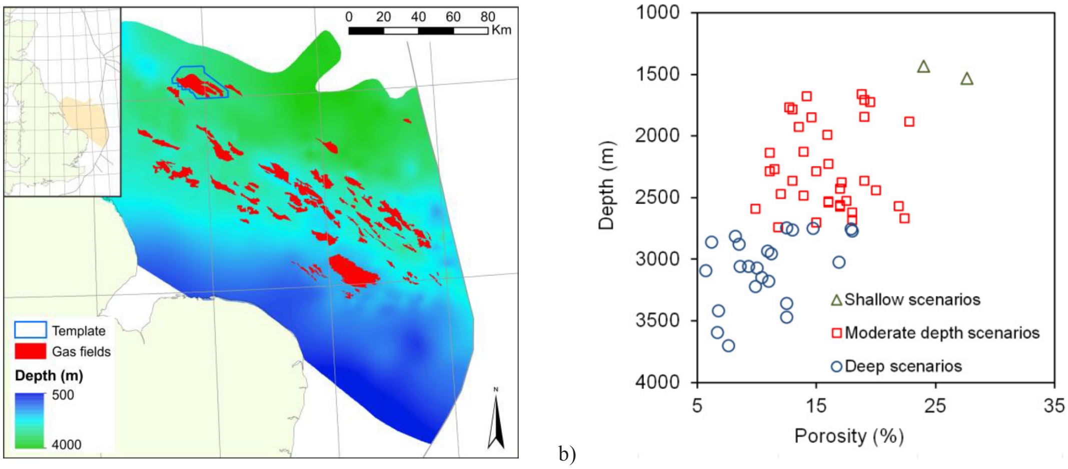


Fig. 1. (a) Location map showing the depth of the Leman Sandstone in the UK sector and the location of the template model; (b) relationship between porosity and current reservoir depth (from varying sources across the UK Southern North Sea).

Regarding the injection scenarios considered, a range of constant CO_2 injection rates were specified. From the 49 wells available in the template (Ravenspurn North), 5 wells were chosen as CO_2 injectors based on well permeability and spatial location within the field, to maximise injectivity and storage capacity. The adopted injection strategy utilised the injector with the highest permeability first, until the given injection rate could not be maintained, subject to a prescribed maximum injection pressure (i.e. pre-production reservoir pressure). Then the second injector was brought on stream to maintain the specified injection rate. This process was continued until all five injectors were brought on stream. The time period over which the specified injection rate could be sustained was recorded and the simulation was repeated for all injection rates. In this way, a set of indicators which characterise the injectivity and effective storage capacity for different storage site area types across the Rotliegend gas fields was obtained.

3. Rotliegend Leman Sandstone Formation

During the late Permian, sediments of the Rotliegend Group accumulated within the Southern Permian Basin, a major east–west trending foreland basin extending from eastern England to east Poland. The UK sector lies entirely within the Anglo-Dutch Basin and trends west- northwest, bounded to the north and south by the Mid North Sea High and London-Brabant Massif respectively, with the Pennine High marking its western boundary [1]. Over 300 m of Rotliegend Group sediments were deposited above a substrate of Carboniferous and older rocks, in an arid– semi-arid tropical desert environment [1]. Present day regional dip is towards the north–northeast. The Leman Sandstone Formation forms the principal gas-bearing reservoir in the UK Southern North Sea, and comprises aeolian and fluvial sandstone across much of the basin, with sabkha and lake-marginal lacustrine facies becoming increasingly common towards its northern limits where it passes into, and inter-digitates with sediments of the overlying Silverpit Formation. The Silverpit Formation is composed of claystones and halites. Above the Rotliegend Group, a marked basin-wide transgression marks the onset of deposition of the Upper Permian Zechstein Group, which comprises >1000 m of halite, anhydrite, mudstone and carbonate rocks in the central part of the basin. Subsequent movement of the salt layers has resulted in a succession of highly variable thickness and is proven to form an effective seal to the many Rotliegend natural gas accumulations within the basin.

The Rotliegend Group is cut by predominantly northwest–southeast trending faults. Fault displacements have caused the compartmentalisation of the Leman Sandstone reservoir within the different hydrocarbon fields. In some fields, different compartments have been developed separately, whereas in others, differential pressure depletion between compartments has caused break-down of these barriers during field production (i.e. The Indefatigable field: [2]).

3.1. Definition of area types

The key parameters that define the Area Types for the Leman Sandstone 3D generic model are its thickness and depth of burial. The depth of the Leman Sandstone Formation in general increases towards the north (Fig. 1a). The greatest thicknesses of the Leman Sandstone are observed within the Sole Pit Trough, a distinct northwest–southeast trending depocentre within the Anglo-Dutch Basin.[1].

Generally, there is a relationship between porosity and depth (Fig. 1b), and a fairly good relationship also exists between porosity and permeability. The porosity and permeability variations within the Leman Sandstone exhibit a complex pattern, being dependent primarily on facies which varies both laterally and vertically, but also by diagenetic processes that took place during burial and uplift. Hydrocarbons within a reservoir inhibit the growth of some inter-granular cements such as illite; thus the timing of gas migration into the reservoir is an important factor in determining its permeability. The thickness of the formation is relevant to potential CO_2 storage capacity, and thus should be considered in addition to depth.

3.2. Ravenspurn gas fields as a template model

The Ravenspurn North and South gas fields are located in the UK sector of the Southern North Sea, in license blocks 42/29, 42/30 and 43/26 [3]. Gas is produced from the Leman Sandstone Formation. These fields were chosen for use in the template model (Fig. 1a) as their structure is typical of the Rotliegend fields in terms of form, size, fault distribution and the various trapping mechanisms present.. The Ravenspurn fields are amongst the deepest of the Rotliegend play, lying at the northern edge of the Sole Pit Trough area. The fields are about 28 × 8 km in size, and exhibit structural trapping in a series of normal fault blocks, predominantly orientated from northwest to southeast. An elongate periclinal structure forms an additional trap in the Ravenspurn South Field. The Lower Leman Sandstone Formation reservoir is juxtaposed against underlying Carboniferous strata (thought to be sealing, non-reservoir rock in this location), and against overlying Silverpit Formation and Zechstein Group rocks. The throw of some faults exceeds 200 m; however none penetrate to the top of the evaporitic Zechstein Group [4], and thus they can be considered to be vertically sealing.

Reservoir rocks were deposited in a desert environment marginal to a permanent desert lake (represented by the Silverpit Formation), and consist of aeolian, fluvial and sabkha facies. The Leman Sandstone inter-digitates with non-reservoir rocks of the lacustrine Silverpit Formation to the north, resulting in a strong component of stratigraphic trapping in this direction. There are complex vertical and lateral facies distributions in the reservoir that were largely controlled by rising and falling water tables during deposition [5-6]. Facies distribution is the primary control on reservoir porosity and permeability. Reservoir quality deteriorates to the northwest with the pinch-out of aeolian sands and inter-digitation with playa lake deposits and increasing mud-rich facies to the northwest [3]. Diagenesis is a secondary control on reservoir permeability, being particularly controlled by the formation of hairy illite which blocks pore throats, drastically reducing permeability. This is more prevalent in the northwest of the field, further reducing reservoir quality. Early gas emplacement in the eastern part of the North field is thought to have inhibited the development of diagenetic illite. Gas from this area was produced without reservoir stimulation, while elsewhere in the field, hydraulic fracturing was necessary for gas production [5].

4. Static model of the Ravenspurn gas fields

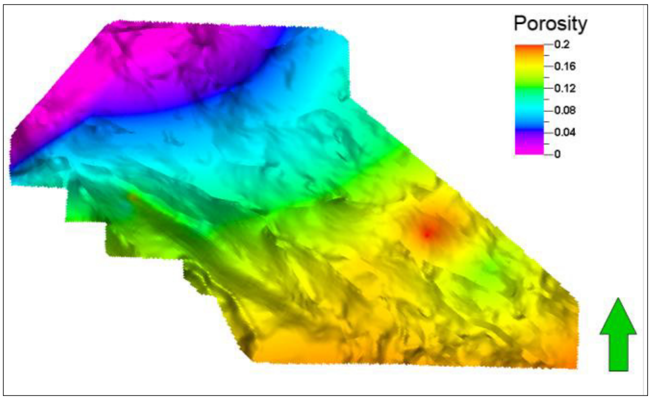
The geological framework model built to represent the Ravenspurn Fields is based on a previously published structure contour map of the Top Leman Sandstone, consisting of depth contours and fault polygons [3].

The contours and fault polygons were used along with formation tops from well data to produce a grid of the Top Leman Sandstone surface, which was then used as a trend surface along with well top data to grid a surface for the base of the Leman Sandstone reservoir (Top Carboniferous/Base Permian Unconformity). These form the primary input to the 3D reservoir model. Six intra-reservoir zones are clearly identified from company composite logs, and were correlated across the model using geophysical logs [3].

4.1. Model attribution

Turner et al. [5] suggest that spatial variations in the lithofacies associations contained within these intra-reservoir zones, reflecting the dynamic interplay between the aeolian and fluvial-playa lake sedimentation, strongly influenced both the overall reservoir architecture and performance. Additionally, diagenesis of the Leman sandstone reservoir resulted in a net loss of porosity and permeability, only part of which can be attributed to compaction, owing to the precipitation of pore-filling and pore-lining illite cement. These spatial and vertical variations were represented in the model attribution by porosity and permeability distributions using the available well log data from the Ravenspurn fields.

The porosity distributions were individually populated for the six stratigraphic zones in the model using upscaled well log data. Using this data, two separate non-linear porosity trends were estimated: (a) ϕ_1 along the North-West direction of the model to represent the decrease in porosity due to sediment deposition and stratigraphic trapping; and (b) ϕ_2 along the South-West direction of the model to represent the decrease in porosity due to illite growth resulting from late gas emplacement. Linear mixing of these trends was attempted using different combination of weights w_1 and w_2: $\phi = w_1 \phi_1 + w_2 \phi_2$, with $w_1 + w_2 = 1$. The best combination of weights results in a porosity (or the pore volume) distribution which represents the best match for the Gas-In-Place (GIP) value. For the Ravenspurn case, the weights $w_1 = w_2 = 0.5$ gave the best approximate match for the reported GIP value of 94 billion sm^3. An example of the estimated porosity distribution for one of the higher porosity reservoir layers, obeying the NW decrease due to stratigraphic trapping and the SW decrease due to illite growth, is illustrated in Fig. 2a. Corresponding permeability distributions were then estimated by applying the correlation function between the porosity and permeability data that was obtained from the well logs for the Rotliegend fields (Fig. 2b). However, a porosity cut-off was implemented assuming that regions having porosity values less than 7.9% are generally of very low permeability, of the order of 0.0001 mD, particularly representing the stratigraphic trap towards the NW region of the model. The Net to Gross (NTG) ratio is also assumed to be uniformly distributed laterally, with vertical heterogeneity in order to represent both the low and high quality layers in the reservoir model.



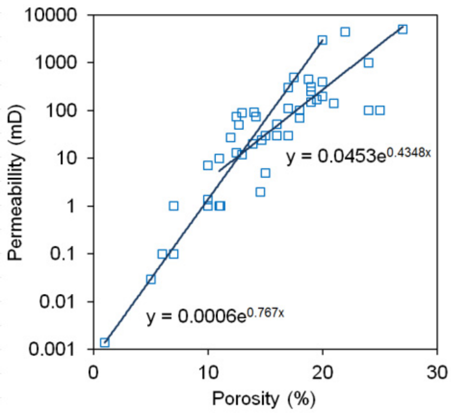


Fig. 2. Ravenspurn field model attribution: (a) porosity distribution; (b) correlation between porosity and permeability data using well logs. Data are taken as minimum, maximum and average values across the Leman Sandstone gas fields (after Gluyas and Hichens [7]).

5. Dynamic modelling of CO_2 injection

5.1. Modelling gas production and CO_2 injection at Ravenspurn fields

There are a total of 72 gas production wells in the Ravenspurn gas fields (49 in the higher permeability Ravenspurn North, and 23 in Ravenspurn South). While the annual gas production for the two fields until the end of 2009 is available, gas production data for individual wells is not publicly available. Before simulating CO_2 injection into the depleted gas reservoir at Ravenspurn, the historic gas production was accounted for. In the absence of individual well production data, the gas production from Ravenspurn North and Ravenspurn South was simulated by imposing group production control implemented in

ECLIPSE on the two groups of wells, while honouring the available annual gas production data for the two fields. With this procedure, the productivity of the wells in a group is ranked. Starting with the highest productivity well, the remaining wells are brought on stream in the order of ranking to satisfy the required production level. In the simulations CO_2 injection was scheduled to start in 2013, with the assumption that the gas production over the period 2010-2012 was maintained at the 2009 level. It was further assumed that the wells are completed in all five zones of the reservoir.

5.1.1. CO_2 injection strategy and key performance indicators

Wells selected for CO_2 injection at Ravenspurn were based upon their productivity (as determined from gas production simulation prior to injection) and spatial location with respect to each other to minimise pressure interference. CO_2 injection at each well was constrained by a preset bottomhole pressure (BHP) limit. In this study, a rather conservative BHP limit was used, which was the initial hydrostatic pressure of the reservoir. The following injection strategy, analogous to the group production control used in the production stage, was adopted: starting with the well with the highest productivity, CO_2 injection at a specified rate was simulated; when the injection rate could not be sustained (when the BHP limit is exceeded), the next well was brought on stream to maintain the same injection rate, and so on. A total of five injection wells for Ravenspurn North and Ravenspurn South were simulated. Injection was terminated when the injection rate could no longer be sustained with all five wells on stream.

One key outcome of this CO_2 injection simulation exercise was the establishment of an injection period (in years) over which a given injection rate could be maintained, subject to the injection BHP limit defined. The obtained time period for sustained injection is hereafter referred to as the Period of Sustained Injection (PSI). Therefore, by varying the injection rate in the simulations, a set of PSI values may be determined, which characterise the dynamic injectivity-linked storage capacity of the storage reservoir, and is thus defined as the primary key performance indicator (KPI). Since the cumulative injected volume at each PSI is also known, a second KPI, the Fraction of (static) Capacity Utilised (FCU), was also defined, which refers to the portion of the storage capacity, estimated based upon the historic gas production, that has been utilised after a period of sustained injection at a given injection rate.

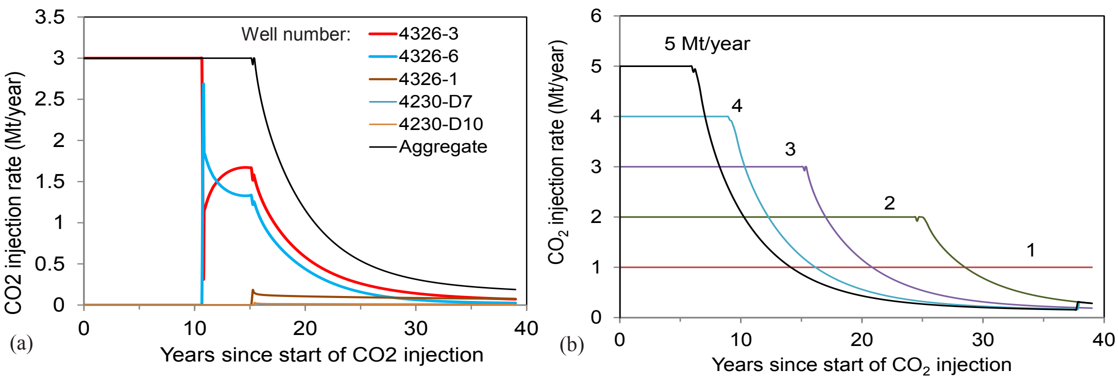


Fig. 3. Determination of key performance indicator PSI for the Ravenspurn fields.

5.1.2. Ravenspurn gas fields simulation results

Following the simulation of gas production from the Ravenspurn fields, CO_2 injection simulations were run for five injection rates, ranging from 1 to 5 Mt/year. Due to relatively low permeability in Ravenspurn South, sustained CO_2 injection, at even 1 Mt/year, could not be maintained. Therefore, only the simulation results for Ravenspurn North are presented here. An example of the simulation results shown in Fig. 3a illustrates that CO_2 injection could be maintained for about 14 years at 3Mt/year, i.e. PSI (3 Mt/y) = 14. The second well (43/26-6) was brought on stream after 10 years of injection into the first well (43/26-3); and the contribution from the remaining three wells was marginal. Fig. 3b compares the simulated injection rate profiles for the five specified injection rates. As expected, the PSI is reduced with increasing injection rate. It ranges from just over five years at 5Mt/year to 50 years at 1Mt/year

Table 1. Key performance indicators PSI and FCU obtained for the Ravenspurn gas fields

Injection rate (Mt/year)	1	2	3	4	5
PSI	50	24	14	7.5	5.1
FCU	0.378	0.363	0.320	0.227	0.193

The storage capacity of Ravenspurn North was estimated to be 132 Mt, based on the cumulative gas production converted to the volume at reservoir conditions. The FCU calculated equals (PSI) × injection rate/storage capacity. The PSI and FCU for the Ravenspurn North are summarised in Table 1.

5.2. Different area types defined in the Rotliegend gas fields

Five Area Types were identified based upon formation depth and thickness for the Leman Sandstone 3D generic model (Fig. 4). One limitation of this approach is that it does not take into account variations in productivity between individual gas fields in the region. As shown in Table 2, two depth intervals and three thickness ranges were considered. During CO_2 injection simulation, as the template model is moved to a particular Area Type, its porosity (and thus permeability) is updated according to the porosity-depth correlation (Fig. 1b)) as is the initial hydrostatic pressure in the model. The difference in thickness, if exists, is accounted for by applying a pore volume multiplier.

During simulation of historical gas production for different Area Types, a range of recovery factors can be used. By applying the same injection strategy as described above, the KPIs for the five Area Types, which characterise the injectivity and effective storage capacity for different storage site types across the Rotliegend gas fields, were obtained. Fig. 5 presents the results obtained using a common recovery factor, the same as that of the Ravenspurn fields. It can be seen that Area Type 1 (deep/moderate thickness) has the highest PSI, followed by Area Type 3 (shallow/thick). The other three Area Types have relatively low injectivity.

Table 2. Definition of Area types for Rotligend gas fields based on depth and thickness.

Area type	Depth (m)	Thickness (m)
1	Deep: 2800-3800	Moderate: 80-180
2	Deep: 2800-3800	Thin: 0-80
3	Shallow: 1800-2800	Thick: 180-280
4	Shallow: 1800-2800	Moderate: 80-180
5	Shallow: 1800-2800	Thin: 0-80

Fig. 4. Location of the 5 area types selected.

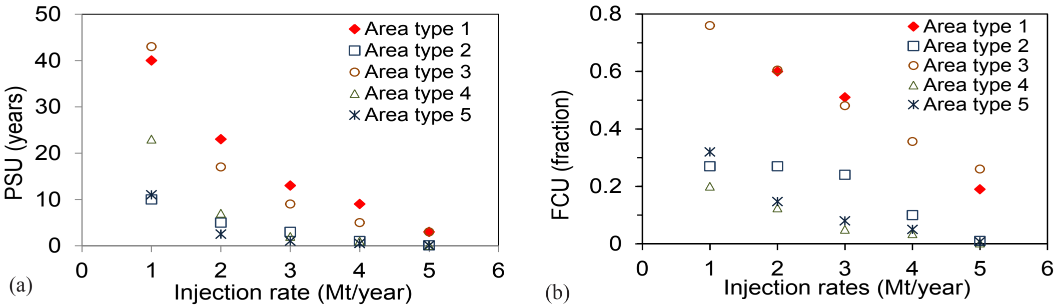


Fig. 5. Key performance indicators PSI and FCU determined for the five area types across the Rotliegend gas fields.

6. Conclusions

In this study, two key performance indicators were identified for the Leman Sandstone Formation, namely the Period of Sustained Injection (PSI) and the Fraction of Capacity Utilised (FCU). Specifically, PSI may be used to select an appropriate CO_2 storage site, or group of sites based on the annual output and duration of operation of the CO_2 source. If the annual amount of CO_2 to be stored is known, FCU will indicate the number of years a given reservoir can be utilised for CO_2 storage.

The significance of these indicators is that they characterise successfully the geological structures and depositional environments which are being considered for CO_2 storage. A limitation of defining the area types solely upon formation depth and thickness may be that this does not take into account variations in productivity between individual gas fields in the region. Current work is considering an alternative attribute described as Pore Volume Produced per Well (PVPW) instead of formation thickness as a proxy to differentiate between fields which may exhibit either better or lesser productivity, and thus injectivity.

Acknowledgements

This research was carried out as part of the UK Research Councils' Energy Programme funded project "Multiscale Whole Systems Modelling and Analysis for CO_2 Capture, Transport and Storage", Grant Reference: NE/H01392X/1.

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