Deep Geological Storage of CO_2 on the UK Continental Shelf: Containment Certainty

Supplementary Note C: Well Analysis Using Peloton WellMaster Database

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1 Introduction

The purpose of this Supplementary Note is to assess the risks of loss of containment from inside the well to outside of the well at any point between seabed (subsea wells)/surface (platform wells) and storage site, for a CO_2 Injection (Active) well and a Decommissioned (Inactive) well. This Supplementary Note C has been written for a technical audience to support the probabilities and leak rates used in the main report Deep Geological Storage of CO_2 on the UK Continental Shelf: Containment Certainty [1] .

Assuring well integrity over the life cycle of the well is fully defined in documents such as ISO 16530-1 Well Integrity [2] or NORSOK D-010 Well Integrity in Drilling and Well Operations [3] or OEUK Well Life Cycle Integrity Guidelines [4]. Well integrity refers to maintaining full control of fluids within a well at all times by employing and maintaining one or more well barriers to prevent unintended fluid movement between geological formations with different pressure regimes or loss of containment to the environment.

In practice this means that the well is designed and operated with two independent barriers, each barrier consisting of several elements. There are established performance standards for each barrier and barrier element, to support monitoring, maintenance, and testing to verify the condition of the barriers. Should one barrier fail then the second barrier will prevent any loss of containment or fluid movement while the failed barrier is repaired.

Whilst the barriers materially reduce the leakage risk for wells there is still a residual potential for this to occur. To assess the potential frequency of such events for a CO_2 Injection Well the following basis and assumptions are used. These reflect the good industry practice embedded in the storage permitting regime.

- Well operator has a clear policy on how well integrity is established and preserved. Performance standards, monitoring requirements, maintenance routines, testing frequencies are defined documented and reported.
- The well design has two independent well barriers.
- The well equipment has been designed, tested and certified for use.
- On handover from the drilling and completion phase to the operating injection phase the two independent well barriers have been installed and tested against the performance standard(s).
- Responsible follow-up of the wells performance and integrity is performed, with regulatory and operator prioritisation of well anomalies and leaks, in order to maintain well integrity. Wells are managed according to Performance Standards and closed in, if required.

Definitions

- **Primary Barrier**: first set of well barrier elements that prevent flow from a source of inflow.
- **Secondary Barrier**: second set of well barrier elements that prevent flow from a source of inflow.
- **Well Barrier Element**: one part of a well barrier.
- **Performance Standard**: a statement, which can be expressed in qualitative or quantitative terms, of the performance required of a system, item of equipment or well barrier element which is used as a basis for managing the risk of a major accident event.

Overview of approach used with the Peloton WellMaster software [5] to assess failure frequencies of a CO_2 injector well (section 3.2) and a decommissioned well (section 4.2). Each step is described in detail:

1. Define well barriers and well barrier elements.
2. Use “Analyser” functionality to assess leak frequency of individual well barrier elements using the Well Master database.
3. Use “Simulator” functionality to simulate the leak frequency of the primary and secondary barrier.
4. Include sensitivities.
5. Combine the leak frequency of the primary and secondary barrier to reflect the likely well operating philosophy.
6. Comparison with results and values used from other recognised papers.

2 Overview of Peloton WellMaster Database

The Peloton WellMaster database [5] has 38 years' worth of well equipment reliability data covering 6,000 wells with 70,000 components and 45,000 well service years from 34 operators from around the globe. The operators provide these data so that they can use them to drive uptime and reliability improvements in the design and operation of their wells. The database is increasing in size every year, the equipment failure statistics may change slightly with every update to the database. This analysis was completed in April 2022. The majority of the data are from oil, gas and water wells with some data from the Norwegian CO_2 injection wells. The data are considered to be applicable for use in assessing CO_2 injection well reliability following filtering to select a sample size that is large enough whilst focussed on well-types that may be classed as analogues to CO_2 Injection Wells on the UK Continental Shelf (UKCS).

The Peloton WellMaster database records equipment failures, not leak rates, these equipment failures will have been assessed against a performance standard. When assessing the impact and risk of a well equipment failure or anomaly a common approach used by well operators is to use the criteria in API RP 14 B (American Petroleum Institute Recommended Practice Design, Installation, Operation, Test, and Redress of Subsurface Safety Valve Systems) with an allowable leak rate 400 centimetres cubed per minute (cm^3/min) liquid or 15 standard cubic feet per minute (scf/min) gas which is equivalent to 1.1 tonnes per day (t/d) of CO_2 as a threshold to record a well failure and take action to resolve the issue. The well barrier failure frequency and calculated leak frequencies have been linked to a CO_2 leak rate that exceeds 1 t/d.

2.1 Summary of Peloton Analyser and Simulator methodology

Well equipment data is collected from those operators who use WellMaster and stored using a hierarchy model that follows the taxonomy pyramid in ISO 14224 (Facility, Systems, Categories Subunits, Component Types) [6] . The equipment data is then used to develop reliability models for each equipment type, in the "Analyser" section of the software. The equipment data can be filtered so that the available equipment data best represents the well equipment to be modelled for an example of the filtering applied see Table 1.

Once the failure frequency distribution has been calculated for each piece of well equipment by the "Analyser" software for example Table 3, the "Simulator" software is then used to combine the equipment models to estimate the failure rate of the "Primary Well Barrier" and the "Secondary Well Barrier" using specified well templates that are aligned with the well design shown in Figure 1.

To generate equipment reliability models using “Analyser”. The most commonly used reliability (distribution) models for wells within the offshore oil & gas industry are the exponential distribution model and the Weibull 2 -parameter model (2P). The exponential distribution model is characterised by the fact that it assumes a constant failure rate independent of time. The Weibull distribution model follows a “bath-tub” type curve with three phases; burn-in, useful life and wear-out, over an estimated wear-out period. The WellMaster software has a routine that sets an “Assumed Wear-out Period”. For this analysis the Exponential Distribution Model was used, the average failure rate is typically higher than the failure rate during the Weibull “Useful Life Period” and there is no requirement to assume or calculate a “wear-out time”

Average failure rate (AFR) for a given component based on a data set for this type of component with X number of failures and a total service time of T years is then:

$$Average\ Failure\ Rate\ AFR\ (failures\ per\ year) = X \div T$$

The Mean Time To Failure (MTTF) based on the Exponential distribution model is then:

$$MTTF(years) = 1 \div AFR$$

When assuming an exponential life distribution model for a given component type, it is sufficient to collect data on the number of hours (or years) of observed time in operational service and the number of failures in the observation period, a large data set provides a sound basis for evaluating the results.

The Simulator has dedicated Well Templates to represent the “Primary Well Barrier” and the “Secondary Well Barrier”, these have been aligned with Figure 1. The well equipment that makes up each well barrier uses the well failure model created using the “Analyser” software as an input to the simulator well templates.

The Simulator then calculates the failure rate of the well barrier by using a combination of different pieces of well equipment with the Well Equipment failure models generated in the Analyser section of the software. A Monte Carlo type simulator is used to calculate the failure rate for 2,000 random scenarios over a 25-year period, these are then aggregated to provide a mean failure rate.

Once the Primary and Secondary well barrier models have been developed then their results are combined to calculate an overall well leakage probability.

3 CO_2 Injector (Active) Well

Wells are constructed using concentric pipes, cement, seals, and valves that form multiple barriers between the well fluids and the outside environment. Well barriers consist of different elements that may be active or passive. Active barriers such as valves can enable or prevent flow, while passive barriers are fixed structures such as the casing and cement.

For the purposes of this assessment the base case well was defined as being a subsea vertical well as shown in Figure 1. This well design has been proven to be effective in oil and gas developments. The injection packer is set at the same depth as the caprock. At depths shallower than the cap rock / injection packer there are always two barriers between the CO_2 and the outside of the well. The cyclical loads caused by changes in pressure and temperature experienced by the completion tend not be transmitted to the “Injector Casing and cement”, the injection packer that seals between the completion and injector casing are designed and tested for these completion loads.

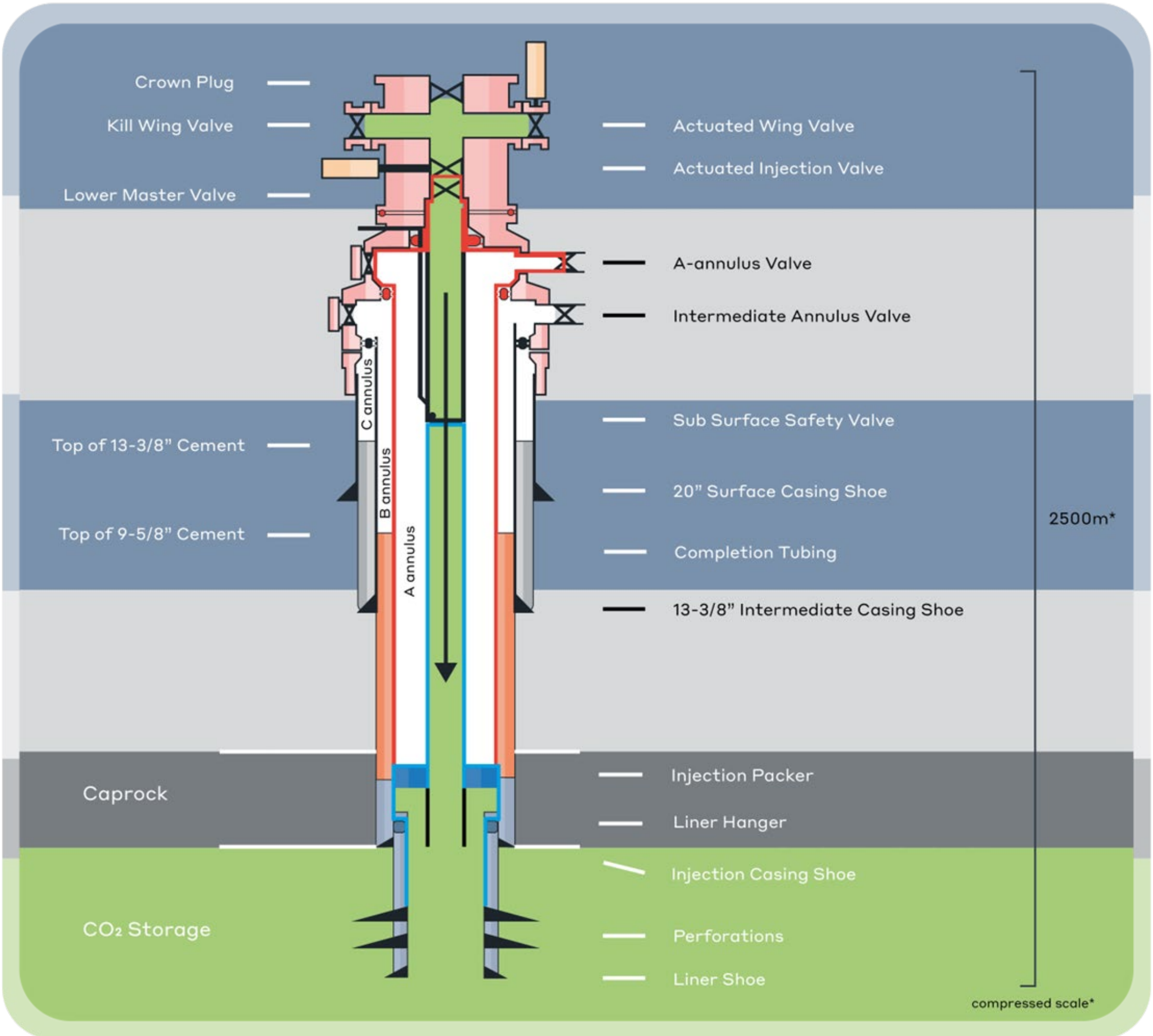

Figure 1 - Well schematic showing well barriers (illustrative purposes only, not to scale)

The completion uses 5-$^1/_2$" tubing with a premium connection, with a tubing retrievable subsurface safety valve and a permanent downhole gauge. The flow of the CO_2 injected into the storage volume is through the Actuated Wing Valve, past the Actuated Injection Valve, down the tubing past the surface controlled Subsurface Safety Valve, through the perforations and into the storage reservoir. The Actuated Wing Valve, the Actuated Injection Valve and the surface controlled Subsurface Safety Valve are connected to the facilities Control System so that they can be automatically closed to shut-in the well if there is a process upset.

This analysis does not differentiate between wells that inject into a Depleted Oil and Gas Reservoir or a Saline Aquifer, although the operating envelopes for the well may be different and some of the hazards may have minor variations, both well types will be designed to operate with two independent well barriers and to address specific hazards for their particular application meaning that the frequency for loss of containment for the well remains the same.

3.1 Define Well Barriers and Well Barrier elements

The primary barrier to contain the carbon dioxide in the storage area consists of:

- The Cap Rock.
- The cement sheath between the Cap Rock and the 9-$^5/_8$" Injection Casing.
- The injection packer.
- The tubing from the injection packer to Surface Controlled SubSurface Safety Valve.
- The Surface Controlled SubSurface Safety Valve.

These items are coloured blue in Figure 1. The leak frequencies associated with the caprock will be discussed in section 3.3.2 of the main report.

The secondary well barrier to contain the carbon dioxide within the well consists of:

- The 9-$^5/_8$" Injection Casing.
- The 9-$^5/_8$" Injection Casing Hanger.
- The Wellhead (casing head spool, tubing head spool).
- The A Annulus Master Valve.
- The Tubing Hanger.
- The Injection Actuated Master Valve.
- The Xmas Tree Block.
- The Swab Valve.

These items are coloured red in Figure 1.

3.2 Assess leak frequency of individual well barrier elements using the Well Master database

For each equipment item in the primary and secondary well barrier a mean time to failure and failure rate per year is calculated using the Peloton Analyser. For each equipment item a series of filters are applied to best represent the equipment that will be used in the CO_2 Injection well. The filters considered, with the rationale for each of the filters are shown in Table 1.

All Cases – No Filters	Reference Point
Post 1 Jul 1996	To reflect improvements in design, technology, installation and operation. The Offshore Installations and Wells (Design and Construction, etc.) Regulations 1996 commenced from 30th June 1996
North Sea (UK, Norway)	Regulations require regular monitoring, testing and reporting to meet performance standards
Well Type (Producer and/or Injector)	Impact on valves with moving parts. For example, injectors tend not to experience reservoir and well debris accumulating on the valve internals causing the valves to pass or fail to close.
No Restore date	When valves are tested all the results are recorded. If a valve fails to meet the performance standard on the first test but then does meet the performance standard on a subsequent test, then the valve has not failed and has been “restored”. With the “no restore date” filter any failed tests prior to a “restored date” are not included in the calculation.

Table 1 - Peloton analyser filters used

As each additional filter is applied the number of component service years will reduce, with the consequence that the calculated failure rates may no longer be representative. The filters are applied with the aim of providing credible data with a reasoned rationale for excluding or including data that will then be used for the simulation, but with a view to retaining a sufficient sample size to be statistically relevant.

3.2.1 Well Equipment and Material Selection

The long-term integrity of a well is dependent on the materials selected to construct the well. Many operators in offshore and subsea developments chose to pre-invest in high quality completion materials to avoid the additional expense and loss of well availability of well workovers. It is expected that high quality corrosion resistant materials will be chosen for these CO_2 injection wells. For example, the tubing materials currently being tested for CO_2 injectors are typically high chrome materials 22% or 25% Chrome. For the completion accessories, production packer and subsurface safety valve, the material Incoloy-925 has been identified as a potential material due to high strength and excellent corrosion resistance. Incoloy 925 is already used for completion accessories in some of the most corrosive oil and gas well environments.

The WellMaster database estimates the failure rate for different equipment types, and although it is possible to filter on different materials and well functions (injector, producer) the data does not include information regarding the operating condition and fluid composition. In addition, filtering on specific materials results in a large reduction in the available data, for which the failure rate may not then be representative of the well and how it is operated.

The regulator will require the operator to demonstrate that materials used to drill and construct the well are suitable for this CO_2 service. This pre-investment into high quality corrosion resistant well materials should lead to failure rates that are within those estimated by from the WellMaster database.

3.2.2 Cement as a Well Barrier

The objective of primary cementing is to provide zonal isolation, to restrict fluid movement between the formations and to support the casing. This requires the cement to bond with the formation rock and the casing, to hold pressure and prevent flow. Cementing is the process of mixing a slurry of cement, cement additives with water and pumping it down through casing so that it fills the space between the casing and the formation. Cement has been an important part of well construction for many decades, in 1953 the API Standard 10A [7] was put forward to provide a standard for six classes of cements that were commonly used in oil- and gas-well cementing operations. Much work has been done to improve the quality of cement and cementing operations in well construction, but still remains an area for continued learning and improvements. A document search on the SPE Library for “cement” identifies over 47,000 papers.

Portland Cement (the most common type used in well construction) is known to react with CO_2 (carbolic acid), increasing the permeability of the cement and therefore any potential leak rate. However, there is also a suggestion that the by-products of this reaction form scales that then act to reduce the permeability. Without flow through the cement the degradation process is slow, limited by diffusion, and the reaction by-products need to be removed to expose fresh cement to allow further degradation; rates of up to 10m in 10,000 years have been quoted (ANNEX A1 CO_2 Storage Liabilities in the North Sea – An Assessment of Risks and Financial Consequences [8]). Field studies in the USA where CO_2 is injected to support oil field development suggest that in the presence of competent original cement, reactions with CO_2 do not seem to adversely affect the cement's capability of preventing migration of CO_2 (A Review of International Field Experience with Well Integrity at Carbon Utilization and Storage Sites [9]).

Failures of cement often appear as "Sustained Casing Pressures" which is an increase in pressure between two concentric barriers, a tubing to casing or casing to casing annulus. Sustained casing pressure can be due to tubular connection failures, casing failures, tubing leaks or cement failure allowing ingress of fluids from either inside or outside the well envelope. A review of environmental risks caused by well construction failures [10] identified single barrier failures (cement and/or tubulars) in the North Sea UK as affecting 34% Wells, (source a 2009 SPE Forum Survey). This percentage will be applicable to all the well annuli, not only those in contact with the target reservoir; there is no indication of the size of the change in casing pressure or the potential source of the pressure, so it should not be taken as a direct indication of the number of wells with a continuous leak.

Bai et al [11] used a dynamic simulator to estimate potential leak rates through cement for a typical CO_2 Injection well over a period of 1,000 years for different cement permeabilities and reservoir pressures (Pr), see Table 2 below. The range of permeabilities of the cement are used to represent the different quality of the cementation. Two reservoir pressures are used, one above and one below the hydrostatic pressure at the chosen reservoir depth, to highlight the impact the direction of the pressure drop has on the leak rate.

Description of Cement Quality	Permeability (mD)	Pr = 50 Bar Peak Leakage Rate (std m3/day)	Pr = 450 Bar Peak Leakage Rate (std m3/day)
Good Cement	0.01	0.000004	0.0006
Poor Cement	10	0.0074	0.343
Defective Cement	1,000	0.742	34.45

Table 2- Extract from Bai et al Results

The peak leakage rate with defective cement and a reservoir pressure above the hydrostatic pressure is modelled as 35 standard metres cubed per day (Sm^3/day) which is equivalent to 0.065 t/d. A well designed and executed casing cementation, that provides a good bond between the cement-to-formation and cement-to-casing, is the key to maintaining good well integrity. Even if the cement does degrade allowing the permeability to increase over time this study indicates the potential leak rate is equivalent to a Seepage Rate.

The database has limited data for external cement sheaths around the casing. For the purposes of this analysis the "external cement sheaths around casing" will have a failure frequency that is half that of the injection packer. The basis of this assumption is that the cementation has been designed and placed following best practices, cement bond logs have recorded good cement and cement bond with casing and rock, a formation integrity test at the shoe prior to drilling the next section has been completed. For the well design shown in Figure 1 cyclical loads caused by changes in pressure and temperature experienced by the completion tend not be transmitted to the "Injector Casing and cement". For the Decommissioned well shown in Figure 2 the cement plugs will not experience cyclic loads. This means that one of the most common failure mechanisms for cement can be avoided.

3.2.3 Well Barrier Elements

The results and the filters applied to each equipment item are shown for the Primary Barrier in Table 3 and for the Secondary Barrier in Table 4. These will be used to simulate independently the leak frequency of the primary barrier and the secondary barrier in section 3.3.

Base Case – Primary Barrier	Filters Applied / Service Years	Failure Rate / Year
Injection Packer	Post 1 Jul 1996, size 9-$^5/_8$" / 15,263	0.002
Anchor Latch	Post 1 Jul 1996/ 16,177	0
Tubing 5-$^1/_2$" 2,000 m	Post 1 Jul 1996, (UK, N) / 7,993	0.004 per 1000 m
Permanent Downhole Gauge	Failure Modes do not indicate a leak	Not included
(Tubing Retrievable Surface Controlled SubSurface Safety Valve)	Post 1 Jul 1996, UK Norway, Inject, no restore date / 3,549	0.009
Cement Sheath – Cap Rock to 9-$^5/_8$" casing	Assumed Failure Rate is half the Production Packer	0.001

Table 3- CO_2 Injector Primary Barrier

Base Case Secondary Barrier	Filters Applied / Service Years	Failure Rate / Year
Subsea XmasTree Block	None / 563	0.007
Subsea Tubing Hanger	Subsea Tree types / 13,026	0
Injection Casing	Use same as Tubing Post 01 Jan 2000, (UK, N) / 15,506	0.004 per 1,000 m
Subsea Casing Hanger	None / 6	0
Injection Master Valve	Post 1 Jul 1996, UK & Norway, No restored data / 1,624	0.003
Annulus Master Valve AMV	Post 1 Jul 1996, UK & Norway, No restored data / 1,468	0.002
Crown Plug	None / 4,312	0
Subsea Wellhead, Tubing Head Spool, Wellhead Connector	None / 5,372	0

Table 4- CO_2 Injector Secondary Barrier

3.2.4 Sensitivities Considered

Although there will be differences between the different well designs used for the CO_2 Injectors the equipment used for the well barriers is expected to be similar. A few sensitivities have been considered to show the impact of differences in well designs.

- Deviated wells – longer sections of tubing and casing will be used with an additional 1,000 m along hole assumed.
- Downhole Choke valve to control the CO_2 injection rate and phase change – If installed below the injection packer it would not be part of the primary barrier, the injection packer would require a penetration there is no specific filter for feedthrough. If installed in the tubing string above the injection packer then failures that resulted in a leak would be linked to the control line.
- Platform Well with a dry tree rather than a Subsea Well.
- A Cement failure frequency set to be 10 times higher than the Base Case.

The impact of these sensitivities on the primary and secondary barriers is shown in Table 5.

Barrier Sensitivities	Filters Applied / Service Years	Failure Rate / Year
Primary Barriers:		
Downhole Control Valve, above injection packer	TrSCSSSV – Post 1 Jul 1996 only control line failures (T-A, A-T) / 27,423	0.003
Injection Packer – with feedthrough	No filter – PES and Well Dynamic packers have zero failures	Not included
Cement Sheath – Cap Rock to 9-$^5/_8$” casing	Failure frequency 10 times higher than Base Case	0.01
Secondary Barriers:		
Platform Well Head (Wellhead assembly topside, casing head spool, tubing head spool)	None / 2,334	0
Platform Xmas Tree	None / 1,846	0.001
Platform PMV-H	Post 1 Jul 1996, (UK & Norway), No restore date / 3,379	0.004
Platform Tubing Hanger	Post 1 Jul 1996, (UK & Norway), / 16,016	0.004
Platform A Annulus Valve	Post 1 Jul 1996, (UK & Norway), No restore date / 2,031	0.003

Table 5- CO_2 Injector Sensitivities Alternative Well Designs and Equipment

3.3 Simulate the leak frequency of the primary and secondary barrier.

The Peloton "Simulator" enables the component equipment with filters applied to be combined to calculate the mean time to failure (MTTF) and leak frequency for the primary barrier using Table 3 and for the secondary barrier using Table 4. The simulator uses a Monte Carlo simulator with 2,000 iterations over a simulation period of 25 years to reflect the expected injection period into the storage site.

The results from this simulation for the base case and the sensitivities are shown in Table 6.

Active Well	Subsea Base Case	Platform Well	Deviated Well (+ 1,000 m Along Hole)	Base Case with Downhole Control Valve	Cement Failure 10 x Base Case
Well Barriers	Failure (/ Year)	Failure (/ Year)	Failure (/ Year)	Failure (/ Year)	Failure (/ Year)
Primary	0.0340	0.0340	0.0444	0.0356	0.0408
Secondary	0.0404	0.0388	0.0508	0.0404	0.0404

Table 6- CO_2 Injector Peloton Simulated Failure Rates

Note: Each Sensitivity has been applied to the Base Case - a Subsea Well.

3.4 Combine the leak frequency of the primary and secondary barrier

The general operating philosophy for well designs with two independent barriers is, if one barrier fails the second barrier can prevent the leak or hazard from occurring while the first barrier is repaired. For the purposes of this assessment, the well barriers / valves will have a six-month testing frequency, if the well barrier / valve fails to meet the performance standard three months is required to plan, mobilise and repair the well barrier / valve that has failed. During this nine-month period (duration since last test plus six months to repair the well barrier) there is a risk that the second barrier will fail.

For a well to leak both the primary and secondary barriers must have failed. The two scenarios below describe how this could occur and the risk of a leak can be calculated;

- The risk of a leak from a Primary Barrier failure followed by a Secondary Barrier failure during the nine-month period the primary barrier has not meet the performance standard = (Primary Barrier Failure / year) x (Secondary Barrier Failure /year x (9 / 12 months)) = 0.034 x 0.040 x 0.75 = 0.00102 leak / year.
- The risk of a leak from a Secondary Barrier failure followed by a Primary Barrier failure during the nine-month period the Secondary barrier has not met the performance standard = (Secondary Barrier Failure / year) x (Primary Barrier Failure /year x (9 / 12 months)) = 0.034 x 0.040 x 0.75 = 0.00102 leak / year.

The risk of a leak from a CO_2 Injection well with two independent barriers = 0.00204 per year (The sum of the risks from the two scenarios above).

Table 7 combines the Primary and Secondary failures per year to give the Risk of a Leak per year using the approach described above.

Active Well	Subsea Base Case	Platform Well	Deviated Well (+ 1,000 m Along Hole)	Base Case with Downhole Control Valve	Cement Failure 10 x Base Case
Risk of Leak / Year	0.0020	0.0020	0.0034	0.0022	0.0025

Table 7- CO_2 injector risk of a leak per year for the base case and sensitivities

4 Decommissioned (Inactive) Well

4.1 Define Well Barriers and Well barrier elements

Once the well is no longer required it will be decommissioned. To decommission a well, permanent barriers, for example cement plugs of an appropriate thickness (usually 10s or 100s of metres), are installed in the well to prevent fluid movement between formations with different pressure regimes or loss of containment to the environment. The permanent barriers used when the well is decommissioned are designed, installed and tested so that no further inspection is required. The surface wellhead, Xmas tree and the upper sections of casing are removed so the surface location can be returned to the original condition. A common method to set cement plugs to as part of the Decommissioning of a well is shown in Figure 2.

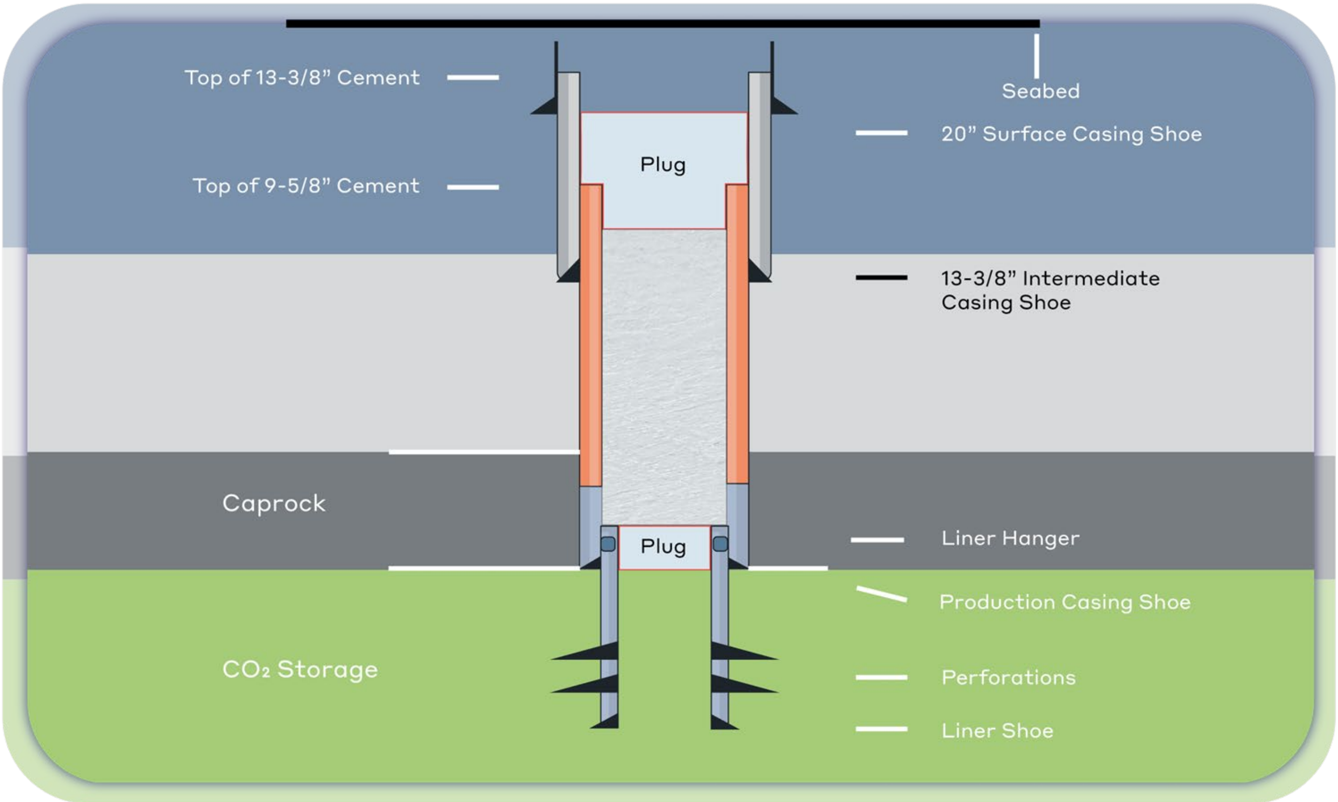

Figure 2- Decommissioned Well with cement plugs

The primary barrier to contain the carbon dioxide in the storage area consists of:

- The Cap Rock.
- The cement sheath between the Cap Rock and the 9-5/8" Production Casing.
- A cement plug inside the casing.

The leak frequencies associated with the Cap Rock will be discussed in section 3.3.2 of the main report.

The secondary well barrier to contain the carbon dioxide within the well consists of:

- The 9-$^5/_8$" Production Casing.
- A cement plug.

4.2 Assess leak frequency of individual well barriers

Following the same approach as the CO_2 Injector well (see section 3.2). The results and the filters applied to each equipment item are shown for the Primary Barrier in Table 8 and for the Secondary Barrier in Table 9. These will be used in the next step of the process to simulate independently the leak frequency of the primary barrier and the secondary barrier. For the purposes of this analysis the "cement plug inside the casing" will have a failure frequency that is half of the production packer. The basis of this assumption is that the cement plug will not experience the pressure and temperature changes that a production packer experiences during the Operating phase.

Base Case – Primary Barrier	Filters Applied / Service Years	Failure Rate / Year
Cement Sheath – Cap Rock to 9-$^5/_8$" casing	Assumed Failure Rate is half the Production Packer	0.001
Cement Plug is represented by Production Packer	Assumed Failure Rate is half the Production Packer	0.001

Table 8- Decommissioned Well Primary Barriers

Base Case Secondary Barrier	Filters Applied / Service Years	Failure Rate / Year
Casing (2,000 m)	Use same as Tubing Post 01 Jan 2000, (UK, N) / 15,506	0.004 per 1,000 m
Cement Plug is represented by Production Packer	Assumed Failure Rate is half the Production Packer	0.001

Table 9- Decommissioned well secondary barriers

4.3 Simulate the leak frequency of the primary and secondary barrier.

The Peloton “Simulator” enables the component equipment with filters applied to be combined to calculate the leak frequency for the primary barrier using Table 8 and for the secondary barrier using Table 9. In the typical project referred to in section 3.3.3 of the main report, the injector wells will be abandoned for 100 years post store closure. The simulator uses a Monte Carlo simulator, 5,000 iterations were run over the 100 years, the results are shown in Table 10. The calculation uses a constant average annual failure rate, as time progresses the cumulative probability of a failure is increasing therefore each year there is a higher risk of both barriers having failed resulting in a leak. The study completed by Bai et al [11] see Table 2 indicates that any leakage rate through the cement plugs will be equivalent to a “seepage rate”.

Inactive Well	Decommissioned Well
Well Barriers	Failure (/ Year)
Primary	0.0018
Secondary	0.003

Table 10- Decommissioned Well Simulated Failure Rates

4.4 Combine the leak frequency of the primary and secondary barrier

In this example the decommissioned well has two cement plugs, these will have been designed, installed and tested so that no further inspection is required. For a leak through the well to occur would require both the primary and secondary barriers to fail, it is not known which barrier will fail first and it will not be possible to identify when a single barrier has failed. The two scenarios below describe how this could occur and the risk of a leak can be calculated;

- The risk of a leak from a Primary Barrier failure followed by a Secondary Barrier failure in any year is the cumulative risk of a Primary Barrier failure since decommissioning multiplied by the annual risk of a Secondary barrier failure in that year.
- The risk of a leak from a Secondary Barrier failure since decommissioning followed by a Primary Barrier failure in any year is the cumulative risk of a Secondary Barrier failure multiplied by the annual risk of a Primary barrier failure in that year.

Should both primary and secondary barriers fail causing a leak to occur and the leak finds a route to surface then the leak may be identified by a seabed survey that is conducted as part of the MMV Plan.

Figure 3 shows how the overall risk of well leakage is calculated. The probability of a "Primary followed by Secondary barrier failure" and a "Secondary followed by Primary barrier failure" follow the same profile against time. Consequently, in Figure 3 only one of these two curves is visible; the yellow curve obscures the grey curve. Each year, as described in the bullets above, the probability increases as the time in which the first barrier has potentially failed is longer. The total probability of a leak is the sum of these two probabilities for that year.

The annual probability of failure will increase with time, therefore, to calculate the average probability failure it is necessary to consider a specific period of time (here 100 years) and the probability of well leakage by the end of that period (otherwise the probability of failure will be underestimated). This is done by summing the annual probability of failure over time, so that by 100 years post-decommissioning (the period considered in the typical store described in section 3.3.3 of the main report) the risk that both barriers have failed and the well has leaked is 0.055, the cumulative risk of the annual failure probability in each of the preceding 100 years. Therefore, the Risk of a Leak from a Decommissioned well with two independent barriers over a 100-year period = 0.055 giving an average Risk of Leak = 0.00055 per year (equivalent to 1 in 2,000).

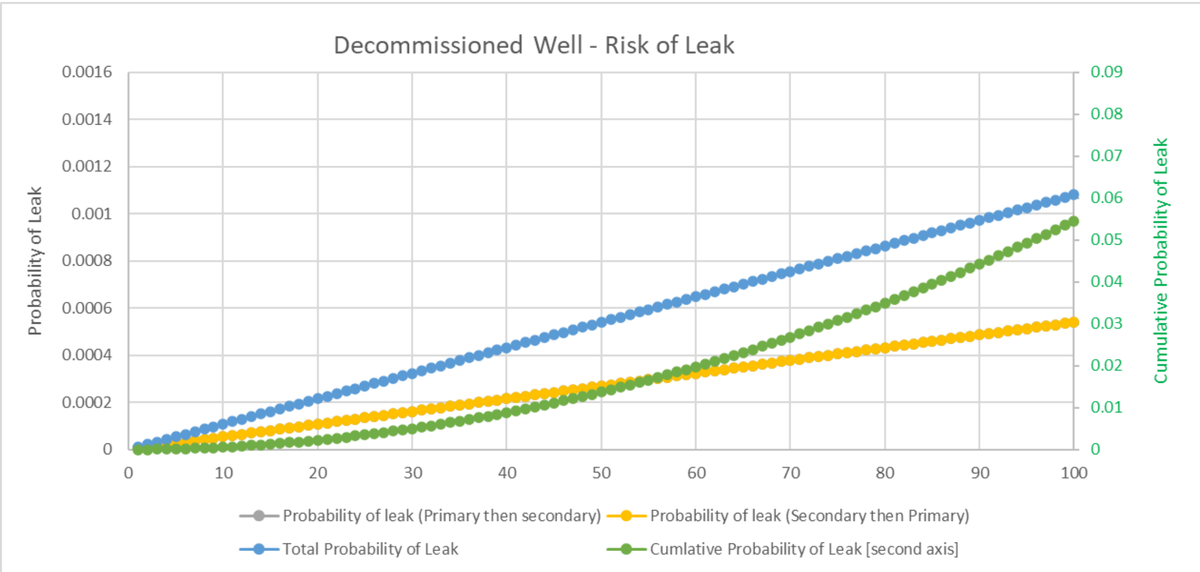

Figure 3- Decommissioned Well risk of leakage

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