EVO ENERGY CONSULTING

Qualitative Risk Assessment of Long-Term Sealing Behavior of Materials and Interfaces in Boreholes KEM-18 – Final Report

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Executive Summary

This report contains the findings of an investigation into qualitative risk assessment of long-term sealing behavior of materials and interfaces in boreholes. A large volume of open literature sources was consulted to answer the key questions associated with the investigation. Sources included journal publications, books and standards from the oil and gas industry (including the drilling, petrophysics, formation evaluation, geology and geomechanics disciplines) but also from the civil engineering and environmental science domains. Moreover, government and government-associated reports were used from various countries worldwide concerned with well integrity and safe and durable well abandonment.

Regarding the key risk factors of importance to the long-term abandonment of onshore oil and gas wells, these appear to be:

- Well age (serving as a convenient proxy for how the well was cemented originally, what the regulatory environment was at the time, what relevant well data is available, as well as the progression of barrier deterioration with time),
- Abandonment date (similar to well age, but then relating to when the well was abandoned),
- Well type (gas, oil, water/ brine) and its reservoir pressure / re-pressurization status. The primary concern revolves around wells leaking methane gas, which dominate the global leakage statistics (e.g., 95% - 99% of the leaking wells in Alberta Canada are leaking methane).
- Cyclic loads experienced by the well during its lifetime,
- Absolute in-situ temperature environment,
- Geological, geomechanical and geochemical environment which the well is exposed to over time,
- Wellbore deviation.
- Combination of risk factors is seen as an added risk.

The set of risk factors is not to be regarded as exclusive: more factors may be of importance, with some candidates already mentioned in this report. However, confirming their influence requires the gathering of a relevant dataset of observed well leakages with associated statistical data analysis for the Dutch onshore abandoned well population. SodM is advised to take steps to obtain such a dataset in future.

A two-pronged approach to risk assessment based on the identified risk factors is recommended here: (1) a simple scorecard approach with traffic lights indicating very high, high, medium and low risk of well integrity failure and associated leakage; (2) a fit-for-purpose probabilistic risk approach to predict the risk and quantity of leakage in the future. Probabilistic analysis may also allow for an evaluation – and possible improvement – of current abandonment designs and regulatory guidelines, and may be used to investigate the long-standing question around acceptable leakage rates.

Cement acts as a competent barrier in most wells, evidenced by the fact that the majority of temporarily suspended and abandoned wells are not leaking (the current average globally is that less than 10% of the well population is currently leaking, although frequencies for individual cases / regions may be significantly higher or lower). It is currently not possible to project out to hundreds to thousands of years, but recovered cement samples from wells that are decades old show that the key properties of intact cement are little changed over that time period. Leakage is therefore not associated with transport

through intact cement. Instead, it primarily occurs when the low-permeability cement matrix gets bypassed with flow through micro-annuli at cement-casing and cement-formation interfaces, through channels, cracks and fractures in annular cement sheaths and abandonment plugs, and through holes in corroded casing. Leakage channels may be created right after primary cementing (due to cement shrinkage, pressure testing, non-removal of filter cake, etc.) or over the well's lifetime (e.g., due to cyclic pressure and temperature loads, impact of geomechanical/geochemical loads on cement and casing).

Various remediation technologies (using chemical, biological or physical mechanisms) are already available to remedy flows in leaking wells, and the topic is an active area of new R&D. Shale- or salt as a barrier technology (SAAB) looks particularly promising to generate reliable, high-integrity barriers in case annular cementing is either poor or missing altogether.

Additional recommendations to SodM coming out of this investigation include:

- To capitalize on the standards and learnings of the Canadian government / regulator, industry workgroups, academics and consultants, etc., who together are leaders in dealing with the challenges of onshore well abandonments since the 1980's, with increased efforts in the last 2 decades. A wealth of relevant information is available from a variety of sources that can benefit onshore well integrity and abandonment management in the Netherlands
- Considering adopting the Canadian practice of checking for sustained casing pressure (SCP), surface casing vent flows (SCVF) and gas migration (GM) outside of the outer casing string, and possibly confirming suspected flow behind casing using cased-hole logging techniques prior to permanent well abandonment, with appropriate remedial action in case of confirmed flows exceeding acceptable norms.
- In case of new urban development close to sites with abandoned wells, it is recommended to develop and implement a pro-active monitoring plan as well as a rapid response action plan for well re-abandonment in case of confirmed leakages. In this regard, it will be useful to track and potentially financially support the development of new (re-)abandonment technology that serves the purpose of quickly and reliably (re-)abandoning wells.
- Well integrity and leakage potential need to be explicitly considered when re-pressuring depleted reservoirs (through practicing enhanced oil recovery methods, underground storage of gas, CO_2 and waste storage, etc.) and / or repurposing old wells for new purposes (e.g., use as injection wells, wells for geothermal heat extraction). Re-pressurization may restore the driving force for flow to surface, possibly leading to leakage on wells with compromised barriers. Changing well purposes may furthermore expose old wells to new loads (e.g., thermal loads on wells re-used for geothermal purposes) which they may not have been originally designed to handle.
- A common approach to well abandonment among North Sea nations (including UK and Norway - even though their focus is primary on offshore abandonments) would be useful. This includes framing the debate on well abandonments in terms of a common time horizon, e.g., 1 million days (~3,000 years).

Glossary / Definition of Terms

Term	Acronym	Definition
Barrier, certified barrier element	CBE	A well abandonment barrier, composed of certified barrier elements (CBE), provides a permanent seal, with isolation from / to surface and from lower pressured zones.
Biogenic gas		Gas created by methanogenic bio-organisms in shallow sediments.
Caprock		Sealing formation functioning as a trap to hydrocarbons in the subsurface.
Carbon capture, (use) and storage	CCS, CCUS	Process of capturing carbon CO_2 before it enters into the atmosphere and storing it underground for an indefinite time period.
Enhanced oil recovery	EOR	Any process used to displace oil from reservoirs in a secondary mode differing from primary oil recovery.
Gas migration	GM	Migration of gas to surface outside of the outer casing string.
Micro-annulus		Narrow channel forming at the casing-cement interface or formation-cement interface due to debonding of the cement from casing or formation respectively.
Oil-based mud / Synthetic-based mud	OBM / SBM	Drilling fluid system with a non-aqueous continuous phase including alkanes (paraffins), alkenes (olefins) and esters.
Ordinary Portland cement	OPC	Cement type used for API class cements.
Permanent plugging and abandonment	P&A	The permanent isolation from surface and from lower pressured zones, of penetrated zones with flow potential in any well that will not be re-entered (Oil and Gas UK 2018).
Permeability [m^2]		Formation property that indicates the ability of fluids and gases to flow through the formation, measured in units of area.
Sustained casing pressure	SCP	Annular pressure build-up (APB) at surface, caused by the failure of an annular barrier to provide zonal isolation.
Surface casing vent flow	SCVF	Annular flow to surface, caused by the failure of an annular barrier to provide zonal isolation.
Temporary abandonment	TA	Temporary well suspension with completion interval isolated by barriers, in anticipation of future use by the operator.
Thermogenic gas (hydrocarbons)		Gas (hydrocarbons) generated from buried organic material under the influence of elevated temperature and pressure.
Top of cement	TOC	Highest location of competent cement in the annulus, usually determined by cased-hole logging (e.g., bond logging).
Trapped Annular Pressure	TAP	Annular pressure build-up (APB) in annular spaces due to expansion of fluids, typically during production operations.
Water-based mud	WBM	Drilling fluid system having water as the continuous phase.
Well leakage (including SCP, SCVF and GM)		Any flow of gas and/or fluids towards the surface resulting from a well barrier failure causing loss of zonal isolation.

1. Introduction

This work was carried out in response to the request for proposal (RFP) titled "*Qualitative risk assessment of long-term sealing behavior of materials and interfaces in boreholes – KEM-18*", reference 202005048 / KEM-18 by the Dutch State Supervision of Mines (SodM/SSM). It covers work conducted by Dr. Eric van Oort of EVO Energy Consulting LLC, based in Austin, Texas, USA, as principal investigator (PI) and Metarock Laboratories Inc., based in Houston, Texas, USA as sub-contractor.

1.1. Study Objective

The study objective was summarized in the RFP document dd. 17 July 2020 as follows (RFP, page 2 of 17):

> *To enable justified decisions on matters where the safety of old or abandoned wells may have an impact. Currently the long-term behavior of cement and steel is reasonably understood. But how do the interfaces of cement and formations, or cement and casing behave? How do formations behave over uncemented sections? In the Netherlands over 1300 onshore wells have been abandoned and in the coming years this number will increase significantly, as will the number of abandoned wells offshore. The sites above these wells will increasingly being used or earmarked for urban development. This raises the need to determine the risks associated with these sites. The older wells in the Netherlands were constructed from the 1940`s onwards and were built and abandoned using traditional steel casing and oilfield cements. The oldest abandoned wells are now nearly 80 years old. While industry assumes that the sealing capability of the casing, cement, and rock formation will not change over time, this assumption is not well founded. In some cases, leak paths were introduced during the construction or production phase; if not addressed during the abandonment phase, these may still exist in the abandoned well as micro-annuli. It is not well understood if these micro annuli remain open, become larger, or close over time due to rock formation movement and/or mineral or petroleum deposits. This research question attempts to address this issue. Specifically, the project is aimed at obtaining a better understanding of the long-term behavior and interaction of cement, steel, and rock in abandoned oil and gas wells, and how this influences the integrity of the abandoned well.*

1.2. Central Research Questions & Stages

The work was laid out in 2 stages covering a total of 6 research questions (question 1 in Stage 1, questions 2, 3, 4, 5 & 6 in Stage 2) as follows (RFP, page 8 of 17):

First stage:

> *1. First stage is a literature study of public studies on long term behavior of cement and cemented casing. Presumably a lot of information will be available within companies such as Schlumberger, BHI and Halliburton. This stage will result in an answer to the question: which are the risk critical elements and parameters determining the long-term sealing capacity of boreholes and can they qualitatively or quantitatively be assessed?*

Second stage could involve detailed studies on:

2. Cement is known to have low permeability; how permeable for the fluids that concern us (gas, oil, water)? How does the permeability of oilfield cement change over a long period of time (e.g., 100 to 500 years) and how does the change affect its sealing effectiveness?

3. How well is steel casing, surrounded by cement, protected against corrosion? How is the corrosion rate affected by the change in permeability of the cement? Will the encased casing corrode in the long term? Can a corroded casing become a leak path?

4. The micro-annulus could be a conduct for fluids. What is the long-term behavior of the micro annulus? Will it be squeezed tight, or can it erode through flowing liquids? Can it be filled with petroleum or mineral deposits?

5. Is there a micro-annulus between cement and formation? How does filter-cake behave, is it permeable?

6. How do plastic formations such as rock-salt and claystone or shale behave around a cemented or uncemented casing, and can they form an effective seal?

1.3. Expected Deliverables & Use

The expected deliverables have been summarized as follows (RFP, page 8 of 17):

1. An inventory of studies and research related to these issues;

2. An analysis of the risk that micro-annuli pose over longer term;

3. An analysis of the risk of cement or casing degradation to the point of failure of the barrier.

The expected use of the study has been outlined as follows (RFP, pages 8 & 9 of 17):

Contribution to a risk instrument: to help assess the risks of leakage from abandoned wells due to cement degradation in the long term, to help identify any additional mitigation measures, and to help with proper planning by local government / town councils for the future land use above abandoned wells in the Netherlands. It might be used to refine drilling guidelines and inspection.

1.4. Study Approach

The RFP explicitly states that: "*It is not foreseen that lengthy laboratory studies are required to come to conclusions on the above. Literature studies on documented effects seen in wells around the world or from laboratory studies carried out by companies or research bodies may be able to answer most of the questions.*" Answering the Stages 1 & 2 questions was therefore weighted towards literature study and risk analysis in the work reported here. The proposed experimental laboratory study was not carried out due to the lack of suitable cement and rock formation materials for testing.

Various international publications were used as data sources to the 6 questions, including:

- **Oilfield journal publications**, such as Society of Petroleum Engineers (SPE) conference and journal papers, American Association of Drilling Engineers (AADE) papers, International Association of Drilling Contractors (IADC) papers, select journal papers (Journal of Petroleum Science and Engineering (JPSE), Journal of Natural Gas Science and Engineering (JNGSE)), etc.
- **Oilfield books & standards**, such as Well Cementing 2nd edition (Nelson & Guillot, 2006), SPE Reprint Series No. 34 – Well Cementing, IADC Drilling Series Well Cementing Operations (Sweatman, 2015), Development in Petroleum Science No.28 Well Cementing (Nelson, 1990), API and ISO standards (e.g. API 10A & B, ISO 10426-1 & 2, etc.).
- **Civil and environmental engineering publications**, such as industry journals and books dedicated to cementing (Cement, Cement & Concrete Research, Applied Well Cementing Engineering, etc.).
- **Rock mechanics publications**, such as American Rock Mechanics Associated (ARMA) papers, Journal of Rock Mechanics and Geotechnical Engineering papers, Journal of Rock Mechanics and Mining Sciences papers, etc.
- **Academic, government and industry reports**, which have been published and are available in open literature. Note that the Dutch government is not alone in its concerns about well integrity and long-term zonal isolation: those concerns are increasingly shared by foreign governments (e.g., Norway, Canada) who are producing relevant documentation materials that make excellent source material (e.g., Norsok D-010 by the Norwegian Oil and Gas Association and Federation of Norwegian Industries, IRP25 (2020) by the Canadian Drilling and Completion Committee-DACC).
- **Open-source data**, provided by academic institutions, governments/regulators, and industry companies. Note that company datasets are often proprietary and not readily available. However, several companies have started to open-source datasets for general use. The PI of this investigation has leveraged his global network of contacts (including representatives from all major oil & gas operators and service companies) for suitable data for this investigation.

In the literature study, a higher emphasis was given to more recent papers and reports with the latest, most updated information, and to papers with higher citation numbers, reflecting their high impact and valuation in their respective disciplines.

1.5. Report Structure

Following this Introduction (Chapter 1), there are separate chapters dedicated to answering Stage 1 & 2 questions (Chapters 2 & 3 respectively). Answers are kept brief to create a relatively concise main report, with further detail on the extensive literature sources consulted given in dedicated appendices. A separate chapter (Chapter 4) is dedicated to qualitative and quantitative risk assessment, answering the question whether the impact of the risk factors on abandoned wells can be qualitatively or quantitatively assessed. Conclusions and recommendations are summarized in Chapter 5.

Furthermore, there are three appendices dedicated to:

- General background knowledge (Appendix A).
- Overview of source material and additional documentation on the Stage 1 question (Appendix B).
- Overview of source material and additional documentation on the Stage 2 questions (Appendix C).

2. First Stage Question and Answer

2.1. Question 1 – Risk Critical Elements & Parameters Determining Long-Term Well Sealing

Question 1*: Which are the risk critical elements and parameters determining the long-term sealing capacity of boreholes, and can they qualitatively or quantitatively be assessed?*

Answer.

Barriers are specifically designed and installed to provide long-term sealing capacity of boreholes. Main requirements and characteristics of barrier materials can be summarized as (Oil & Gas UK 2015):

- *Having very low permeability[1] – to prevent flow of fluids through the bulk material.*
- *Provide an interface seal – to prevent flow of fluids around the barrier; the material provides a seal along the interface with the adjacent materials such as steel pipe or rock; risks of shrinkage and de-bonding are to be considered.*
- *The barrier materials must remain at the intended position and depth of the barrier.*
- *Long-term integrity – long lasting isolation characteristics of the material, not deteriorating over time; risks of crack and debonding are to be considered.*
- *Resistance to downhole fluids and gases (e.g., CO_2, H_2S, hydrocarbons, brine) at foreseeable pressures and temperatures (*to prevent material degradation, corrosion, etc. – EVO*).*
- *Mechanical properties to accommodate loads at foreseeable temperatures and pressure.*

These requirements immediate point to some of the main risks associated with barrier integrity failure over time during the well abandonment phase. Key considerations in this regard are:

- How the barrier was established in the first place, e.g., what cementing materials and practices were used to cement the well originally, and when the well was abandoned (with setting of cement plugs, annular remediation, etc.). Consequences of poor mud displacement are shown in **Figure 2.1.**
- Any process that leads to the deterioration of the barrier permeability, thus permitting upward migration of formation fluids and gases through the barrier bulk material.
- Any process that compromises the barrier's interface seals or cracks / fractures its bulk material, allowing fluids and gas to bypass the barrier's intact bulk material.
- Any process that compromises the position and depth of the barrier.
- Any process that degrades the barrier chemically over time at downhole conditions (temperature, pressure, exposure to downhole fluids/gas).
- Any process that degrades the barrier mechanically at downhole conditions (mechanical loads on the abandoned well due to formation movement / creep, compaction / consolidation / subsidence, fault (re-)activation, etc.).

[1] Oil and Gas UK (2015) consider a "low permeability" to mean 10 μD (~ 10^{-17} m^2) for cement. Nelson and Guillot (2006) specify a cement permeability of 100 μD (~ 10^{-16} m^2) for gas and 10 μD (~ 10^{-17} m^2) for fluids (oil/water/brine).

- The (remaining) driving force for flow to surface, and any processes that will re-pressurize depleted reservoirs (such as underground storage of natural gas, CO_2, waste fluids, etc.) intersected by the abandoned well.

Figure 2.1 – Examples of large aperture channels in annular cement due to incomplete mud displacement during primary cementing, which become high permeability leak paths for fluid and gas flow to surface. After Griffith et al. (1992), reproduced in Sweatman et al. (2015). Copyright Society of Petroleum Engineers (SPE), reproduced by permission.

The specific barriers we are mainly concerned with for boreholes that are plugged and abandoned are casing strings that have been left in the hole, cement sheaths between the downhole formations and the casing strings, and cement plugs (either by themselves or in combination with bridge plugs) inside casing strings or left to seal in open hole. Cement has historically been a preferred barrier material, with most regulations pertaining to well plugging and abandonment written in terms of minimum lengths of cement sheaths and plugs required to isolate subsurface zones. This is because cement is believed to have properties similar to the caprock formations (Oil and Gas UK 2015). Hence, the majority of the discussion to follow will revolve around cement, with other barrier materials only mentioned where appropriate.

Consideration of the above, in combination with extensive review of the source material, indicates that the main risk critical elements are:

- Well age and abandonment date
- Well type, reservoir pressure & re-pressurization
- Cyclic loads experienced during well lifetime
- Elevated temperature
- Geological / geomechanical factors
- Chemical factors
- Wellbore deviation
- Combination of above factors
- Additional / minor factors

Each of these factors is discussed individually and succinctly in the following sections, citing key motivation for its selection, with more detail from the source material given in Appendix B. The reader is also encouraged to read the background material provided in Appendix A, particularly when new to the topics of well cementing and well plugging and abandonment. The discussion on qualitative and quantitative risk assessment is postponed until Chapter 4, which is exclusively dedicated to the subject.

2.2. Well Age and Abandonment Date

The investigation of a wide variety of sources shows that well age is the single most important risk factor when it comes to borehole sealing capability or lack thereof. Well age is presented here as an "accumulated" risk factor, i.e., a proxy variable that reflects 4 separate elements that contribute to the risk of well leakage:

1. **Cementing technology and practices used to originally cement the well and abandon it**. It is well-known that an oil or gas well with poor casing cementation may lack zonal isolation, and may allow flow to shallow zones (e.g., shallow aquifers) and to surface, leading to sustained casing pressure (SCP) and surface casing vent flows (SCVF). The quality and reliability of the original casing cementation and of cement plugs set during the abandonment phase are therefore very important to prevent well leakage. Throughout the 20th century, from the early 1900's when casing cementing was first practiced, up to the present, there has been a considerable evolution in the development and adoption of cementing technology, best practices and guidelines. The history of cement technology developments is documented in texts such as the SPE Monograph on Cementing by Smith (1987), the Worldwide Cementing Practices by API (1991), and the comprehensive textbook on Well Cementing by Nelson and Guillot (2006). The latter document reflects the modern understanding of competent well cementing and cement barrier installation, while more recent publications reflect further refinements in cementing systems, logging techniques, modeling capabilities, etc. With respect to well age, different era's, each with their own risk profile for well leakage, can be distinguished, as follows.
   - ***Before 1955*** – This is a period of still rudimentary understanding of cementing, lacking essential technology and standards. Some notable achievements and milestones in this period are summarized in **Table 2.1**, with more detailed information in Appendix B. The first API committee to study cementing started in 1937, but meaningful standards were not yet available and adopted until more than a decade later, with API Code 32 released in 1948 and API RP 10B issued as a standard in 1956. Apart from concerns about how wells were cemented in this period, it is often the case that these wells lack relevant documentation and data. The risk of potential well leakage is therefore highest ("very high" on a relative scale, see Chapter 4) in this particular time period.
   - ***1955 – 1975*** – This is a period of extensive cementing standards development and adoption, with more versatile cementing systems becoming available. In this period, key cementing additives that serve as retarders, accelerators, extenders, fluid loss control agents, etc. are developed, many of which are still routinely used today. Important milestones are the introduction of API's "basic cement concept" in 1968, the first published report on annular gas flow / migration after cementing by Halliburton in 1970, and the first published cement displacement studies by Esso and Halliburton in 1972. Documentation is improving with more complete hardcopy records. The risk of potential of well leakage from non-optimum well cementation should, however, still be considered "high" (see Chapter 4) in this period.
   - ***1976 – 1995*** – This period is characterized by more mature API standards, improved understanding of processes such as cement shrinkage and gas migration with ways and systems to prevent / mitigate it, of the importance of good annular displacement, and of the effects of temperature and pressure on cement. This period also sees the maturation of cement evaluation through bond

logging techniques. Electronic well documentation, however, is not yet widely available. Important milestones are Smith's SPE Monograph on Cementing published in 1987, and API's Worldwide Cementing Practices published in 1991. The risk of potential well leakage should be considered "medium" in this time period (see Chapter 4).

- ***1996 – Present*** – This is the lowest risk modern era of well cementation with much-improved understanding of zonal isolation and barrier management, mature standards, advanced casing and cement logging techniques, and electronic data recording of cement job planning as well as pumping data, logging data and post-job evaluation and reporting. An early milestone in this period is Smith's *Handbook on Well Plugging and Abandonment* published in 1993, which contains almost all of the accepted well abandonment practices that are still in use and widely accepted today[2].

2. **Regulations governing cementing and zonal isolation requirements at the time the well was constructed**. Regulations usually leverage and build upon industry standards, and adoption usually lags behind the creation of these standards by several years due to the governmental review process. There has therefore also been an evolution in regulatory policy and associated enforcement towards better, more defined, and stricter guidelines informed by the aforementioned evolution of cementing technology, best practices and guidelines. King and King (2013) directly correlate stronger oil and gas well construction regulation with a lower potential for methane migration (see Appendix B). Conversely, weak/sub-standard regulations or absence of regulations correlate with a high potential for gas migration. A study by Bachu and Watson (2009) on failures of CO_2 and acid gas injection wells in Alberta Canada showed that proper regulation of such wells implemented after 1994 has led to a lower incidence of well failures, in fact becoming lower than the failure rate of the general well population.
3. **Data availability, quality and completeness on older wells**. Missing / incomplete data for very old wells and the progressive improvement towards complete electronic records has already been mentioned as an issue of concern under (1). Lack of data is one of the main complicating factors when attempting to perform quantitative risk assessment on older wells, which usually requires complete and reliable input values for an extensive set of variables (see Chapter 4).
4. **Cement exposure time to challenging subsurface conditions**. Cement sheaths and plugs when properly installed can withstand challenging subsurface conditions for long periods of time, as discussed in the remainder of this document. However, deterioration of both the cement and the casing can happen if the barriers were not properly installed or are missing altogether. Barrier degradation due to exposure to geomechanical loading and chemical attack/corrosion will be progressive with time, with the risks of a leak path being generated and flow to surface increasing over time.

[2] *Smith's 1993 Handbook contains a complete overview of the well P&A requirements enforced by all US states with active oil and gas developments at the time. A recent survey of US state regulations by EVO Energy Consulting shows that the current P&A requirements by these states have changed very little from those contained in Smith's overview, in some cases remaining entirely unaltered.*

Table 2.1. – High-level milestones in wellbore cementing from the early 1900's to the present day, based on information from Smith (1987), API (1991), Smith (1993), Nelson and Guillot (2006) and API (2021).

Date	Milestone	Reference
1903	First documented use of neat cement to shut off water flow	F.F. Hill
1910	First well cemented with two-plug method in California	A.A. Perkins
1919-1920	Established cementing business in North Texas; cement first well blowout (Oklahoma); developed jet mixer	E.P. Halliburton
1929	First laboratory for evaluating cement properties	E.P. Halliburton
1930	Use of bentonite in drilling fluids and cement (as extender)	
1934	Locating top of cement (TOC) with temperature survey	Schlumberger Co.
1937	First API committee to study oilwell cements established	American Petroleum Institute
1940	Introduction of bulk cement	Halliburton Co.
1946	First published study on use of cementing centralizers	Teplitz and Hassebroek (1946)
1948	First published studies on cement displacement	Howard and Clark (1948)
1952	First edition API Code 32 for testing cement	API RP 10B
1953	First study published on lost circulation during cementing	Bugbee (1953)
1953	Introduction of fluid loss control agents for cementing	Phillips Petroleum Co.
1957	Introduction of heavy weight agent to increase cement density	Halliburton Co.
1961	Squeeze cementing studies published	Beach (1961)
1968	Development of "basic cement concept"	API (1968)
1970	First report on annular gas flow / migration after cementing	Halliburton
1972	First published cement displacement studies	Esso and Halliburton
1979	Introduction of foam cement	Cementing service companies
1982	Studies on annular temperature and pressure change after cementing	Exxon Company
1983	New US cementing regulations	Texas RRC and Industry
1987	Publication of SPE Monograph on Cementing	Smith (1987)
1988	Shell study on gas invasion and migration in cement annuli	Stewart and Schouten (1988)
1990	Publication of Well Cementing by Dowell Schlumberger	Nelson (1990)
1991	Publication of API Monograph on Worldwide Cementing Practices	API (1991)
1992	Publication of SPE Reprint Series No. 34 - Cementing	SPE (1992)
1992	ExxonMobil study on cement sheath stress failure	Goodwin and Crook (1992)
1993	Publication of Handbook on Well Plugging and Abandonment	Smith (1993)
1995	First publication of Halliburton Cementing Tables	Halliburton
1996	Publication of Halliburton HTHP Cementing Manual	Halliburton
2006	Publication of Well Cementing, 2nd edition, Schlumberger	Nelson and Guillot (2006)
2015	Publication of Well Cementing Operations, IADC Drilling Series	Sweatman (2015)
2015	Publication of Guidelines on Qualification of Materials for the Abandonment of Wells, Issue 2	Oil and Gas UK (2015)
2019	Publication of Technology Roadmap to Improve Wellbore Integrity	NRCan (2019)
2020	Publication of DNVGL-RP-103 Risk-Based Abandonment of Wells (Edition September 2020, amended September 2021)	DNV (2020)
2020	Publication of Introduction to Permanent Plug and Abandonment of Wells	Saasen and Khalifeh (2020)
2021	Publication of API Recommended Practice RP 65-3, Wellbore Plugging and Abandonment	API (2021)

A compelling visual representation of the effect of well age on well leakage comes from Brufatto et al. (2003), which was adopted as the first graph in the authoritative text on cementing by Nelson and Guillot (2006), showing the percentage of Gulf of Mexico (GOM) wells with SCP as a function of well age in **Figure 2.2**. These very high SCP percentages are attributed to poor primary cementing practices used at the time of original well construction.

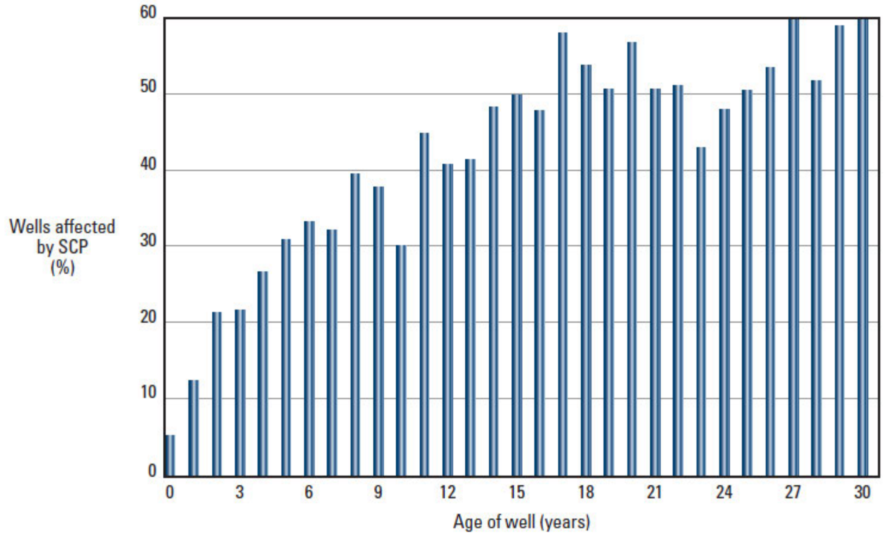

Figure 2.2. – Percentage of GOM wells affected by SCP as a function of well age. Data from Nelson and Guillot (2006), with original source being Brufatto et al. (2003). Information is for prior years (i.e., 30 years = 2003 – 30 = 1973). Copyright Schlumberger, reproduced by permission.

Significant relevant information on well age as a risk factor comes from the United States, where many of the older wells are located in areas with large well inventories, in states such as Pennsylvania, Texas, Colorado, and California. Chilingar and Endres (2005) relate the serious environmental hazards presented to urban development by the Los Angeles basin oilfields in California, many of which with wells dating back to the 19th century. Although not all the problems are well-related (some involve natural gas migration up faults and fracture zones), serious events have caused surface releases of gases and fluids, leading to surface contamination, poisoning events from toxic gases and fluids, serious near-misses and even explosions. For instance, an explosion in 1985 which demolished a department store and injured 23 people was related back to an old well casing that had developed leaks as a result of corrosion, allowing natural gas to find a pathway to the surface. In the following two quotes, Chilingar and Endres (2005) reflect on the risks and hazards associated with ageing wells:

"*Accordingly, the poor cementing and completion practices, <u>typical of the many old wells located in the Los Angeles basin, are giving rise to very serious environmental problems associated with gas leakage to the surface in the annular space</u> (…).*"

"*<u>Oil and gas wells must be carefully evaluated, and old wells must be re-abandoned to protect against the risk of oilfield gases migrating up the old wellbores and entering the near surface environment</u>. There has been a long history of this very serious problem, establishing that the prior well abandonment procedures have often been inadequate in dealing with this extremely dangerous problem.*"

In various publications, G. King and his collaborators (King and King 2013; King and Valencia 2014; King 2015; King and Valencia 2016) reflect on the environmental risks of leaking wells. Their work is primarily directed at addressing the well integrity concerns associated with hydraulically fractured wells. Moreover, it challenges work by others (e.g., Kang 2014; Davies et al. 2014; Ingraffea et al. 2013) which attribute the existence of annular pressure and flow to surface to well integrity failures. Instead, King promotes the idea of natural methane seepage from near-surface zones that overlie oil- and gas fields as the main contributor to observed methane emissions around wells. King, however, readily admits that older wells present potential risks and problems. King and Valencia (2014) state:

"There is no question that un-plugged or improperly plugged oil and gas wells, dating from the 1860's to 1930's and later, are a potential threat and, in some areas of early oil booms, unmarked wellbores still exist and pose a pollution pathway to aquifers from surface spills and a lesser risk from oil or gas well developments."

Various other publications reflect on the risk of well age on well leakage. Two quotes from prominent papers are given here, with more information provided in Appendix B. From Williams et al. (2021):

"*Well specific factors such as the well age, abandonment date, wellbore deviation, well platform (i.e., onshore versus offshore), and external factors (e.g., earthquakes) could control methane emissions from abandoned oil and gas wells (…)*"

From Loizzo et al. (2013), reflecting on the re-use of an old wellbore for CO_2 injection and downhole storage:

"Older wells are commonly recognized as the most likely pathway for CO_2 to migrate from the injection zone to other zones or to the surface. (…) A particular issue for wells drilled before the 1990s, when technological advances almost eliminated the problem, is that of mud channels left behind during the cement placement process. These defects present the highest risk because of their relatively large flow area."

Two important studies used extensively in this study appear to anti-correlate with well age, showing either no effect of well age or the inverse effect, with a higher rate of well failures in more recent years. The important work by Watson and Bachu (2009) analyzing a large set of statistical data on abandoned well wells in Canada concludes that there is no effect of well age. The dataset used, however, has no data on old wells and therefore does not allow the factor of well age to be properly delineated. The work is discussed in more detail in Appendix B. Ingraffea et al. (2014), quoted by Jackson (2014), observe a slightly higher failure rate of wells in Pennsylvania completed in period of 2009 – 2012 than in the period of 2000 – 2008 (1.5% vs. 1.9% respectively). There could be several reasons for this observation: (1) greater regulatory scrutiny in the earlier period (as mentioned by Jackson (2014)); (2) more emphasis on leakage reporting in more recent years; (3) more recent wells using more extensive fracturing (larger fracks, progressively larger number of frack stages) that impart more cyclic loading on the well, leading to a higher annular barrier failure rate. Moreover, Ingraffea et al. (2014) indicate that older wells in Pennsylvania are apparently rarely inspected, skewing the statistical data on well integrity failures for such older wells.

2.3. Well Type, Reservoir Pressure & Re-Pressurization

In order for upward migration of fluids and gases to take place, a leak path, a source and a driving force to surface are needed, as explained in more detail in Appendix A. Without a driving force, upward flow cannot be sustained. Two quotes from King and King (2013) make this point very clearly:

- "*The potential for leaks to the environment may diminish rapidly as the reservoir pressure is depleted. Low-bottomhole-pressure wells do not have the driving force to oppose constant hydrostatic pressure of fluid outside the wellbore; hence, if a leak path is formed through the sequence of barriers, the highest potential is for exterior fluids (usually salt water) to leak into a wellbore. However, if gas leaks into the wellbore, buoyancy will drive it upward toward the wellhead.* "
- "*Most importantly, the pressure inside a completed producing oil or gas well drops constantly during primary production. In oil wells, with little or no gas pressure, the potential for liquids inside well to flow to the outside of the well is sharply reduced considering the outside fluid gradients that increase the outside (leak-opposing) pressure with increasing depth. Gas wells are not affected in quite the same manner. Although decreased pressure in the gas well diminishes the driving pressure, the lack of liquid hydrostatic backpressure allows more pressure near the surface than would be possible in an oil well.*"

These statements indicate that wells intersecting depleted reservoirs may lose the ability to sustain flow to surface, even when the barrier to surface is not intact. This may the reason why the frequency of well failure and SCP/SCVF on older wells is not higher than already observed. Natural Resources Canada (NRCan 2019) indicates that as many as 20% of the older, non-serious leaking wells have ceased leaking without remediation, which could be due to reservoir depletion and/or flowpath plugging (NRCan 2019).

However, the notable exception to this, already mentioned by King and King (2013), are gas and low-density condensate wells. These wells are different, because flow to surface can be driven by buoyancy (i.e., a density contrast driving convective flow), irrespective of residual reservoir pressure. The highest well leakage risk is therefore associated with (older) gas wells. From Williams et al. (2021):

- "*In terms of the well type, gas wells have been shown to emit more methane than oil or combined oil and gas wells.*"

This statement is substantiated by the reported findings of field studies monitoring methane emissions by Kang et al. (2014), Brandt et al. (2014), Boothroyd et al. (2016), Kang et al. (2016), Townsend-Small et al. (2016), Pekney et al. (2018), Williams et al. (2019), Riddick et al. (2019), Schout et al. (2019), Ingraffea et al. (2014, 2020), Zhou et al. (2021) and Lackey et al. (2021); for a comprehensive overview of these studies, see Appendix A. All these publications show that leakage is primarily associated with gas wells. The Alberta Energy Regulator (AER) estimates that 95% to 99% of the SCP/SCVF and GM occurrences in Alberta, Canada are associated with methane gas (NRCan 2019).

This methane gas may be of "thermogenic" origin if it comes from deep oil and gas reservoirs where the gas finds a leak path through the barriers to surface, or of "biogenic" origin. In the latter case, the gas is generated at shallower depths by micro-organisms, and this gas can find a way to surface through the conduit of a well leakage pathway associated with the well's shallow outer annuli. The situation is complicated by the fact that "thermogenic" gas observed at surface is not always an indication that leaking oil or gas wells are the culprit: the gas might have found a way to surface through natural pathways such as faults and fractures through caprock. Neither does the observation of "biogenic" gas mean that leaking oil and gas wells are not involved, given that compromised shallow annuli of these wells could provide a leak path for the biogenically generated gas to reach surface. More details are given in Appendix A.

One important observation of nearly all studies is that leakage rates are not uniform across sets of wells found to leak in the field: some wells (called "super-emitters", leaking more than 300 m^3 CH_4/day) leak disproportionally more than other wells and tend to skew the average values for the datasets. Examples are given in Appendix A, where the topic is discussed in further detail.

Special care is to be taken when depleted reservoirs re-pressurize naturally (e.g., by subsurface fluid flows) or when artificially re-pressurizing previously depleted reservoirs, which may have lost the ability to sustain flow to surface but can regain this ability due to reservoir re-pressurization, or when crossflow between wells is induced, e.g., by connecting waste injection wells with leaking abandoned wells through subsurface fractures. Such scenarios become relevant when practicing (Oil and Gas UK 2015):

- Natural gas storage in depleted reservoirs
- Water- / CO_2 flooding for reservoir pressure maintenance and enhanced oil recovery (EOR)
- Waste-water injection
- Reservoir re-fracturing
- CCS/CCUS - CO_2 storage in (depleted) oil and gas reservoirs

CO_2 storage using old wells as injectors or in reservoirs intersected by old wells is a particularly significant risk for the future. This is because of the considerable amount of attention given to the topic presently, and secondly because CO_2 under certain condition can deteriorate both steel casings through corrosion as well as Portland cement barriers that are of low quality and not properly formulated chemically to deal with CO_2 attack. These risks need to be taken explicitly into account when considering the re-use of old wells and depleted reservoirs for CO_2 storage. From King and Valencia (2014):

- *"The advancement of the idea to store CO_2 in depleted oil and gas reservoirs has brought new challenges and new concepts to well integrity both before and after abandonment. <u>Large scale studies of wells prior to CO_2 storage have illustrated a potential for leaks in abandoned wells if the reservoirs are re-pressurized by CO_2. Fields that have been highly developed with infield drilling and especially with older completion methods may be poor candidates for injection, repressuring and storage of CO_2.</u> CO_2 also presents a corrosion challenge that will need to be addressed. Well designs for CO_2 storage are available and safe but the older wells may pose a problem."*

At the time this report was compiled, there was a high-profile case in Texas, USA, involving an old well leaking to surface because of induced crossflow with a waste injection well (see Bussewitz and Irvine 2021). The leaking well had not been leaking prior to being "re-energized" by the waste injection in the injection well, with fluids and associated chemicals finding a path of least-resistance through the subsurface to the "sink" presented by the leaking well.

2.4. Cyclic Loads during Well Lifetime

Cyclic loads imparted on the casing and cement during its lifetime, including drilling/well construction, stimulation and completion, production or injection phases, can be a significant risk factor for well leakage. Depending on the type of well, operations will impose occasional or cyclic pressure and/or thermal stresses at various magnitude and frequency. Pressure increases in the well (e.g., during pressure testing of casing) and/or temperature elevation (e.g., after a bringing a well on production) will cause casing expansion with associated compression of the cement behind it. This increase in radial compressive stress and reduction of tangential stress can fail the cement in tension and lead to radial stress cracks in the cement sheath that could become conduits for the migration of fluids and gas (Goodwin and Crook, 1992; Ravi et al., 2002, see **Figure 2.3**). Lowering pressure and lowering temperature (or actively cooling) the casing leads to the inverse effect, i.e., casing contraction with a reduction in radial stress (Todorovic et al. 2016). The consequence of this could be debonding of the cement from the casing, leading to the development of a micro-annulus that can serve as a leak path for upward migration of fluids and gases (Dusseault et al., 2000; Zhang and Bachu, 2011; Dusseault and Jackson, 2014) – see also Section 3.3. The likelihood of damage to the cement and cement-casing interface goes up with the number of occurrences or cycles experienced by the casing-cement system, and their amplitude (i.e., the magnitude of the temperature / pressure variation, see for instance Kuanhai et al. 2020).

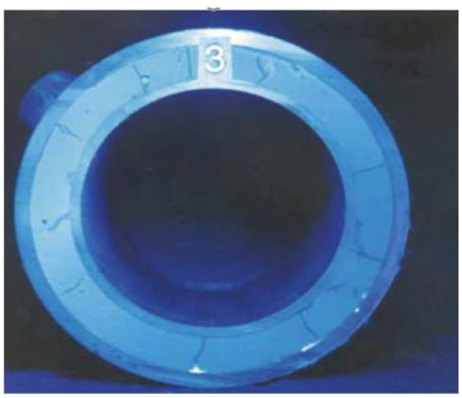

Figure 2.3 – Radial cracking of cement in response to cyclic loads. Image adopted from Watson et al. (2002). Copyright Society of Petroleum Engineers (SPE), reproduced by permission.

Certain wells and wellbores are more at risk than others (Dusseault et al. 2000). Wellbores used for injection associated with waterflooding and enhanced oil recovery operations, which involve operations with large cooling cycles, are particularly vulnerable to leakage. Statistics from Canada show that thermal recovery wells (e.g., cyclic steam and steam injection wells) which experience large temperature changes and associated "thermal shock" (Bour 2005) exhibit disproportionally high leakage rates (Bachu 2017).

During well completion and production stages, stresses change frequently due to dynamic loading, temperature variations, casing perforation, hydraulic fracturing, pressure testing, changing flow rates and shutting in wells (Vignes and Aadnoy 2010, Lecampion et al. 2011, Davies et al. 2014, Nygaard et al. 2014, Barreda et al. 2018). Hydraulically fractured wells with many frac stages expose the well to both high pressures and pronounced cooling cycles associated with high-rate water and proppant injection. The likelihood for the formation of micro-annuli and stress fractures in the cement increases significantly for these wells because of the considerable loads on casing and cement involved (Watson and Bachu 2008). As an example, Ingraffea et al. (2014, 2020) identified elevated well failure rates among unconventional, hydraulically fractured horizontal shale wells compared to conventional wells in the state of Pennsylvania.

Cyclic loads are well-understood to be a leading cause of well integrity problems and thereby well leakage. According to King and Valencia (2013):

- "*In general terms, well construction problems can be caused by leaking pipe connections, inadequate cementing, corrosion, cyclic loads, thermal extremes, Earth stresses, abrasion, and other factors.*"

The effect of cyclic loads on well integrity has been extensively studied in laboratory investigations (Boukhelifa et al. 2005, Teodoriu et al. 2008, Shadravan et al. 2014a&b, De Andrade et al. 2015, Manceau et al. 2015, Shadravan et al. 2015, Vrålstad et al. 2015, De Andrade et al. 2016, Todorovic et al. 2016, Vrålstad et al. 2016, Therond et al. 2017, De Andrade et al. 2019, Vrålstad et al. 2019, Zeng et al. 2019, Wu et al. 2020, Zhao et al. 2021) and modeling work (Singh et al. 2017, Wang and Taleghani, 2017). An overview of this work is given in Appendix B. These studies have clearly shown that cyclic loading is the main cause behind the formation of micro-annuli at casing-cement and casing-formation interfaces, and of tensile cracking of the cement itself. Lab studies and field work have also shown that casing-cement system of wellbores needs to be specifically designed to be able to withstand cyclic thermal and mechanical/hydraulic loading. If the casing-cement system is unable to adapt to changing conditions, it will fail in response to cyclic loading (Thiercelin et al. 1998, Bosma et al. 1999, Ravi et al. 2002a&b, Watson et al. 2002, Boukhelifa et al. 2005, Bellabarba et al. 2008). There is consensus among cementing experts that a flexible, plastically deforming cement with a relatively low compressive strength, high tensile strength and high tensile-to-compressive strength ratio is better equipped to handle cyclic loads that a high-compressive strength, hard-brittle cement (Goodwin and Crook 1992, Bour 2005, Nelson and Guillot 2006). Moreover, the tensile strength of cement can be increased artificially, e.g., by the incorporation of fibers (van Vliet et al. 1995, Giesler and Schubert 2019, Yang et al. 2020). An inherent weakness of ordinary Portland cements (OPC), however, is the relatively low shear bond strength between casing and cement, which is typically in the range of only 100 – 200 psi (0.7 – 1.4 MPa) even when using bonding agents (Evans and Carter 1962, Ladva et al. 2004, Khalifeh et al. 2018, Kamali et al. 2021). When the casing-cement shear bond fails in response to cyclic loading, debonding happens and a micro-annular leak path will be formed.

Special care is to be taken in future when considering the re-use of old wellbores for injection purposes (e.g., re-injection of waste material, for waterflooding / EOR purposes, for storage of CO_2) or for geothermal well purposes (Pilko et al. 2021). The new operation of injection of cold fluids (such as CO_2 at very low temperatures, leading to Joule-Thompson cooling, see Oldenburg et al. 2007 and Todorovic et al. 2016) or production of hot fluids may expose these wellbores to cyclic pressure and temperature loads that they have never experienced before and which they may not be equipped to handle (e.g., because of limitations of their original cement designs), creating potential well integrity issues and associated leakage problems.

2.5. Elevated Temperature

The risk of temperature cycling, i.e., repetitive heating and cooling cycles, was discussed as a risk factor in Section 2.4, but absolute temperature by itself should be considered a risk factor for well integrity failures and well leakage as well. To use the quote by King and Valencia (2013) once more:

- "*In general terms, well construction problems can be caused by leaking pipe connections, inadequate cementing, corrosion, cyclic loads, thermal extremes, Earth stresses, abrasion, and other factors*."

The image in **Figure 2.4** was presented by King and King (2013) comparing the relative risk of well integrity failure for different well types. The wells with the highest risk of well failure are fire flood wells, cyclic steam injection wells, and HPHT wells, i.e., all wells encountering highly elevated peak temperatures during their lifetime. According to King and King (2013):

- *The oldest producing wells, for example, are more than a century old and many have not leaked, while high-pressure, high-temperature (HP/HT), thermal-cycled, and corrosive-environment wells may have a well life of a decade or less before permanent plugging and isolation is required*."

This view on risk is substantiated by findings by Bachu (2017) in Canada, showing that of the 3276 wells with recorded GM in Alberta, close to half (45.9%) were thermal wells, with the balance being conventional wells (which are drilled at a much higher volume). The high failure risk for such wells derives from a combination of temperature cycling and high absolute / peak temperatures. Note that high absolute temperatures exacerbates the impact of load cycling (Yuan et al. 2013).

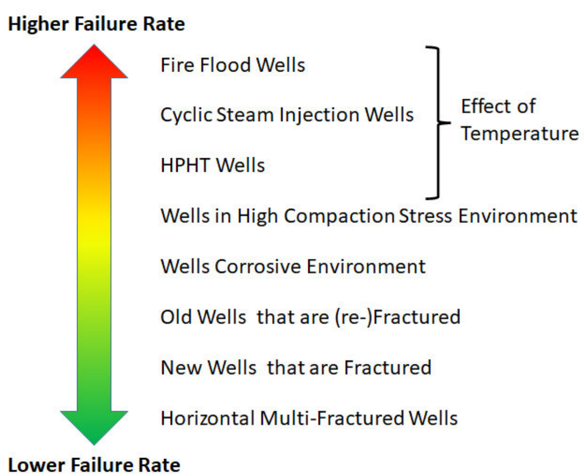

Figure 2.4 – graphical representation of relative failure frequency by well type, according to King and King (2013). Note that the top 3 categories all relate to wells with elevated temperature and/or temperature cycling. Note that some of the other risk factors are included in this visual representation as well, such as corrosion ("corrosive environment"), geomechanical loading ("high compaction environment"), and old wells being re-fractured. Copyright Society of Petroleum Engineers (SPE), reproduced and modified by permission.

The chemical/mineralogical changes of cement at elevated temperatures over time have been extensively studied (Saunders and Walker 1954, Eilers and Root 1976, Eilers and Nelson 1979, Nelson et al. 1981, Eilers et al. 1983, Krilov et al. 2000, Fabienne et al. 2002, Le Saout et al. 2006a&b, Kutchko et al. 2007, 2008 & 2009, Lin and Meyer 2009, Sauki and Irawan 2010, Salim and Amani 2013, Deshner et al. 2013, Omosebi et al. 2015). Eilers and Root (1976) were the first to address the issue of cement strength retrogression at high temperatures, which was addressed by adding silica (fine silica sand or silica flour) to stabilize high temperature cement formulations (Eilers and Nelson 1979). This led to the development of more stable formulations for geothermal wells (Nelson et al. 1981) and the development of cement formulations for steamflood and fireflood wells (Nelson and Eilers 1983). Eilers and Nelson (Eilers et al. 1980) were also the first ones to elucidate the complicated mineralogical changes that cement can undergo at high temperatures with the formation of pectolite, scawtite, truscottite, or xonotlite crystalline cement phases. Each of these phases has its own strength and permeability characteristics, with a tendency towards lower strength (i.e., strength retrogression) and higher permeability[3]. It suffices to say here that the high temperature transformation of OPC cement with added silica is anything but trivial and not entirely predictable. Moreover, cement phase transformation continues throughout the life of the well, including the plugging and abandonment phase (Omosebi et al. 2015). Work by Reddy et al. (2016) indicates that even with addition of silica there remains continued strength retrogression of Portland cement at elevated temperatures, which not only affects its mechanical strength but also its permeability, which is increased. There is still very little known about how this will affect cement plug and sheaths in high temperature abandoned wells over prolonged periods of time. There is information of cements samples recovered from wells that are several decades old (e.g., Carey et al. 2007, Beltrán-Jiménez et al. 2021, Skadsem et al. 2021) showing good stability of the cement unless degraded by chemical attack, but it is currently not yet possible to extrapolate to longer timeframes (hundreds/thousands of years), especially not for HPHT environments. A classification of normal and HPHT subsurface temperature and pressure regimes is given in **Figure 2.5** (note that the major service providers Baker Hughes, Halliburton and Schlumberger all have slightly different definitions of what constitutes a HPHT, Ultra-HPHT or Extreme HPHT environment, see Shadravan and Amani 2012).

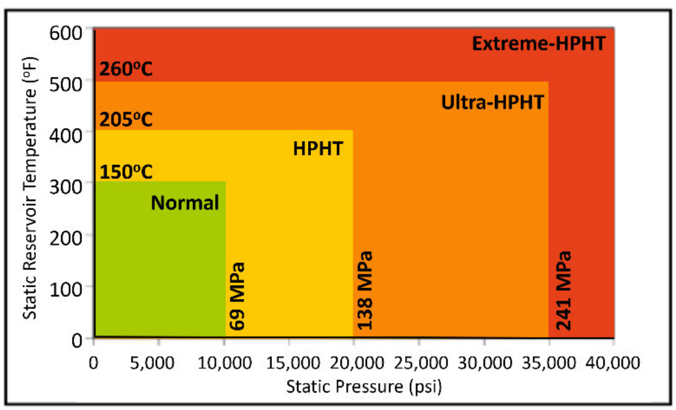

Figure 2.5 – Classification of normal, HPHT, Ultra-HPHT and Extreme HPHT downhole pressure and temperature environments, using the classification according to Schlumberger (from Shadravan and Amani 2012). Copyright Society of Petroleum Engineers (SPE), reproduced and re-drawn by permission.

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[3] *see Omosebi et al. 2015 and references therein for a description of the transformation of calcium silicate hydrate (tobermorite and C-S-H gel) to more stable crystalline phases at elevated temperature. For a more detailed discussion on how this work has influenced modern cement designs and alternative non-Portland cement designs, see Nelson and Guillot (2006).*

Distinctive mineralogical change of cement at elevated temperature is an important reason why testing at elevated temperature cannot be used to artificially "age" cement samples at an accelerated pace to get a better view on the behavior of cement over long time periods (i.e., hundreds to thousands of years). The mineralogical changes that occur at high temperature, as described above, simply would not occur at lower temperatures, even over prolonged time periods. Quotes from "Guidelines on Qualification of Materials for the Abandonment of Wells" (Oil & Gas UK 2015) that relate to this important fact are:

- *It should be stressed that caution should be employed when interpreting extrapolated results of this type (i.e., ageing tests conducted at elevated temperature – EVO), and such results should be viewed, at best, as indicative.*
- *<u>The use of accelerated temperatures to produce accelerated ageing is not suitable for Portland cement</u> and should be assumed to be unsuitable for other materials unless proving otherwise is available.*

There are additional well integrity risks associated with wells at high absolute temperature environments, encountered in HPHT and thermal recovery wells, that can have consequences for leakage during the well abandonment phase:

- Trapped annular pressures (TAP, see Oudeman and Bacarezza 1995, Oudeman and Kerem 2006) can occur when fluids trapped in uncemented or incompletely cemented spaces behind casings of HPHT wells expand under the influence of temperature, potentially damaging cement sheaths, casing strings and their connections.
- Imrich et al. (2016) considered the well integrity of thermal recovery wells, including Cyclic Steam Stimulation (CSS, also known as "Huff and Puff"), Steam-Assisted Gravity Drainage (SAGD, or "Steam-Soak"), Vapor Assisted Petroleum Extraction (VAPEX), Continuous Steam Injection and In-Situ Combustion. They looked specifically at specific well integrity issues associated with the surface casing and its cementation, issues caused by low slurry density requirements and original low-temperature environment during primary cementing without specific ability to handle higher temperatures and associated thermally induced cement degradation as well as high thermal cycles during production.
- Thermal expansion of casing can lead to casing / liner buckling and associated casing / liner deformation, with associated risks to casing / liner integrity and the wider well integrity.
- HPHT environments often present combined risks of both elevated temperature and presence of acid gas (H_2S, CO_2) and/or corrosive brines (Krilov et al. 2000, Aiex et al. 2015, Omosebi et al. 2015 & 2017, Mainguy et al. 2019) or complicated geomechanical conditions (Ravi and Hunter 2003, Heathman and Beck 2006, Teodoriu et al. 2013, Yuan et al. 2013, De Gennaro et al. 2017), increasing the well integrity challenge during the productive life of the well and after abandonment. See also Section 2.9.

Finally, it is important to note that HPHT wells are also more difficult to abandon. In the "Guidelines for the Abandonment of Wells", Oil and Gas UK (2018) state the following:

- *The placement and numbers of barriers (…) apply to the temporary abandonment or (permanent) abandonment of HPHT wells. With the increased complexity and criticality of these wells, there should be special emphasis on recharging to high pressure, caprock depletion, thin pressure transition zone, liner deformation, temperature cycling, <u>primary cement degradation due to high temperature</u>, reservoir compaction and subsidence, etc.*

2.6. Geological/geomechanical factors

Geological and geomechanical influences on the well are recognized as a lead cause of well integrity failures, which is well-recognized in open literature. To refer again to King and Valencia (2013):

- "*In general terms, well construction problems can be caused by leaking pipe connections, inadequate cementing, corrosion, cyclic loads, thermal extremes, <u>Earth stresses</u>, abrasion, and other factors.*"

Well shear, usually observed as casing deformation, is deformation of the well due to localized geomechanical shear slip that intersects the well (Ewy 2021). Formation bedding planes, faults and natural fractures are typical slipping surfaces at which well shear occurs. Compacting (or inflating) conventional reservoirs can trigger shear deformation in overburden formations and at reservoir/caprock interfaces. Overviews of well shear and associated casing deformation problems are provided by Bruno (1992, 2001, 2002), Dusseault et al. (2001) and most recently Ewy (2021). Field observations come primarily from the USA (California, Gulf of Mexico and Texas, see Frame 1952, McCauley 1974, Hilbert et al. 1999, Dale et al. 2000, Fredrich et al. 2000, Li et al. 2003, Yuan et al. 2013) and North Sea (Kristiansen et al. 2000, De Gennaro et al. 2017, Yuan et al. 2018), but the problem occurs worldwide. A particularly well-known case in the North Sea involves the reservoir compaction and subsidence problems at the Ekofisk prospect (Schwall and Denney 1994, Schwall et al. 1996). Most recently, casing shear problems have also been reported in unconventional shale reservoirs in Argentina (Rimedio et al. 2015), Canada (Meyer et al. 2018) and China (Casero and Rylance 2020). **Figure 2.6** shows casing deformation examples from the field.

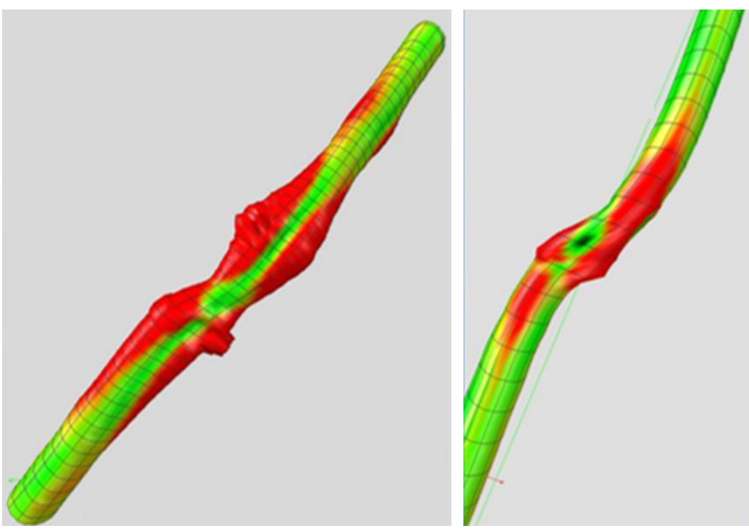


Figure 2.6 – Examples of casing image logs showing (left) casing edging and (right) casing shear as a result of geomechanical loading of casing. Images courtesy Trent Kaiser, Noetic Engineering, reproduced by permission.

Reservoir compaction and subsidence can damage both casing and cement. Dusseault et al. (2001) indicate that the dominant casing deformation mechanisms are localized horizontal shear at weak lithology interfaces in the overburden formations (Hamilton et al. 1992), localized horizontal shear at the top of production and injections intervals, and axial compression with casing buckling in the production interval, primarily near perforations. Shear stresses can also lead to rupturing of weak cement-casing and cement-formation bonds and fracturing of cement, creating micro-annuli and fracture channels (Jinnai and Morita 2009, Um et al. 2014a&b). The damage is not limited to the annular cement sheath, and the detrimental effect of reservoir deformation on cement plug integrity has been studied by Mainguy et al. (2005, 2007), Willis et al. (2019), and Arjomand et al. (2021).

In addition, reservoir depletion and compaction, as well as re-pressurization and inflation, can lead to fault (re-)activation and associated seismicity (Frame 1952, Zoback et al. 2001, Zoback and Zinke 2002, Yuan et al. 2013). Slip on faults and associated earthquake events are high-energy events that can significantly damage the well integrity of both producing and abandoned wells. A recent study by Kang et al. (2019) analyzing geospatial data of 579,378 oil and gas well and 196,315 earthquake events (magnitudes greater than 1.0) occurring at locations in Oklahoma, California, and British Columbia, showed overlapping clusters in these three states. The authors argue for the need to investigate the role of earthquakes on wellbore leakage through additional analysis of earthquake characteristics, wellbore attributes, and empirical field studies of oil and gas well leakage, including abandoned wells.

Highly creeping formations and formations in active tectonic areas can cause casing collapse failures, particularly on improperly cemented sections, through point-loading. The problem is well-known for fast-creeping members of the Zechstein salt formation (see Bacaud 2004, Kriesels 2004), and has been observed in the tectonically active area of the foothills of Columbia (Last 2002). Proper cementation of casing can shed loads on casing and provide considerable relief against casing collapse (Last 2002, Jammer et al. 2015), but in its absence the unbalanced loads provided by fast-creeping or tectonically activated formations on casing may first lead to ovalization and subsequently to full-scale collapse, with associated loss of well-integrity. Note that more controlled creep leading to more uniform loading of the casing by creeping formations can be very beneficial – and can be actively exploited – for “shale/salt as a barrier” purposes, discussed in more detail in Section 3.4.

The general recommendation for maintaining well integrity over extended time periods is to strengthen the casing as much as possible and to guarantee a fully cemented annulus. Preferably, the cement should exhibit good plastic / ductile behavior and flow / creep easily under applied stress to provide the necessary casing support and avoid casing point-loading (Nelson and Guillot 2006). Given the long timescales involved in well abandonment and the ever-changing geologic and geomechanical environment, it is clear that the impact of the geologic environment and geomechanical well loading should be considered a prominent risk factor during the well abandonment phase.

2.7. Chemical Factors – Casing Corrosion & Chemical Cement Degradation

Adverse chemical interactions at downhole pressure and temperature can corrode casing and degrade cement, jeopardizing the ability of casing and cement to continue their function as barriers during the productive life of the well and the well abandonment phase. The issue of casing corrosion will be discussed in more detail in Section 3.2, with focus on chemical cement degradation here. Chemical degradation of concrete has been very well-studied in the civil engineering literature, given the importance of concrete in the construction industry. For excellent comprehensive reviews, see Scrivener and Young (1997), which also deals with steel corrosion in construction operations, and Glasser et al. (2007). Detailed information on oilfield cement degradation under the influence of chemistry can be found in Nelson and Guillot (2006). What follows are some of the main mechanisms by which oilfield cements can degrade in the subsurface.

Sulfate attack and resistance.

Downhole brines containing sodium sulfate and magnesium sulfate can react adversely with cement hydration products. These sulfates can react with precipitated calcium hydroxide (Portlandite) to form magnesium hydroxide ($Mg(OH)_2$), sodium hydroxide (NaOH) and calcium sulfate (gypsum, $CaSO_4$), e.g. (Nelson and Guillot 2006, Glasser et al. 2008, Schwotzer et al. 2016):

$$Ca(OH)_2 + MgSO_4 + 2H_2O \rightarrow CaSO_4.2H_2O + Mg(OH)_2$$

$$Ca(OH)_2 + Na_2SO_4 + 2H_2O \rightarrow CaSO_4.2H_2O + 2NaOH$$

In the first reaction, swelling occurs due to the replacement of $Ca(OH)_2$ by $Mg(OH)_2$ which can lead to strain within the material and associated strength loss. In the second reaction, an increase in cement porosity occurs because NaOH is much more soluble than $Ca(OH)_2$. The calcium sulfate can in turn react with aluminates to form ettringite ($[Ca_3Al(OH)_6.12H_2O]_3.(SO_4)_3.2H_2O$), thaumasite ($Ca_3[Si(OH)_6.12H_2O]$ .CO3.SO4), and mixtures of these phases. The associated expansion (e.g., of ettringite) can lead to loss of compressive strength, cement cracking, and damage to tubulars. Cements with lower concentrations of tri-calcium aluminate (C_3A) are less sensitive to sulfate attack after setting, and the impact of sulfate attack is reduced above 140°F due to reduced solubility of magnesium sulfate and sodium sulfate above this temperature. The severity of sulfate attack can be substantially reduced by addition of pozzolans (e.g., fly ash, slag) to the cement mix, see **Figure 2.7**.

Decalcification.

Decalcification is the slow process of dissolution of portlandite and the gelatinous calcium silicate hydrate (C-S-H) phase in the cement. It involves the leaching of calcium and hydroxide ions from the pore solution to the external environment, particularly upon long-term exposure of the cement to freshwater and acidic pore fluids over prolonged periods of time (Dow and Glasser 2003). The consequences of such ionic leaching over time are an increase of porosity and permeability as well as a loss of mechanical strength.

Figure 24 Effect of cement exposure to magnesium brine (20 day exposure at 120°C and atmospheric pressure).

Top figure, samples left to right:

(1) original Class G cement;
(2) Class G after exposure;
(3) Class G + Halad D after exposure; (4) Class G + silica flour after exposure

Bottom figure, samples left to right (all samples after exposure) :

(1) Slag-mix + sand ;
(2) Slag-mix;
(3) PozMix 140 A;
(4) PozMix 80

Slag-mix = 30% portland cement clinker + 70% blast furnace slag with calcium sulphate additive

Figure 2.7 – Significant difference in response of (top) Portland cement samples, and (bottom) blast furnace slag and pozzolan-based samples to exposure to magnesium brine for 20 days at 120°C. Images and data courtesy Shell Research.

Chloride penetration.

Penetration of chlorides into undamaged cement, driven either by capillary action, diffusion driven by a chemical potential gradient, permeation under pressure or transport driven by electrical potential gradients (Bavarian et al. 2018), does not appear to readily lead to detrimentally altered solid phases that can cause expansion of cracking (Glasser et al. 2008). Chlorides can react with aluminate phases to form Friedel's salt ($3CaO.Al_2O_3.CaCl_2.10H_2O$), but this does not appear to jeopardize important cement properties such as strength and permeability. The concern revolves primarily around chlorides reaching the casing and destroying the iron oxide layer that protects the casing from corrosion (Bavarian et al. 2018). The concerns about chlorides usually extend to other halides as well, and casing corrosion problems have been noted recently with $CaBr_2$ as well (Skadsem et al. 2020, Beltrán-Jiménez et al. 2021).

Acid attack: H_2S, CO_2 and associated carbonation.

A considerable body of published research is available on the interaction of cement with CO_2 due to the interest in downhole carbon CO_2 storage (see Appendix B for an overview). Penetration of CO_2 into intact bulk cement initiates a series of reactions involving both ions dissolved in the cement pore solution as well the hydrated cement itself. Carbonate ions formed from the dissolution of CO_2 can react with Ca^{2+} to form calcium carbonate ($CaCO_3$) and other carbonate phases, in a process referred to as "carbonation". The drop in pH values associated with these reactions furthermore leads to the dissolution of Portlandite ($Ca(OH)_2$) and calcium-silicate-hydroxide (C-S-H) gel. The basic chemistry is as follows (Bruckdorfer 1986):

Dissolution of CO_2 in water: $CO_2 + H_2O \leftrightarrow H_2CO_3 \leftrightarrow H^+ + HCO_3^-$

Reaction with Portlandite, carbonation: $Ca(OH)_2 + H^+ + HCO_3^- \rightarrow CaCO_3 + 2H_2O$

Reaction with C-S-H gel, carbonation & silicate gel formation:

$$C - S - H\ gel + H^+ + HCO_3^- \rightarrow CaCO_3 + amorphous\ silicate\ gel$$

This carbonation process can become self-limiting when a protective layer of carbonate is formed onto the cement and casing. The drop in pH associated with CO_2 dissolution, however, can have a detrimental long-term effect. The studies into cement-CO_2 interaction show that the deterioration of cement over time progresses only very slowly, as shown in the data compilation by van der Kuip et al. (2011) and reproduced in **Figure 2.8**.

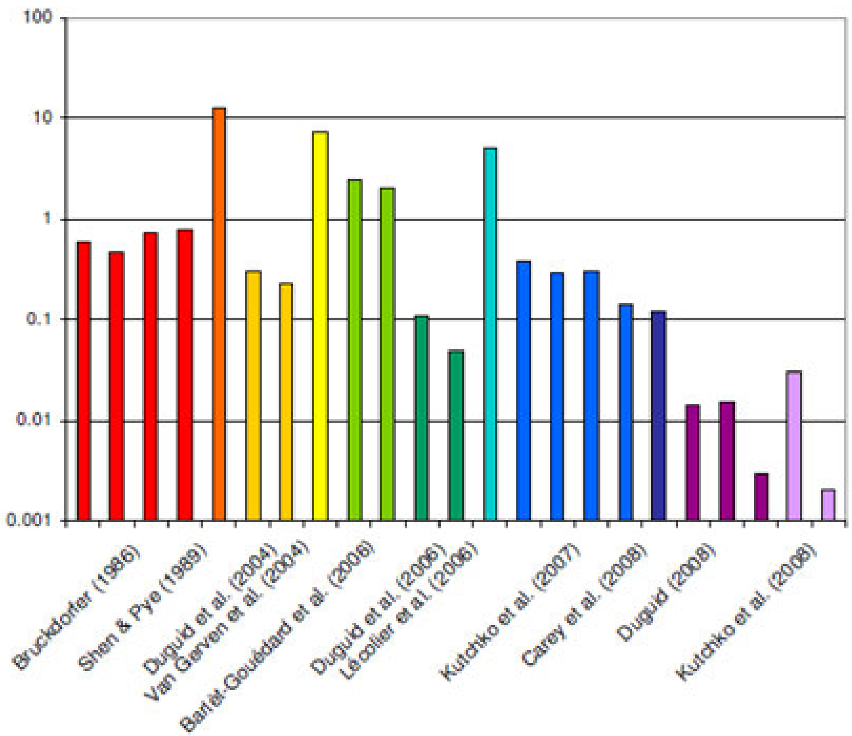


Figure 2.8 - Extrapolated penetration depths of aqueous CO_2 in cement under in situ reservoir conditions after 10,000 years. Overview obtained by van der Kuip et al. (2011) from numerous degradation experiments described in literature [Bruckdorfer 1986, Shen and Pye 1989, Duguid et al. 2004, 2006 & 2008, van Gerven et al. 2004, Barlèt-Gouedard et al. 2006, Lécolier et al. 2006, Kutchko et al. 2007 & 2008, and Carey et al. 2008. Vertical axis is in meters of chemically affected cement. Copyright Elsevier, reproduced by permission.

The analysis by van der Kuip et al. (2011) of a wide range of sources (Bruckdorfer 1986, Shen and Pye 1989, Duguid et al. 2004, van Gerven et al. 2004, Barlet-Gouedard et al. 2006, Duguid et al. 2006, Lécolier et al. 2006, Kutchko et al. 2007, Carey et al. 2008 (published in 2010), Duguid et al. 2008, Kutchko et al. 2008) indicates that only a few meters of cement will be negatively affected over a period of 10,000 years. There is, of course, a large degree of uncertainty when extrapolating to this time period. For instance, chemical cement deterioration may accelerate if the cement sheath or plug gets damaged through other processes, such as geomechanical loading. The discussion on this is postponed until Section 3.2.

While there are numerous literature studies on the interaction of cement with CO_2, there are only a few dedicated to the interaction of cement with H_2S or a combination of CO_2 and H_2S (Krilov et al. (2000), Benge and Dew (2006), Moroni et al. (2008), Lécolier et al. (2008 & 2010), LeNevue (2011), Garnier et al. 2012, Wilkie et al. (2014), Zhang et al. (2014), Vrålstad et al. (2016) and Omosebi et al. (2017)). The general finding is that neat OPC formulations are rapidly and highly damaged by H_2S, leading to profound loss of strength and increase in porosity and permeability. This was attributed to the very acidic environment presented by H_2S in solution, leading to leaching of hydrated cement phases, with total dissolution of Portlandite and severe decalcification of calcium silicate hydrates (e.g., Lécolier et al. 2010). To guarantee the long-term functioning of a cemented barrier exposed to H_2S, either by itself or in combination with CO_2, it is recommended to limit the components in the set cement formulation that can adversely react with the acid gasses (Benge and Dew 2006, Moroni et al. 2008). This can be achieved either by augmenting OPC with significant additions of pozzolan (e.g., 35/65 pozzolan / OPC mixtures, see Zhang et al. 2014, Vrålstad et al. 2016), or use alternative, high-alumina, low-calcium non-Portland cement formulations (Benge and Bow 2006). Use of mineral additions that have a high reactivity with H_2S and can act as sacrificial agents, such as Fe_2O_3 (hematite) and Mn_3O_4 (hausmanite), still resulted in severe cement damage (Lécolier et al. (2007, 2008). This approach requires more study.

In the "Guidelines for the Abandonment of Wells", Oil and Gas UK (2018) reflect on the special considerations for abandonment of wells containing H_2S, CO_2 and magnesium ions as follows:

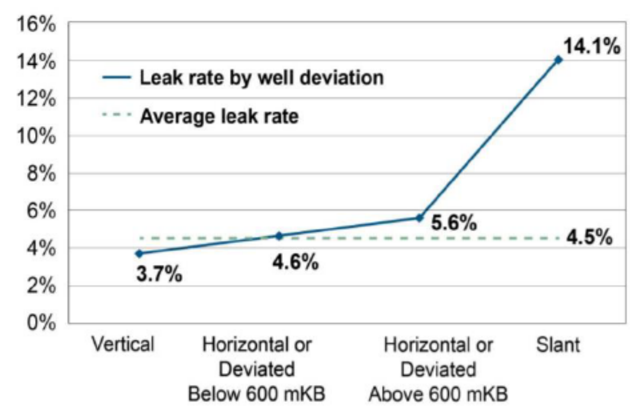
- ***Wells containing H_2S***. *The barriers placed in a well containing H_2S should be chosen and designed to withstand the corrosive environment it is intended to isolate.*
- ***Wells containing CO_2***. *(…) The barriers placed in a well with significant concentrations of CO_2 should be chosen and designed to withstand the potential effects of the gas on cement, and steel components of the well and on subsurface formations. CO_2 may degrade cement in the presence of water, in particular Portland cement, increasing its permeability. CO_2 will also accelerate corrosion of steel and can increase the permeability of subsurface formations, for example by (thermal) fracturing of shales.*
- ***Wells containing magnesium salts***. *Magnesium salts may pose a risk to cement, both during placement and to the long term cement integrity. Magnesium salts may degrade Portland cement, lowering its mechanical strength and increasing permeability. Any cement designs should take into account the presence of zones containing magnesium salts.*

2.8. Well Deviation

Another factor reflecting complexity in well construction is well deviation. The evidence for well deviation as a main risk factor comes from several main sources, with strong field-based evidence from leaking well observations in Canada and the USA. Watson and Bachu (2009) reviewed the statistics of the Alberta Energy Resources Council (ERCB) for more than 315,000 oil, gas, and injection wells in Alberta, Canada, including well leakage data reported at SCVF or gas migration (GM) outside of casing. **Table 2.2** and **Figure 2.9** show the outcome of a study for a reduced set of 20,725 wells. Whereas 9.2% on average of the total number of test wells had SCVF problems, 32% of the deviated wells suffered from these problems, i.e., an increase of a factor more than 3. The difference is even greater for GM problems: 5.7% of test wells suffered from GM problems, but this number increased to 34% for deviated wells, and increase by a factor 6. Other relevant findings from the Watson and Bachu (2009) study are given in Appendix A and B. Subsequent studies by Hardie and Lewis (2015) and Bachu (2017) have confirmed the earlier findings, with additional data for a larger set of wells studied (see Figure 2.9).

Table 2.2 – Comparison of SCVF/GM occurrence in the province of the test area, showing the higher frequency of leakage in deviated wells. Adopted from Watson and Bachu (2009). Copyright Society of Petroleum Engineers (SPE), reproduced by permission.

	Alberta	Test Area	Percentage in the Test Area	Deviated wells in the Test Area
Total number of wells	316,439	20,725	6.5%	4,560
Well with SCVF	12,458	1,902	15.3%	1,472
Wells with GM	1,843	1,187	64.4%	1,550
Wells with GM/SCVF	176	116	65%	-
SCVF percentage	**3.9%**	**9.2%**	-	**32%**
GM percentage	**0.6%**	**5.7%**	-	**34%**
Combined percentage	**4.6%**	**15.5%**	-	**66%**



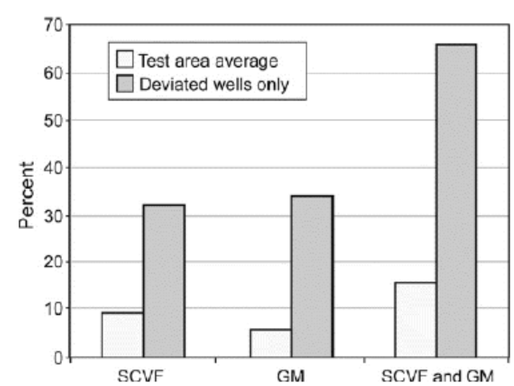


Figure 2.9 – (top and bottom right) Percentage of SCVF and GM occurrences in a test set of 20,725 wells in Alberta, Canada, comparing the statistics for all wells with those obtained for deviated wells only. Adopted from Watson and Bachu (2009). (bottom left) Additional information on wells cemented to surface in Alberta, Canada, suffering from SCVF and GM as a function of well direction by Hardie and Lewis (2015). Increasing deviation correlates with a higher leak rate frequency. Copyright Society of Petroleum Engineers (SPE), reproduced by permission.

Lackey et al (2021) recently published public data on wells with SCVF and/or SCP and potential GM from 3 US states (Colorado, New Mexico, and Pennsylvania). The results comparing statistics for vertical and deviated directional wells are reproduced in **Table 2.3.** For the entire set of evaluated data (105,031 wells) it was found that the frequency of SCVF and/or SCP for vertical wells was 11%, whereas the frequency for deviated directional wells was 30.3%, and increase by a factor ~3. Note that these results are very similar to those obtained by Watson and Bachu (2009). Moreover, the chance of potential GM outside of casing was found to be 1.0% for vertical wells, compared to 3.1% for deviated directional wells, again an increase by a factor ~3. These obvious differences appear to make well deviation one of the most important risk factors for well integrity failure and associated leakage.

Table 2.3 - The total number of tested wells, wells that have exhibited SCP and/or SCVF, and wells that have exhibited a degree of SCP sufficient to potentially induce gas migration (GM) in each state, basin, and region considered, categorized by well orientation. The "Directional Wells" category includes both deviated and horizontal wells, while wells with unknown orientation are included under the "All Wells" category, but are not shown separately. "N/D" indicated no data. Data adopted from Lackey et al. (2021). Copyright PNAS, reproduced under Creative Commons Attribution-NonCommercial-NoDerivatives License 4.0 (CC BY-NC-ND).

	All Wells			**Vertical Wells**			**Directional Wells**		
	Total Tested	SCP and/or SCVF (%)	Potential GM (%)	Total Tested	SCP and/or SCVF (%)	Potential GM (%)	Total Tested	SCP and/or SCVF (%)	Potential GM (%)
Total	105,031	15,130 (**14.4%**)	706 (**1.5%**)	86,547	9,562 (**11.0%**)	385 (**1.0%**)	18,368	5,561 (**30.3%**)	321 (**3.1%**)
States									
Colorado	22,108	4,593 (20.8%)	671 (3.0%)	13,404	2,130 (15.9%)	351 (2.6%)	8,704	2,463 (28.3%)	320 (3.7%)
New Mexico	25,925	2,507 (9.7%)	35 (0.1%)	24,180	2,357 (9.7%)	34 (0.1%)	1,630	143 (8 8%)	1 (0.1%)
Pennsylvania	56,998	8,030 (14.1%)	N/D	48.963	5,075 (10.4%)	N/D	8,034	2,955 (36.8%)	N/D
Basins									
Denver-Julesburg	11,394	3,015 (26.5%)	576 (5.1%)	7,072	1,443 (20.4%)	277 (3.9%)	4,322	1,572 (36.4%)	299 (6.9%)
Permian	2,191	153 (7.0%)	0 (0%)	1,986	135 (6.8%)	0 (0%)	193	18 (9.3%)	0 (0%)
Piceance	4,209	895 (21.3%)	31 (0.7%)	644	195 (30.3%)	12 (1.9%)	3,565	700 (19.6%)	19 (0.5%)
Raton	2,951	9 (0.3%)	0 (0%)	2,941	9 (0.3%)	0 (0%)	10	0 (0%)	0 (0%)
CO San Juan	3,477	666 (19.2%)	64 (1 8%)	2,679	478 (17.8%)	62 (2.3%)	798	188 (23.6%)	2 (0.3%)
NM San Juan	23,708	2,352 (9.9%)	34 (0.1%)	22,174	2,220 (10.0%)	33 (0.1%)	1,435	125 (8.7%)	1 (0.1%)
San Juan	27,185	3,018 (11.1%0	98 (0.1%)	24,853	2,698 (10.9%)	95 (0.4%)	2,233	313 (14.0%)	3 (0.1%)
Pennsylvania oil and gas districts									
Northwest	23,284	2,491 (10.7%)	N/D	22,420	2,390 (10.7%)	N/D	863	101 (11.7%)	N/D
Eastern	9,543	2,117 (22.2%)	N/D	5,214	309 (5.9%)	N/D	4,329	1,808 (41.8%)	N/D
Southwest	24,171	3,422 (14.2%)	N/D	21,329	2,376 (11.1%)	N/D	2,842	1,046 (36.8%)	N/D

It should be noted that the higher risk of well leakage for deviated wells in the dataset by Lackey et al. (2021) may not be entirely due to well deviation alone. Most recent wells in states like Pennsylvania are horizontal shale wells. This raises the possibility that these wells may be experiencing higher leakage rates due to cyclic pressure loads associated with hydraulic fracturing. Even if this were the case, this argument does not apply to the dataset by Watson and Bachu (2009), which covers wells drilled before the shale "revolution" of drilling horizontal wells that are extensively hydraulically fracked.

There are very plausible reasons why well deviation has a negative effect on well integrity causing leakage:

- **Deviated wells are more difficult to drill than vertical wells**, with consequences that can have a "knock-on" effect on cementing and achieving zonal isolation. For instance, in normal stress environments, it is more difficult to stabilize deviated wells. When wellbores break out and enlarge due to instability, they become more difficult to properly cement (e.g., difficulty removing gelled-up mud from enlarged, poor caliper hole during displacement, when annular flow rates reduce significantly in enlarged hole). Deviated wellbores are also more difficult to clean during drilling, such that cuttings and other debris may still be left in the hole when casing is run and cemented, interfering with achieving good zonal isolation. Directional drilling furthermore may generate a tortuous, spiralized wellbore that may be difficult to properly displace during cementing and in which good casing centralization may be difficult to achieve. Casing may deform and buckle during casing running in deviated hole, increasing risk of casing failures and achieving poor zonal isolation, etc.

- **Deviated wellbores are more difficult to cement than vertical wells**. For instance, achieving casing centralization with good stand-off is much more challenging in deviated and horizontal holes, and an eccentric casing string can lead to cement channeling and leaving bypassed mud in the annulus. Casing movement (i.e., rotation (preferred) or reciprocation) which benefits cement displacement becomes more difficult in deviated hole and may not be possible due to casing / liner hanger restrictions. In addition, there are stringent requirements for free water control in the cement formulation to prevent a water channel on the high side of the deviated wellbore, etc.

- **Plug setting is more difficult in deviated hole during the abandonment phase**. Depending on density and viscosity contrasts it may be difficult to hold "balanced" cement plugs in place in deviated hole without the high-density cement "slumping" to the low side of the hole. Current best practices usually dictate the setting of a solid retainer (bridge plug or cement retainer) to serve as a bottom to hold a P&A cement plug in place, but this may not have been practiced during the abandonments of older deviated wells. Hence, it becomes more likely that abandonment plugs in older deviated wells might be leaking (or may simply not be present, as was found in old Canadian wells (NRCan 2019)).

- On the positive side, in recent studies for shales in the North Sea that form annular barriers in the absence of cement, it was found that deviated wells had a higher incidence of such barriers forming successfully than vertical wells. This topic is discussed in more detail in Section 3.4.

In current hole cleaning and extended reach drilling (ERD) practice, it is generally accepted to consider wells with a deviation in the range of 0^{o} – 30^{o} as "near-vertical wells", while the wells drilled at 30^{o} – 90^{o} are "high-deviation" wells. Following this convention, which is well-supported by physics, we will consider near-vertical wells as "low risk" and high-deviation wells as "high risk" from a well leakage perspective (see Chapter 4).

2.9. Combination of Risk Critical Factors

The presence of more than one significant risk factor can compound the risk of well integrity failure during the well's life cycle, including the abandonment phase. This is the case when combined loads are acting on the casing-cement system (Ichim et al. 2016), either at the same time or sequentially in time (for instance, when cyclic loading causes damage to the cement sheath that allows CO_2 and H_2S to migrate at later stages to further deteriorate the cement sheath and the casing to exacerbate the leakage rate). According to the DNVGL-RP-E103 recommended practice (DNV 2020), Section 4.2.2:

A permanent well barrier may consist of any material or combination of well barrier elements (WBEs) as long as it provides the following functionalities:

- *withstand the <u>maximum anticipated combined loads</u> to which it may be subjected*
- *function as intended in the environments (pressures, temperature, fluids, mechanical stresses) that may be encountered*
- *prevent unacceptable flow between zones / formations downhole (including water-bearing)*
- *prevent unacceptable hydrocarbon flow to the external environment*
- *remain robust and reliable for long-term integrity.*

Examples of combined loads, which result in compounded risks of well integrity failure, are:

- HPHT conditions and the presence of geomechanical loads acting upon the cement-casing system (Teodoriu et al. 2013, De Gennaro et al. 2017, Mainguy and Innes 2019).
- HPHT conditions and the presence of corrosive gases and brines (Shen and Pye 1989, Krilov et al. 2000, Lécolier et al. 2010, Aiex et al. 2015, Omosebi et al. 2015, Omosebi et al. 2017).
- HPHT conditions and cyclic pressure / temperature loading (Ravi et al. 2003, Yuan et al. 2013, Ichim et al. 2016).
- Wells that have experienced significant cyclic loading leading to the formation of a micro-annulus, in the presence of corrosive gases and brines that can deteriorate casing and cement.
- High-deviation wells in challenging environments with HPHT conditions and complex geomechanical environments (Salim and Amani 2013, de Andrade and Sangesland 2016).
- High-deviation wells with eccentric casing having experienced significant cyclic loading, such as hydraulically fracture wells with many frac stages (De Andrade et al. 2014, Shadravan et al. 2015, Vrålstad et al. 2019).

If such conditions exist at abandoned well sites, it is prudent to pay additional attention to well integrity and leakage because of increased risks. When performing risk analysis with qualitative scorecards (see Chapter 4) it is proposed to weigh situations with combined loads proportionally higher. This can be done by recognizing situations with combined risk factors as a separate risk factor (as is done here), or alternatively by weighing the risks of individual risk factors higher if high risks occur concurrently.

2.10. Additional Risk Factors

In their extensive study of leakage of wells in Alberta, Canada, Watson and Bachu (2009) identify several additional risk factors not mentioned earlier in this report. Whether these factors are of importance to abandoned wells in the Netherlands can only be determined if more data, and particularly leakage data (i.e., field observations of SCP/SCVF and GM), becomes available for these abandoned wells. Anticipating that such data may become available at some point in the future to test the relevance of these additional risk factors, they are included here for completeness with a brief description.

- **Geography & well density**. Leakage problems were found by Watson and Bachu (2009) to be more likely in certain geographic areas, and with higher well densities. It is likely that this geographic variation in well leakage is caused by underlying geological factors, as suggested by Saponja (1999) and Dusseault et al. (2014), as well as associated well construction differences. The correlation with higher well density may be caused by crossflow between wells during reservoir re-pressurization, e.g., when EOR waterflooding is practiced (Dusseault et al. 2014).
- **Fluctuations in oil price ("boom and bust" cycles), changes in regulatory environment**. It might be expected that during periods with low oil-prices there is less attention paid to well integrity and/or that well integrity could be compromised by operator cost-cutting measures. Watson and Bachu (2009), however, found quite the opposite trend for their Canadian wells, where high oil prices correlated with higher failure rates. This was attributed to lower availability of necessary materials and equipment (and probably human resources that were spread too thin during periods of high well construction activity). Stricter regulatory enforcement correlated with lower failure rates.
- **Non-cased vs. cased hole, use of bridge plugs**. Watson and Bachu (2009) and Nygaard and Lavoie (2010) found that wells that were drilled but not cased had lower failure rates during abandonment than wells there were cased. Apparently, abandonment plugs work better when set in the open hole sections of non-cased wells than when having to rely on cement plug integrity inside the casing and cement sheath integrity in the annulus for cased wells. Note that cement will generally bond better to formation than to casing, and that the formation of a micro-annulus at the casing-cement annulus is a regular occurrence in cased wells (Ladva et al. 2004, Nelson and Guillot 2006). Cast iron bridge plugs with nitrile elastomers were found to rapidly degrade and become non-sealing during abandonment due to degradation of the elastomer seals and corrosion of unprotected steel. Wells that were abandoned with bridge plugs only (no cement) had very high rates of failure and leakage.
- **Operator / licensee.** Watson and Bachu (2009) found that it mattered which party drilled, operated and abandoned the well. Some operators were apparently better / more diligent than others when it comes to well P&A excellence. Such variation in operator performance can be mitigated by having very clear regulatory expectations that need to be met by all operators.

In addition, there may be other factors to consider:

- **Well abandonment complexity.** This appears to be a logical risk factor candidate, but probably difficult to prove without having more data from a range of abandoned wells with different complexities available. Moreover, given the advances in abandonment technology in recent years, it is expected that current P&A operations are probably very reliable despite their complexity. For a definition of well abandonment complexity, see Oil and Gas UK (2018).

- **Identification of micro-annulus and other flow paths using bond logging**. As discussed in more detail in Section 3.3, a micro-annulus is an important leak path for fluids and gases to surface. With the continued improvement in cased hole cement bond logging technology (Combs et al. 2014, Zhang et al. 2019, Govil et al. 2020, Kristiansen et al. 2021), new developments in spectral noise logging (Gardner et al. 2019), fiber-optic cement measurements (Wu et al. 2017, Raab et al. 2019), a new proposed annular verification tool (De Andrade et al. 2019), new cement formulations with the ability to probe for well integrity (Nair et al. 2017, Pollock et al. 2018) as well as new logging interpretation methods and workflows (Issabekov et al. 2017, Kalyanraman et al. 2017, 2021) it is becoming possible to identify the presence of micro-annuli and other flow paths in annular spaces with a high degree of certainty. If a positive identification of a continuous flow path can be made using these techniques, then this will evidently identify a risk of well leakage during abandonment. However, such a positive identification should also trigger remedial action to plug the leak path using chemical, biological or physical means (such as the use of resins/silicates, biological agents, casing expansion – see Appendix A). It therefore remains to be seen if leak path identification will actually prove to be a risk factor for well leakage, or will actually correlate with lower leakage frequencies due to the pro-active remedial action taken.

3. Second Stage Questions and Answers

This Chapter contains answers to Stage 2 questions, with accounting of source material and additional details given in Appendix C.

3.1. Question 2 – Cement Permeability

Question 2. *Cement is known to have low permeability; how permeable for the fluids that concern us (gas, oil, water)? How does the permeability of oilfield cement change over a long period of time (e.g., 100 to 500 years) and how does the change affect its sealing effectiveness?*

Answer.

General. *Cement permeability is typically below 100 μD (0.1 mD ~ 10^{-16} m^2) for gas, and below 10 μD (0.01 mD ~ 10^{-17}m^2) for water/brine and oil. If the cement sheath or plug is intact, there is minimum / negligible leakage through the cement matrix at such low permeabilities. Permeability does scale with porosity and density – the higher the porosity and the lower the density of the cement, the higher the permeability. The permeability of intact cement appears to be very stable over time: little change has been observed in lab experiments and field observations conducted over the timespan of a few years to several decades. However, there is currently no way to reliably extrapolate to a time period of 100 – 500 years; attempts to accelerate the ageing of cement by exposing it to higher temperature are invalid, as elevated temperature profoundly changes cement mineralogy and micro-structure, which influence permeability. Cement permeability can deteriorate under the influence of elevated temperature, mechanical damage to the cement matrix, and chemical attack of the cement. Exposure to CO_2 may in certain cases actually lower cement permeability through the process of carbonation and silicate gel precipitation, as has been observed in several studies. In all, the main concern on well leakage is transport through mud channels, cement fractures, micro-annuli at cement-casing and cement-formation interfaces, i.e., high-permeability flow channels that bypass the dense cement matrix, rather than transport through the bulk of the cement itself. This is confirmed by effective permeability determinations of leaking wells in the field.*

Details.

Neat Cement Permeability. Measurement of neat Portland cement permeability dates back originally to the early 1950's (Morgan and Dumbaud 1952, Powers et al. 1954), while the first reported values in oilfield literature of water and gas permeabilities were by Goode (1962). He found that Class A cement permeability for gas was less than 100 μD (~10^{-16} m^2), while water permeabilities were less than 10 μD (~10^{-17}m^2), see **Table 3.1**. These permeability values have generally stood the test of time, and have been confirmed in more recent years by measurements by Parceveaux and Sault (1984), Nowamooz et al. (2015), Le-Minous et al. (2017), and Bauer et al. (2019). There is also significant literature on the permeation properties of cement and concrete in the civil engineering discipline (see e.g., Watson and Oyeka (1981), Dhir et al. (1989), Bamforth (1991), Cui et al. (2001), Yang et al. (2019) and references therein). This work focuses primarily on the permeation behavior of cement/concrete at atmospheric conditions, but the work has relevance for oilfield conditions as well. Table 3.1 gives an overview of permeability values for neat cement slurries for a variety of sources. **Figure 3.1** reproduces two figures from Yang et al (2019) that compare the permeability ranges observed for neat cement with various rock formations (based on work by Brace 1980, Wang and Narasimhan 1985), showing that cement permeability is similar to the upper-end of the range of permeabilities reported for shale, to the mid-range of permeabilities reported for clay formations, and to the lower-end (tight) range of permeabilities reported for sandstones, limestones and siltstones. Nelson and Guillot (2006) recommend a cement permeability smaller than 0.1 mD (100µD), while API recommends a permeability limit of 0.2 mD (200 µD), see Kutchko et al. (2009).

Simulations by Nowamooz et al. (2015) based on data for lab measurements and field observations shows that an adequately cemented borehole with an annular cement permeability k ≤ 1 mD can prevent methane and brine leakage over a time scale up to at least 100 years. A poorly cemented annulus with k ≥ 10 mD, however, could yield methane leakage rates in the range of 0.04 m^3/day – 100 m^3/day, with brine leakage rates after 100 years at 10^{-5} m^3/day – 10^{-3} m^3/day.

An important observation on the long-term stability of cement permeability was made by Carey et al. (2007), who found that the air (gas) permeability of the “grey” bulk cement recovered from a 30-year old SACROC CO_2 injection well was still in the range of 0.1 - 0.25 mD, which is only slightly above the boundaries of 0.1 mD and 0.2 mD recommended by Nelson and Guillot (2006) and API respectively.

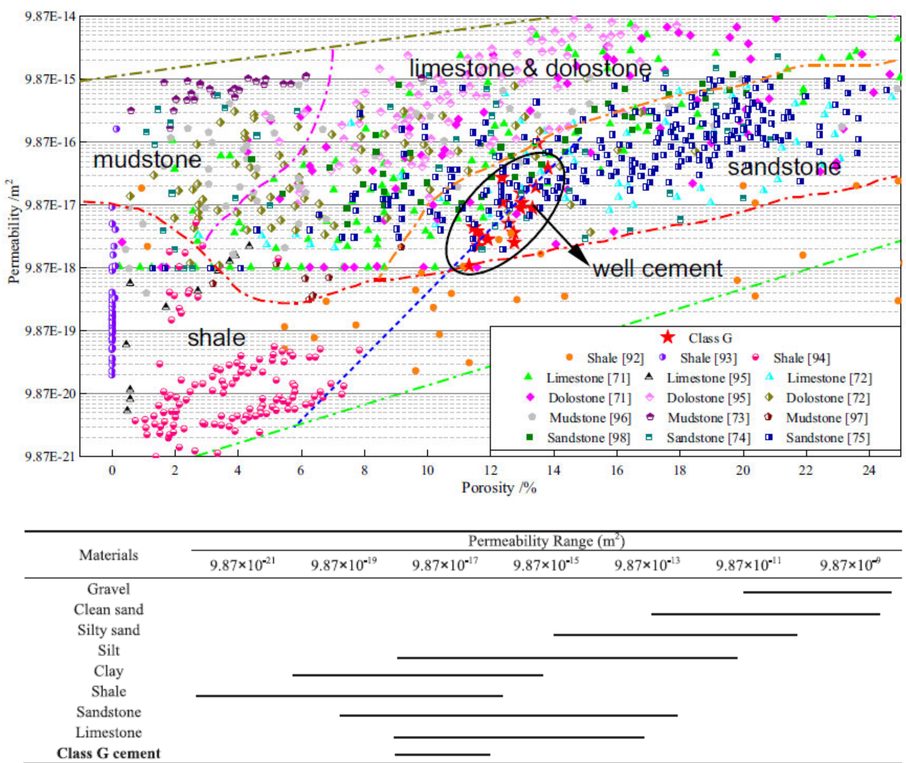


Figure 3.1 – (top) Comparison of porosity and permeability data for neat cement and various rock formations; (bottom) Permeability ranges for neat oilfield cement and various rock formations. Graphs from Yang et al. (2019). Copyright Elsevier, reproduced by permission.

Table 3.1 – Cement permeability data from various sources, obtained under various conditions for water, air/gas and oil, as indicated.

Source	Cement Type	Experimental Conditions	Permeability Measurement Details & Results
Bauer et al. (2019)	Class G	50°C, 7-day	Water permeability 50 µD at 0.7 MPa confining pressure; 1.8 µD at 1.2 MPa confining pressure; 0.2 µD at 13.8 MPa confining pressure
Carey et al. (2007)	OPC (unspecified, probably Class H)	Room temperature, atm. pressure, untreated & dried	Analysis of field cement samples after 30 years of exposure in a CO_2 injection well. Untreated samples of "grey" cement had air permeability of 0.09 mD (0.02 mD standard deviation), while "orange" cement had air permeability of 0.23 mD (0.14 mD standard deviation). Values for oven-dried samples (120°C) were higher (17.6 mD and 0.35 mD for grey and orange cement respectively)
Cui et al. (2001)	OPC (no specification)	Room temp., 7 & 210-day	Water content (W/C) 0.3: 2.66 nD (7-day), < 0.027 nD (210-day) Water content (W/C): 0.4: 8.11 nD (7-day), 0.35 nD (35-day), 0.12 nD (210-day)
De Rozières and Ferrière (1991)	Class C & Class G, foamed cement slurries	27°C, 3-day	Class C, broad BSD: 50 µD (1.77 SG), 7.6 µD (1.46), 17 µD (1.22), 54 µD (1.08), 89 mD (0.90 SG), 58.9 D (0.61 SG) Class C, narrow BSD: 1.25 mD (1.46), 5.7 mD (1.22), 25.7 mD (1.08), 1.99 mD (0.90 SG), 6.8 D (0.61 SG) Class G, broad BSD: 25 µD (1.8 SG), 39 µD (1.45), 160 µD (1.27), 44 mD (1.12), 12.0 D (0.86 SG), 5.3 D (0.61 SG) Class G, narrow BSD: 3 mD (1.45), 14.5 mD (1.27), 173 mD (1.12), 676 mD (0.86 SG), 3.7 D (0.61 SG)
Dhir et al. (1989)	Concrete	Room temp., 7-28 day	Air permeability (350 psi confining pressure): 3 – 600 µD, depending on water-to-cement content and curing conditions Water permeability: (1200 psi confining pressure): 1 – 233 µD, depending on water-to-cement content and curing conditions
Goode (1964)	Class A + 4% bentonite, various Class A & C blends	80/120/140°F, 7 & 28-days	Air permeability (7-days, Class A + 4% bentonite): 0.8 – 1.15 µD (80°F), 8 – 15 µD (120°F), 18 – 33 µD (140°F) Air permeability (28-days, Class A + 4% bentonite): 18 – 33 µD (80°F), 3 – 7 µD (120°F), 16 – 31 µD (140°F) Water permeability (28-days, various Class A & C blends): < 1 mD (80°F and 100°F); < 100 µD (120°F and 140°F); Water permeability (28-days, neat Class A & C blends): generally < 10 µD for all temperatures
Lecolier et al. (2010)	Cement slurries with silica fume and crushed sand	Not specified. Water permeability before & after H_2S	Regular cement (w/c=0.44): 6 µD (0 months), 5 µD (3 months); Mortar: 10 µD (0 months), 0.3 µD (3 months), 10 µD (12 months); Cement I: 3 µD (0 months), 3 nD (3 months), < 0.01 nD (12 months); Ageing 21 days in H_2S: cement slurry (w/c/=0.44) 0.46 µD before / 44 µD after H_2S exposure; Cement I: 6.5 nD before / 10 µD after H_2S exposure
Le-Minous et al. (2017)	Class B & G	80°F, 2,500 psi confining pressure	4 µD for Class B; 9 µD for Class G; permeability increase with increasing seawater (SW) contamination, up to 640 µD for a 50/50 Class G / SW blend
Parceveaux & Sault (1984)	Class G w/ & w/o bonding agent	20°C,	Neat Class G cement: 5 µD before damage, 300 µD after damage. Neat Class G cement with bonding agent to increase shear bond strength: 84 µD after damage
Watson and Oyeka (1981)	OPC (no further specification)		Oil permeability measured in the range of $3.10^{-10} – 33.10^{-10}$ cm/s, depending on water-to cement ratio, porosity, and applied oil pressure. Decreasing permeability with time. Oil values lower than water permeability
Yang et al. (2019)	Class G	7-day, various temperatures	10 µD – 1 mD (see Figure 3.1)

Foamed Cement Permeability. De Rozières and Ferrière (1991) developed a technique to cure foam cement under downhole pressure and temperature conditions, finding that curing foamed slurries at atmospheric pressure with a gas content that would exist downhole did not properly represent material properties. Their measurements on Class C and G foamed cements show a strong influence of nitrogen bubble-size distribution (BSD), with a broad BSD leading to a higher compressive strength and lower permeability than a narrow BSD. In general, the permeabilities of foamed slurries are significantly higher than those of neat slurries. Permeability increases with foam quality. For small bubbles and narrow BSD, the increase in permeability is progressive, while for a broad BSD the permeability remains low and then increases sharply once density is reduced to a critical value (between 1.2 – 1.3 SG for Class G, and between 1.1 – 1.2 SG for Class C). The results by Rozières and Ferrière (1991) are included in Table 3.1. Nelson and Guillot (2006) indicate that foamed cement permeability increases strongly when foam quality exceeds 40%, a threshold that also makes the cement sensitive to excessive fracturing when perforated.

Temperature Influence on Cement Permeability. The effect of temperature on cement permeability has been extensively studied for applications in HPHT wells, thermal wells (such as steam-assisted gravity drainage (SAGD) wells), and geothermal wells. Only key points are summarized here; for a more complete discussion, see Nelson and Guillot (2006) Chapter 10, and Appendix C. During cement hydration, the tri-calcium silicate (C_3S) and di-calcium silicate (C_2S) components convert into a gelatinous calcium silicate hydrate referred to as the C-S-H phase, which is ultimately responsible for strength, stability and permeability of the cement (Nelson and Guillot 2006). This C-S-H phase is a stable binder for temperatures below 110°C (230°F). As first shown by Nelson and Eilers (1985), above 110°C the C-S-H phase converts to alpha di-calcium silicate hydrate (α-C_2SH), which is highly crystalline and denser than the C-S-H phase, which can degrade the set cement strength over time ("strength retrogression") and increase its permeability. Within 1 month, the measured permeability becomes 10-100 times higher than the 0.1 mD value recommended for cement permeability. Strength retrogression can be mitigated by increasing the silica-to-bulk-lime ratio, typically accomplished by adding a pozzolan such as fine silica sand or silica flour to the slurry at 35%-40% by weight of cement (BWOC). Nelson and Eilers (1985) obtained Class G slurries with added silicate sand and silica flour that showed satisfactory stability of permeability after curing at 230°C (~450°F) and 320°C (~600°F). Monitoring the permeability behavior for a period of 2 years with continued exposure to elevated temperature, however, still showed strength retrogression and an increase of permeability over time. These results are confirmed with more recent work by Reddy et al. (2016) on deepwater high-temperature cements. The latter showed that all cement formulations, irrespective of the amount of silica flour added, suffer from strength retrogression at elevated temperature over time. This provides further motivation for selecting elevated temperature as a risk factor, particularly for wells at in-situ temperatures > 230°C (~450°F) cemented with OPC formulations.

CO_2 and H_2S Influence on Cement Permeability. The interaction of CO_2 on cement properties, including the permeability of intact and fractured cement as well as cement samples with interface debonding, has been extensively studied. A detailed discussion on CO_2 interaction with cement is given in Section 2.7. The results among different authors are slightly confusing: most studies (including Bachu and Bennion (2009), Wigand et al. (2009), Garnier et al. (2010), Laudet et al. (2011), Huerta et al. (2013, 2015), Newell and Carey (2013), Walsh et al. (2013), Wenning et al. (2013), and Cao et al. (2016)) show that reactive flow of CO_2 in cement bulk material, fractures and micro-annuli may become self-limiting because of carbonate precipitation and silica gel precipitation that plug the fracture and destroy its permeability. Laudet et al. (2011), for instance, exposed intact cement to CO_2 flow, observing an initial permeability of 1.9 μD decreasing to 1.6 μD after 4 days of exposure, and then becoming too low to measure within the resolution of the test apparatus. However, other studies (Luquot et al. (2013), Cao et al. (2013), Walsh et al. (2014a&b)) observed an increase in cement permeability upon CO_2 exposure. The issue was addressed by Carroll et al. (2016), indicating that long-term permeability of cement annuli and fractures depends on both the initial fluid residence time (a function of flow rate) of the CO_2 in the fracture and fracture aperture width. Fractures tend to fill with calcite and plug when residence times are above a certain threshold, and remain open when residence times are below the threshold. Moreover, longer fractures with smaller apertures tend to self-seal upon CO_2 exposure, while fractures tend to open in flow regimes with shorter path lengths and larger apertures (e.g., Luquot et al. 2013). The study by Lecolier et al. (2010) showed an increase in cement permeability of 2-3 orders of magnitude after exposure of cement to H_2S for 21 days, with profound lowering of cement compressive strength as well.

Field observations of effective permeability of leaking wells. Effective permeabilities have been calculated for various kinds of field data from leaky wells, primarily to evaluate the potential of re-purposing old oil and gas wells for CO_2 storage purposes. Crow et al. (2010) determined the effective permeability of a 3.4 m cement sheath in a 30-year-old producing wells from a natural CO_2 reservoir to be 0.5 – 1 mD using the vertical interference test (VIT – see Gasda et al. 2008). Gasda et al. (2013) determined effective permeability to be in the range of 1 mD to > 100 mD while analyzing 9 VIT measurement over 3 - 13 m intervals on 3 existing wells. Note that these sources only considered discrete sections of the wellbore, not the entire well. More holistic estimates of effective permeability for the entire well were obtained by the group of S. Bryant, using methods developed and applied by Wojtanowicz et al. (2001) and Xu et al. (2001) to estimate effective permeabilities from SCP and SCVF data. Huerta et al. (2009) used SCP data to determine effective permeabilities of 140 mD and a range of 0.1 – 5.0 mD for two Canadian onshore gas wells respectively. Tao et al. (2013) and Tao and Bryant (2014) used SCVF and detailed well construction data to determine permeability for 256 wells in British Columbia to be in the range of 10 μD to 10 mD. Calculated leakage rates (calculated for CO_2 leakage in CCS projects) was in the range of 10^3 g/yr to 10^5 g/yr. Manceau et al. (2015) in their 1:1 in-situ experiment in the Opalinus Clay formation in Switzerland observed effective permeabilities higher than intact cement or caprock intrinsic permeability, concluding that preferential flow occurred at the cement interfaces, with permeability values strongly influence by pressure and temperature cycling. Finally, Kang et al. (2015) analyzed effective permeabilities for 42 plugged and unplugged oil and gas wells in Pennsylvania, determining these to fall in the wide range of 1 nD to 100 mD. This very wide range of 8 orders of magnitude in effective permeability illustrates the difference between negligibly slow gas transport through intact cement barriers, and much faster transport through cement interface micro-annuli and cement fractures bypassing the cement matrix.

3.2. Question 3 – Casing Corrosion

Question 3*. How well is steel casing, surrounded by cement, protected against corrosion? How is the corrosion rate affected by the change in permeability of the cement? Will the encased casing corrode in the long term? Can a corroded casing become a leak path?*

Answer.

General. C*asing corrosion prior to – and during – well abandonment may lead to well leakage. Holes in a corroded casing barrier can become prominent leak paths for flow of fluids and gases to surface. Field data shows that casing is very well protected from corrosion for long periods of time when competent cement is well-bonded to casing, apparently even in highly corrosive reservoir environments. This situation changes, however, when either there is no cement or poor-quality cement in the annulus (e.g., insufficient TOC across a reservoir with corrosive gases)) or if the cement has – or develops over time - a leak path that allows corrosive agents to reach the casing and negatively affect it. Corrosion by CO_2 has been particularly well-studied because of downhole CO_2 storage applications. CO_2 appears to damage bulk cement only very slowly (over periods of 1000's of years) and has shown self-healing and plugging of smaller cement channels (but widening of larger channels). Both effects may limit the corrosive impact of CO_2 on casing. The topic is an active area of investigation given the interest in using old well for CCS/CCUS purposes. Cast iron bridge plugs with elastomer seals appear to deteriorate very quickly in subsurface environments and cannot be relied upon as barriers by themselves; they should always be used in combination with cement or other sealing material.*

Detail

Recent gas releases associated with corrosion. One of the worst uncontrolled natural gas releases to the environment in recent history (2015-2016 timeframe) was the Alisa Canyon gas well leak (also known as the Porter Ranch gas leak or blowout) in California. The root cause was a casing leak caused by corrosion. The direct cause was believed to be a rupture of the 7 in. well casing due to microbial corrosion resulting from casing contact with groundwater (Blade Energy Partners 2019). The well (SS 25) was originally drilled in 1953 and had insufficient protection from cement in the groundwater zone. An estimated 97,100 tonnes of methane and 7,300 tonnes of ethane were released into the atmosphere (Conley et al. 2016), making the carbon footprint of this release larger than the 2010 Deepwater Horizon / Macondo spill in the Gulf of Mexico (Walker 2016). Another prominent example was the 2012 Elgin well failure and gas release in the North Sea (Henderson and Hainsworth 2012), attributed to stress corrosion cracking caused by casing exposure to calcium bromide ($CaBr_2$) brine. Significant field data on casing corrosion comes from the Middle East (Al-Yateem et al. 2013; Narhi et al. 2015; Alsaiari et al. 2017), Canada (Watson and Bachu 2008, 2009; Dusseault et al. 2014), USA (Dethlefs et al. 2008; Kamgang et al. 2017), Europe and the North Sea (Loizzo et al. 2015, Beltrán-Jiménez et al. 2021). More detail is given in Appendix B.

Corrosion Mechanisms. King and King (2013) note that casing corrosion is a natural phenomenon encountered with every engineered steel structure worldwide. However, corrosion damage can be significantly accelerated if there are corrosive agents negatively affecting the casing (Brondel et al. 1994, Dusseault et al. 2014). Main concerns during well abandonment are exposure to acid(-forming) gases such as CO_2 and H_2S, forming carbonic acid (H_2CO_3) and sulfurous acid (H_2SO_3) in aqueous solution, which are low pH fluids that can corrode low-carbon iron at rates of millimeters per year (Han et al. 2011a, Carroll et al. 2016). These low pH fluids can also attack and damage cement (see Watson and Bachu, 2008). Other chemical agents are corrosive brines, dissolved oxygen, and unreacted acid treatment fluids. Casing may corrode by chemical corrosion (by H_2S, CO_2, concentrated brines, unreacted acids), electro-chemical corrosion (galvanic corrosion, stray-current corrosion, crevice corrosion), microbial corrosion (due to bio-organisms such as sulfate-reducing bacteria, which produce H_2S), and mechanical corrosion (cavitation, erosion, erosion corrosion, corrosion fatigue, sulfide stress corrosion, chloride stress cracking and stress corrosion cracking). For a detailed discussion on corrosion protection and prevention, see Brondel et al. (1994), Abdallah et al. (2013), and Robertson and Chilingar (2017). **Table 3.2** gives an overview of corrosion problems and solutions according to Abdallah et al. (2013).

Field observations of leaking wells. Field data shows that casing is very well protected from corrosion when cement is well-bonded to casing. Field data for wells in Alberta, Canada reported by Watson and Bachu (2009) shown in **Figure 3.2** indicates that external casing corrosion is minimum in deep carbonate reservoirs with very significant H_2S content in wells where the casing-cement bond is good. They, however, also showed that corrosion damage can become very significant when casing is not well-protected by cement. They found that the occurrence of SCVF/GM correlated strongly with either having a low TOC with insufficient reservoir coverage by cement or having exposed casing sections due to larger cement channels, the cause being external casing corrosion creating leaks through the casing wall.

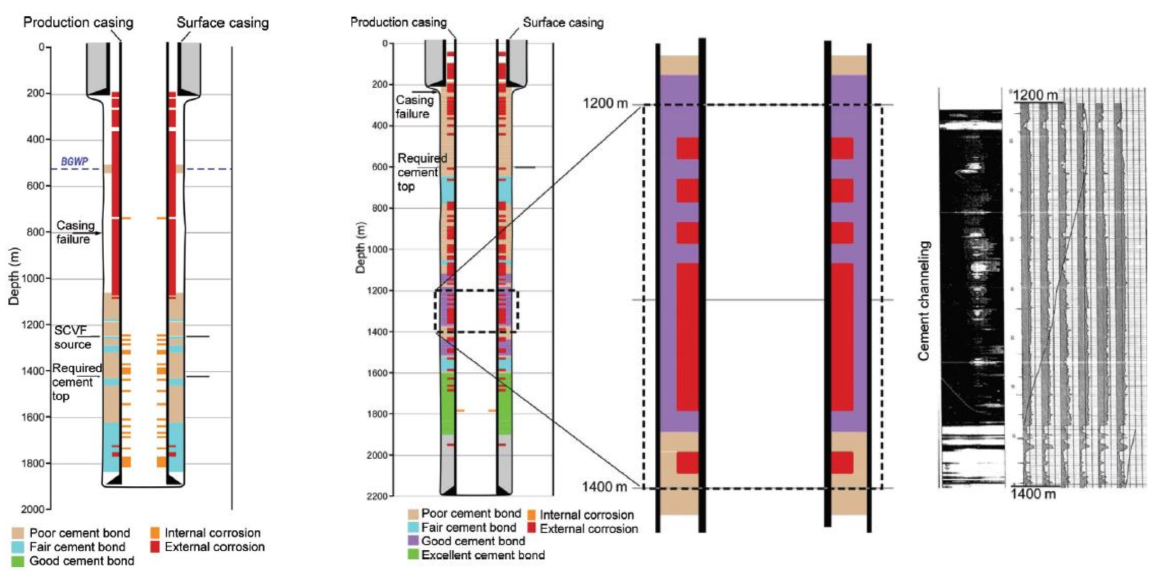


Figure 3.2 – (left) cement and casing quality in a well in Alberta, Canada, showing extensive external casing corrosion above TOC; (right) Well-log analysis showing casing-cement bond quality and casing corrosion, with an example of corrosion caused by cement channeling in otherwise well-bonded cement. From Watson and Bachu (2009). Copyright Society of Petroleum Engineers (SPE), reproduced by permission.

Table 3.2 – Summary of oilfield corrosion problems and solutions, according to Abdallah et al. (2013). Copyright Schlumberger, reproduced by permission.

Problem	*Cause of Corrosion*	*Control / Prevention Methods*	*Monitoring*
Oxygen corrosion	• Oxygenated water • Internal attack • External attack	• Resistant materials • Oxygen scavengers • Oxygen stripping • Improved seal design • Coatings • Cathodic protection	• Resistant Materials • Oxygen scavengers • Oxygen stripping • Improved seal design • Coatings • Cathodic protection
Hydrogen sulfide corrosion pitting	• Water from production aquifer or other deep aquifer • Water contaminated by stripping of lift gas	• Degassing at low pressures • Control of contaminated gas • Resistant materials	• Probes • Iron counts • Wall thickness surveys
Sulfate-reducing bacteria (SBR)	• Anaerobic fluids • Stagnant fluids • Conditions under scales or other deposits	• Biocides • Chlorination	• Anaerobic bacteria counts • Chlorine residuals measurements
CO_2 corrosion	• Water from production aquifer or other deep aquifer • Water contaminated by stripping of lift gas	• Degassing at low pressures • Control of contaminated gas • Resistant materials	• Probes • Iron counts • Wall thickness surveys
H_2S stress corrosion cracking Hydrogen-induced cracking	• Produced fluids containing H_2S • Anaerobic systems contaminated with SRB	• Suitable materials	• Materials quality control
Acid corrosion	• Stimulation and cleaning acids	• Acid inhibitors	• Acid inhibitor checks
Galvanic (bi-metallic) corrosion	• Two metals with different ionic potentials in a corrosive medium	• Electrical isolation of metals (Cathodic coating) • Improved design	• Design reviews
Pitting corrosion (rapid corrosion at defects in inert surface film)	• Immersion • Inert surface films	• Materials selection	• Equipment inspections
Subdeposit corrosion	• Wet solids deposits • Biofilms • Porous gaskets	• Pigging • Biocides • Improved sealing and design • Minimum velocity design	• Equipment inspections • Bacteria counts
Crevice corrosion	• Poor design • Imperfections in metal	• Improved design • Materials selection	• Equipment disassembly and inspection • Leak detections
Chloride corrosion (rapid cracking on exposure to hot chloride media)	• Salt solution • Oxygen and heat	• Materials selection	• Equipment inspections • Oxygen analysis
Fatigue	• Rotating equipment • Wave-, wind- or current-induced loads	• Vibration design	• Equipment inspections

Corrosion through leaking cement. Even when cement is well-bonded, there is a concern of negative affects by corrosive agents over time, first on the cement, leading to cement degradation and casing-cement bond deterioration, followed by corrosive impact on the now unprotected casing. This effect has been particularly well-studied for the influence of CO_2, given the high level of interest in downhole CO_2 storage. It is generally found that the chemical degradation influence of CO_2 on intact bulk cement, a process controlled by (slow) diffusion of CO_2 into the cement, occurs at a very slow rate. Based on the analysis by van der Kuip et al. (2011) of a large numbers of CO_2-cement interaction studies, cement degradation by CO_2 progresses on the order of less than 1 m of affected cement per 10,000 years on average. For details, see Section 2.7.

Micro-annular transport of CO_2 along the casing-cement interface may trigger corrosion passivation by cement because of precipitation of iron carbonate onto the casing that provides protection to corrosion. Han et al. (2011b) reported corrosion rate reductions by a factor of 20 due to formation of iron carbonate scale on casing through cement passivation. Such reduced corrosion rates may still be problematic given the long exposure times involved for abandoned wells. However, it has been found that when small channels or micro-annuli are present in the cement along which CO_2 migrates, there is a good chance that self-healing / self-plugging behavior will close off such flow paths. Based on experimental work (Bachu and Bennion 2009; Huerta et al. 2013, 2014, 2015) and analysis work (Brunet et al. 2013, 2016, Luquot et al. 2013), it appears that reactive transport of CO_2 in long channels with small apertures (such as micro-annuli with widths < 100 μm) may be self-limiting, leading to self-plugging of these channels. Several mechanisms, including carbonate precipitation, silica gel precipitation, relative permeability effects, fines migration, and re-precipitation of cement phases have been proposed for the plugging mechanism (for an overview, see Carroll et al. 2016). Effective channel self-plugging would not only stop flow to surface but also strongly limit the corrosive action by CO_2.

For shorter channels with larger apertures (widths >> 25 μm), however, adverse reaction with CO_2 may lead to a widening of the channels over time, increasing flow to surface and accelerating the transport of corrosive agents that could negatively impact the casing (Carroll et al. 2016). According to a recent study on casing corrosion by Beltrán-Jiménez et al. (2021):

- *However, micro-annulus created by the cracking and debonding due to thermo-mechanical failure, and the mud channels formed due to the contamination of drilling fluid/mud, <u>can accommodate the aggressive ions or acidification of the cement-casing interface which is detrimental to the protective film of the steel casing</u>.*

The work by Beltrán-Jiménez et al. (2021), which forms a set with the work on logging measurements by Palacio et al. (2020), a series of seepage experiments to better understand leakage potential by Skadsem et al. (2020), and an ultrasonic bond log evaluation by Gardner et al. (2021), was conducted on recovered sandwich sections of 13 3/8-in. (72 lb/ft N-80) and 9 5/8-in. (47 lb/ft C-95) casing and associated cement from a well originally drilled and completed in the Valhall field in the Norwegian sector of the North Sea. The well was on production for 33 years and showed SCP late in its productive life. The well had $CaBr_2$

brine trapped and stationary between the two casing strings. The 4 papers are to date the most complete analysis of recovered casing and cement from a leaking well. The work showed conclusively that corrosion of the casing was correlated with the presence of a film of mud between the cement and the steel casing, implying that a mud channel facilitated casing corrosion by halides (chlorides and bromides). Ultrasonic logs and seepage experiments confirmed the presence of a (micro-) annulus behind the casing.

A similar study on a recovered sample of casing, cement and shale caprock was conducted for a 30-year old well used for CO_2-flooding at the SACROC unit in West Texas (Carey et al. 2007). The recovered bulk cement had air permeabilities in the tenths of millidarcy range (0.1 mD), indicating that it had retained its ability to prevent significant upward flow of CO_2. There was, however, indication through the deposition of carbonate precipitation that CO_2 had traveled up the casing-cement and cement-shale interfaces. CO_2 had traveled up the casing wall and infiltrated the casing threads, causing corrosion. Moreover, the cement in contact with the shale was heavily carbonated, showing the presence of calcite, aragonite, vaterite and amorphous alumino-silica caused by the reaction with CO_2. Note that a leak path of corrosive agents along the cement-shale interface can still lead to casing corrosion when corrosive agents migrate above the TOC, coming into contact with the casing at that point.

Studies of the effect on H_2S on cement are not as numerous as those carried out with CO_2, but dedicated work has been done by Krilov et al. (2000), Benge and Dew (2006), Lécolier et al. (2007, 2008, 2010), Moroni et al. (2008), Garnier et al.(2012), Zhang et al. (2014) and Vrålstad et al. (2014). The outcome of these studies is discussed in Section 2.7. There appear to be no studies of casing corrosion in conjunction with cement barrier deterioration, but the corrosive effect of H_2S on casing is well-known (see for instance Abdallah et al. 2013, Table 3.2).

Bachu and Watson (2009) studied failure frequencies of wells used for pure CO_2 injection and acid gas (CO_2 + H_2S) disposal. Main conclusions, highlighting the importance of proper well construction and appropriate regulatory enforcement, are:

- Wells specifically built for CO_2 or acid gas injection had significantly lower failure frequencies than wells drilled and completed for other purposes.
- Wells specifically built for CO_2 or acid gas injection had significantly lower failure frequencies than old wells that were converted for injection purposes.
- Almost all injection well failures were tubing or packer-related, with few incidences of SCVF and GM.
- Acid gas (CO_2 + H_2S) disposal wells had lower failure frequencies than pure CO_2 injection wells, attributed to a higher level of diligence on the part of the operators and more stringent regulatory requirements due to the environmental and occupational safety risks of H_2S.
- Implementation of a proper regulatory framework for drilling, cementing, completion and abandonment of CO_2 and acid gas injectors resulted in a significant drop in failure frequency after 1994 when this framework was implemented.

3.3. Questions 4 & 5 – Micro-Annulus Behavior & Presence

Question 4. *The micro annulus could be a conduct for fluids. What is the long-term behavior of the micro annulus? Will it be squeezed tight, or can it erode through flowing liquids? Can it be filled with petroleum or mineral deposits?*

Question 5. *Is there a micro annulus between cement and formation? How does filter-cake behave, is it permeable?*

Given the fact that both questions 4 and 5 deal with the topic of micro-annuli, the response is combined here.

Answer. *A micro-annulus between cement and casing can develop as a result of poor primary cementing, cement shrinkage after cement setting, testing cement too quickly without waiting for proper WOC time, or subsequently during the life of the well due to cyclic pressure and/or temperature loading leading to cement debonding at the casing-cement interface. A micro-annulus represents a high permeability flow path (k > 10 mD) which bypasses the low-permeability cement matrix, thereby becoming an effective conduit for upward movement of fluids and gases to surface. Little is known about natural plugging of micro-annuli, although this is expected to occur with oil-based fluids and (carbonated) brines. A method has been suggested to actively use gas condensate to plug a micro-annulus, and it has been demonstrated that a micro-annulus can become plugged upon* CO_2 *exposure. It may also be possible that squeezing formations (mobile salts and shales) acting on the cement sheath can close a micro-annulus. A large variety of techniques have been developed to squeeze off micro-annuli artificially during well remediation and re-abandonment, e.g., by perforating casing and squeezing either chemicals (e.g., microfine cement, resins, silicates, nanoparticles) or biological agents to plug the leak path. Melting bismuth alloys and expanding the casing have shown promise as physical methods to close micro-annuli and other cement leaks.*

Mud filter-cake has a low permeability (k ~ 1μD) of itself, but it is crucial that it is effectively removed from the wellbore during cement displacement[4]. Otherwise, the filter cake will interfere with cement bonding effectively with the rock formation, possibly creating a (micro-) annulus at the cement-formation interface that can become a leak path to surface.

Details. Well leakage may occur if there is a conduit / pathway in the annular space or if well abandonment plugs are leaking. As discussed in the answer to Question 2 (Section 3.1), after a high-quality cement job with good cement displacement, the set cement reaches a low permeability that does not allow gas to migrate at any appreciable rate through the water-filled pores of the cement matrix. This situation changes, however, if there is a flowpath bypassing the low-permeability cement matrix. Well-known causes of such flowpaths include (Nelson and Guillot 2006; Loizzo et al. 2013):

[4] *Unless mud-to-cement conversion technology (Cowan et al. 1992, Nahm et al. 1995) is used, which allows for effective conversion of the mud filtercake into cement during displacement.*

- A low top of cement (TOC), either by faulty design, poor cement job execution or lost circulation during cementing. Cement can only form a sealing barrier if it completely covers a reservoir zone.
- Channels from cement channeling through mud or mud being by-passed during displacement. If left behind casing, the mud will eventually dehydrate, crack, and allow upward flow of fluids and gas.
- Gas migration channels ("chimneys") that formed when the loss of hydrostatic head during cement gelation allowed gas to come into the annular space (Stewart and Schouten 1986).
- Cement damage, i.e., cracks and fractures, incurred by the cement sheath after setting, for instance by mechanical damage (see Sections 2.4 and 2.6).
- A free water channel in a deviated well with improper cement design (no control of free water).
- A dehydrated filter cake that has not been removed from the wellbore wall prior to cement placement.
- Micro-annuli caused by debonding between either cement and rock, between cement and casing, or both. An image of a micro-annulus obtained by x-ray computer tomography (CT) scanning as obtained by Vrålstad et al. (2019b) is shown in **Figure 3.3.**

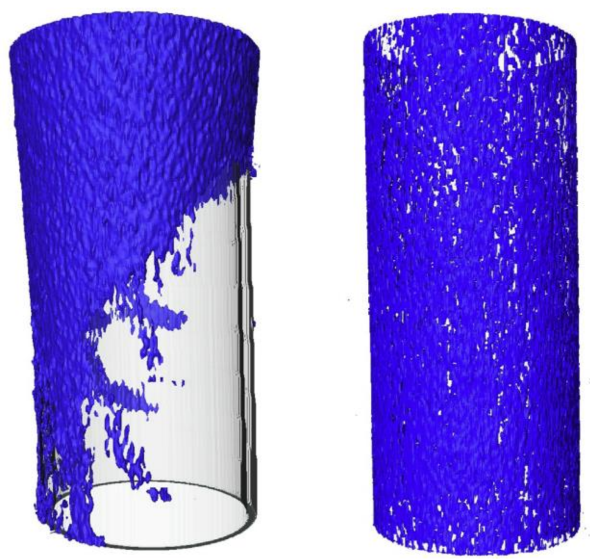


Figure 3.3 – Two examples of x-ray computed tomography (CT) visualizations of experimentally obtained non-uniform micro-annuli. The blue color shows cement debonded from the inner casing. Adopted from Vrålstad et al. (2019b). Copyright Elsevier, reproduced by permission.

According to Nelson and Guillot (2006):

- *"The primary driver for gas to migrate in the long term is the formation of a pathway for the gas to travel after the cement has set. (…) The path for long-term gas migration is more likely to be through a micro-annulus, a mud channel, a channel of bypassed lead cement slurry, a free-water channel, a dehydrated filtercake, or any mechanical failure of the cement sheath caused by imposed stresses. Space for entry can come from chemical shrinkage of the cement, bulk shrinkage of the cement, and dehydration of mud channels, free-fluid channels, and filtercakes."*

In the following, the discussion is limited to filter cake and micro-annulus formation and presence, in accordance with Question 4 & 5.

Formation of micro-annulus during or after cement setting can happen for one of the following reasons (Stewart and Schouten 1988, Bonett and Pafitis 1996, Wojtanowicz et al 2000, Heathman and Beck 2006, Nelson and Guillot 2006, Bois et al. 2011, Kupresan et al. 2014, Sweatman et al. 2015):

- **Bulk volume reduction due to chemical shrinkage of the cement** after setting (Justnes 1995, Baumgarte et al. 1999, Dusseault et al. 2000, Nelson and Guillot 2006). When cement hydrates, the volume of the reaction products is less than that of the reactants. When cement start to develop compressive strength, this total chemical shrinkage (also called autogenous shrinkage) can manifest itself as bulk volume reduction. This can be exacerbated by the presence of dissolved gases, high curing temperatures, and early set (Dusseault et al., 2000). Autogenous shrinkage can result in a volume loss of a few percent up to around 4-6% (Ravi et al., 2002; Stein et al., 2003). This is more than sufficient to reduce the radial total stress in the cement, which will lead to formation of a vertical micro-annulus at the cement-formation interface, as discussed in detail by Dusseault et al. (2000). Improved cement design with flexible, expanding and self-healing cements can address challenges with cement shrinkage (see El-Hassan et al. 2005, Baumgarte et al. 1999, Moroni et al. 2007, resp.)
- **Reduction of casing diameter by pressure decrease in the well**. This can happen when the cement job is displaced with a heavier fluid than the annular fluids (mud, spacer and cement), leading to pipe expansion. When this heavy fluid is replaced at a later time by a lighter fluid, the casing will contract and a micro-annulus at the casing-cement interface may form. Other causes are poorly timed casing pressure tests during waiting-on-cement (WOC) time, and tripping in drillpipe (e.g., to drill out the casing shoe) with high surge pressures. Both effects lead to casing expansion followed by contraction, triggering the creation of a micro-annulus.
- **Reduction of casing diameter by a temperature decrease in the well**. A typical example is displacing cement jobs with cold fluids, for instance during wintertime in colder climates or in offshore deepwater environments for wells at large water depths. Placing cold displacement fluid next to heated, exothermally reacting cements in the annulus can lead to casing/liner expansion and/or contraction, leading in turn to formation of micro-annuli at cement/casing and cement/formation interfaces.
- **Inflating casing by holding pressure on surface when floats are not holding after a cement job**, followed by a release of this pressure creating the micro-annulus.
- **Cyclic pressure and temperature variations during the life of the well.** Pressure and temperature variations in the well lead to contractions and expansions of the casing and the cement behind it. Their difference in expansion coefficients and the stresses built-up in the cement sheath can lead to cement debonding from casing with the formation of a micro-annulus, as well as additional damage to the cement sheath in the form of radial and axial cracking (also referred to as “disking”). Typical lifetime cyclic loads include swab and surge pressures during drilling, pressure and temperature variation during reservoir completion and stimulation (e.g., hydraulic fracturing), and repeated well shut-in / start-up cycles during production. The topic is discussed in more detail in Section 2.4.

- **Influence of geomechanical and geochemical impact after well abandonment**. Geomechanical stresses acting on the casing-cement and cement-formation interfaces can cause shear failure and associated debonding, creating micro-annuli. Adverse geochemical effects such as cement interactions with acid gases such as CO_2 and H_2S can lead to widening of pre-existing flow channels, worsening wellbore leakage over time.

Leakage through a micro-annulus.
A key question is how severe the flow through a micro-channel can be. King and Valencia (2014) remark that:

- *"Flow up the pipe-to-cement or cement-to-formation micro-annuli depends on the size and extent of the micro-annuli. Measurements in the field by logs and pressure transient analyses as well as in the laboratory have estimated the permeability of a real micro-annuli as a five to six fold range from about 0.00001 mD to 10 mD with the dominant micro-annuli being 0.01 to 0.02 mD (Duguid et al., 2013; Tao et al. 2013). Linear flow through any distance of such small micro-annuli would reduce the gas escape rate to a very small value."*

This statement unfortunately confuses the permeability of the micro-channel with the effective permeability of the well (which was the quantity measured in the Duguid et al. (2013) and Tao et al. (2013) studies) and does not quantify the gas escape rate. Oil and Gas UK (2015) provided a simplified procedure based on Darcy's law to estimate the rate of flow (Q, in m^3/s) of a fluid or gas when a micro-annulus is present between a cement sheath and casing as follows:

$$Q = k\, x_{ma} w_{ma} \left[\frac{\Delta P}{\mu L}\right]$$

Where:

Q = flow rate of fluid of gas [m^3/s]
k = permeability of the micro-annulus [m^2]
x_{ma} = circumference of the micro-annulus behind casing [m]
w_{ma} = aperture (width) of the micro-annulus [m]
ΔP = pressure difference between top and bottom of the barrier [Pa]
μ = dynamic viscosity of the fluid/gas, assumed to be constant [Pa.s]
L = length of the barrier [m]

For the example of a micro-annulus on the outside of a 9 5/8" OD casing string (x_{ma} = 76.8 x 10^{-2} m) with an aperture of 25 μm (w_{ma} = 25 x 10^{-6} m), for a barrier length of 100 ft (L = 30.48 m) with a pressure differential of 5000 psi between reservoir and surface (ΔP = 34.47 MPa) for methane with a constant dynamic viscosity of μ = 4.0 x 10^{-5} Pa.s, and with an assumed micro-annular permeability of 50 Darcy (k = 4.9345 x 10^{-11} m^2), we obtain a flow rate of:

Q = 2.67 x 10^{-5} m^3/s = 0.096 m^3/hour = 2.31 m^3/day = 845 m^3/year.

This estimate is assumed by the authors to be a worst-case scenario for micro-annuli, given that actual annuli in the field may be filled with water, grease, gels and particles (leading to a lower effective permeability), and that the downhole gas viscosity may be higher; these effects will reduce the flow rate to surface. The value of ~ 2 m^3/day as a worst case estimate[5] is indeed a relatively small value, but could still prove problematic if a well leaking at this rate is located within – or close to – urban centers. For wells that are leaking at a higher rate, it can be safely assumed that the leak-path is not a micro-annulus, but involves a large / wider flow channel such as a cement fracture. For more sophisticated modeling of gas flow through cement-casing micro-annuli, see Stormont et al. (2015, 2018), and Zhao et al. (2019).

Blocking and remedying an annular flow channel.

There is still little known about spontaneous blocking of micro-annuli. The authors of "*Guidelines on Qualification of Materials for the Abandonment of Wells*" (Oil and Gas UK 2015) certainly indicate that is plausible that micro-annuli can become filled with "*grease (i.e., petroleum precipitates), gels and particles*". Two additional data-points are provided by the fact that (1) the presence of micro-annuli indicated by high-resolution CBL/VDL and ultrasonic logs is wide-spread, and (2) the majority of leaking wells diagnosed in the field are not "super-emitters" but leaking at rates much lower than the worst-case rate detailed in the previous paragraph. This combination of wide-spread micro-annular occurrence and modest leakages rates for the majority of leaking wells would lead to the logical conclusion that the majority of micro-annuli in the field are either plugged to a certain extent or do not form a continuous flowpath to surface. Moreover, it seems logical to assume that self-plugging has a higher probability of occurring with oil reservoirs (e.g., precipitation of asphaltenes, waxes etc.) and brine reservoirs with reactive components (with plugging by dissolved CO_2 leading to carbonation observed in various studies, see Sections 2.7, 3.2 and 3.3) than with gas reservoirs, but the topic appears not to have been studied beyond CO_2 carbonation investigations. Studies have shown that exposure of cement micro-annuli and channels to CO_2 can lead to self-plugging for long channels with small apertures (such as micro-annuli), but also chemical erosion and widening for channels with wider apertures (see discussion in Section 2.7).

Duan and Wojtanowicz (2005) proposed plugging micro-annuli with gas condensate as a way to shut-off SCP. The basic idea is to expose the cement to a sudden pressure decrease, forcing gas to go through its dew point. This condition would then form condensate that could "self-plug" the micro-annulus. Other than the idea being promoted on theoretical grounds, there are no records of further studies or field implementations. Daniel and Radonjic (2019) suggested adding gilsonite, a naturally occurring asphalt, to cement, which will swell and expand when contacted by hydrocarbons to shut-off hydrocarbon flow. Note that this is also the mechanism behind "self-healing" cements (see Le Roy-Delage et al. 2010).

The traditional way to solve annular gas migration problems is to either cut and pull or section-mill casing and set an open-hole abandonment plug, or perforate casing and perform remedial squeeze cementing to stop gas flow and reduce gas pressure to surface. This can be very difficult with a low probability of

[5] *In the recent probabilistic risk assessment studies by Arild et al.(2018) and Willis et al. (2019), an acceptable leakage rate of 5.2 x 10^{-5} m^3/s = 0.187 m^3/hour = 4.49 m^3/day = 1640 m^3/year is used.*

success (not exceeding 50-60%, see Saponja 1999, Wojtanowicz et al. 2001, Cowan 2007) for the following reasons (Nelson and Guillot 2006):

1. Gas channels may be very difficult to locate behind casing and intersect effectively when perforating casing prior to squeezing cement, especially if they are less than 1 mm in width.
2. Gas channels may be too small to be effectively filled by cement. Microfine cements have been developed to make cement penetration in channels more effective (Heathman et al. 1993).
3. Squeezing cement at high pressure may be enough to break cement bonds or initiate formation fracturing, further worsening gas migration problems.
4. Cement repairs may be expensive, particularly offshore and in remote locations (Cooke et al. 1982).

In addition to squeezing microfine cement, novel systems and techniques have been developed in recent years for improving the probability of success in blocking cement channels. A more complete overview of these methods that employ chemical means (squeezing with resins, silicates, nanoparticles), biological means (bacteria causing carbonation and plugging) or physical means (melting of bismuth alloys, casing expansion to close micro-annuli and cement fractures) is given in Appendix A. Other methods to stop annular flow, such as the Casing Annulus Remediation System (CARS) or Bleed-and-Lube approach, are based on injecting high-density fluid into the affected annulus. These approaches have only been partially successful (see Wojtanowicz et al. 2001, Demirci and Wojtanowicz, 2018a&b).

Filter cake. Fluid filter cake plays an important role in well construction to prevent excessive seepage losses of drilling and completion fluids to permeable formations, thereby allowing such fluids to act as primary well control barriers, and to keep drillstring differential sticking tendencies in check. Nelson and Guillot (2006) dedicate an entire section on the discussion of filter cake, its properties and its role in cementing. Although filter cake itself has very low permeability (~ 1μD according to Nelson & Guillot) and will not permit significant flow through it, it can present problems if it is not properly removed prior to cement placement. If left in place, the filter cake will dehydrate and present a flow path to surface. Mud conditioning prior to cementing, pumping of chemical flushes and spacers, as well as pumping in a turbulent flow regime are usually adopted as best practices to remove the mud cake and allow the cement to properly bond with the formation. Not removing the mud cake will lead to improper bonding of the cement and significantly reduced shear bond strength (Dusseault et al. 2000, Yong et al. 2007, Agbasimalo and Radonjic 2014), which will likely create a micro-annulus at the cement-formation interface that can become a pathway for leakage. Especially when non-aqueous fluids (NAF, i.e., OBM and SBM) are used, cement will not bond with the filter cake and contamination of the cement by the oil-phase and chemical in the filter cake will interfere with proper setting of the cement at the cement-formation interface (Aughenbaugh et al. 2014). The concerns around cement bonding to filter cake have been a motivating factor in the development of “mud-to-cement” conversion and “universal fluid” technology (Wilson et al. 1990, Cowan et al. 1992, Nahm et al. 1995). In such systems, unreacted cementitious material (slag) is run continuously in the mud during drilling, and will thereby take part in building the filter cake. During cementing, this cement gets activated, ensuring that any non-removed filter cake will solidify and harden, thus minimizing any well integrity problems with dehydrated filter cake.

3.4. Question 6 – Plastically Deforming Formations Forming Annular Barriers

Question 6*. How do plastic formations such as rock-salt and claystone or shale behave around a cemented or uncemented casing, and can they form an effective seal?*

Answer. *It has been known for over a decade now (since the work of Williams et al., 2009), with mounting evidence from both laboratory, modeling and field studies, that plastically deforming shale and salt / evaporite formations under certain conditions can move radially inward into uncemented or poorly cemented annular spaces, filling them and contacting the casing to form an effective pressure-tight barrier. Such barriers have now been accepted in the NORSOK D-010 (2021) standard and the UK's Guidelines for the Abandonment of Wells[6] (Oil & Gas UK 2018), with associated criteria for their evaluation and qualification. They have become commonplace considerations in the plugging and abandonment (and, most recently, even new construction) of offshore wells in the UK and the Norwegian sectors of the North Sea, leading to simplified and more cost-effective offshore well plugging operations (by eliminating of the need for casing cutting & pulling or milling, setting open-hole abandonment plugs, etc.). Concise information relevant to Question 6 is given below, with more detailed background given in Appendix C.*

Details.

Mechanism. Extensive research as well as field evidence has shown that the predominant mechanism behind the "shale/salt as a barrier" (SAAB) phenomenon is creep, i.e., time-dependent plastic rock deformation under a constant load. Other mechanisms have been considered (including shear / tensile rock failure, compaction / consolidation, liquification, thermal expansion, and chemical effects), but have been mostly eliminated with mounting evidence in support of creep. Creep is a function of primarily rock type, rock properties and mineralogy, temperature, pressure, and secondary factors (Fabre and Pellet 2006). Not all shale and salt/evaporite formations exhibit effective creep behavior that will lead to barrier formation. Work to date shows that shales with high clay content (> 50% clays, in particular smectites or mixed layer smectite/illite), high porosity, low degree of matrix cementation, low UCS, low cohesion and friction angle, and ductile (non-brittle) failure behavior make good candidates for forming barriers through creep. Members of the Hordaland and Rogaland Tertiary shales (Lark, Horda and Lista shales) in the North Sea region have been shown to form competent barriers, and deeper shales from the Cromer Knoll Group (of Cretaceous age) also show potential for barrier formation (Kristiansen et al. 2021). Note that creep barriers have not yet been investigated or reported for offshore and onshore Netherlands geological environments. It, however, seems likely given the correspondence in geology between formations encountered in the UK/Norway sectors and those in the Dutch sector (see Crittenden, 1982), that young reactive shales of the Upper, Middle and Lower North Sea Groups will form such barriers, and that potentially Cretaceous shales from the Chalk and Rijnland Groups (e.g., the Holland and Vlieland Shales) may also form them or can possibly be induced to form them. This will require further study.

[6] This guideline states: "*If it can be demonstrated that the resulting seal of the formation against the casing is adequate to prevent flow from the present fluids at the anticipated future pressures, then such a seal is acceptable as a replacement for a good annulus cement bond.*"

Halite formations at sufficient in-situ temperatures will exhibit creep behavior (Zhao et al. 2016) that can lead to annular barrier formation (Lavery and Imrie 2017). Modeling studies by Orlic et al. (2014, 2019) have made the case that Zechstein evaporites in the Netherlands could form sealing well barriers. The Zechstein case, however, requires careful attention and further study (see *Risks* below). Creep barrier formation appears to be strictly limited to argillaceous shale formations and mobile salts, thereby excluding sandstones, siltstones, limestones, granites and basalts (see also NORSOK D-010 2021) .

Effective Barrier Sealing. Annular sealing by shale and salt has been observed in both the lab and the field. Lab studies have shown that immediately after forming the shale barrier achieves a low initial permeability (of only a few micro-Darcies, μD), comparable to the permeability of a competent cement barrier. It has been speculated that a newly formed shale barrier will reduce its permeability over time to that of the native shale formation, which is usually in the nano-Darcy (nD) range (which would be three orders of magnitude better than a cement barrier). It has also been demonstrated that once the barrier forms, it can hold differential pressures up to effective in-situ horizontal stress values over very short distances.

In the field, shale and salt barriers indicated on cased-hole logs have been pressure-tested by perforating casing and performing an annular pressure communication test (preferred) or (extended) leak-off test (LOT), see Williams et al. (2009) and Raaen and Fjær (2020). Successful tests have not only been used to qualify barrier integrity, but also to correlate good barrier integrity with clear signatures observed in sonic (CBL/VDL) and ultrasonic cased-hole logs. Sophisticated new log analysis techniques have been developed to accurately determine the annular contents behind casing, and even observe annular contents through multiple casing strings. These techniques can now distinguish between gas/liquid, settled barite, light and conventional cement, and various types of formation in field logs (Govil et al., 2021). The objective of this work is to qualify the creep barrier from cased-hole log signatures alone, without the need for casing perforation and actual pressure testing. Criteria for acceptance of creep barriers based on log responses have been developed and are adopted, e.g., in the NORSOK D-010 (2021) standard, requiring the application of two independent logging tools (i.e., sonic and ultrasonic) for verification.

It has been observed that creeping salt can improve the bond quality of a poor cement barrier (Lavery and Imrie 2017). This has not (yet) been reported for shales. It is likely that moderate creep loads imparting on annular cement sheaths can close small channels and micro-annuli, as suggested by Loizzo (2014); however, larger channels / fractures may actually hinder shale and salt from forming a good barrier (in which case, “no cement barrier” would be better than a “poor cement barrier”, as “no cement” could lead to the formation of a competent creep barrier). In addition, very high creep loads may actually damage cement sheaths. The topic requires further study.

Although the data on shale/salt barriers is still being gathered, it is expected that such barriers will provide excellent sealing for a very long time period. This statement is based on the well-known fact that shale and salt cap rocks can provide hydrocarbon reservoir sealing for millions of years, and have the ability to self-heal when damaged (Horseman et al, 1997; Kristiansen et al. 2018). Creep barriers are therefore truly “replacing the overburden” (see Appendix A) when it comes to annular isolation.

Artificial Barrier Stimulation. It has been shown that annular barriers form on the timescale of weeks to months for formations that have a natural tendency to form such barriers through creep (Kristiansen et al. 2021). An active area of research and field experimentation is currently dedicated to: (1) accelerating the timescale for barrier formation; (2) stimulating barriers for shale (and salt) formations that do not form them naturally. The stimulation mechanisms (Kristiansen et al. 2018) that are actively being explored and further developed are: (a) formation temperature increase – an increase in temperature through artificial downhole heating accelerates creep rates; (b) pressure drawdown – a sudden drop in pressure may shock the formation and weaken the near-wellbore zones, leading to annular closure; (c) changing the chemistry of the annular fluid, which may weaken shales and accelerate creep rates. All of these mechanisms have been shown effective in accelerating barrier formation. Work is currently ongoing to stimulate barriers in formations that do not form them naturally by weakening shales artificially (see Gawel et al. 2021 for a recent investigation into attempts to dissolve cementation with acid in Pierre I shale in order to weaken it), but it is at present unknown if this is a viable route to barrier formation.

Risks. When it comes to integrity of the casing set across a shale or salt barrier, it is important that the casing is designed to handle the load of the in-situ formation stresses that will impart on it when there is formation contact, and that this load is distributed uniformly around the casing. Note that in uncemented sections, the casing lacks the load-shedding protection by cement (which is often not explicitly considered in casing design, but can have a significant effect in minimizing the loads on casing, see Jammer et al. 2015) when contacted by formation. Moreover, casing is typically designed to handle uniform loads, not point loads. If the casing is not equipped to handle the (unbalanced) loads imparting onto it, it may ovalize and potentially fail in a collapse mode (Kristiansen et al. 2018), which could create a leak path to surface. Mild casing ovalization has been observed in halite formations (Lavery and Imrie 2017) and shale formations (Lavery et al. 2019, Noble et al. 2021) contacting casing strings. Point-loading may be an issue in very fast-creeping/squeezing formations, such as the Carnallite and Bischofite members of the Zechstein formation. Note that wells through the Zechstein usually require special provisions in term of casing strength and wall thickness to guard against salt-induced collapse, see Bacaud (2004) and Kriesels (2004). Hence, SAAB application in the Zechstein requires further study with associated risk assessment.

Kristiansen et al. (2021) have very recently extended the use of creep barriers to the construction of new wells. They noted, however, that their attempts to accelerate barrier formation through pressure drawdown in the wellbore has led to potential well control issues. Recent preliminary work by Bauer et al (2021) has indicated that actively stimulating a shale barrier by pressure drawdown may lead to the development of a micro-annulus upon elastic formation rebound. This micro-annulus may then become a possible leakage pathway to surface. There appears to be some ambiguity on the interpretation of the log data regarding the size of this micro-annulus. More work, such as actual pressure-testing of barriers stimulated by pressure drawdown that exhibit log signatures indicative of a micro-annulus, is warranted to determine whether such a micro-annulus would indeed compromise the shale barrier in the long term.

4. Well P&A Risk Assessment

4.1. Introduction

The question of how well leakage risk assessment could / should be done either quantitatively or qualitatively was integral part of the KEM-18 workscope. The development of a risk assessment tool itself, however, was not in this workscope, but could be addressed in future work. In the following, an overview of several risk assessment approaches to well integrity published in recent open literature is given first, outlining the positives and negatives of each approach. From this, a recommendation is made on how to best accomplish future well leakage risk assessment for onshore wells in the Netherlands.

4.2. Historical Approaches to Risk Assessment

4.2.1. Approach by Watson & Bachu

Watson and Bachu (2008) developed a very practical qualitative / semi-quantitative approach for identification of wells with high leakage potential. The specific application was identification of CO_2 leakage potential of wells that were used for CO_2-based EOR, but the approach has more general applicability as well. Watson and Bachu conducted extensive analyses of risk factors that affected the leakage potential of wells in shallow parts of Canadian wells first (Bachu and Watson 2006, Watson and Bachu 2007), and broadened that approach to include leakage from deeper wells sections in their 2008 paper. Using the risk factors, they were able to derive values for shallow leakage potential (SLP) and deep leakage potential (DLP) metrics in the following way. Identified risk factors were assigned values reflecting their influence on either shallow or deep leakage potential. An example of this is shown in **Table 4.1**. These values were added to give an accumulated (risk) score, by which the leakage potential was then assessed. The accumulated scores by which the evaluated wells were assessed as having either low, medium, high or extreme leakage potential are given in **Table 4.2**.

For specific risk factors, Watson and Bachu (2008) were able to perform a more in-depth evaluation given the fact that they were specifically concerned with leakage of wells used for CO_2 EOR purposes. They looked in-depth into chemical (in-)compatibility of cement formulations (used to initially cement the wells under study) with CO_2, and assigned specific risks if the wells had been previously stimulated with perforations, hydraulics fracture treatments and acid treatments (leading to cyclic loading and chemical effects that increased the risks of well leakage).

What turns the risk evaluation by Watson and Bachu (2008) from a qualitative assignment of criterion scores into a (semi-)quantitative approach is the fact that they had access to a large amount of actual leakage data of wells under study (in the Pembina and Zama oil field of Alberta) obtained by the Alberta Resource Conservation Board (ERCB). They were thereby able to tune their method to determine the best cut-off values between what constituted to be a low, medium, high or extreme risk of well leakage. Their results for the Pembina and Zama fields are reproduced in **Figure 4.1**. As an example, their cut-off score of >400 for extreme SLP (see Table 4.2) corresponded with a 7% risk of wells falling into the extreme risk category. This compared very well with the observation of 6.1% of wells actually leaking in the field.

Table 4.1 – Example of risk factors, evaluation criteria, assigned criterion score and default (lowest) value per criterion as used in the risk evaluation approach by Watson and Bachu (2007). Copyright Society of Petroleum Engineers (SPE), reproduced by permission.

Shallow Leakage Factors			
Factor	**Evaluation Criterion**	**Assigned Value**	**Default (Lowest) Value**
Well spud date	1965 – 1990	3	1
Well Abandonment date	< 1995	5	1
Surface casing size	≥ 244.5 mm	1.5	1
Well type	Cased	8	1
Geographic location	Special Test Area	3	1
Well total depth	> 2500 m	1.5	1
Well deviation	1.2 – 1.8 degrees	1.5	1
Cement to surface	No / Unknown	5 / 4	1
Additional plug	No / Unknown	2 / 1.5	1
Deep Leakage Factors			
Fracture stimulation	Count = 1 / Count > 1	1.5 / 2	1
Acid treatment	Count = 1 / Count = 2 / Count >2	1.1 / 1.2 / 1.5	1
Perforations	Count > 2	2	1
Abandonment type	Bridge Plug	3	1
Abandonment status	Not Abandoned	2	1

Table 4.2 – Shallow and deep leak potential scoring as used in the risk evaluation approach by Watson and Bachu (2007). Copyright Society of Petroleum Engineers (SPE), reproduced by permission.

Shallow Leak Potential (SLP) Metric		Deep Leak Potential (DLP) Metric	
Low	< 50	Low	< 2
Medium	50 – 200	Medium	2 – 6
High	200 – 400	High	6 – 10
Extreme	> 400	Extreme	> 10

The main merit of the approach by Watson and Bachu is that it is relatively simple and straightforward, informed by statistical data of observed well leakage in the field. It is mentioned in the paper that the method was coded into a computer-based tool to compile and mine regulatory data to determine future well leakage potential. Moreover, it is mentioned that the tool can be used for risk assessment of consequences of leakage, e.g., by overlaying the analyzed well distribution with population density, ground water information, presence of H_2S in the subsurface, etc. A potential drawback of the approach is that it is “static” in time, such that it does not account for the increase in leakage frequency that might be observed when time progresses and wells age. In addition, the approach requires statistical data of observed well leakages for calibration of cut-off values in accumulated scores.

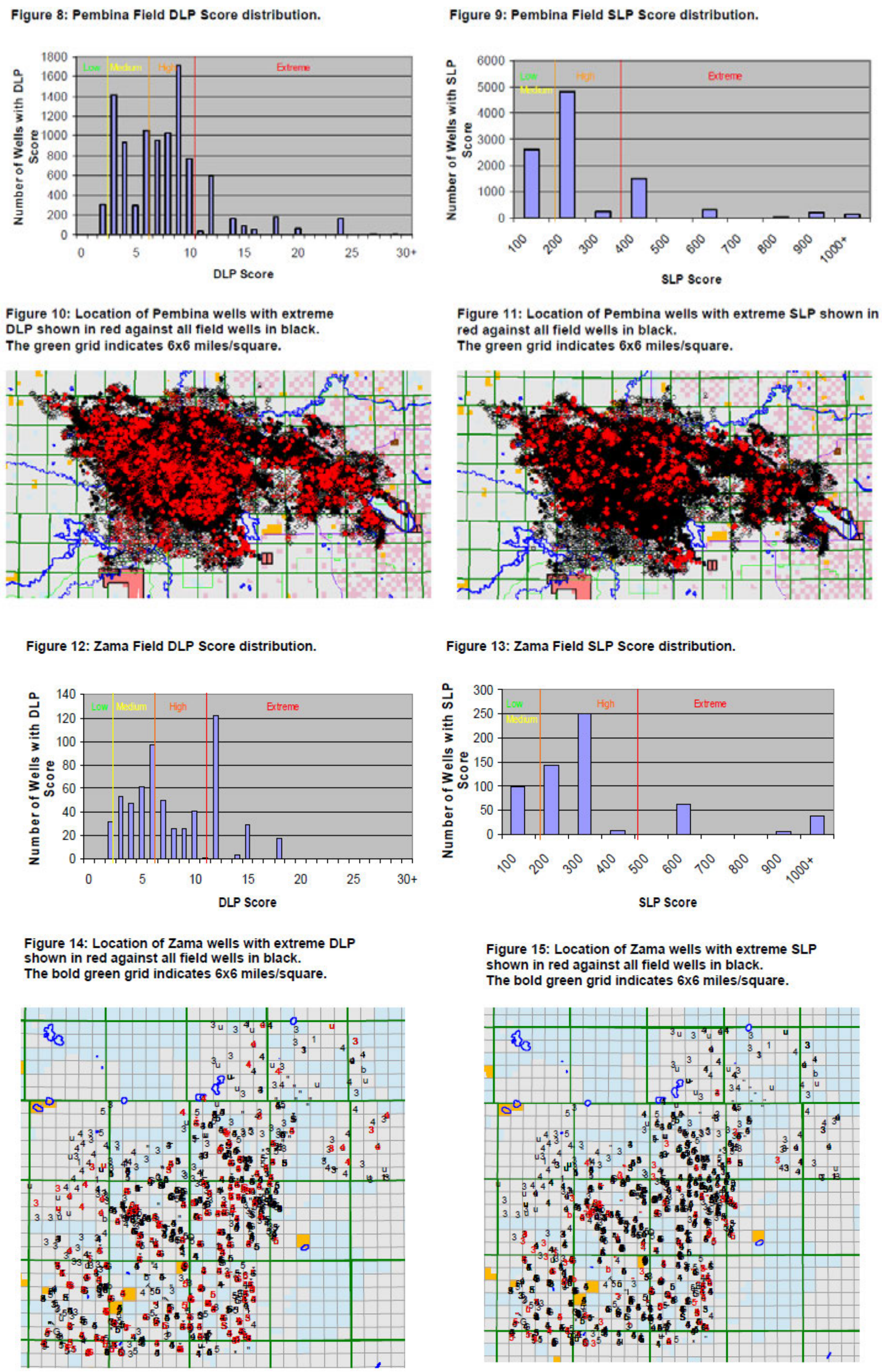


Figure 8: Pembina Field DLP Score distribution.

Figure 9: Pembina Field SLP Score distribution.

Figure 10: Location of Pembina wells with extreme DLP shown in red against all field wells in black. The green grid indicates 6x6 miles/square.

Figure 11: Location of Pembina wells with extreme SLP shown in red against all field wells in black. The green grid indicates 6x6 miles/square.

Figure 12: Zama Field DLP Score distribution.

Figure 13: Zama Field SLP Score distribution.

Figure 14: Location of Zama wells with extreme DLP shown in red against all field wells in black. The bold green grid indicates 6x6 miles/square.

Figure 15: Location of Zama wells with extreme SLP shown in red against all field wells in black. The bold green grid indicates 6x6 miles/square.

Figure 4.1 – Reproduction of graphs by Watson and Bachu (2008) with DLP and SLP scores (separated by cut-off values into low, medium, high and extreme risk categories), and maps showing location of wells with extreme leakage risks, for (top) Pembina field; (bottom) Zama field. Copyright Society of Petroleum Engineers (SPE), reproduced by permission.

4.2.2. Approach by DNV

Det Norske Veritas' subsidiary DNV (formerly DNV-GL) developed a risk-based approach for well abandonment, which is documented in publications by Ouyang and Allen (2016), Buchmiller et al. (2016), Fanailoo et al. (2017), and in report RP-E103 "Risk Based Abandonment of Wells" (DNV 2020). The latter report can be used for risk-based decision-making, applicable to (see Buchmiller et al. 2016):

- Evaluation of well abandonment designs.
- Well design optimization in relation to cost and materials.
- Evaluation of environmental performance for P&A wells.
- Independent assessment and evaluation.
- Guidance and quality assurance of P&A planning.
- Stakeholder communication.

As indicated in the various sources, the RP pertains to permanent abandonment of offshore wells, and is not applicable for onshore wells, suspended wells and temporary abandoned wells. The risk-based abandonment assessment is based on 5 steps (Fanailoo et al. 2017, DNV 2020), following guidance by the ISO 31000 standard on risk management (ISO 2018):

1. Establishing the risk context
2. Identifying well barrier failure modes
3. Performing risk analysis
4. Performing risk evaluation
5. Conducting qualification for well abandonment design

The 5-step process is shown graphically in **Figure 4.2**.

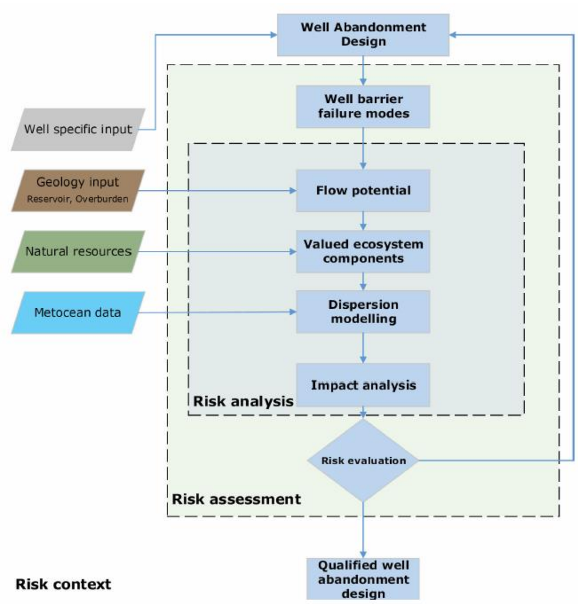


Figure 4.2 – Elements in DNV's well abandonment risk assessment, adopted from Buchmiller et al. (2016). Copyright Offshore Technology Conference (OTC), reproduced by permission.

Step 1 "Establishing the risk context" involves evaluation of the applicable regulatory environment (Fanailoo et al. 2017), and evaluation of main input elements for the analysis, which can be grouped (Buchmiller et al. 2016, DNV 2020) into 4 data categories, with details shown in **Table 4.3**.

1. Well specific data (well design, well history and current status).
2. Geology data (reservoir and overburden condition).
3. Environmental data (environmental resource overview).
4. Site-specific data (e.g., metocean data, including current including salinity and temperature profiles).

It also involves an estimation of flow potential (subdivided as no flow potential, limited / moderate / significant flow potential), defined by DNV as the potential by a hydrocarbon-bearing containing moveable hydrocarbons large enough to have a potential environmental or safety impact. Moreover, an evaluation is made if the permanent well barrier design is fit for purpose and can withstand the effects of any reasonable predictable chemical or geological process, providing the following functionalities:

- Withstand the maximum anticipated combined loads to which it can be subjected.
- Function as intended in the environment (pressures, temperature, fluids and mechanical stresses). that can be encountered throughout each entire lifecycle.
- Prevent unacceptable hydrocarbon flow to the external environment.

Step 2 "Identifying well barrier failure modes" involves:

- Identification of failure and degradation mechanisms and categorization of threats according to established consequence categories.
- Identification of additional threats related to unique aspects of the well abandonment design.
- identification of interdependencies between different failure modes related to failure, including potential for cascading.
- Identification of effects that may increase the likelihood of occurrence or severity of consequences.

Step 3 "Performing risk analysis" involves 4 sub-steps:

1. Assessing the downhole flow potential of the well abandonment design using the maximum anticipated flow potential from the identified hydrocarbon bearing formation(s).
2. Establish site specific environmental and safety criteria.
3. Dispersion modeling.
4. Combine flow potential analysis and dispersion modeling.

Step 4 "Performing risk evaluation" uses the outputs of the risk analysis step to assist in decision making and comparing the well abandonment design to the applicable risk acceptance criteria.

Step 5 "Conducting qualification for well abandonment design" qualifies whether a proposed abandonment design complies with the risk assessment criteria and can be considered acceptable If found unacceptable, a revised design should be proposed and evaluated, re-starting the 5-step process.

Table 4.3 – Relevant input parameters for P&A well risk assessment by DNV RP-E103 (DNV 2020). Copyright DNV AS, 2021, reproduced by permission. o DNV does not take responsibility for any consequences arising from the use of this content.

Category	Detail	Clarification
General	Well details	Number, field and location of wells; type of well (production / injection); future usage plan for the wells
	Field Architecture	Subsea of platform, high-level description
	Water depth	Water depth
Reservoir & Overburden	Number of flow potential overburden formations	Any formation which contains moveable fluids in the form of hydrocarbons or abnormally pressured water
	Hydrocarbon-bearing formations I	Name and geologic formation; true vertical depth (TVD) range (top & bottom); contents of formation, including hydrocarbon composition, volume; original, current and future pressures
	Additional hydrocarbon-bearing formations	Name and geologic formation; true vertical depth (TVD) range (top & bottom); contents of formation, including hydrocarbon composition, volume; original, current and future pressures; cross-flow potential
	Subsurface factors	Presence of hydrogen sulfide (H_2S), carbon dioxide (CO_2), geological faults, pore-pressure/fracture gradients
	Geologic barrier formations	Formations that are, or can be qualified as, barrier
Wellbore	Well history summary	Well barrier diagram & schematic; annuli fluids and annuli operating limits; primary well barrier status including status of tubing/casing/liner; secondary well barrier status including status of casing/cement including cement quality; previous abandonment activities including sidetracks;, wellbore stability diagrams, temperature plots, mud logs, pressure tests, openhole logs; challenges during well construction (caving, losses, wash-out, cementing problems, borehole instability issues, geological challenges), known well integrity issues (leaks, degraded components, pressure containment issues)
	Current and previous well operating status	Well status details, including the wells operational mode and whether the well has additional equipment, for example, gas lift
	Well flow assurance history	Wax, sand, hydrate and scale issues
Site-specific	Metocean data	Ocean current, including salinity and temperature profiles
	Environmental resource overview	Uniqueness, rarity or important of environmental resources special importance for life-history stages of species
	Site-specific safety	General or site-specific safety requirements

For further details of the risk evaluation process, see DNV (2020). The risk evaluation process has been used as a tool for operators to simplify and reduce costs of well abandonment designs, as documented by Fanailoo et al. (2017) with various field examples. The focus was to find the optimum balance between the number and type of well barriers vs. cost, based on modeling of fluid flow through micro-cracks in cemented barriers considering a range of failure modes. The systematic method employed by operators in the North Sea for their well P&A's resulted in cost savings in excess of 50%. The basic idea is therefore to use risk evaluation to optimize P&A cost and effort using simpler alternative well abandonment configurations that meet all acceptance criteria and do not significantly increase risks.

As main and important positive of the DNV approach, it should be mentioned that this is the most comprehensive, all-encompassing approach to well abandonment risk evaluation proposed and used to date, with a thorough evaluation of a large set of relevant input data. On the negative side, the current risk evaluation approach only applies to offshore wells and not (yet) to onshore wells (the focus of the KEM-18 study). However, it should be possible to extend the approach to onshore wells as well with appropriate modifications (e.g., no need for Metocean information, different environmental impact data, different geological environments, etc.). This is furthermore a very "data-intensive" approach that requires the gathering of a large set of high-quality input data. This will require considerable effort and resources, while a high-quality dataset may not even be available for older wells. In addition, the DNV RP-E103 standard only contains the high-level outline of how the proposed risk assessment process should be executed, with many of individual sub-steps, sub-processes and sub-models not specified and detailed (and most likely confidential and proprietary to DNV). This means that any risk assessment following this approach cannot be conducted independently and would require the explicit involvement of DNV. An additional concern would furthermore be the underlying complexity, relevance and errors of "black-box" evaluation models (e.g., evaluation of the degree of leakage over time through compromised barriers), knowing the limitations of both physics-based and data-driven models to approximate reality.

4.2.3. Approach by IRIS / NORCE

Scientists from IRIS (currently NORCE) developed a barrier approach to abandonment failure risk assessment (Arild et al. 2017, 2018). The chosen workflow is shown graphically in **Figure 4.3** and involves 5 steps:

1. Select the number and types of barriers to be in place.
2. Decompose each barrier into corresponding barrier elements.
3. Assist the failure mode(s) of each barrier element.
4. For each failure mode assist the failure probability and consequence.
5. Aggregate the failure probabilities and consequences in a barrier system risk picture representing the total failure probability and total leakage rate for the barrier system.

This type of workflow is well known from a variety of equipment and systems integrity studies in the oil and gas industry. However, such studies usually have an abundance of reliable data available on failure mode frequencies and consequences, making risk assessment relatively straightforward.

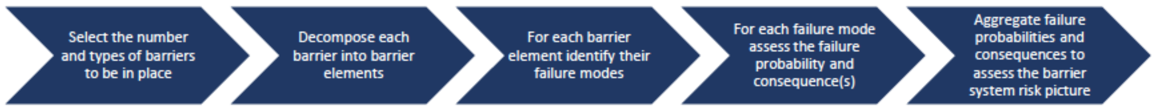


Figure 4.3 – Schematic overview of the workflow for assessing well containment performance by Arild et al. (2017). Copyright Society of Petroleum Engineers (SPE), reproduced by permission.

For permanently plugged and abandoned wells such data is much scarcer and more fragmented, and in general only partially available. A modeling framework for quantification of probabilities and consequences was adopted to integrate the various pieces of available fragmented information and to deal with input parameters uncertainty. Uncertainty was propagated by means of Monte Carlo simulation, using suitable probability distribution functions for input parameters. Sensitivity analysis provided information about the relative importance of the input parameters which could subsequently be used to prioritize risk reducing measures. This approach allowed for quantification of the barrier failure probability within a given time period, the potential consequences of barrier failure, and uncertainties related to these. The approach allowed for quantification of well barrier failure probability which scarce data. The paper by Arild et al. (2018) details the entire calculation procedure including the assessment and assignment of probability functions to inputs, and assessment of consequences, including the mean time to well / barrier failure and expected leakage rates. An example for an example well is given in the paper and reproduced in **Figure 4.4**.

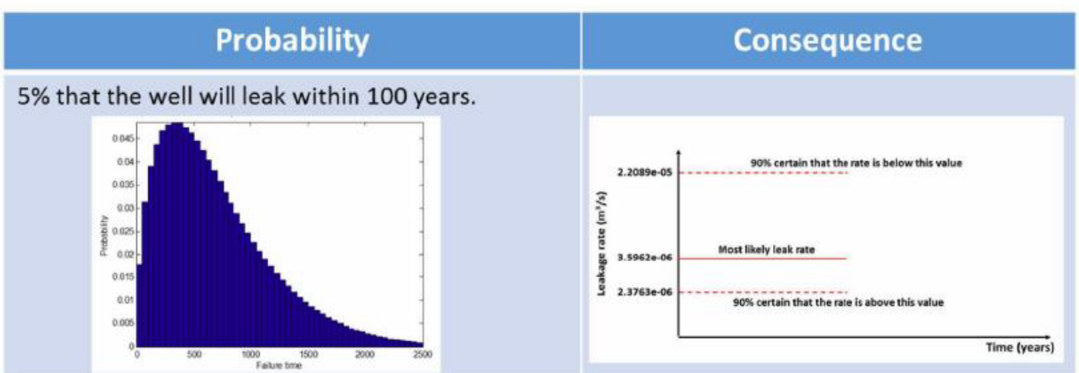


Figure 4.4 – Presentation of the detected leakage probability and the leakage rate (consequence) for an example well given by Arild et al. (2017). Image adopted from Arild et al. (2017). Copyright Society of Petroleum Engineers (SPE), reproduced by permission.

On the positive side, this approach uses proven oil & gas industry methodology for "mean life expectancy" (MLE) determination and allows for quantification of not only risk but also expected leakage rates. On the negative side, the approach may be over-simplistic in the evaluation of the impact of various risk factors on MLE and leakage rates. Moreover, the assignment of probability distribution functions to relevant parameters appears quite subjective and arbitrary. The approach would have merit, however, if its predictions could be tested and verified using a large set of statistical data of historical well abandonment failures and leakage rates. Such a dataset is unfortunately not yet available for the Netherlands, but the approach could be verified in areas where such datasets are available (e.g., in the USA and Canada – this raises the issue, however, in how far risk evaluations obtained on US and Canadian well datasets can be extrapolated to wells abandoned in the Netherlands).

4.2.4. Approach by Heriot-Watt University

In very recent papers, Johnson et al. (2021a,b) of Heriot-Watt University presented another probabilistic framework to model the transient conditions within the well P&A system rather than relying on steady state P&A models. Based on the cement integrity model for individual cement plugs with micro-annuli developed by Bois et al. (2019), Johnson et al. (2021a,b) extend modeling of flow through cemented barriers to the entire P&A system and are able to predict well leakage conditions over long timescales (i.e., hundreds to thousands of years, with published data up to 3000 years, approximately 1 million days). The P&A system modeling uses grid-based finite difference simulation approach for flow simulation using sub-models for reservoir and near-wellbore conditions, shallow formation layers with flow potential, and the well itself. **Figure 4.5** shows the mind map for the input parameters, with color coding of most certain (shown in black) and least certain (shown in red) parameters.

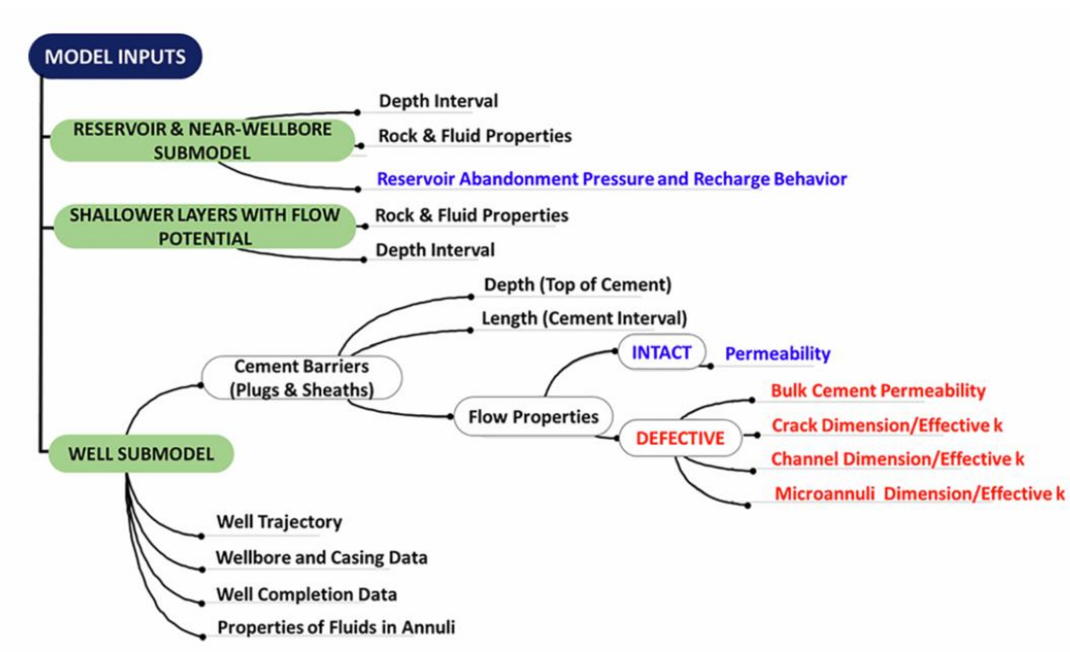


Figure 4.5 – Mind map of model input parameters used by Johnson et al. (2021b) for probabilistic risk-based well abandonment modeling. Parameters in black are well-known and least uncertain, parameters in red are critical and uncertain, while parameters in blue are useful to have if available. Image adopted from Johnson et al. (2021b). Copyright Society of Petroleum Engineers (SPE), reproduced by permission.

Well-known, simple models are adopted for e.g., flow through intact cement, micro-annuli and cement fractures, effective total permeability in case of heterogenous flow through compromised barriers, etc. Suitable probability functions were applied to uncertain parameters as input to Monte Carlo simulations. This approach makes it possible to include information from actual log observations, such as the annular cement sheath responses and flow properties obtained from actual recovered casing-cement sections, as done by Gardner et al. (2019), Govil et al. (2020), Palacio et al. (2020), Skadsem et al (2020) and Beltrán-Jiménez (2021).

A typical example of output from the model is illustrated in **Figure 4.6**, showing the expected leakage rates for three different P&A designs with intact plugs over a period of 3000 years. In addition to the ability to compare different P&A design in this way, the approach lends itself to:

- Supporting risk-based P&A design, with the ability to rank different P&A scenarios on user-defined P&A key performance indicators while accounting for uncertainty in input parameters, and to optimize P&A designs.
- Identifying critical modeling input parameters (such as cement plug/sheath length, permeability of bulk cement / micro-annulus / fracture, residual / re-pressurized reservoir pressure, etc.) to reduce modeling uncertainty and to provide guidance for relevant data-gathering.
- Providing decision-making support when planning well workovers and re-abandonments, e.g., to remediate leaking annular barriers.

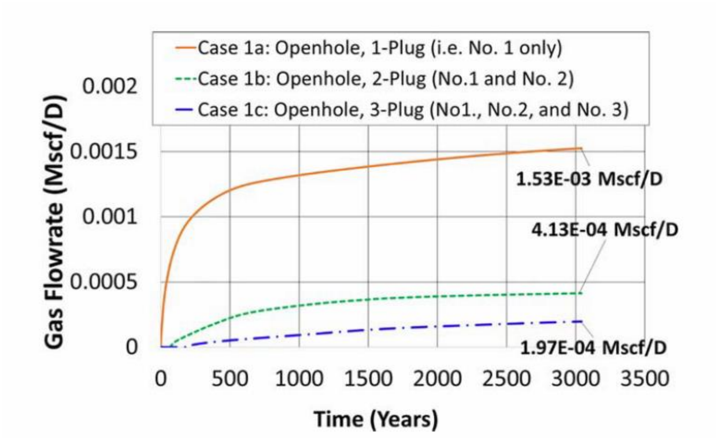


Figure 4.6 – Illustration of modeling output for a modeled case with 1, 2 and 3 cement barrier plugs in place. Image adopted from Johnson et al. (2021a). Copyright Elsevier, reproduced by permission.

This approach by Johnson et al. (2021a,b) has many advantages, including a straightforward modeling approach that is not overly complex and does not require extensive data inputs, is based on relatively simple, transparent models, can take actual field observations/measurements of permeability and leakage into account and use these for calibration, can extrapolate over long time-horizons (hundreds to thousands of years), and be used for the guiding well intervention and re-abandonment. On the downside, similar to the approach by Arild et al. (2018) the sub-models used may be too simplistic and unrealistic. Moreover, the approach is currently only limited to modeling of cement barrier degradation and does not yet include the modeling of other types of barrier materials and of time-dependent degradation of casing strings (e.g., due to corrosion). Finally, the approach does not yet include the effects of time-dependent temperature, pressure, formation geomechanics (creep, subsidence, shear-induced casing displacements, etc.) and formation chemical effects and barrier degradation. However, such effects may be added in future updates to the modeling approach.

4.2.5. Miscellaneous Approaches

For completeness, a chronological overview of other recent approaches to well integrity and abandonment risk evaluation, which are considered of lesser interest to the KEM-18 investigation, are briefly summarized here. For further details, please consult the source material.

Loizzo et al. (2015) developed an evidence-based approach to well integrity risk assessment to identify high risk scenarios and "must act" remedial situations for wells in the Paris-basin of France. In this approach, observed evidence from in-depth failure analyses is used to build and to calibrate barrier failure scenarios, as well as to validate barrier degradation mechanisms (primarily casing corrosion due to injected brine, resulting in aquifer pollution) and their dynamics. Using scenario evaluation, a criticality metric (the product of probability and severity) was derived for each well in the basin, resulting in a complete risk profile for the entire basin. The merits of the approach revolve around using actual data from historical failure observations for relevant wells, and explicitly considering the role of time. Such an evidence-based approach requires, of course, that historical well integrity failure data is readily available.

Zulqarmain et al. (2017) of LSU developed a Fault Tree Analysis (FTA) technique for the evaluation of the leakage of depleted oil and gas reservoirs and suitability for CO_2 geological sequestration purposes. The approach, which was developed for wells in South Louisiana drilled in the 1950's and 1960's, takes into account wellbore type (more specifically cased and uncased wellbores), distance between CO_2 injector and leaking well(s), and boundaries of the CO_2 storage zone and overlying buffer layers to calculate a quantitative well leakage index. This index can be used to quantify the expected CO_2 leakage rate and volume for a period of 30 years, and to optimize leaking well – injector spacings.

In a series of closely related papers, Brechan et al. (2018a,b,c,d) of NTNU announced the creation of a new well integrity model (named Life Cycle Well Integrity Model – LCWIM) and software platform. The papers make a convincing case for the need to tie well integrity monitoring and modeling together across all well lifetime phases, including the P&A phase. The papers, however, are unfortunately too sparse on the underlying detail to independently perform a well abandonment risk analysis.

Willis et al. (2019) used a probabilistic approach similar to the one proposed by Arild et al. (2017) with a workflow similar to the DNV approach (see Section 4.2.3 and 4.2.2 respectively) for long term abandonment plug integrity evaluation. Use was made of Monte Carlo simulation to calculate statistical life and probability of both individual plugs and complete well P&A designs given uncertainty in modeling parameters. The study mainly served the purpose of comparing the leakage potential of cement to that of bismuth plugs, favoring the latter in terms of time to failure even though modeled plug lengths were much shorter for bismuth.

4.3. Recommended Approach to Risk Assessment

In recommending an approach for onshore well leakage risk assessment in the Netherlands, two important factors need to be considered:

1. Wells have been drilled in the Netherlands since the 1940's. Old(er) wells may lack the detailed, high-quality data needed to conduct rigorous quantitative risk assessment.
2. These is a current lack of actual well leakage data obtained in the field, and of statistics studies conducted using such data. One of the few actual studies done to date for onshore wells in the Netherlands is the work reported by Schout et al. (2019) and Schout (2020). However, this study covers only 29 land wells in the Netherlands, a very small fraction of the total well population.

Given these factors and limitations, a practical, two-pronged approach to risk assessment is proposed.

First, following the example of Watson and Bachu (2008) described in Section 4.2.1, a simple qualitative scorecard approach with traffic light indicators could be developed, based on the major (and, if desirable, minor/additional) risk factors identified. This scorecard would score wells as either very high (red), high (orange), medium (yellow) or low (green) risk for the various risk factors. Numerical scores can be assigned to the various risk levels, and additional weighting could be applied for the various risk factors (i.e., making some risk factors count more than others on a relative scale). **Table 4.4** gives an example of what the evaluation table for such a scorecard could look like at a high level, with more granularity to be worked out for the individual risk factors (e.g., how to judge the severity of cyclic loads throughout a well's lifetime, which geomechanical loads to include as dictated by the subsurface environment, etc.). **Table 4.5** gives an example of how individual wells could subsequently be scored to generate an overall well risk score, using a score in the range 0 - 3 for individual risk factors ranging from low to very high.

Similar to Watson and Bachu (2008), it would then be possible to create geographical maps overlaying the obtained risk score on top of the overall abandoned and to-be-abandoned well populations to identify wells and well clusters of highest risk that require highest attention and scrutiny. Unlike Watson and Bachu (2008), however, it will not be possible initially to identify cut-off values on risk corresponding to actual observed leakage frequencies until more datasets of observed leakages in the field become available.

The main advantages of such an approach are, of course, its simplicity and the fact that it can be applied with relatively low levels of effort with sparse, high-level well data and known geological / geomechanical / geochemical data of subsurface formations intersected by the wells under consideration. The downsides of the approach are the fact that the risk estimation is static in time and not quantitative in key variables such as leakage rates that can be expected from wells with well integrity failures over time.

In addition to such a qualitative approach (which would become semi-quantitative if anchored and validated by actual statistical well leakage data, similar to Watson and Bachu (2008)) it is recommended to explore more quantitative probabilistic risk assessment. The approach by Heriot-Watt described in Section 4.2.4 seems well-suited for this purpose, combining the merits of relatively "lean" data requirements (cf. Figure 4.5) with useful probabilistic risk analysis and associated outputs (cf. Figure 4.6).

Table 4.4 – Scoring criteria for a simple scorecard approach to risk assessment.				
Risk Factor \ Risk	***Very high (score 3)***	***High (score 2)***	***Medium (score 1)***	***Low (score 0)***
Well age	Drilled < 1955	Drilled 1955 - 1975	Drilled 1976 - 1995	Drilled > 1995
Abandonment date	Abandoned < 1955	Abandoned 1955 - 1975	Abandoned 1976 - 1995	Abandoned >1995
Residual reservoir pressure - HC type	High - gas	Medium - gas High – oil or brine	Low – gas Medium – oil or brine	Low – oil or brine
Cyclic loads during well lifetime§	Very high	High	Medium	Low
In-situ temperature	Ultra / Extreme HPHT (>200°C, >400°F)	HPHT (150 °C - 200°C, 300°F - 400°F)	Elevated (100 °C - 150°C, 210°F - 300°F)	Low (< 100°C, < 210°F)
Geological / geo-mechanical factors§§	Large effects	Medium effects	Low effects	Not present
Chemical factors§§§	High impact	Medium impact	Low impact	Not present
Well Deviation	High deviation (> 30 degrees)		Low / no deviation (0 - 30 degrees)	
Combined factors	>3 high+ rates factor combined	3 high+ rated factors combined	2 high+ rated factors combined	0-1 high+ rated factors

§ Cyclic loads that could be considered would be varying temperature cycles, e.g., during frequent well shut-ins, hydraulic fracturing jobs, casing pressure tests, pressure / temp. loads imparted during work-over / re-completion / abandonment, etc.

§§ Geological effects that could be considered would be presence of reservoir compaction and subsidence, occurrence of fault re-activation, presence of creeping formations, etc.

§§§ Factors to consider here are the concentrations of acid gases (CO_2, H_2S) and corrosive brines (e.g., magnesium brines) the well is exposed to, the number of acid stimulation treatments the well has received, etc.

Table 4.5 – Examples of well scoring to assess overall relative risk of well leakage.			
	Well 1	**Well 2**	**Well 3**
Well Age	2	3	0
Abandonment Date	1	2	0
Residual Pressure / HC	2	0	1
Cyclic loads	2	1	2
Temperature	1	0	2
Geomechanics	3	1	2
Chemical Factors	3	1	0
Well deviation	3	0	3
Combined factors	3	1	3
Total Score	20	9	13

Even for older wells with unknown or poorly defined casing, cementing and well abandonment status, it might still be possible to generate “archetypes” of expected well status and run probabilistic risk scenarios on these. Well designs of older wells are generally simpler and of lower complexity than more recent / current wells, such that generation of such archetypes should be a relatively simple task. For more recent wells with better data-availability, the accuracy of the data-input will improve markedly, and the quality of probabilistic analysis will improve accordingly. However, even this more sophisticated approach will ultimately require calibration and validation with actual well leakage observations in the field. SodM is therefore advised to obtain such well leakage datasets.

An additional benefit that could come out of probabilistic risk analysis is an evaluation of whether the current abandonment rules and regulations for onshore wells in the Netherlands are already at optimum or can be further optimized and improved. The Dutch regulations currently specify single abandonment plugs of relatively long length (100 m, ~300 ft), which is different from for instance UK and Norwegian regulations which have implemented double barrier approaches with shorter plug lengths (See Appendix A). Probabilistic risk assessment scenarios could provide guidance on the optimum well abandonment design to guarantee maximum long-term well integrity (see also Lavrov and Torsæter 2016, 2018). Risk assessment may also be used to resolve a longstanding question on what acceptable leakage conditions are (Dusseault et al. 2014, NRCan 2019). Context for this sensitive topic could be provided by comparing the results of leakage rates derived by risk assessment with other socially accepted releases that are natural or man-made (e.g., methane releases from agriculture).

Finally, the DNV approach to risk assessment described in Section 4.2.2 may be considered for more recent wells with excellent data-quality and data-completeness, provided the current offshore well-based approach can be modified for onshore wells. As indicated, there will be considerable effort and cost involved to carry out such analysis for a large population of land wells. Small-scale pilot studies could, however, be conducted first to see if this more sophisticated approach has merit and provides additional value. It would be particularly interesting to find out if the DNV risk assessment approach would yield results that are significantly different from the results of the aforementioned scorecard and more basic probabilistic risk assessment approaches.

5. Conclusions and Recommendations

Regarding the main risk critical elements and parameters determining long-term sealing or lack thereof of boreholes (question 1, stage 1) it was found that these revolve mainly around:

- When and how the well was originally cemented (correlating with well age).
- When and how the well was abandoned (correlating with abandonment date).
- The well type (i.e., gas, oil or water/brine well – well leakage is mostly associated with gas wells).
- The residual reservoir pressure, and whether the reservoir is being re-pressured through enhanced oil recovery (water or CO_2 floods), underground storage (of wastewater and CO_2), etc.
- The cyclic pressure and temperature loads the well experienced throughout its lifetime.
- The (elevated) in-situ temperature environment to which the well is exposed.
- Geological / geomechanical factors, such as the occurrence of subsidence, slip on faults, creeping formations imparting high non-uniform casing collapse loads, etc.
- Chemical factors, such as exposure of the well barriers to corrosive gases (CO_2, H_2S) and brines.
- Wellbore deviation, with a higher frequency of well leakage observed for deviated wells.
- Combination of the above factors.

There may be additional risk factors that play a role in long-term well integrity during abandonment. Several additional factors have been suggested in this report based on literature data. It will require the generation of a comprehensive observed well leakage dataset with associated statistical data analysis to decide which other risk factors might be importance (see below).

For the stage 2 questions (question 2 – 6), it was found that:

- Q2: Intact cement has very low permeability to gas, oil and water/brine, such that observed well leakages are not due to transport through the cement but are instead associated with defects (micro-annuli, channels, fractures) that allow flows to surface to bypass the low-permeability cement matrix. Cement is furthermore a very stable material under normal temperature and pressure conditions, such that it is expected to retain its barrier properties for very long periods of time. Although it is currently not possible to extrapolate over hundreds to thousands of years, it has been observed from samples obtained from wells that are several decades old that cement properties are little changed.

- Q3: Casing is normally well-protected against corrosion by intact cement, unless the cement is missing (e.g., because of a low TOC) or is compromised by deterioration (e.g., presence of cement micro-annuli, fractures, channels, chemical cement dissolution etc.). CO_2 negatively affects bulk cement slowly with reactions that can become self-limiting, while small channels and micro-annuli may become plugged due to carbonation and gel precipitation; larger channels, however, may widen and further deteriorate under the influence of CO_2. These findings are important when considering underground CO_2 storage in depleted reservoirs. Holes in corroded casing can become a prominent leak path for flows to surface.

- Q4&Q5: Micro-annuli can be formed in different ways, ranging from cement shrinkage during primary cementing to debonding caused by cyclic loads over the well's entire lifetime. It is possible that they become blocked by grease, gels, particles and condensate as well as the effect of squeezing formations (salt, shale), but these mechanisms are mostly uncontrollable and cannot be relied upon to maintain or recover well integrity. Micro-annuli and other cement defects can be remedied artificially by annular treatment through chemical means (e.g., treatments with resins, silicates etc.), biological treatment (use of biomineralization) and physical means (e.g., use of deformable metals and casing expansion). Despite its low permeability, filter cake needs to be removed before cement placement because its presence will interfere with cement bonding to formation, potentially leading to cement-formation debonding and the formation of a cement-formation micro-annulus.
- Q6: Squeezing shale and salt formations can form competent barriers in uncemented or poorly cement annuli, with excellent hydraulic integrity over short distances. Such barriers have now been accepted in foreign standards and regulations (e.g., Norway's NORSOK D-010). Certain shale and salt formation will form barriers naturally, and it has proven possible to stimulate and accelerate barrier formation artificially using manipulation of the pressure, temperature and chemical environments the creeping formation is exposed to. The load-bearing capacity of the casing and its connections needs to be sufficient to handle the creep load to prevent excessive ovalization and potential collapse of the casing. A concern is non-uniform casing loading in fast-creeping formations.

Qualitative and quantitative risks assessments face the challenges of the lack of detailed, high-quality data for older wells, and the lack of well leakage data from field observations. A two-pronged approach to risk assessment is proposed, using (1) a simple qualitative scorecard system following the work of Watson and Bachu (2008) in Canada to identify wells in the overall population at highest risk of leakage; (2) a quantitative probabilistic approach proposed by Johnson et al. (2021a,b) of Heriot-Watt university and others, where (older) wells with incomplete / missing data can be represented by suitable "archetypes" when performing leakage risk analysis. It also may be useful in future to explore DNV's more data-intensive approach to well abandonment risk analysis, provided that the approach can be broadened to onshore wells and that the involved effort, time and costs can be justified.

Risk assessment may further be used to evaluate current well abandonment designs and expectations and possible improvements to these, while also being useful in answering the long-standing question on what acceptable leakage rates are. Context for the latter can be provided by comparing leakage rates derived from probabilistic risk analysis with other forms of socially accepted natural or man-made (e.g., agriculture) methane releases.

Additional recommendations coming out the investigation include:

- There is an opportunity to capitalize on the standards and learnings of the Canadian government / regulator, industry workgroups, academics and consultants, etc., who together are to be considered global leaders in dealing with the challenges of onshore well abandonments since the 1980's, with increased efforts in the last 2 decades. Government regulators and industry have worked together successfully for decades to improve well integrity and reduce daily emissions from leaking wells, with significant results (e.g., 40% reduction in emissions from non-serious wells in Alberta from 2000 to 2016, see NRCan 2019). There is an abundance of Canadian data and source material, some of it referenced in this report, that can benefit future management of onshore well integrity and leakage in the Netherlands. Particularly useful sources of information include:

- The *Technology Roadmap to improve Wellbore Integrity* (NRCan 2019), developed by Natural Resources Canada (NRCan) in collaboration with Canada's Wellbore Integrity and Abandonment Society (WIAS).
- The annual reports by Canada' Orphan Well Association (OWA 2014-2020) on the state of dealing with orphaned wells throughout Canada, with emphasis on Alberta where the majority of wells are located.
- *Directive 020 – Well Abandonment* by the Alberta Energy Regulator (AER 2021)
- Industry Recommended Practices (IRPs) by the Drilling and Completion Committee (DACC), in particular *IRP 25 – Primary Cementing* (DACC 2017), *IRP 26 – Wellbore Remediation* (DACC 2020), and *IRP 27 – Wellbore Decommissioning* (DACC 2021).
- The work by M. Dusseault and collaborators, particularly the document *Towards a Road Map for Mitigating the Rates and Occurrences of Long-Term Wellbore Leakage* (Dusseault et al. 2014).
- The work by T. Watson and S. Bachu, which has been used extensively throughout this study (Watson et al. 2002, Watson 2004, Watson and Bachu 2008, Watson and Bachu 2009, Bachu and Bennion 2009, Bachu and Watson 2009, Bachu 2017).

- It is recommended to explore including the Canadian practice of explicitly checking for SCP/SCVF and GM, the latter preferably using the method described by Schout et al. (2019), and remediating if present as part of the Dutch regulatory expectation prior to permanent well plugging and abandonment. If there is reason to suspect annular leakage, it may be useful to re-enter and log the well using latest techniques (e.g., spectral noise logging) to investigate flow behind casing and remediate any confirmed annular flow accordingly when flows exceed acceptable norms.
- It is strongly recommended to acquire more well leakage data in the field using appropriate field analysis techniques, such as those already employed in the Netherlands and reported by Schout et al. (2019) and Schout (2020) – see Appendix A. This then would allow for relevant statistical analysis and verification of the risk factors governing long-term well integrity and well leakage behavior. It would also allow for pro-active re-abandonment of wells that are already leaking, or with a high degree of certainty are expected to leak in the near-future.
- When planning to reclaim land previously used for oil and gas activities with the presence of abandoned wells for new urban development, it is recommended to:
  - Develop and implement a very pro-active leakage monitoring program using historical lessons from previous urban developments near ageing oil and gas developments, such as communicated by Chilingar et al. (2003) and Chilingar and Endres (2005) for California in the United States.

Monitoring measures to consider are gas migration monitoring, subsidence monitoring, air toxics monitoring, and soil and groundwater monitoring – see Appendix A.

- Develop a rapid response action plan that uses appropriate proven technology to quickly and durably re-abandon wells if leakage is confirmed by monitoring.
- Continue to track, and possibly stimulate and financially support, the development of superior well (re-)abandonment technology that improves the reliability of well abandonments, maintaining regulatory flexibility to quickly incorporate such novel technology in the rule-making when proven useful.

- If depleted reservoirs are going to be repressurized in future for EOR purposes through water- or CO_2 flooding, underground gas storage, CO_2 injection / CCUS, etc. it is important to explicitly consider the well integrity of pre-existing wells intersecting these reservoirs. Re-pressurization may restore the driving force that supports flow to surface, which could lead to the sudden onset of leakage/flow at surface and into shallow formations.
- Similarly, it is important to consider well integrity and leakage potential when repurposing old wells for new purposes, such as geothermal heat extraction. The new purpose may expose the well to loads it was not originally designed for and may not be equipped to handle.
- A common approach to well abandonment among North Sea nations (including UK and Norway - even though their focus is primary on offshore abandonments) would be useful, as already mentioned by SodM (SSM 2018) and Janssen and van der Sijp (2020). This includes framing the debate on well abandonments in terms of a common time horizon, e.g., 1 million days (~3,000 years).

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Appendix A. Essential Background

A.1. General Introduction

In order to properly understand the findings of the KEM-18 study, it is beneficial to be familiar with some essential background, context, and perspective, which is provided in this Appendix. The following topics are discussed here:

- A.2. - Barriers and long-term barrier integrity
- A.3. - Overview of well abandonment materials
- A.4. - Conditions for migration of fluids and/or gases to surface
- A.5. - Consequences of well leakages & monitoring
- A.6. - Recovery of well leakages
- A.7. - Abandonment rules and regulations overview
- A.8. - Overview of global leakage measurement studies and findings.

A.2. Barriers and Long-Term Barrier Integrity

A very brief introduction to well plugging and abandonment using barriers is provided here in order to better understand risks to barriers providing long-term well integrity. For more details, see dedicated texts such as the *Introduction to Permanent Plug and Abandonment of Wells* by Saasen and Khalifeh (2020).

Throughout the lifecycle of a well, including its plugging and abandonment phase, the integrity of a well needs to be guaranteed using the deployment of suitable barriers. The NORSOK D-010 (2021) standard defines well integrity as the "*application of technical, operational and organizational solutions to reduce the risk of uncontrolled release of formation fluids and well fluids throughout the lifetime of the well*". Impenetrable barriers are the means to prevent such an "*uncontrolled release of formation fluids and well fluids"*. Throughout each stage of a well's life, the general intent will be to maintain two qualified, independently operating well barriers, designated as a primary and a secondary barrier. The primary well barrier provides a first enclosure to hydraulically seal a potential source of flow, such as an oil or gas reservoir with the ability to sustain flow to surface. The second barrier also provides a sealing enclosure around this potential source of flow, but acts as a back-up to the primary barrier and is normally not engaged unless the primary barrier fails or is bypassed. In some cases, the primary and secondary barrier can be combined, e.g., when using long cement plugs during abandonment.

The specific primary and secondary barrier, made up of specific well barrier elements (WBE), change depending on the well's lifecycle phase, as shown in **Figure A-1** and **Table A-1**. During drilling, the primary barrier is the hydrostatic column of mud in the well at overbalance to the formation pore pressure, having the ability to form a proper filter cake to avoid fluid losses to permeable formations (which would jeopardize its ability to control fluids and gases in potential flow zones due to the loss of hydrostatic head). The secondary barrier is usually provided by the BOPs. Casing, cement behind casing in annular spaces, and cement plugs in open-hole or cased hole are the barriers during the well plugging and abandonment phase[7]. An example for a simple well abandonment is shown in **Figure A-1**. Furthermore, in addition to the installation of primary and secondary barriers an additional plug is installed at surface, known as the environmental plug or surface plug (among other names). It is the shallowest plug in the well plugging the main bore and annular spaces, but is not a true barrier as the surrounding formation cannot hold high pressures. Its main functions are to avoid exposure of the surrounding environment to hazardous fluids (e.g., leftover drilling fluids, cement spacers, etc.) still present in annular spaces of the well, to minimize the impact of leaks from unidentified sources close to surface, and. for offshore wells, to minimize swabbing seawater or freshwater into shallow formations through the well's annuli. For land wells, the

[7] *Permanent bridge / mechanical plugs are sometimes used in abandonment designs but cannot be relied upon as WBE due to concerns associated with the long-term reliability of their steel and elastomer elements, a justified concern given their high observed rate of failure in the field (Watson and Bachu 2009). They can serve a useful purpose in acting as a base foundation for plug placement of cement or alternative materials, particularly in deviated hole to avoid slumping of (heavy) cement.*

wellheads is usually but several feet below the surface, leaving no signatures behind on surface if the well is truly sealed.

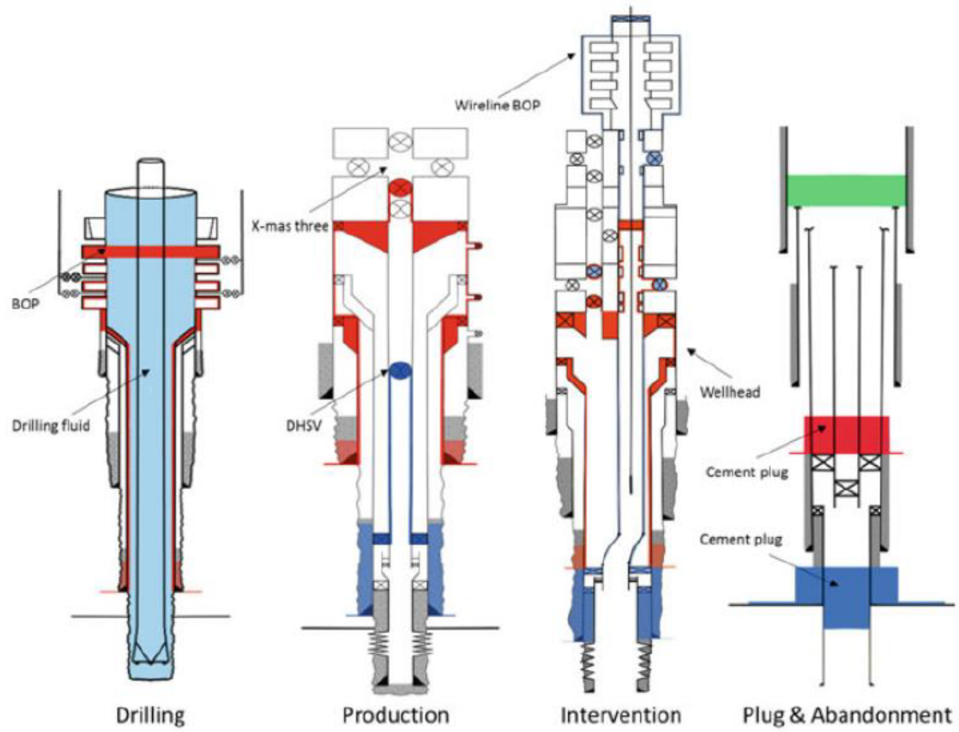

Figure A-1 – Schematic representation of the two-barrier approach during well lifetime, with color coding corresponding to entries in Table A-1 (blue = primary barrier, red = secondary barrier). Adopted from Saasen and Khalifeh (2020) with Anders et al. (2015) as the original source. Copyright Society of Petroleum Engineers (SPE), reproduced by permission.

Table A-1 – Primary and secondary barriers during well lifetime, color coding corresponding to Figure A-1. Copyright Society of Petroleum Engineers (SPE), reproduced by permission.

Well Lifecycle Phase	Primary Barrier	Secondary Barrier
Drilling	Hydrostatic mud column, overbalanced to formation pore pressure, with filter cake	Casing, casing cement, wellhead, BOPs
Production	Casing, casing cement, packer, tubing and downhole safety valve (DSV)	Casing, casing cement, wellhead, tubing hanger, Christmas tree
Intervention	Casing, casing cement, deep-set plug, hydrostatic mud column at overbalance	Casing, casing cement, wellhead, BOPs
Plug & Abandonment	Casing, casing cement, cement plugs	Casing, casing cement, cement plugs

Barriers should provide “long-term integrity” (NORSOK 2021; Oil & Gas UK 2015). What this means in terms of actual time is often left unspecified. Ideally, well integrity should be provided for an indefinite time period. However, this makes it difficult to assess well integrity risks and determine effective policy and actions in the foreseeable future. Hence, the discussion around well integrity is usually framed around more definite timeframes. The Dutch State Supervision of Mines (SodM/SSM) has framed the KEM-18 discussion in terms of well reliability in terms of a 100 - 500 year period, whereas UK and Norwegian regulators have started to discuss the topic in terms of “1 million days”, i.e. approximately 3000 years.

Main characteristics of barrier materials (Oil & Gas UK 2015) are:

- *Very low permeability – to prevent flow of fluids through the bulk material*
- *Provide an interface seal – to prevent flow of fluids around the barrier; the material provides a seal along the interface with the adjacent materials such as steel pipe or rock; risks of shrinkage and de-bonding are to be considered*
- *The barrier materials must remain at the intended position and depth of the barrier*
- *Long-term integrity – long lasting isolation characteristics of the material, not deteriorating over time; risks of crack and debonding are to be considered*
- *Resistance to downhole fluids (e.g. CO_2, H_2S, hydrocarbons, brine) at foreseeable pressures and temperatures*
- *Mechanical properties to accommodate loads at foreseeable temperatures and pressure*

The NORSOK D-010 standard adds to these requirements, specifying that the materials should be non-shrinking and behave in a ductile / non-brittle fashion to be able to withstand mechanical loads / impact. Ordinary Portland cement (OPC) is generally accepted and most used as the primary material for cement barriers used in permanent well abandonment, and most regulations globally are formulated in terms of required depths and minimum lengths of cement sheaths and plugs to provide zonal isolation (see Section A.7). Cement is considered to have properties similar to the rock formations it is substituting for in the abandoned well. Cement opposite geologic barriers is thought to be “restoring the caprock”, as shown graphically in **Figure A-2**. As mentioned by King and King (2013), <u>cement does not have to be a perfect sealing barrier for every foot of the total cemented area</u>; however, at least some part of the cement column must act as a durable and permanent seal that isolates fluids from movement to surface. The required amount of “perfect” cement that provides hydraulic isolation has been shown to be a minimum of 50 ft (~15 m), with 100 ft (~30 m) being the more generally accepted number (King and King 2013).

Cement is functioning as expected in most abandoned wells, as evidenced by the fact that the majority of wells surveyed globally to data do not currently leak (see Section A.8 – global measurement averages show that less than 10% of abandoned wells are leaking, although the number can be higher or lower for specific areas). However, along with its merits, cement also has some weaknesses and can be compromised under certain conditions, discussed in this report. There is therefore active R&D ongoing into alternative materials and methodologies that overcome the downsides of cement. The alternative materials should conform to the same requirements as for cement, as outlined above.

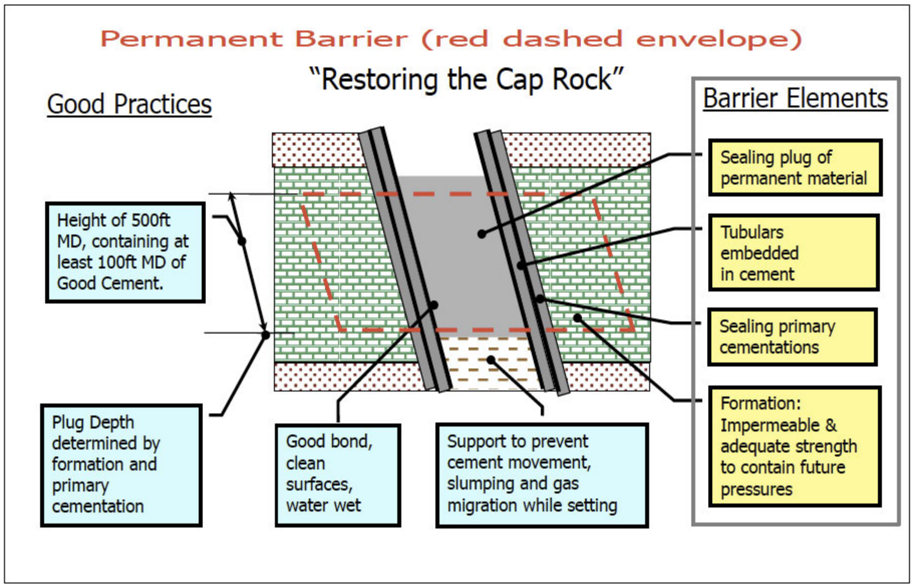

Figure A-2 – Schematic representation of "restoring the caprock", where barriers made from specific well barrier elements (WBE) such as cements plugs and annular sheaths, tubulars such as casing strings embedded in cement and also the low-permeability rock formation act together as WBEs to form a permanent well seal. Indicated also are what are considered good well abandonment practices, such as bottom support for cement plugs, good bonding of cement to casing and formation, etc. Image from Oil & Gas UK (2015). Copyright Offshore Energies UK (OEUK), reproduced by permission.

A.3. Overview of Well Abandonment Materials

A.3.1. Pro's and Con's of Portland Cement as an Abandonment Material

When applied properly and under the right circumstances, cement can be a very effective abandonment material, as evidenced by the majority of wells abandoned to date that are not leaking[8]. The requirements for an optimum sealant that has both a liquid/fluidic and solid/set state have been summarized by Bosma et al. (1999), and are summarized in **Table A-2**. This table also reveals clues as to the risk factors to sealant stability and integrity in abandoned wells over long periods of time, such as thermal stability under downhole conditions, resisting attacks from downhole chemicals, and ability to withstand operational well completion and production loads as well as geomechanical stresses. It is clear that ordinary Portland cement (OPC) meets many of the requirements given in Table A-2. It is therefore not a surprise that virtually all the legislative requirements governing well P&A are written in terms of minimum requirements for plugging wells with cement, e.g., specifying minimum length for cement plugs and cement sheaths. According to Oil and Gas UK (2015):

- *P.13 - Portland cement is currently the most used barrier material in permanent well abandonment. This is because it is considered to have similar properties to the caprock it is replacing. In existing abandonments, cement is functioning as required in most cases, but there are operational limitations and situations where cement may not be the most appropriate material*.

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[8] There are exceptions to this statement for certain fields and geographies with very high incidences of barrier or well integrity failure, such as the Santa Fe oilfield in California, the Ann Mag field in South Texas, and the Gulf of Mexico in general, but the failure rate on average is globally typically below 10%, see Davies et al. (2014).

Table A-2 – Desirable short term and long term properties for wellbore sealants, modified from Bosma et al. (1999). Copyright Society of Petroleum Engineers (SPE), reproduced by permission.	
Short Term Properties in Liquid/Fluidic State	**Long Term Properties in Solid/Set State**
Environmentally acceptable	Thermally stable under downhole pressure and temperature conditions
Desired density	
Pumpable through drillstring / tubing	Preferably detectable in annular space by conventional logging techniques
Mixable at surface	
Non-settling under static and dynamic conditions	Resist attacks from downhole chemicals (gases, brines, etc.)
Zero free water	
Desired pump / thickening / set times	Possess the mechanical properties to withstand stresses from various downhole operations and geomechanical processes
Desired fluid loss control	
Desired strength development	
100% placement in annulus	Provide zonal isolation for the life of the well, including the long abandonment phase
Resist formation gas / fluid influx	

Table A-3 summarizes the various advantages and positives associated with the use of cement as abandonment material. As indicated in the statement above, however, there are limitations and downsides to the use of cement, also summarized in Table A-3.

Table A-3 – Positives and negatives about the use of OPC as a well abandonment material.	
Advantages	**Limitations**
Inexpensive	Cement production is 2nd highest emitter of CO_2 globally
Well-known, readily available material	Sensitive to contamination by drilling fluids and spacers during displacement
Easily pumpable material over long distances, will conform to shape (annulus, plugs)	Tendency to shrink (autogenous, chemical) while setting
Property modification possible with extensive range of cement formulations and additives	Material tends to fail in a brittle mode, with limited matrix re-healing after failure
High compressive strength after setting, typically 1000's of psi (10's of MPa)	Low tensile strength, low tensile-to-compressive strength ratio (tensile strength typically ~10% of compressive strength)
Low matrix permeability (typically $k < 10$ µD), effective at restricting fluid and gas flow	Low shear and hydraulic bond to casing and rock formations (casing-cement shear and hydraulic bond strength typically 100 – 200 psi, 0.7 – 1.4 MPa)
Durable over long periods of time (e.g. Roman cemented structures surviving to present day)	Sensitive to chemical attack (e.g., from acid gases) and strength retrogression at elevated temperature
	Allowing gas migration during cement gelation with loss of ability to transmit hydraulic pressure

Many of the limitations and negatives summarized in Table A-3 (shrinkage, sensitivity to chemical attack, strength retrogression, gas migration) can be addressed by proper cement formulation and cementing practices. Formulation examples include (note that this is not meant to be a complete overview):

- **Shrinkage.** Chemical or autogenous shrinkage of cement in the range of 0.5% - 5.0% has been observed by various authors (Parcevaux and Sault 1984, Chenevert and Shrestha 1991, Sabins and Sutton 1991, Justnes et al. 1995, 1996; De Rozières and Sabins 1995, Backe et al. 1998, Baumgarte et al. 1999, Reddy et al. 2007). It can lead to cement debonding from casing and formation, forming a micro-annular leak path. It can also allow for gas migration. Shrinkage can be mitigated by cement reformulation to control crystal growth, using admixtures such as latexes, and using gas-generating expansive agents such as aluminum (Al) and zinc (Zn) (Sutton and Prather 1986, Olvera et al. 2019), or using non-Portland cements such as slag cements with reduced shrinkage (Cowan et al. 1994).
- **Low tensile strength and tensile-to-compressive strength ratio, brittle rather than ductile failure behavior.** Tensile strength of cement is typically on the order of 1/10th of the compressive strength. Low tensile strength makes the cement vulnerable to tensile fracturing, e.g., in response to cyclic pressure and temperature loads (see Section2.4 and B.4). Additions of fibers (Stroisz et al. 2019, van Vliet et al. 1995, Santos et al. 2020, Giesler and Schubert 2019) is one way to improve tensile strength.
- **Sensitivity to chemical attack.** Sensitivity to chemical attack can be addressed by cement reformulation. Sensitivity to acid gas attack, for instance, can be addressed by raising the ratio of silicate and aluminate phases compared to the calcium oxide phase, e.g., by silica or pozzolan addition (Zhang et al. 2014) or using alternative cementing materials such as geopolymers (Khalifeh et al. 2015, Liu et al. 2017, Liu 2017).
- **Strength retrogression**. Strength retrogression, which is the reduction of cement strength and increase in cement permeability at elevated temperatures is typically mitigated by adding 30% - 40% silica flour or sand to cement formulations (Nelson and Guillot 2006).
- **Gas migration**. When cement gels, it temporary loses the ability to transmit hydrostatic fluid pressure, allowing formation gas to migrate through the cement and form a leak path through it until it sets. It is therefore desirable to have the transition period from liquid to solid set cement be as quick as possible (“right angle set”). In addition, gas blocking agents and foam cement can be used.
- **Self-healing.** When brittle cement fails, it generally does not re-heal spontaneously. Various approaches developed to allow cement to re-heal, such as the use of elastomers that swell when contacted by hydrocarbons migrating through the cement (Le Roy-Delage et al. 2010, Shadravan and Amani 2015). Alternatives include geopolymers, which are alkali-activated materials that have shown true self-healing of their matrices upon damage (Liu et al. 2017, Liu 2017).

For these measures to be effective, however, they should have been implemented in field cementing practice at the time when the well was constructed or abandoned. Furthermore, there remain some inherent cement weaknesses such as low shear bond strength that are more difficult to address. This presents long-term risks during well construction, operation and abandonment phases. A particular well leakage risk, for instance, is debonding of cement from casing and formation, creating a micro-annulus that can become a pathway for upward migration of fluids and gases.

A.3.2. Cement Alternatives

As indicated, cement has historically been the "de facto" well abandonment material, and the vast majority of well abandonment guidelines around the world are specified in terms of minimum volumes and lengths of cement columns and plugs. There are, however, other abandonment materials, some with a considerable history (such as sand and clay mixtures) and others that are new and emerging (such as bismuth plugs) to consider. According to Oil and Gas UK (2015):

- *(P.15) Cement is currently used in wells as the prime material for abandonment purposes. This does not preclude the use of other materials. Alternative materials should, in principle, conform to the requirements above. The long-term integrity of materials should be documented.*

A comprehensive overview is given in **Table A-4**. This topic is currently an active field or research and development, dedicated to finding superior wellbore sealants and sealing strategies that improve upon Portland cement and other conventional sealants (Bosma et al. 1999, Jimenez et al. 2016). It is therefore to be expected that more candidate materials for well P&A will become available in the coming years, with variations on – and deviations from – the major sealant themes outlined in Table A-4. Some materials have shown great promise for the future (such as bismuth alloys, see Fulks et al. 2019) and deformable rock formations, but very little is yet known about their long term sealing ability. Given that the KEM-18 questions are primarily related to OPC, it is the primary topic of discussion. The exception is Question 6 of Phase 2, which relates to the use of shale and salt as deformable rock formations (Type "F" in Table A-4) for forming effective annular barriers in cases where there is no annular cement barrier.

Table A-4 – Overview of abandonment materials (after "Guidelines on Qualification of Materials for the Abandonment of Wells", Oil & Gas UK, 2015). Copyright Offshore Energies UK (OEUK), reproduced by permission.

Type	Material	Examples
A	Cements & ceramics (setting materials)	Portland, pozzolan, slag, phosphate-based cement, hardening ceramics, alkali-activated materials (AAM) / geopolymers, including fiber reinforcements
B	Grouts (non-setting materials	Sand and/or clay mixtures, bentonite pellets, barite plugs, calcium carbonate and other inert particle mixtures
C	Thermosetting polymers and composites	Resins (epoxies, polyesters, vinyl esters, etc.), including fiber reinforcements
D	Thermoplastic polymers and composites	Polyethylenes, polypropylenes, polyamides, PTFE, PEEK, PPS, PVDF and polycarbonates, including fiber reinforcements
E	Elastomeric polymers and composites	Natural rubber, neoprene, nitrile, EPDM, FKM, FFKM, silicone rubber, polyurethane, PUE & swelling rubbers, including fiber reinforcements
F	Deformable rock formations	Claystones, shales and salts displaying in-situ creep behavior
G	Gels	Polymer-based (polysaccharides, starches, etc.), silicate-based, clay-based, diesel / clay (gunk) mixtures
H	Glasses	
I	Metals	Steel, alloys (such as bismuth-based materials)
J	Modified in-situ materials	Barrier materials formed from casing and / or formation through thermal or chemical modification

A.3.3. Abandonment Materials Testing

Cements are specified and tested in accordance with API standards (including API Spec 10A *Cements and Materials for Well Cementing*, API RP10B-2 *Recommended Practice for Testing Well Cements*) and ISO standards (including ISO 10426-1 *Petroleum and natural gas industries — Cements and materials for well cementing — Part 1: Specification*, ISO 10426-2 *Petroleum and natural gas industries — Cements and materials for well cementing — Part 2: Testing of well cements*). In addition to standard API and ISO tests, specialized tests (see Oil & Gas UK (2015) for a more complete overview) have been developed for testing cement permeation (permeability to fluids and gases), dimensional stability (shrinkage and expansion behavior), rock-mechanical properties (elasticity, strength and failure parameters), key characteristics such as bond strength, decomposition temperature, etc. In addition — and of special relevance to this report — dedicated experimental techniques have been developed and applied to investigate fluid/gas interaction behavior (e.g., interaction with corrosive brines and gases such as CO_2 and H_2S) and response to cyclic pressure and temperature loads of the casing-cement-formation system that can jeopardize the long-term stability of cement and casing barriers. Test set-ups have been developed ranging from small benchtop tests to large-scale laboratory test rigs (see for instance van Eijden et al. (2017) for state-of-the-art zonal isolation testing performed by Shell) and full-scale field laboratories (see Manceau et al. (2015) for an example of testing the effects of cyclic pressure and temperature loading in the Opalinus Clay formation in the Mont Terri Underground Rock Laboratory, Switzerland).

A key question of concern is how cement and casing barriers will behave over very long time periods (hundreds to thousands of years), and if they will be able to continue to provide well integrity, zonal isolation and protection from leakage. We are currently severely limited in answering this question, because it is not (yet) possible to reliably accelerate the ageing of barriers to investigate their behavior over long time periods. In their "*Guidelines on Qualification of Materials for the Abandonment of Wells*", Oil and Gas UK (2015) discuss ageing tests, with recommendations to expose barrier materials to worst-case downhole conditions in terms of pressure, temperature and simulated in-situ fluids (SIFs) in autoclave test configurations. Testing at 1, 3, 6, 12 months and longer (similar to the test protocol used by Vrålstad et al. 2016, who exposed cement to crude oil, brine and H_2S in brine to 100^{o}C at 500 bar for 1, 3, 6 and 12 months) is recommended, with specific guidelines for testing given (see Oil and Gas UK (2015) for details). Once a series of values is obtained for a full time-sequence, it may be possible to extrapolate to the required barrier lifetime. The case of polymer degradation over time is specifically discussed by Oil and Gas UK (2015), and it is recommended to follow Arrhenius rate law (an exponential decline over time) to predict the rate of polymer integrity decline over time. The procedure is shown in **Figures A-3** and **A-4**.

However, when it comes to cement, the following statements apply (Oil and Gas UK 2015):

- *It should be stressed that caution should be employed when interpreting extrapolated results of this type (i.e., ageing tests – EVO), and such results should be viewed, at best, as indicative.*
- <u>*The use of accelerated temperatures to produce accelerated ageing is not suitable for Portland cement and should be assumed to be unsuitable for other materials unless proving otherwise is available.*</u>

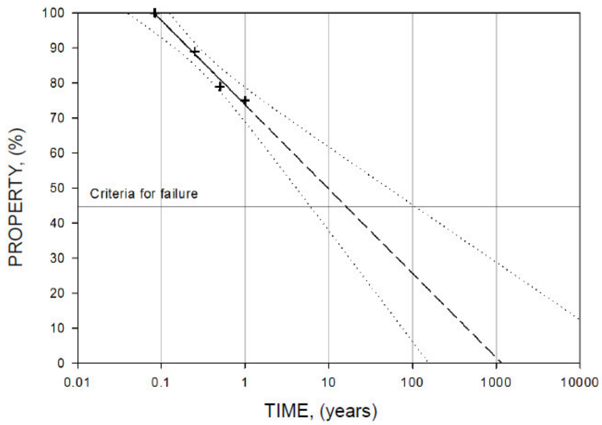


Figure A-3 – Deterioration of a key material property (e.g., sealing ability) of a material undergoing ageing testing, with extrapolation to future ages (as indicated by dashed line, extrapolating from 4 measured datapoints). Dotted lines are the 95% confidence limits for the extrapolated line. Adopted from Oil and Gas UK (2015). Copyright Offshore Energies UK (OEUK), reproduced by permission.

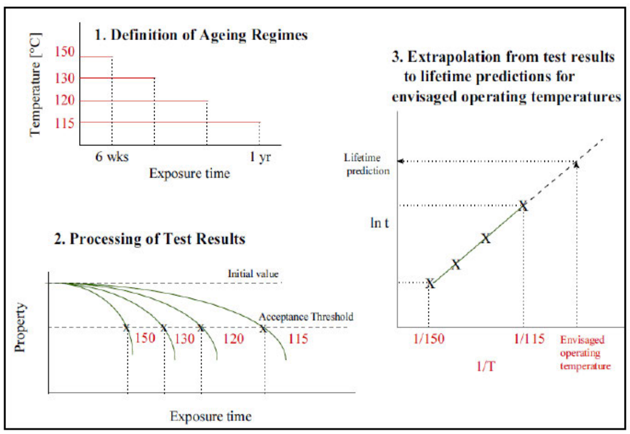


Figure A-4 – Graphical representation of a 3-step procedure for predicting the lifetime of a material using a series of ageing tests conducted at a series of test conditions (pressure, temperature, fluid exposure etc.). Adopted from Oil and Gas UK (2015). Copyright Offshore Energies UK (OEUK), reproduced by permission.

As explained earlier, using elevated temperatures to accelerate the ageing of cement is invalid, because such temperatures cause mineralogical changes in the cement that would not occur at lower temperatures, even at prolonged time periods. If representative cement ageing testing cannot (yet) be done, there may be other ways to proceed in determining long-term risks, including:

- Learning from cement and casing samples recovered from actual wells in the field that are now many decades old. This has been done, for instance, by analyzing samples from a 30-year old CO_2 flooding operation at the SACROC unit in West Texas (Carey et al. 2006), and for a 35-year old well in the Valhall field in the North Sea (see Gardner et al. 2019, Govil et al. 2020, Palacio et al. 2020, Skadsem et al 2020, and Beltrán-Jiménez (2021). Such studies show the behavior of well integrity barriers over longer periods of time – and under more realistic in-situ exposure conditions – than laboratory analysis. They therefore provide a better basis for extrapolation to longer time-frames.
- Probabilistic risk analysis is discussed in detail in Chapter 4 of this report. Of key importance to such analysis is how accurate the (sub-)models (such as used to quantify the likelihood and quantity of leakage through well abandonment barriers) are that are used to extrapolate over long time periods. They may, however, provide useful results if their prediction for e.g. well leakage frequency among the entire population of abandoned wells can be calibrated with actual field data.

A.4. Conditions for migration of fluids and/or gases to surface

In order for gases and fluids to migrate to surface, three conditions have to be met (Watson 2004, NRCan 2019):

1. A leak source needs to exist.
2. A driving force needs to be present to instigate the migration of fluids and/or gases to surface.
3. A leak path through a barrier needs to be present by which flow to surface can occur.

The first condition is self-evident: a porous and permeable reservoir needs to be present that is the source of fluids and/or gas that can migrate to surface. The latter two conditions are discussed in more detail below.

A.4.1. Driving Force and Flow Potential Analysis

There are essentially three driving forces for flow to surface:

1. **Pressure Gradient**. Hydraulically driven flow to surface (advective flow) will occur if the permeable reservoir holding gas, oil, brine or combination holds enough pressure to overcome the hydrostatic head in the cement barrier. Pressure depletion at the end of a well's productive life may limit the residual pressure available within such a reservoir to still support flow to surface.

2. **Buoyancy**. Buoyancy is movement due to differences in density under the influence of gravity, a convective flow process. Irrespective of residual reservoir pressure, there may still be flow to surface if a material density contrast exists between the fluid in the barrier (usually cement mix water) and the reservoir gas and/or fluid. The effect is stronger with an increasing difference in density: buoyancy effects will be strongest for light gases such as methane, and will be reduced for heavy crudes and higher density brines. Buoyancy is the main reason why wells in depleted gas reservoirs may still suffer from vent flows to surface if an open leak path exists.

3. **Concentration / Chemical Potential Gradient**. Diffusion is the process where a difference in concentration, leading to a chemical potential gradient, drives the transport of gases and ions in fluids. Diffusion is generally a very slow process when taking place across intact barriers, but must be taken into consideration when considering long time scales. On time scales < 100 years, mass transport by diffusion can generally be neglected and only advective and convective flow are important (Loizzo 2014). For time periods > 100 years, all mechanisms of transport need to be considered.

A.4.2. Leak Paths and Permanent Well Barrier Failure Modes

New pathways to surface can be created under certain conditions when wells are drilled through fluid- and gas-bearing strata, allowing in particular natural gases, which are more buoyant than brines or crude oil to migrate vertically to shallower formations (NRCan 2019). **Figures A-5** and **A-6** give a graphical overview of main fluid migration pathways in abandoned wells. Prominent reasons for well leakage are (note that numbering below does not correspond to numberings used in the figures):

1. **No cement.** What may seem like a trivial defect but is often overlooked in reviews of cement leakage is simply the fact that there is often no cement in the annulus, or that TOC is much lower than expected, leaving reservoirs without proper upper isolation. For cement plugs in the wellbore, cement can get contaminated during mud displacement and slump in deviated wells, leading to the situation that there may be no hardened abandonment plug at the intended location.
2. **Along the interface between casing and external cement**. This typically takes the form of a micro-annulus between the casing and cement due to debonding of the latter. Debonding and micro-annulus formation is worsened by expansion and contraction of the casing under the influence of thermal and pressure loads inside the casing, as well as shear loads acting on the cement. A complicating factor is the relatively weak shear bond between the cement and the casing. This is considered a main leak path, leading to a majority of vent flows and sustained casing pressure events observed at surface.
3. **Along the interface between casing / tubing and internal cement plug**. A micro-annulus can also form between cement and internal metal surfaces of casing and any tubing left in the hole.
4. **Along the interface between cement and rock formations**. Cement generally bonds more strongly to formations than to the casing, such that the cement-casing bond tends to rupture first before the cement-formation bond is compromised. The cement-formation bond, however, may also be weak or non-existent if residual filter cake is left on permeable formations and/or non-aqueous is fluid left on permeable and non-permeable formations because of poor mud and filter cake displacement.
5. **Flow through bulk cement permeability, effect of cement dissolution / alteration**. Cement is a low-permeability material (permeability $k < 0.1$ mD, and as low as 0.1 μD) that generally prevents any significant flow through its matrix driven by hydraulic pressure gradients or diffusion, even for long periods of time. The topic is discussed in more detail in Section 3.1. Flow through the cement matrix can be enhanced, however, when there is reactive transport that increases the permeability of the cement by dissolution and chemical alteration, or when the cement fabric gets damaged.
6. **Annular cement failure (cracking, fracturing)**. Pressure testing, hydraulic fracturing, impact damage etc. can all put compressive loads onto the casing that lead to the cement behind casing failing in tension. In addition, cement may fail because of external geomechanical loads associated with squeezing formations, reservoir compaction and subsidence, etc. The resultant cracking and fracturing of the cement can present leak paths for flow to surface.
7. **Leak in casing body or connection**. Leaks in the casing pipe body and/or connections, e.g., caused by corrosive processes, can lead to bypassing of cement barriers and flow to surface. This mechanism played a lead role in high profile well failures at the 2012 Elgin failure in the North Sea (Henderson and Hainsworth, 2014), and the 2015-2016 Aliso Canyon gas well failure in California ((Blade Energy Partners 2019).
8. **Large-scale casing / cement damage due to geomechanical processes**. Well shear triggered by subsidence and fault slip with associated seismicity can do large-scale damage to cement and casing.
9. **Damage to caprock.** Caprock damage as a results of completion/intervention practices and potentially leak recovery practices (e.g., high temperature melting) may allow annular barriers to be by-passed.

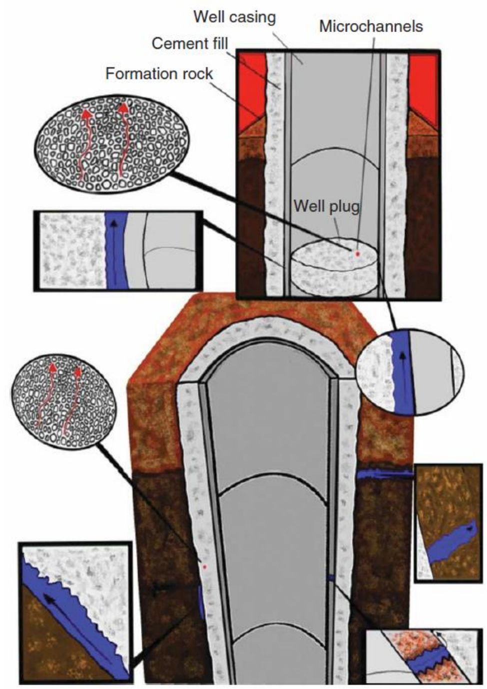


Figure A-5 – Usual representation found in majority of published literature, showing pathways for migration of gas and fluids to surface (after Nygaard et al. 2014). Copyright Society of Petroleum Engineers (SPE), reproduced by permission.

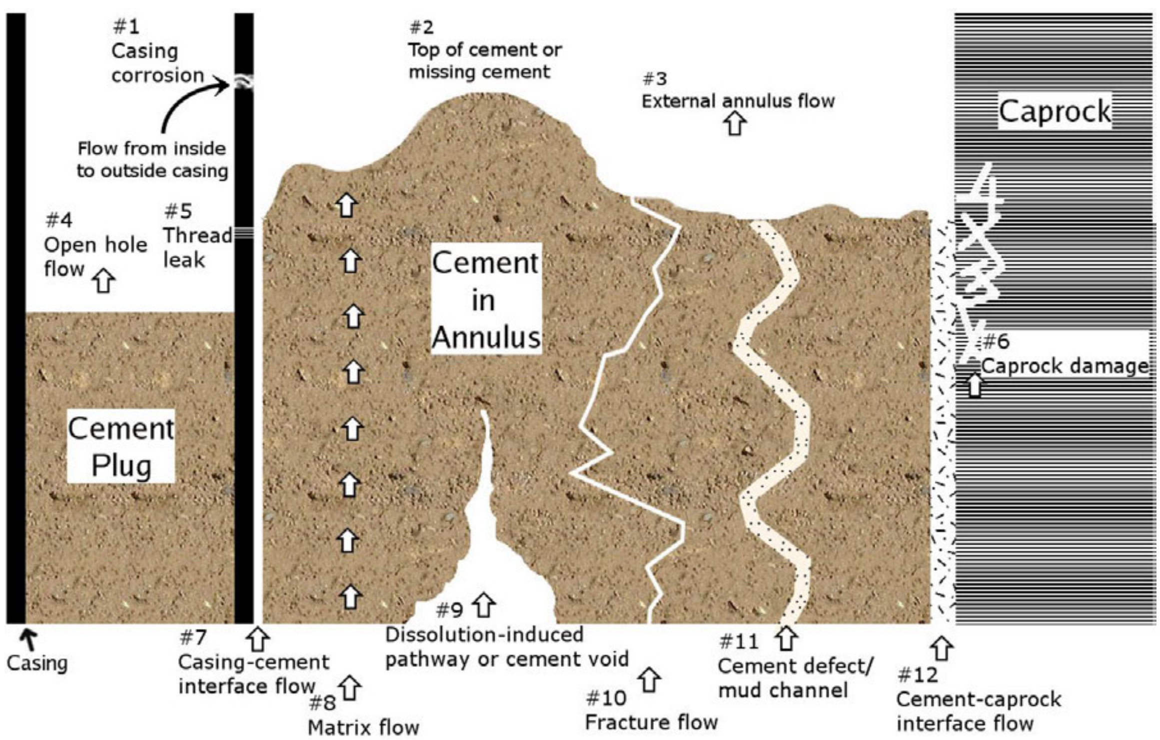


Figure A-6 – Twelve pathways for well leakage based on work on well integrity for CO_2 storage by Viswanathan et al. (2008) and Carroll et al. (2016). Reprinted with permission from Viswanathan et al. (2008). Copyright 2008 American Chemical Society (ACS), reproduced by permission.

In this report, the all-encompassing term "well leakage" is used throughout, meaning all processes whereby natural and man-made fluids (oil, brine, fracturing fluids, re-injected waste fluids) and gases (hydrocarbon gases, but predominantly methane (CH_4), CO_2, and H_2S) because of well integrity failure(s) migrate upward from deeper formations to shallower formations (such as shallow aquifers) and to surface, either through the wellbore itself (in case of leaking casing and/or cement plugs) or through leaking annular spaces, or outside of the outer casing string. The terms "gas migration" (GM) and "gas seepage" in this report mean leakage of gas outside of the outermost casing string, following the Canadian convention (NRCan 2019). Two other terms used frequently are "sustained casing pressure" (SCP) and "surface casing vent flow" (SCVF). The former term means the pressurization observed at surface of a casing annulus caused by well leakage; the latter is an actual outflow and release of fluids/gas measured from the well, through either the main bore or a casing annulus. Casing access is usually controlled by valves, which may be opened to vent gas into to the atmosphere (vented casing, leading to SCVF) or closed to prevent venting (non-vented casing, leading to SCP). In the latter non-vented case, a free gas column may develop behind the exterior casing below the surface casing, which may actually exacerbate GM: if sufficient gas pressure accumulates in the column, the gas can migrate upward outside of the surface casing and potentially into adjacent formations (e.g., into shallow aquifers) if the gas pressure exceeds the pore pressure and capillary entry pressure of these formations (Dusseault et al. 2014, Wu et al. 2016). The concepts of SCP/SCVF and GM are illustrated in **Figure A-7** for horizontal hydraulically fractured wells.

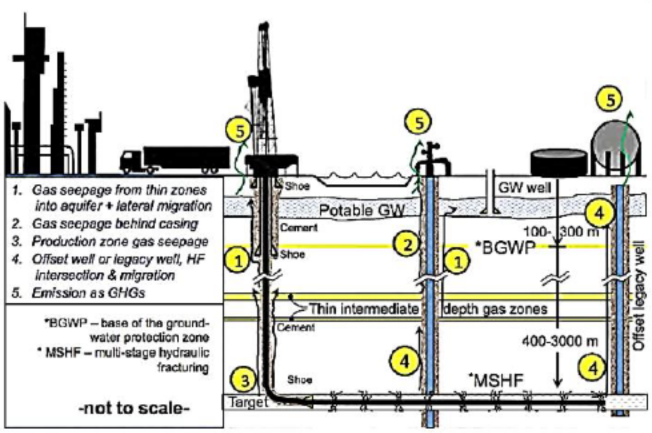
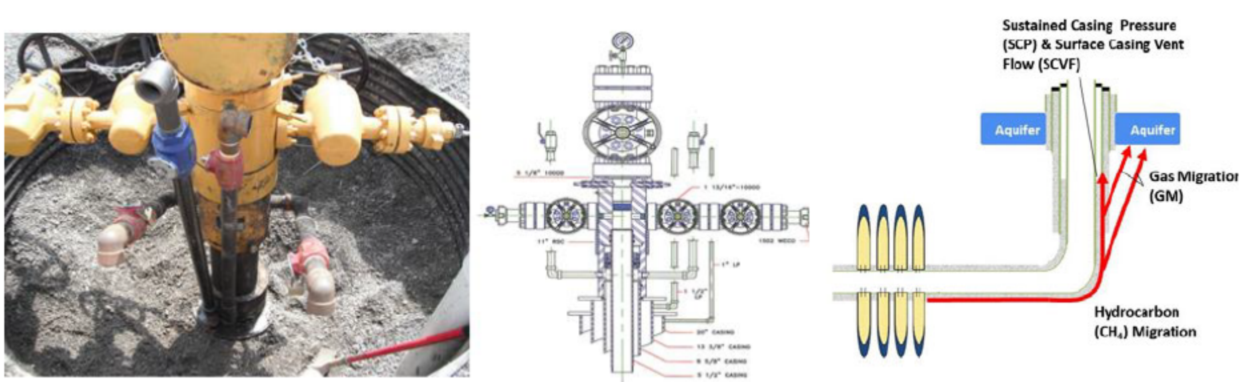


Figure A-7 – (top left) Potential leakage paths during horizontal shale gas development (after Dusseault et al. 2014; reproduced with permission by M. Dusseault); (bottom left) vent pipes welded on wellhead to facilitate annular venting; (bottom right) SCP/SCVF and GM illustrated using a horizontal shale gas development example.



A.4.2. Sources of Well Leakage

As highlighted by King and King (2013), when considering well leakages, it is important to appreciate what are man-made leakages and what are natural seeps of hydrocarbons. Around the world, there are natural seeps where oil and gas find a pathway to the surface through natural faults and fractures. More than a 1000 of such oil seeps occur in North America, with as much as 10,000 seeps estimated worldwide (Etiope (2009a); see Etiope (2009b, 2015) for natural methane emissions in Europe). Natural seepage significantly contributes to the global atmospheric methane budget at a rate of 5 – 10 Bcf/D - see King and King (2013) and references therein. Seep maps often show a direct correlation with existing oil and gas fields, as the presence of oil and gas seeps is often a first indicator of the presence of prospective hydrocarbons that are later accessed by E&P development. It is important to rule out natural seepage when leakage is observed at a wellsite to properly understand – and take corrective action against – the true root cause.

Natural seeps notwithstanding, it is of course quite possible for hydrocarbons and other fluids and gases to leak from wellbores with well integrity failures, as discussed in the previous sections. Leakage from a wellbore, most often methane gas, can come from several potential sources, depending most prominently on formation geology, stratigraphy and well location (Dussault 2000, Watson and Bachu 2009, Slater 2010, Dusseault and Jackson 2014, Dusseault et al. 2014). Hydrocarbons that have formed in deep reservoirs due to degradation of organic material under the influence of elevated temperature and pressure are referred to as being from a “thermogenic” or “petrogenic” origin, whereas methane gas that has formed at shallow to intermediate depths by methanogens is referred to as being from a “biogenic” origin. A combination of both thermogenic and biogenic hydrocarbon generation may occur as well for certain formations. Thermogenic and biogenic hydrocarbons can be distinguished by carbon isotope analysis. The abundance of the common carbon isotope ^{12}C and much rarer ^{13}C carbon isotope for observed hydrocarbons is compared with lab standards, allowing a carbon isotope fingerprint to be established. Each hydrocarbon-bearing geologic formation has its own carbon isotope fingerprint, thereby allowing hydrocarbons to be traced back to their formation of origin (see NRCan 2019 and references therein).

The results of isotope analysis into hydrocarbon origins can be surprising. In Canada, for instance, it has been found that most of the observed well leakages do not involve thermogenic hydrocarbons from production reservoirs, but instead originate primarily from shallower virgin-pressured non-commercial gas-bearing formations that were by-passed during drilling, completion and production. The production reservoir hydrocarbons are often well-isolated using highest-quality production casing cementations, whereas shallower hydrocarbons find a leak-path in the annular cement sheath through lower-quality “lead” cements generated with fillers / extenders and used for intermediate and surface casing string cementations (Watson and Bachu 2008 & 2009, Dusseault and Jackson 2014). For a North Sea example of shallow gas migration along leaking hydrocarbon wells, see Vielstädte et al. (2017). Quoting Bachu (2017): *To conclude, in the great majority of cases the gas migrating outside well casing does not originate in the production reservoir, but in overlying strata, particularly organic rich shales and coal beds. In some cases* *the gas migrating to surface is of shallow biogenic origin. This makes more difficult the task of identifying the gas source and remediating the well, leading to less methane emissions into the atmosphere.*

A.4.3. Flow Potential Analysis

For formations with the potential to flow, DNV (2020) in Recommended Practice DNVGL-RP-E103 "*Risk Based Abandonment of Wells*" argue for performing flow potential analysis as part of overall well abandonment risk analysis. Its objective is to understand the magnitude and consequence of inflow by fluids and gas, looking at the maximum anticipated flow potential from identified formations including leakage during abandonment. As part of the analysis, an overview of all potential flow zones should be compiled, including all hydrocarbon and water-/brine-bearing formations penetrated by the well. Key formation properties such porosity, permeability, connected volume, gas or fluid type and pressure should be included in the analysis to understand the flow potential. The analysis should take into account residual reservoir pressure, buoyancy, reservoir re-pressurization (by natural gas storage, CO_2 storage, EOR), and crossflow (e.g., wastewater injection communicating between wells through fractures). Formations with flow potential should be categorized in a qualitative way in accordance with **Table A-5**.

Table A-5 – Qualitative categorization of flow potential for wells with moveable fluids/gases, as proposed by DNV (2020). Copyright DNV AS, 2021, reproduced by permission. DNV does not take responsibility for any consequences arising from the use of this content.

Categories of Flow Potential	***Description***
No or limited flow potential	Formations with flow potential where moveable gas or fluids present or in the future cannot under any circumstances have an environmental or safety impact
Moderate flow potential	Formations with flow potential where moveable gas or fluids present or in the future may have an environmental, but no safety impact
Significant flow potential	Formations with flow potential where moveable gas or fluids present or in the future may have an environmental and safety impact

An important lesson from the Canadian well leakage experience mentioned in the previous Section A.4.2 is that non-commercial formations with flow potential should be included in this analysis, not just shallow aquifers and deep hydrocarbon reservoirs, which are the traditional focus of attention.

NRCan (2019) indicate that identification of potential flow zones is aided by (1) formation evaluation characterization (i.e., logging during the drilling phase), (2) carbon isotope analysis, to determine carbon isotope footprint to help identify the origin of observed fluids / gases during well abandonment; (3) acoustic emission logging (e.g., noise logging) to identify flowing fluids/gases behind casing.

A.5. Consequences of Well Leakages

One of the main intents of this KEM-18 study is to gain insight to allow for the safe reclamation of old well sites for redevelopment, such as potential future urban developments. There are relatively few references in literature that deal explicitly with the impact of oil and gas development, and particularly abandoned wells, on urban development. However, excellent case studies are provided by Endres et al. (1992), Gurevich et al. (1993), Chilingar et al. (2003), Chilingar and Endres (2005), Baciu et al. (2008), Fry (2013) and Robertson and Chilingar (2017). Negative consequences of leaking, abandoned wells include:

- **Surface release of methane, an important greenhouse gas (GHG)**. The warming potential of methane over a 20 year period is 86 times that of CO_2 (e.g., Kang et al. 2016). Releases from abandoned wells are typically on the order of 5% of overall methane emission from oil and gas industry activities. An additional concern is air quality and safety, although there is no direct link of human or animal health for non-safety-related exposure to methane (Jackson et al. 2011, NRCan 2019).
- **Potential contamination of shallow aquifers used for potable water and agricultural purposes**. Aquifer contamination from oil, gas and fluids migration were discussed in early studies by Harrison (1985) and Spangler et al. (1996). Contamination of shallow aquifers by natural gas leakage from deeper horizons migrating upwards has long been contested (e.g., Davies 2011, challenging work by Osborn et al. 2011) but shown to occur in studies by Jackson et al. (2013), Vidic et al. (2013), Jackson (2014), Darrah et al. (2014), Vengosh et al. (2014) and Robertson and Chilingar (2017). NRCan (2019) reported that gas migration caused by wellbore leakage from hydrocarbon wells has been implicated in the contamination of groundwater in a small percentage of cases in Canada (Szatkowski et al., 2002; van Stempvoort et al. 2005, Tilley and Muehlenbachs 2011, see also Muehlenbacks 2010 & 2012).
- **Fire, explosion and asphyxiation risk**, from accumulation of flammable/combustible gases such as methane, see Endres et al. (1992), Gurevich et al. (1993), Chilingar and Endres (2005) and Robertson and Chilingar (2017).
- **Surface pollution and poisoning**, with release of potentially toxic natural or man-made substances (e.g. H_2S, benzene/toluene/xylene/ethyl benzene - BTEX, hydraulic fracturing fluids with chemicals), see e.g. Chilingar and Endres (2005), Shonkoff et al. (2014) and Robertson and Chilingar (2017).
- **Negative impact on surface vegetation**. Vegetation can deteriorate as a result of methane migration in groundwater and vadose zones. Oftentimes, the earliest signs of well leakage are the occurrence of dead vegetation around old, buried wellheads. The impacts are more commonly due to CO_2-induced asphyxia and stress due to oxidation of methane to CO_2 in the shallow vadose zone, and rarely due to methane asphyxia directly (see Dusseault et al. 2014, NRCan 2019, and references therein).
- **Economic burden on industry and orphan well funds.** According to NRCan (2019), the cost to remediate leaking wells ranges from tens of thousands of dollars[9] for simple cases, but may go up to millions of dollars for more complex ones (Raimi et al. 2021).

[9] *Typical cost to abandon a well in North America is in the range of $10,000 - $20,000 for plugging only according to Kang et al. (2019) and Raimi et al. (2021), with additional costs for surface remediation*.

As discussed further in Section A.8, the majority of methane releases will happen through "super-emitters", i.e., leaking wells with a disproportionate amount of leakage compared to the average. It is to be expected that such high emitters will be relatively easy to identify. Smaller emitters, however, may be more difficult to identify, while their low-rate emissions may still become a problem in urban settings. Small releases may accumulate over time, e.g., in crawl spaces below buildings, leading to explosion risks. Prolonged exposure to low concentrations of toxic substances may also prove harmful. In addition, there is the risk that wells that have intact barriers currently will experience a barrier failure at some point in the future, for instance through adverse downhole chemical or mechanical impacts to the barrier. The question then becomes: "*how is a barrier failure best managed in an urban setting*"?

The work by Chilingar and Endres (2005), Dusseault et al. (2014) and Robertson and Chilingar (2017) provides comprehensive guidance on how the situation is best managed from a monitoring standpoint. The authors recommend a set of comprehensive monitoring strategies that include:

- **Well identification** – Any monitoring program should, of course, first start with proper identification of the location of old wells, which for older abandoned and buried land wells in the days before the application of GPS technology can be an issue.
- **Gas migration monitoring** – A recommended way to identify well leakage is using the static flux chamber measurement used by Kang et al. (2016), and by Shout et al. (2019) for their survey of 29 onshore wells in the Netherlands, see Section A.8. Dusseault et al. (2014) provides an overview of typical tests conducted in Canada for vent flow identification, including bubble tests and gas migration surveys (see also Watson 2009, Slater 2010). They furthermore recommend the adoption of Ventmeter^{TM} technology (by Doull Site Assessments).
- **Subsidence monitoring** – Subsidence monitoring in former oil and gas producing areas will be prudent, because ongoing subsidence can damage abandoned wells (see Section 2.6) and also give rise to subsurface faulting and fracturing, opening up new paths for hydrocarbon migration to surface.
- **Air toxics monitoring** – in areas of concern, it may be prudent to monitor the release of air toxics from abandoned wells, including in particular BTEX and H_2S.
- **Soil and groundwater monitoring** – Given the potential for seepage of gas into shallow formations such as shallow aquifers without any indication at surface, it is recommended to install a multi-level groundwater monitoring system, to be sampled and analyzed by trained hydrologists (Dusseault et al. 2014).

Finally, as appropriately mentioned by Chilingar and Endres (2005), it is prudent when considering building over – or close to – abandoned well sites, that land planning and permitting requires adequate room to allow access for well intervention equipment to re-enter old wells when they start leaking, in order to be able to properly re-abandon them.

A.6. Identification of Well Leakage Sources and Recovery from Well Leakages

The remediation process to recover from well leakages typically involves 4 steps (NRCan 2019):

1. Identify the source of the leak and migration pathways to surface.
2. Develop access to the source and leakage pathways[10].
3. Seal the leak (aiming for a permanent seal).
4. Verify success.

Identifying the leak(s) behind casing typically involves the use of some type (or combination of) logging and testing methods. **Table A-6** gives an overview (Kiran et al. 2017) of the uses and limitations of the different types of logs that are available to identify the leak source and migration pathways.

Table A-6 – Uses and limitations of different types of log methods to verify well integrity and identify leak sources. From Kiran et al. (2017). Copyright Elsevier, reproduced by permission.

Method	Uses	Limitations
CBL/VDL	Identifies well-bonded cement, debonding at wet casing and formation	No prediction of mud channels, vertical cracks, gas chimneys, and radial variation in cement
Ultra-sonic Imaging Log	Identifies well bonded cement, mud channels in good cement, gas chimneys, and debonding at wet casing	Unable to delineate mud channels in week cement, vertical cracks, debonding at dry casing and formation, and radial variation in cement
Isolation Scanner	Capable of showing goods meant, mud channels, gas chimneys, thick vertical cracks, the bonding add wet casing and formation, and cement radial variation	No prediction on thin vertical cracks and the bonding at dry casing
Radioactive Tracer Survey	Used to detect leaks	Incapable of predicting the quality of cement or casing
Temperature / Acoustic Noise Logs	Detects anomalies due to leak	No insights on cement
Corrosion Log	Identifies corrosion in the casing, tubular, and even casing behind the cemented zone such as surface casing	No insights on cement
SAPT/VIT	Assessment of the hydraulic properties of the cemented annulus zone under study	No evaluation of cement and casing quality

Figure A-8 reproduces Figure 2 presented by De Andrade et al. (2019), showing the characteristics of acoustic cement evaluation methods and their combination. This information was used to justify advocate

[10] In newer remediation methods such as melting casing and cement, or using casing expansion to seal micro-annuli behind casing, it is not necessary to develop access to the source and leakage pathways, and action is taken directly within the casing itself without the need for casing perforation, abrasive jetting, casing milling, etc..

for the development of a new Annulus Verification Tool (AVT) to complement the acoustic tools and address their remaining weaknesses (De Andrade et al. 2019).

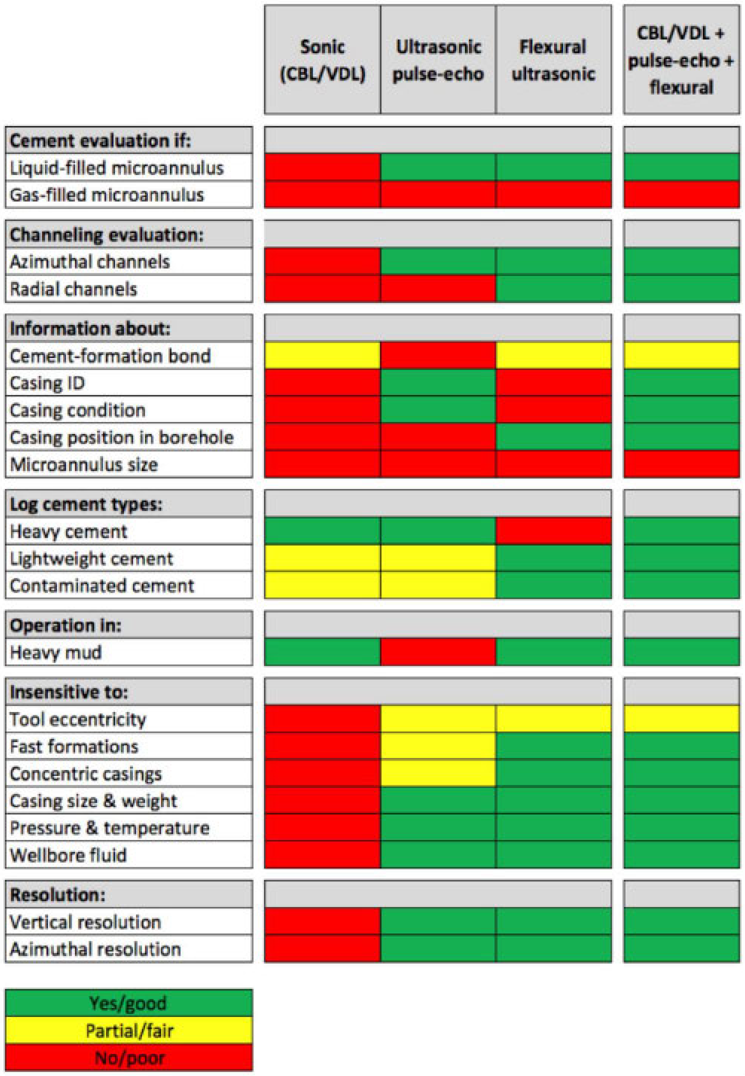


Figure A-8 – Summary of the characteristics of acoustic evaluation methods, rated yes / good (green), partial / fair (yellow) and no / poor (red) in various cement evaluation categories. The combination of the three main types of methods (CBL/VDL, ultrasonic pulse-echo, flexural ultrasonic) is shown in the rightmost column. From De Andrade et al. (2019), Figure 2. Copyright Society of Petroleum Engineers (SPE), reproduced by permission.

Once the leak source and pathway(s) are identified, the annulus is remediated through either a regular cement squeeze (Hook and Ernst 1969, Saponja 1999, Wojtanowicz et al. 2001, Cowan 2007), where the remediation treatment is forced through perforations (or alternatively through openings made by abrasive jetting, see Zwanenburg et al. 2012) in the casing and the cement, or circulated in place using the Perf-Wash-Cement (PWC – also known as a "circulation squeeze") technique (Ferg et al. 2011, Delabroy et al. 1997, Joneja et al. 2018, Lucas et al. 2018). In the latter method, two sets of perforations are used creating a circulation path into – and out of – the annular space. A sealant is now squeezed / circulated into the annulus. Regular cement squeezes have a poor success rate (Saponja 1999, Wojtanowicz et al. 2001, Cowan 2007, Dusseault et al. 2014), but alternative squeezes and non-squeeze / non-circulating treatments are available, including:

- **Microfine cement** will improve the penetration depth compared to regular cement, increasing the chance of plugging cracks and channels (Heathman et al. 1993). The use of particles, however, will still be a barrier to entry for very small channels and micro-annuli, an obstacle that is overcome by using solids-free materials (e.g., resins and silicates, see below).
- **Thermoset polymers / resins**, which can be used for plugging and casing remediations using a solids-free material (for recent sources with field applications, see Jones et al. 2013, McDonald et al. 2014, Urdaneta et al. 2014, Beharie et al. 2015, Alsaihati et al. 2017, Alkhamis et al. 2019 & 2020). Systems include epoxy resins (greatest bonding strength, relatively fast curing times), phenolic resins (higher thermal stability, easier to control curing time, but higher viscosity and HSE concerns) and furans (better control over resin maturation time compared to epoxies and lower viscosity with more penetration in narrow cracks and micro-annuli, but shrinkage during curing), see NRCan (2019). Resins are not sensitive to acid gases and do not degrade like cement. Their long term resistance to elevated temperatures is still unknown (Heseltine 2016). Resins have been considered as full replacements for cement, but significant limitations include their volumetric shrinkage behavior and HSE risks.
- **Gelling materials, such as silicates**. High ratio sodium and potassium polysilicates can precipitate and gel under the influence of pH and presence of divalent cations, thereupon forming an effective sealing material that can also fix casing leaks and protect against corrosion (Borchart et al. 1992, Creel and Crook 1997). High ratio sodium silicate was proven to be a cost-effective solution for dealing with SCP / SCVF in Canada (McDonald and Li 2017). Silicates provide the advantage of a solids-free remediation method, but with a material that is more benign from an HSE perspective, an advantage over resins.
- **Pressure-activated sealants.** A pressure-activated polymerization reaction creating a sealing material was described by Rusch et al. (2004) and used successfully to mitigate SCP for a Gulf of Mexico well.
- **Nano-particles**. Nano-sized particles can be used with the intent to physically block very small channels / micro-annuli with apertures as small as 20 μm behind casing (Todd et al. 2018).
- **Biological agents to trigger biomineralization**, using a method described by Cunningham et al. (2014) and Phillips et al. (2016). Bio-organisms, which are given access to nutrients (such as urea) and a calcium source, can form calcite, which in turn can plug fractures, reduce permeability and reduce the negative influences of CO_2.
- **Low-melting point materials such as bismuth alloys with heating**. A new method involves introducing a metal alloy (typically based on bismuth) with a low melting point into the annulus, facilitated by melting using a heater in the wellbore (Fulks and Carragher 2021). After the molten material cools down once more, it can form a solid plug in the annulus. Bismuth plugs are also currently being promoted as well abandonment plug alternatives to cement (Fulks and Carragher 2019 & 2020).
- **Shale/salt-as-a-barrier with chemical or pressure shock activation.** Some shale and salt formations can form high-integrity creep barriers in uncemented / poorly cemented annuli, and the creep rate can be beneficially influenced using chemical means or pressure shock when there is annular access. The topic is discussed in detail in Section C.4.

Alternative annular remediations that do not involve casing/cement perforation:

- **Cut & pull casing or section-mill casing to set an open-hole abandonment plug**. This is the conventional solution that usually involves the highest amount of effort and the highest cost, typically requiring a drilling rig to complete the task. The incentive for operators is currently to avoid having to cut & pull or section-mill casing and perform a rigless well abandonment, which leads to significant cost-savings when carrying out offshore well abandonments in particular.
- **Melting casing using thermite, potentially augmented with low melting-point bismuth alloys**. In a series of recent papers, Carragher and Fulks (2018a&b) and Fulks et al. (2020) have outlined an approach where high thermal heat from thermite ignition is used to melt casing, annular material and caprock as well as bismuth material, which, when cooled down, will form a metallic plug. Although promising, a concern with this technology is potential damage that is being done to the caprock formation(s) due to thermal shock of temperatures over 2000°C (Rios et al. 2021).
- **Casing expansion.** Casing expansion relies on physical expansion of the casing to close micro-annuli behind casing. The technology builds on the solids expandable tubular technology developed by Shell (Filipov et al. 1999). Studies by Kupresan et al. (2013, 2014) showed the viability of the expansion idea for SCP/SCVF control, with noteworthy reductions in permeability of lab-scale cement samples. This work has received very recent follow-up by Suncor Energy working with Noetic Engineering (Chartier et al. 2020) and Shell working with Utrecht University (Wolterbeek et al. 2018, 2019, 2021). Appreciating that successful expansion against fully set cement would not be viable (Fanguy et al. 2004), the latter partnership has focused on localized casing expansion (LCE) to reduce flow behind casing. Two field-deployable tools, a "Local Expander" and an "Energetic Expander" were extensively modeled, lab tested, and subsequently field-tested in the Groundbirch field in Canada on wells (3 wells for each tool) with SCVF. The two tools operate by different principles, but they both expand the casing only at a limited number of distinct locations. The lab and modeling studies showed that both tools can reduce flow and effective permeability behind casing by one to two orders of magnitude, without cracking the cement or significantly affecting casing collapse and burst strength. Field studies showed effectively zero residual flow for all six trial wells. Subsequent field applications have meanwhile happened in Canada and in the USA (Appalachia), substantiating the earlier trail results. A 92% SCVF reduction and 98% SCP reduction have been reported for a recent Canadian well (Wolterbeek et al. 2021). Challenges facing this approach are: (1) regulatory, i.e., will highly localized restoration of well integrity over a short distance be acceptable from a regulatory standpoint; (2) technical, e.g., how will the expanded casing behave over long time periods with an annular flow channel that is remediated only at distinct locations (with the possibility of corrosive fluids/gases still able to reach the casing through an unremediated micro-annulus below the casing expansion points).
- **Shale-as-a-barrier with temperature activation**. A 3rd way of artificially stimulating shale/salt as a barrier (in addition to using chemical means and pressure-shock, see above) is by temperature elevation to accelerate creep rates. This method does not require annular access and can be accomplished using a heater in the wellbore. Concerns revolve around local heating and associated induced compressive stresses in the casing and its connections, as well as potential heat damage to the rock formation. The topic is discussed in more detail in Section C.4.

A.7. Abandonment Rules and Regulations Overview

Table A-7 gives an overview of the regulations in various North Sea countries and global comparisons, with requirements on minimum number of barriers and their minimum length, based on information from van der Kuip et al. (2011) and Fanailoo et al. (2017) (based on original information by J. Schoenmakers).

Table A-7 - Well abandonment regulatory guidelines for North Sea nations, Australia, Canada (Alberta) and USA (GOM). After van der Kuip et at. (2017) and Fanailoo et al. (2017). Copyright Elsevier, reproduced by permission.

Country / Regulator	Regulations	Minimum No. of Barriers	Minimum length of barriers
Denmark	A Guide to Hydrocarbon Licenses in Denmark	2	100 m (~300 ft)
Germany	German Federal Mining Act	1	100 m (~ 300 ft)
Netherlands	The Mining Legislation of the Netherlands	1	100 m (~ 300 ft)
Norway	NORSOK Standard D-010	2	100 m (~ 300 ft)
United Kingdom (UK)	Guidelines for the Suspension and Abandonment of Wells	2	~30 m (100 ft)
Australia	Western Australia: Schedule of Onshore Petroleum Exploration and Production Requirements Queensland: Petroleum and Gas (Production and Safety) Regulations	1	~30 m (100 ft)
Canada, Alberta	Directive 20 of the Energy Resources Conservation Board	1	~8 m (25 ft)
United States (USA) - BSEE	30 CFR §250 Subpart Q – Decommissioning Activities (§§ 250.1700 - 250.1754)	2	~30 m (100 ft)

Tables A-8 and A-9 provide more detailed overviews at cement plug requirements at the deepest casing shoe and at the level of reservoirs or permeable layers in uncased zones, respectively, based on information from van der Kuip (2011) .

Table A-8 - Cement plug requirements at the deepest casing shoe level. After van der Kuip et al. (2011). Copyright Elsevier, reproduced by permission.

Country	Option	Minimum length	Minimum extension above / below casing shoe		Comments
			Above	Below	
Denmark	Either	100 m (~300 ft)	50 m (~150ft)	50 m (~150ft)	
	Or	50 m (~150ft)	50 m (~150ft)	0	+ Mechanical plug within 50 m from deepest casing shoe
Netherlands	Either	100 m (~300 ft)	100 m (~300ft)	0	
	Or	50 m (~150ft)	50 m (~150ft)		+ Mechanical plug
Norway	Either	100 m (~300 ft)	50 m (~150ft)	50 m (~150ft)	
	Or	50 m (~150ft)	50 m (~150ft)	0	+ Mechanical plug inside deepest casing
UK		~30 m (100 ft)	~30 m (100 ft)	0	
Canada, Alberta		15+ m* (~50+ ft)	15 m (~50 ft)	*	* Depends on formation

Table A-9 - Cement plug requirements at the level of reservoirs or permeable layers in uncased zones. After van der Kuip et al. (2011). Copyright Elsevier, reproduced by permission.

Country	Option	Minimum length between zones	Minimum extension above / below casing shoe		Comments
			Above	Below	
Denmark		50 m (~150 ft)	50 m (~150 ft)	50 m (~150 ft)	
Netherlands	Either	Across reservoir			
	Or	100 m (~300 ft)			
	Or	Natural distance			
Norway		100 m (~300 ft)	50*		* With respect to source of outflow
UK		~30 m (100 ft)	~ 30 m (100 ft)§		§ If formation fracture pressure could be exceeded
Canada, Alberta	Either	30 m (~100 ft)	15 m (~50 ft)	15 m (~50 ft)	At depths < 1500 m
	Or	60 m (~200 ft)	15 m (~50 ft)	15 m (~50 ft)	At depths > 1500 m

A.8. Overview of Global Barrier Failure and Leakage Measurement Studies

A useful global comparison of oil and gas well integrity, highly relevant to well plugging and abandonment, was published by Davies et al. (2014). **Table A-10** modifies Table 3 of the Davies et al. (2014) paper, with data selected for onshore wells only. Note that this data considers all well barrier failures, not just those occurring at abandoned wells (although in many cases, particularly those reported for sites in the USA, the data was obtained for plugged and abandoned wells). The average barrier failure rates for ~380,000 combined onshore and offshore wells drilled in Canada, China, Netherlands, Norway, UK and US was 7% percent, while the average for ~350,000 onshore wells only (see Table A-10) was 5.2%. However, there is all large range in the failure rate numbers, from a low 1.9% (USA nationwide gas storage - IPCC 2005) to a very high 75% (Santa Fe Springs Oilfield, California - Chilingar and Endres 2005).

Note that the data does not include the failure rate numbers reported King and King (2013), who reported extra-ordinary low numbers of well leakage incidents and spills for P&A'd wells in the United States, for states including Texas and Ohio (5 P&A related incidents out of 185 cases investigated for 65,000 wells for Ohio, and 1 P&A-related incident out of 211 cases investigated for 250,000 wells in Texas). King and King (2013) derive their low numbers from regulatory databases on reported spills, not from leak measurement investigations at actual well sites. This leads to very low failure rates that appear to be disconnected from those reported by other sources.

Table A-11 gives an overview of well leakage measurement studies in which barrier failure has not only been observed, but where the extent of the leakage has also been quantified, including measured flow rates to surface and effects on shallow aquifers.

Table A-10 - Compilation of published statistics (sources as indicated) on well barrier and well integrity failure, including information on well age, number of wells included in study, well location, and terminology used to describe nature of well barrier or integrity failures. Modified from Davies et al. (2014). Copyright Elsevier, reproduced by permission.

Country	Location	No. Wells studied	% Wells with integrity failure	Additional information	Published source
Bahrain	Bahrain (wells drilled 1932 - 2004)	750	13.1	Failure of surface casing with some leaks to surface	Sivakumar and Janahi (2004)
Canada	Alberta, Canada (wells drilled 1910 - 2004)	316,439	4.6	Wells monitored 1970 - 2004. Well integrity failure: SCVF and GM	Watson and Bachu (2009)
Canada	Saskatchewan, Canada (dates unknown)	435	22	Wells monitored 1987-1993. Well integrity failure: SCVF and GM	Erno and Schmitz (1996)
China	Daqing Field, China (wells drilled ~1980 - 1999)	6860	16.3	Barrier failure	Lan et al. (2000)
China	Gudao Reservoir, China (wells drilled 1978-1999)	3461	30.4	Barrier failure in oil-bearing layer	Peng et al. (2007)
China	Gunan Reservoir, China (dates unknown)	132	6.1	Barrier failure	Peng et al. (2007)
China	Hetan Reservoir, China (dates unknown)	128	5.5	Barrier failure	Peng et al. (2007)
China	Kenli Reservoir, China (dates unknown)	173	2.9	Barrier failure	Peng et al. (2007)
China	Kenxi Reservoir, China (dates unknown)	160	31.3	Barrier failure	Peng et al. (2007)
Indonesia	Malacca Strait onshore / offshore (wells drilled ~1980-2004)	164	4.3	Well integrity & barrier failures. Further 41.4% high risk of failure	Calosa and Sadarta (2010)
Netherlands	Netherlands (dates unknown)	31	13	Barrier failure	Vignes (2011)
Netherlands	Netherlands (June-July 2017)	29	3.4	CH_4 leakage to surface	Schout et al. (2019)
UK	4 Basins across UK	102	30	Elevated CH_4 interpreted as barrier failure	Boothroyd et al. (2016)
USA	Ann Mag Field, South Texas, USA (wells drilled 1998e2011)	18	61	Wells drilled 1998 - 2011. Well barrier failures mainly in shale zones	Yuan et al. (2013)
USA	Marcellus Shale, Pennsylvania, USA (wells drilled 1958 – 2013)	8030	6.26	Well integrity and barrier failure. 1.27% leak to surface	Davies et al. (2014)
USA	Marcellus Shale, Pennsylvania, USA (wells drilled 2008 - 2011)	3533	2.58	Well integrity and barrier failure	Considine et al. (2013)
USA	Marcellus Shale, Pennsylvania, USA (wells drilled 2010 - 2012)	4602	4.8	Well integrity and barrier failure	Ingraffea et al. (2014)
USA	Marcellus Shale, Pennsylvania, USA (wells drilled 2014 - 2018)	62,483	5.6	Well integrity and barrier failure	Ingraffea et al. (2020)
USA	Nationwide Gas Storage Facilities (<1965 - 1988)	6953	6.1	Well integrity and barrier failure	Marlow (1989)
USA	Nationwide CCS/Natural Gas Storage Facilities (dates unknown)	470	1.9	Well integrity failure. Described as significant gas loss	IPCC (2005)
USA	Pennsylvania, USA (wells drilled 2008-2013)	164	4.3	Wells drilled 2005 - 2012. Well integrity and barrier issues. Leak to surface in 0.24% wells	Vidic et al. (2013)
USA	Santa Fe Springs Oilfield (discovered ~1921), California, USA	>50	75	Well Integrity failures. Leakage based on the 'observation of gas bubbles seeping to the surface along well casing'	Chilingar and Endres (2005)

Table A-11 – Overview of studies conducted into leakage of methane to surface or into groundwater.

Source	Area of study	Leakage Observations
Baciu et al. (2008)	Eastern Romania	Estimated total CH_4 emission is 40 x 10^6 g CH_4 /year over 30,000 m² area, of which 8–9 x 10^6 g CH_4 /year are naturally released, 30–35 10^6 g CH_4 /year emitted from shallow boreholes.
Boothroyd et al. (2016)	UK	Elevated CH_4 detected on wells within a decade of drilling. CH_4 flux was 364 ± 677 x 10^3 g CO_{2eq}/well/year with a 27% chance that the well would have a negative flux to the atmosphere independent of well age.
Brandt et al. (2014)	Canada & USA	Total emissions estimated at 7 – 21 x 10^{12} g/year CH_4 from NG production and processing, NG distribution and use, NG hydraulic fracturing, shale gas hydraulic fracturing, petroleum hydraulic fracturing, abandoned oil and gas wells and geologic seeps (NG = natural gas).
Darrah et al. (2014)	USA (Marcellus & Barnett Shale)	Analysis of 113 and 20 samples of drinking water in the Marcellus and Barnett shale plays, resp. Study identified 8 discrete clusters of fugitive gas (methane, ethane, noble gases) contamination, 7 in Pennsylvania and 1 in Texas with increased contamination through time. Noble gas isotope measurements and hydrocarbon data show 4 contamination clusters to gas leakage caused by annular cement failures, 3 involving production gases and 1 to an underground gas well failure.
Davies et al. (2014)	Bahrain, Canada, China, Indonesia Netherlands, Norway, UK, USA	Barrier failures and well integrity failure numbers given in Table A-10.
Erno and Schmitz (1996)	Canada (Lloydminster Area)	SCVF rates varying from 0.01 to about 200 m³/well/day. GM rates generally less than 0.1 m³/well/day, no wells greater than 60 m³/well/day.
Forde et al. (2019)	Canada (British Columbia)	Study into retention of CH_4 and conversion to CO_2 during gas migration. GM at 15 of the 17 well pads investigated showed CH_4 and CO_2 effluxes ranging from 0.017 to 180 µmol/m²/s (0.024 to 250 g CH_4/m²/day) and 0.50 to 32 80 µmol/m²/s (1.9 to 122 g CO_2/m²/day). Study confirmed the limitations of visual observations and surface measurements to diagnose CH_4 leakage.
Ingraffea et al. (2020)	USA (Pennsylvania)	CH_4 emissions averaging 22.1 x 10^9 g CH_4 (−16.9, +19.5) between 2014 and 2018 from 62,483 wells (47% of statewide well inventory). Extrapolating to 2019 oil and gas well inventory yields well mean emissions of 55.6 x 10^9 g CH_4.
Jackson et al. (2013)	USA (Pennsylvania)	Study of 141 drinking water wells across NE Pennsylvania (Marcellus), investigating natural gas concentrations and isotopic signatures with proximity to shale gas wells. Methane and ethane levels were respectively 6 times and 23 times higher for homes <1 km from natural gas wells. Propane was also detected in 10 water wells within 1 km well distance. Data indicates that homeowners living <1 km from gas wells may have drinking water contaminated with stray gases.
Kang et al. (2014)	USA (Pennsylvania)	Mean methane flow rates at 19 well locations were 270 g CH_4 /well/day (varying between 6.3 x 10^{-4} g CH_4 /well/h to 86 g CH_4 /well/h) . Mean methane flow rate at control locations was 4.5 × 10^{-3} g CH_4 /well/day. Three out of the 19 wells were high emitters with emissions 3 orders of magnitude higher than median flow rate of 1.3 g CH_4 /well/day.

Table A-11 continued – Overview of studies conducted into leakage of methane to surface or into groundwater.

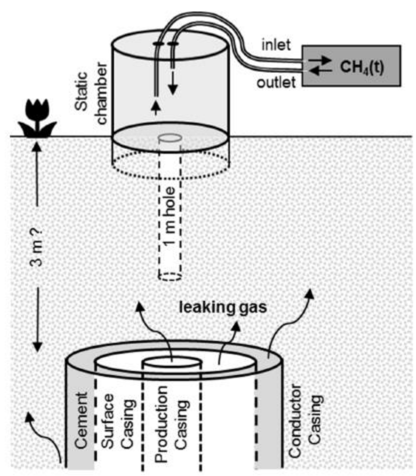
Source	Area of study	Leakage Observations
Kang et al. (2016)	USA (Pennsylvania)	Study involving 163 well measurements of (isotopes of) methane, ethane, propane, n-butane and noble gas concentrations from 88 wells in Pennsylvania. High emitters are best predicted as unplugged gas wells and plugged/vented gas wells. Emissions range from below detection limit to 100 g CH_4/well/hr. Extrapolation over 470,000–750,000 abandoned wells in Pennsylvania estimates state-wide emissions at 0.04–0.07 Mt (10^{12} g) CH_4 per year, approximately 5–8% of annual anthropogenic methane emissions in Pennsylvania.
Lebel et al. (2020)	USA (California)	Analysis of 121 wells in California, finding mean emissions of 0.286 g CH_4/h for 96 plugged wells, 35.4 g CH_4/h for 35 idle wells, 10.9 g CH_4/h for 1 unplugged well, and 190 g CH_4/h from 6 active wells
Lackey et al. (2021)	USA (Colorado, New Mexico, Pennsylvania)	Very important study into the frequency of well leakage in Colorado, New Mexico and Pennsylvania. No leakage values communicated, but detailed breakdown of leakage frequencies for wells exhibiting SCP/SCVF and GM.
McMahon et al. (2018)	USA (Colorado, Piceance Basin)	In-depth study of a well drilled in 1956 and abandoned in 1990 leaking thermogenic CH_4. No evidence seen of soil leaking methane to atmosphere, but elevated methane levels (16-20 mg/l) noted in shallow groundwater, indicating that oxidation of methane in shallow sediments is obscuring well leakage observation at surface. Concern noted about thousands of similar wells in the Piceance Basin. .
Osborn et al. (2011)	USA (Marcellus and Utica shale plays)	Study into thermogenic CH_4 contamination of aquifer overlying shale plays, finding mean and maximum methane concentrations of 19.2 and 64 mg CH_4/l within 1 km of gas wells, with background being at only 1.1 mg CH_4/l
Pekney et al. (2018)	USA (Hillman State Park, Pennsylvania)	Emissions from 22 wells ranged from non-detection (less than 90 g CH_4/well/day) to 4180 g CH_4/well day. Mean at 700 g CH_4/well/day, standard error 210 g CH_4/well/day.
Riddick et al. (2018b)	USA (West Virginia)	Study of CH_4 emissions from 112 plugged and 147 unplugged wells in West Virginia , yielding 0.1 g CH_4/hr and 3.2 g CH_4/hr on average, respectively. Highest emitting unplugged abandoned wells I were the most recently abandoned with the mean emission of wells abandoned between 1993 and 2015 of 16 g CH_4/hr compared to the mean of those abandoned before 1993 at 3×10^{-3} g CH_4/hr.
Riddick et al. (2020)	USA and UK	Study into variability of CH_4 emission over time. CH_4 emissions at all wells varied over 24 hr periods (with range 0.2-81,000 mg CH4/hr). Average emissions varied by a factor of 18 and ranging from factors of 1.1–142. No statistically significant correlation between the magnitude of emissions and temperature, relative humidity or atmospheric pressure. Results indicate that high CH_4 emission events tend to be short-lived, such that short-term (< 1 h) sampling can miss them.
Townsend-Small et al. (2016)	USA (Colorado, Ohio, Utah, Wyoming)	Analysis of 138 wells (126 in western US, 12 in eastern US), of which 119 plugged and 19 unplugged wells. 6.5% of wells had measurable CH_4 emissions. Overall mean emissions were 1.38 g CH_4/h (95% percentile at 3.17 g CH_4/h. 25% of unplugged wells emitted > 5 g CH_4/hr, with average at 10.02 g CH_4/hr. Overall methane emissions from onshore abandoned wells estimated at 1.6 x 10^4 kg CH_4/hr, which is a small fraction of the 7.3 x 10^9 kg CH_4/hr total emissions from oil and gas systems (see e.g., Brandt et al. 2014).

Table A-11 continued – Overview of studies conducted into leakage of methane to surface or into groundwater.

Source	Area of study	Leakage Observations
Schout et al. (2019)	Netherlands	Study most relevant to the Netherlands, with a survey of 28 abandoned gas wells and 1 oil well out of 900 abandoned onshore wells. Leakage of thermogenic origin was detected at 1 well (3.4% frequency) with the total methane flux estimated at 443 g CH_4/hr. Conclusions reached include that methane emissions from leaking gas wells in the Netherlands are likely negligible compared to other sources of anthropogenic emissions of methane, constituting < 1% of emissions from the Dutch energy sector. Subsequent follow-up work (Schout et al. 2020) indicate that high amounts of CH_4 leakage (up to 10 m^3/day) can be retained in the subsurface, without any methane reaching the surface. This significantly limits the ability to diagnose well leakage using surface measurements.
Stone et al. (2016, 2019)	USA (Colorado)	Two studies supported by NSF into aquifer contamination in Piceance, Raton, and San Juan Basins (Stone et al. 2016) and Wattenberg field (Stone et al. 2019). Barrier failures related to improper plugging of old(er) wellbores, presence of shallow hydrocarbons not covered by cement, casing corrosion, and poor production casing cementation. Migration of hydrocarbons into shallow aquifers and surface soil found associated with wells drilled before 1961 in the San Juan Basin, 2004 in the Piceance Basin and 2005 in the Raton basin. Higher risk of hydrocarbon migration correlated with age of the wells with less robust well designs. Very similar observations for Wattenberg field. Overall risk of barrier failures with hydrocarbon migration into aquifer was low (<< 1%) for all basins/fields.
Vielstädte et al. (2015)	North Sea (Norwegian sector)	Study of 3 abandoned wells in 81-93 m water depth in Norwegian sector of North Sea showing seepage into water. Gas was of biogenic origin with the seabed gas flow in range 1 – 19 tons CH_4/well/yr. Total annual seabed emission at 24 tons, very similar to the estimated amount of natural seepage site at the Tommeliten site.
Williams et al. (2019)	Canada (New Brunswick and Nova Scotia)	Study of methane emissions from abandoned coal mine operations in Nova Scotia and oilfield operations in New Brunswick. CH_4 migration found at one oil and gas site ($2.4 \pm 3.1 \times 10^2$ mg/m^2/day) and one abandoned coal site ($1.0 \pm 1.1 \times 10^2$ mg/m^2/day .
Williams et al. (2020)	Canada & USA	Very complete overview of methane emission in US and Canada, still covering only 0.01% of all wells. Methane emissions ranging from 1.8×10^{-3} g/h to 48 g/h with a mean of 6.0 g/h depending on well plugging status, well type and region. Top 10% of emitting well account for 84% of emissions. Only 10 high-emitting wells with over 100 g/h measured to date, contributing 65% of cumulative emissions. Quote: "*Well-specific factors such as well age, abandonment date, well bore deviation, well platform (i.e., onshore vs. offshore), and external factors (e.g., earthquakes) could control emissions from AOG* (abandoned oil and gas – EVO) *wells, meaning that emission factors may need to reflect these relationships.*
Zhou et al. (2021)	USA (California)	Study of 86 non-associated NG well pads (66 active and 20 idle well pads) in northern California. Emission rate from active non-associated NG well pads estimated at 9.5 kg CH_4/day. Extrapolation to entire state indicates 3.2×10^9 g CH_4/year, representing ~5% of CH_4 emissions from the oil and gas sector in California. Emission rates showed that roughly 15% of active well pads are responsible for >85% of the total measured emissions, indicating that emissions are largely controlled by super-emitters.

There have been several recent methane leakage studies pertaining to the oil and gas industry in the Netherlands, including those by Vielstädte et al. (2017), Yacovitch et al (2018a&b), Juez-Larre et al (2019) and Hensen et al. (2019). These studies, however, are not entirely specific to well leakages due to barrier failures associated with plugged and abandoned wells. Vignes and Aadnøy (2010) and Vignes (2011) present valuable studies on well barrier failures in the North Sea, with primary focus on Offshore Norway operations but with some data on the Netherlands as well. The most relevant work, however, has been published by Schout et al. (2019) and Schout (2020), performing an in-depth study of methane leakage measurements on a limited number of land wells in the Netherlands. This work used the static flux chamber measurement method also used by Kang (2014) with a detection limit of only ~1 x 10^{-6} g CH_4/h (e.g., Lebel et al. 2020). A schematic representation of the equipment is shown in **Figure A-9**.

Figure A-9 – Schematic representation of the static flux chamber measurement carried out above plugged, cut and buried abandoned wells. Equipment was originally used by Kang (2014) and Kang et al. (2016), and used by Schout et al. (2019) for measurements at 29 abandoned wells in the Netherlands. Copyright Elsevier, reproduced by permission.



Schout et al. (2019) found thermogenic methane at well MON-02, a well originally producing from the Monster gas field in the West Netherlands Basin and abandoned in the 1990’s. The hydrocarbon reservoir targeted consisted of a series of Triassic layers known as the Main Bundsandstein Subgroup, located at a depth of 2800 – 3000 m TVD. An important finding from the study was that neither surface scanning nor static flux chamber measurements carried out at surface proved capable of detecting the methane leakage: only the static flux measurements conducted at 1 m depth proved effective. This result showed that the leaking methane was largely retained in the subsurface upon its migration to surface (a process subsequently studied by Schout et al. 2020), e.g., by oxidation in the shallow vadose layer. It also indicated that surface measurement techniques may miss diagnosing abandoned well leakages.

Comparing the data from Table A-10 with the (limited) results from Schout et al. (2019) and Schout (2020), i.e., a failure rate of 3.4% (1 well in 29), we see that the Netherlands ranks among the countries with the lower failure rate. Reasons for this may be that most wells in the Netherlands were drilled after the 1940’s, the relatively good engineering standards in Western Europe, and effective regulatory policies. This is encouraging, but also shows that the issue of leaking wells should not be dismissed in the Netherlands in areas with high well densities and when sites are to be re-used for urban developments.

A majority of the studies mentioned in Table A-11 found that the well datasets contained "super-emitters" which emitted methane at disproportionally high rates, thereby skewing averages (see Dusseault et al. 2014, Kang et al. 2016, Ingraffea et al. 2020, Williams et al. 2020, Zhou et al. 2021). For instance, the Alberta Energy Regulator (AER) found that 30 % of total methane emissions from leaking wells was from a low number of super-emitters having vent flow rates greater than 300 m^3/day, with the remainder coming from a much larger number of non-serious wells with an average rate of 13.2 m^3/day (NRCan 2019). Of the 10,326 wells that were leaking, 96.7 % were classified "non-serious" and 3.3% as "serious". **Figure A-10** shows a graphical representation of the findings, with the cut-off between "non-serious" and serious" at an emissions rate of 300 m^3/day.

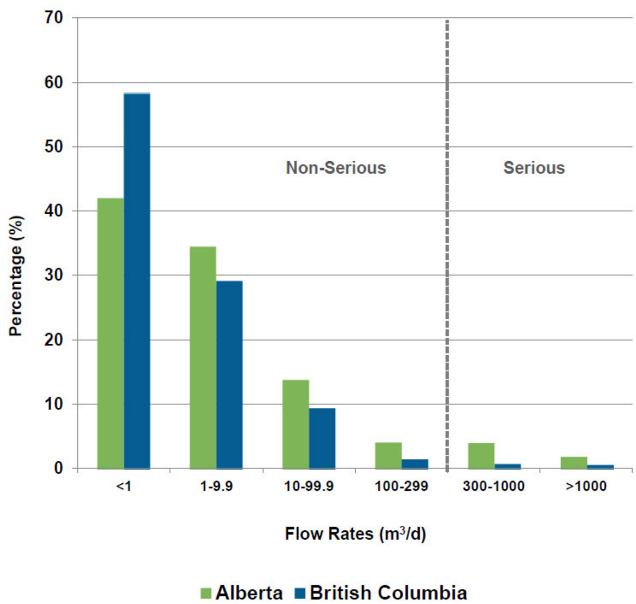


Figure A-10 - Overview of methane flow rates (in m^3/day) of leaking wells shown as percentage of the total of leaking wells for the provinces of Alberta and British Columbia in Canada. Graph by Hardie & Lewis (2015). Reproduced with permission by the Alberta Energy Regulator (AER).

AER considers a vent flow severe, requiring immediate remediation, if the following criteria apply:

1. Vent flow adjacent to unprotected (i.e., uncemented) surface casing, and/or next casing string,
2. Vent flow rate at 300 m^3/day and/or equal to a surface casing vent stabilized shut-in pressure > one-half the formation leak-off pressure at the surface casing shoe, or 11 kPa/m times the surface casing setting depth (in meters),
3. Vent flow with H_2S present,
4. Hydrocarbon liquid (oil) vent flow,
5. Saline water (> 4000 mg/l) vent flow,
6. Usable water flow, where surface shut-in pressure is as in (2),
7. Vent flow due to a wellhead seal failure or casing failure, or
8. Vent flow that constitutes a fire, public safety, or environmental hazard.

Non-severe vent flows must be monitored annually for a minimum of 5 years, or until the leak dissipates, to ensure the leak does not become more severe (for details, see Dusseault et al. 2014).

Appendix B. First Stage Question 1 – Main Sources & Additional Details

B.1. Main Sources on General Risk Elements

The following were the main sources for identifying the set of risk factors associated with the first stage question 1 of the KEM-18 study:

- **General publications on well integrity failures**
  - **Publications by G. King and collaborators** (King and King 2013; King and Valencia 2014; King 2015; King and Valencia 2016, Barreda et al. 2018). King is a well-known authority on well integrity in the USA. His publications are mainly concerned with the integrity of hydraulically fractured unconventional shale wells, but also address general well integrity issues throughout the entire life of oil and gas wells.
  - **Publications dealing with well abandonments in Canada**. The problem of abandoned / orphaned wells that are leaking has been well-studied in Canada, with the Canadian government / regulator, working with research institutes and companies, being very pro-active in delineating this problem and taking steps to address it. There are a significant number of relevant publications dealing with Canadian well failures, P&A experiences and well leakage statistics, including papers by Schmitz et al. (1996), Erno and Schmitz (1996), Gasda et al. (2004), Celia et al. (2005), Watson and Bachu (2008, 2009), Bachu and Watson (2009), LeNeveu et al. (2011), Diller et al. (2011), Macedo et al. (2012), Choi et al. (2013); Davies et al. (2014), Dusseault et al. (2014), Hardie and Lewis (2015), Bachu (2017), Magsipoc et al. (2018), Williams et al. (2020), and Gasda (2020). In addition, there are important industry / government standards and best practices documents, including Directive 020 on well abandonment by AER (2016), the Industry Recommended Practices (IRP) by the Drilling and Completion Committee (DACC 2017, 2020 & 2021), the annual reports by the Orphan Well Association (OWA 2014 – 2020), and The Technology Roadmap to improve Wellbore Integrity by Natural Resource Canada (NRCan 2019).
  - **Publications dealing with general abandoned well integrity**, including Stewart and Schouten (1988), Goodwin and Crook (1992), Calvert et al. (1994), Bellabarba et al. (2008), Jackson (2014), Loizzo (2014), Sweatman et al. (2015), Kiran et al. (2017), Achang et al. (2020), Jafariesfad et al. (2020).
- **Publications on well leakage measurements and observations**
  - **Publications by M. Kang and collaborators**, including Kang (2014), Kang et al. (2014), Kang et al. (2015), Kang et al. (2016), Kang et al. (2019), Riddick et al. (2019a&b), Lebel et al. (2020), Riddick et al. (2020), and Williams et al. (2020). Kang and collaborators have conducted important studies on leakages of wells in the United States (Pennsylvania and Virginia), Canada and the UK.
  - **Other studies dealing with well leakage measurements and observations globally**, including Lan et al. (2000), Chilingar and Endres (2005), Peng et al. (2007), Tjelta et al. (2007), Baciu (2008), Calosa and Sadarta (2010), Osborn et al. (2011), Røed et al. (2012), Considine et al. (2013), Fry et al. (2013), Jackson et al. (2013), Vidic et al. (2013), Yuan et al. (2013), Brandt et al. (2014), Darrah

et al. (2014), Ingraffea et al. (2014), Vengosh et al. (2014), Shonkoff et al. (2015), Peischl et al. (2015), Vielstädte et al. (2015), Boothroyd et al. (2016), Stone et al. (2016), Townsend-Small et al. (2016), McMahon et al. (2018), Pekney et al. (2018), Stone et al. (2019), Ingraffea et al. (2020), Lackey et al. (2021). An overview of the most relevant studies in presented in Appendix A.

  - **Publications relevant to the North Sea Area / the Netherlands**, including Vignes et al. (2010), Vignes (2011), Vielstädte et al. (2017), Yacovitch et al. (2018a&b), Hensen et al. (2019), Juez-Larre (2019), Schout et al. (2019), Schout (2020) and Schout et al. (2020).

- **General reference publications.**
  - **Reference works**: Handbook on Well Plugging and Abandonment (Smith 1993), monograph on Well Cementing 2nd edition (Nelson and Guillot 2006), IADC Drilling Series publication on Well Cementing Operation (Sweatman 2015), Introduction to Permanent Plug and Abandonment of Wells (Saasen and Khalifeh 2020).
  - **Standards and policy documents**: Publications by Oil & Gas UK (Guidelines on the Abandonment of Wells, on Qualification of Materials for the Abandonment of Wells, and on Well Abandonment Cost Estimation), Nogepa Industry Standard 45 (2019), Directive 020 by Alberta Energy Regulator - AER (2016), NORSOK D-010 (2021), API RP 65-3 on Wellbore Plugging and Abandonment by the American Petroleum Institute (2021).

The following provides additional background on the total set of risk elements identified in the answer to Question 1. Several publications explicitly address the risk factors and parameters affecting long-term sealing ability and leakage rates from field data, succinctly summarized in the following.

King and Valencia (2014) state: "*In general terms, well construction problems can be caused by leaking pipe connections, inadequate cementing, corrosion, cyclic loads, thermal extremes, Earth stresses, abrasion, and other factors.*" These factors, of course, also cause well integrity problems after well P&A. They compare to the risk factors identified in this report as shown in **Table B-1**.

Table B-1 – Well construction problems identified by King and Valencia (2014) compared to the risk factors identified in this study.

Risk Factors in This Report	Well construction problems according to King and Valencia (2014)
Well age	Leaking pipe connections Inadequate cementing
Elevated temperatures	Thermal extremes
Cyclic loads experienced during well lifetime	Cyclic loads
Geological / geomechanical factors	Earth Stresses
Chemical factors	Corrosion

Saasen and Khalifeh published a monograph dedicated to permanent plugging and abandonment in 2020, indicating main challenges associated with well P&A's (with their information primarily based on wells from offshore Norway). **Table B-.2.** compares these challenges to the risk factors identified in this study.

Table B-2. – Well construction problems identified by Saasen and Khalifeh (2020) compared to the risk factors identified in this study.

Risk Factors in This Report	Main Well P&A Challenges according to Saasen and Khalifeh (2020)
Well age	Lack of data from old wells Verifying cement behind second casing string
Well type & residual reservoir pressure	Sustained casing pressure (SCP) Uncertain ultimate reservoir pressure after abandonment
Elevated temperatures	High temperatures
Geological / geomechanical factors	Unconsolidated formations Formation permeability Changes in formation strength as a result of depletion Tectonic stresses exerted by formation (e.g. shear stress and subsidence)
Other factors	Deep section milling (complexity in well abandonment)

In their comprehensive "*Guidelines on the Qualification of Materials for the Abandonment of Wells*" issued in 2015, Oil and Gas UK discuss challenges to barriers during their lifetime, which includes 5 of risk factors selected in this study (reservoir pressure, temperature and pressure cycling, absolute temperature, mechanical stresses, and chemicals) and their interconnections:

"After placement and activation, the permanent barrier material will have to withstand external loadings, and variations in these loadings, without losing functionality as part of a permanent barrier. Likely operating conditions are listed below (...)

- ***Pressure and variation**: Pressure will change during the productive life of a field or due to recharging of a depleted reservoir to original pressure. (...) Wellbore under barriers may eventually become pressurized due to connectivity with deeper strata. (...) Fields may be charged for storage of gas or CO_2. During abandonment operations (e.g., pressure/ inflow testing, fluid change) rapid decompression may damage certain barrier materials.*

- ***Temperature and variation**: Temperature will change during the production life of a field, but follows geological patters when left undisturbed. Redevelopment of an abandoned field may also lead to temperature changes, e.g., during steam injection. Thermal changes may also result from fluid injection, gas storage or CO_2 injection in previously abandoned fields.*

- ***Mechanical stresses and variation**: Naturally occurring formation creep, subsidence or tectonic forces may act on a permanent barrier. Additionally, changes in temperature will cause expansion and contraction. (...) Loads on casing may change form tension to compression during abandonment. (...)*

- ***Chemicals**: Barrier materials may be exposed to native substances such as hydrocarbons, CO_2, H_2S and brine, as well as non-native chemicals deriving from production. (…) Such materials may either undergo reactions with the barrier material which lead to deterioration, or leach constituents from the barrier material, this compromising its integrity. Operating temperatures and pressures may influence rates of reaction and leaching. "*

In an important study on well leakage of Canadian wells, Watson and Bachu (2009) evaluated the potential for natural gas and CO_2 leakage along wellbores in Alberta, Canada using statistical SCVF/GM data from 315,000 oil, gas and injection wells. Factors of influence are summarized in **Table B-3**.

Table B-3 – Factors and their impact on SCVF/GM of wells in Canada, according to Watson & Bachu (2009). Copyright Society of Petroleum Engineers (SPE), reproduced by permission.

No Apparent Impact	Minor Impact	Major Impact
Well age	Licensee	Well deviation
Well operational mode	Surface casing depth	Well type (wells drilled and abandoned, or drilled, cased and abandoned)
Completion interval	Well total depth (TD)	Abandonment method
H_2S or CO_2 presence	Well geographical density	Oil price, regulatory changes, SCFV/GM testing

Well deviation was found to have a major impact on SCVF/GM occurrence. This increased incidence was attributed to effects such as insufficient casing centralization, differential settlement of cement, insufficient control of free water (creating a flow channel on the high side of the hole), etc. (Jakobsen et al. 1991). On the influence of well type, the overall leakage rates was ~4.5% of total, but this percentage increased to ~14% for wells that were not simply drilled and abandoned but also cased. The latter wells offered additional leak path outside of casing through annular conduits. Surprisingly, wells that were abandoned using bridge plugs with cement placed on top of them were found to be more prone to leakage than wells that used only cement plugs and/or cement squeezes. Higher failure of bridge plugs was noted when CO_2 was injected for underground storage purposes, attributed to adverse effects of CO_2 on bridge plugs elastomers and seals. The welded casing cap were found to be highly unreliable as a barrier.

Under the factors of "no apparent impact" were (surprisingly) well age, well-operational mode, completion interval, and presence of H_2S and CO_2. These need some clarification. Well age was expected to have a significant impact, but this could not positively be established because older wells abandoned before 1995 did not have reported SCVF/GM data available – thus, well age may still have been an important factor, but there simply was no data available to confirm this. Furthermore, the presence of H_2S and CO_2 is not a significant factor <u>if wells are competently cemented</u>, but corrosion caused by H_2S and CO_2 is a major source of well leakage when reservoirs are not sufficiently covered (e.g. by insufficient TOC) or if cement channeling has occurred.

Natural Resources Canada (NRCan) in collaboration with Canada's Wellbore Integrity and Abandonment Society (WIAS) developed a Technology Roadmap to improve Wellbore Integrity (NRCan 2019), which states the following on the influence of designing, drilling and constructing wells:

> *<u>How a well is designed, drilled and constructed is critical in determining the likelihood of leakage over its lifetime, including post-abandonment</u>. Leakage occurs when pathways develop in the cement that is used to seal the annular space both between casings, and the outermost casing and borehole face, and fluids invade and migrate upwards in these. Leakage also may occur when fluids migrate from inside to outside the casing due to corrosion of the casing or leaky connections. The failure of annulus seals is primarily the result of poor mud displacement during cementing, gas migration into cement during setting, micro-annulus or stress crack formation during operation, or autogenous shrinkage during cement hydration leading to the formation of a micro-annulus.*
>
> *<u>Drilling oil and gas wells remains a challenging task considering their requirements (e.g., depth, length, pathway), environment (pressure, temperature, fluid composition), and operating conditions (e.g., cyclic high pressure and temperature for fracked and thermal heavy/oil sands wells)</u>.*
>
> *<u>(…)</u>*
>
> *<u>Wellbore integrity can be compromised by defective well construction, or as a result of chemical and mechanical stresses (pressure, temperature) that damage the well during the operational or abandonment phases (Carrol, 2016)</u>. During drilling and cementing, problems that may lead to poor cement sheath and compromised casing integrity include thread leaks between casing joints, fluid losses/low cement top, poor cement quality, development of mud or gas channels in the cement, cement shrinkage, inadequate filter cake removal, formation damage during drilling, or fractured cement (Carrol,2016). These concerns can generally be addressed with improved drilling and cementing practices during the well construction phase.*
>
> *<u>Leakage can also result from various events over the life of the well, often associated with mechanical disturbances or pressure and temperature changes during production, injection, stimulation or change out of wellbore fluids. These circumstances may cause cement sheath cracking or cement debonding and micro-annulus formation. During the operational (post-completion) phase, defects in well construction may develop into problems such as dissolution-induced cement defects, formation of microannuli, chemical degradation of cement, development of fractures in the annulus cement, and casing and tubular corrosion. These types of failure may be addressed through management of wellbore conditions (e.g. temperature and pressure) and the chemical and mechanical properties of the cement (e.g. Young's modulus, and tensile, shear and bond strengths) (Watson et al., 2002).</u>*

Figure B-1 shows a graph used by Jafariesfad et al. (2020) to show what considerations are important in terms of cement placement, post placement short-term, and post-setting long-term to achieve a long-lasting cement sheath. It is based on work by Bosma et al. (1999), Ravi et al. (2002a,b, 2003), Nelson and Guillot (2006), and Jafariesfad (2017a). It supports the chosen set of risk factors in this study:

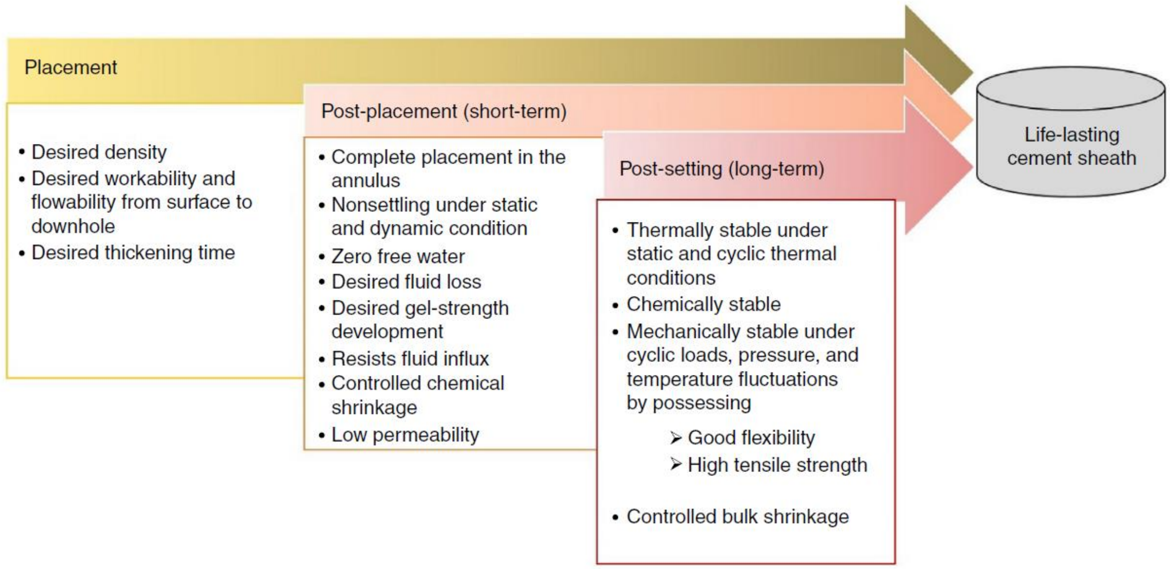


Figure B-1 – Factors of importance to placement, post-placement (short-term) and post-setting (long-term) periods. From Jafariesfad et al. (2020). Copyright Society of Petroleum Engineers (SPE), reproduced by permission.

The considerations shown in Figure B-1 for placement and post-placement-short term, as well as controlling bulk shortage post setting, all relate to cementing technology and practices used. In this report, those elements are represented by well age. The considerations during long term post-setting, which are all represented in the set of risk factors selected in this report, include:

- Thermal stability under static and cyclic thermal conditions
- Chemical stability
- Mechanical stability under cyclic loads, pressure and temperature fluctuations

In their general review of main causes of well integrity and barrier failure, Kiran et al. (2017) mention:

- Technology and practices used to cement the well originally.
- Influence of temperature in high-temperature environments, leading to cement strength retrogression.
- Negative impact of pressure and temperature cycling on the casing-cement interface.
- The effect of reservoir re-pressurization through carbon sequestration, underground gas storage, EOR/water-flooding and re-fracturing operations.
- Corrosion of casing and chemical attack of cement.
- Existing and induced geomechanical stresses.

It is easily verified that all of these factors are included in the set of risk factors proposed here, with the state of cement technology and practices once again represented by well age.

B.2. Main Sources on Well Age as a Risk Factor

The main sources for selecting well age as a risk factor are the same as those used to select the entire set of risk factors mentioned in Section B.1. King and King (2013) provide the following quote relating to "Age vs. Construction Era or Vintage":

*"For any risk rating, time is a consideration that cannot be ignored. In well construction, time has at least four major influences (*three of which are quoted here – EVO*).*

1. *Time impacts the knowledge available at the time of well construction. This in turn must reflect the knowledge that went into forming the design of the well the materials available at the time of construction and the knowledge-based regulations that governed the construction at that time. Failure rates measured in a specific time are artifacts of that period; they should not be reflective of wells designed and completed later. In well construction, the last 15 years[11] have arguably brought more advances (new pipe alloys, better pipe joints, improved coatings, new cements, and subsurface diagnostics by seismic and logging delivering better understanding of Earth forces) than the previous 15 decades of oil and gas operations.*
2. *Early-time failures reflect both the quality of well construction and general early component failure (similar to items on a new car that must be repaired in the first few weeks of operation).*
3. *Time reflects the potential for natural degradation of materials and changing earth stresses, both natural and man-made. Structures age; that is inescapable. The impact of aging, however, is highly geographically variable and controllable to a degree with maintenance. Structures in dry climates and soils often age slowly, while structures in wet areas, salt-spray zones, acid soils, and tectonically active areas can be degraded and even destroyed in a few years. The oldest producing wells, for example, are more than a century old and many have not leaked, while high-pressure, high-temperature (HP/HT), thermal-cycled, and corrosive-environment wells may have a well life of a decade or less before permanent plugging and isolation is required."*

Table B-4 reproduces a Table presented by King & Valencia (2013), showing an approximate timeline for pollution potential by era, ranging from high to moderate to lowest. The chosen era approximations largely follow the era division of associated risk in this work, with the period before 1970 indicated as moderate risk, important casing and cementing developments happening since the 1950's with accelerations happening in the 1970's, and the period after 1988 (~1990) indicated as lower risk. Note that important developments regarding well integrity assessments did not happen until the 2000's, indicated as the era of lowest risk.

[11] King and King (2013) wrote their paper in 2013, thereby implying that the modern era of well isolation with appropriate barriers starts around 1990, as adopted in this document.

Table B-4 – Approximate timeline for pollution potential by era, according to King and Valencia (2013). Copyright Society of Petroleum Engineers (SPE), reproduced and modified by permission.

Time Era Approximation	Operation Norms	Era Potential for Pollution From Well Construction
1820s to 1916	Cable-tool drilling; no cement isolation; wells openly vented to atmosphere	High
1916 to 1970	Cementing steadily improving	Moderate
1930s to present	Rotary drilling replacing cable tool; pressure-control systems and well containment systems developed	Moderate
1952 to present	Hydraulic fracturing commercialized; reduced the number of development wells and required better pipe, couplings, and cement isolation	Low (from fracturing aspects)
Mid-1960s to 2000	Gas-tight couplings and joint makeup improving	Moderate for vertical wells, joint designs improving for horizontal wells
Mid-1970's to present	Cementing improvements, including cement design software; data on flow at temperature; dynamic cementing; swelling cement; flexible, gas-tight and self-healing cements entering market	Lower
1988 to present	Multiple-fractured horizontal wells; pad drilling reducing environmental land footprint up to 90%. Improvements in lower toxicity chemicals from late 1990s	Lower
2005 to present	Well-integrity assessments; premium couplings; adding additional barriers and cementing full strings	Lower, particularly after 2010 when state laws were strengthened on well design.
2008 to present	Chemical hazard and endocrine disruptors recognized in fracturing chemicals and sharply reduced. Real-time well integrity needs being studied to achieve early warning and problem avoidance	Lowest yet, most states caught up with design and inspection requirements.

King and King (2013) also reflect on the impact of properly enforced regulations on the occurrence of gas migration at oil and gas well as well as water wells, with a graph reproduced in **Figure B-2**. This impact of the regulatory climate on the occurrence of well leakage shows in the well leakage statistics of wells in Pennsylvania (Ingraffea et al., 2014, 2020) and Bachu (2017). Quoting the latter:

- *This also confirms a prior finding that, overall, abandoned wells are more prone to GM (and SCVF) than either active or suspended wells (Watson and Bachu, 2009). <u>This is likely related to the fact that abandoned wells generally are older and were drilled and completed under a less stringent regulatory regime and using older technology and materials</u>.*

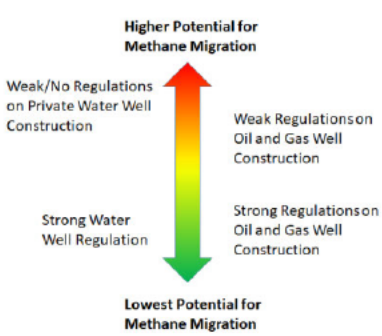


Figure B-2 – Factors involved in gas migration showing the relative impact of applicable regulations on the occurrence of methane migration according to King and King (2013). Copyright Society of Petroleum Engineers (SPE), reproduced and modified by permission.

Industry recommended practice (IRP) 27 on Well Decommissioning by the Canadian Drilling and Completion Committee (DACC 2021) dedicates a separate Appendix to the importance of well age for well abandonment. It is included integrally below.

Appendix B: Well Age

Regulations, recommended practices, training and technology have evolved so the age of the well may impact the likelihood of a risk occurring. Wells drilled decades ago often lack essential documentation, especially if ownership of the well has changed, which can increase uncertainties in the planning process.

The information in this section comes from various industry sources and is intended to show some of the potential considerations for wells of a certain error based on regulations, industry practices and technology available at the time. It is not a definitive list.

Table 20. Spud Pre-1955

Consideration	***Impact(s)***
Early cable tool rig casing cemented in place by dumping cement slurry into the open hole and then placing the casing in the cement slurry in the bottom of the borehole	• *Usually only the bottom 1-2 joints are cemented in place.* • *Increased risk of openhole crossflow, non- centralized casing, poor casing conditions or lack of circulation to surface leading to poor hydraulic isolation*
Poor cement slurry quality due to: • *Equipment.* • *Cement additive(s).* • *Poorly defined (or lack of) cementing procedures* • *use of bagged cement caused cement slurry quality and consistency challenges.* *it wasn't until the 1930s that equipment was developed that mixed and pumped cement down the hole in a continuous fashion, improving the quality of the cement job*	• *Increased probability of a lack of hydraulic isolation two potential inconsistency of cement slurry and job execution practices.*
Regulations only required covering hydrocarbon zones with cement	• *Increased probability of a lack of hydraulic isolation due to potential crossflow between upper open hole water bearing zones that need to be isolated.*
Wells often have multiple casing strings, often with non-standard sizes. *progression to the use of standardized casing sizes occurred overtime*	• *Current bridge plugs don't always fit.*
Bagged cement is only option for cementing	• *Lack of consistency in cement slurry quality may not provide for adequate hydraulic isolation.*

Table 21. 1955 - 1975

Consideration	***Impact(s)***
Regulations still only required covering hydrocarbon zones with cement.	• *Increased probability of lack of hydraulic isolation due to potential crossflow between upper open hole water bearing zones that need to be isolated.*
Bulk cement equipment introduced in the early 1970s but not commonly used so issues surrounding bagged cement still present	• *Lack of consistency in cement slurry quality doesn't always provide adequate hydraulic isolation.*
More focus starts to be placed on the importance of cement additives and cement design.	• *Improved probability of achieving hydraulic isolation with more consistent cement slurry quality.*
Groundwater protection regulations introduced.	• *Required more stringent practices to ensure hydraulic isolation.*

Table 22. 1976 - 1985

Consideration	***Impact(s)***
Job execution practices improve and become more standardized.	• *Improved probability of achieving hydraulic isolation with more consistent practices.*
Significant increase in activity beginning in the early 1980s meant lack of classroom training. Training is more on the job.	• *Potential for decrease in probability of achieving hydraulic isolation due to job execution errors or sub-optimal surface mixing operations that resulted in variation in cement slurry density/integrity*
Introduction of the NEP program in the early 1980s had companies minimizing costs, sometimes at the expense of quality cementing practices.	• *Decreased probability of achieving hydraulic isolation due to inconsistent or improper cement slurry properties for the well conditions (e.g., use of additives, fluid loss, etc.).*
Bulk cement capabilities more commonplace (compared to bagged cement). improvements in cement quality with new additives, operational design and consistency.	• *Improved probability of achieving hydraulic isolation with more consistent cement slurry quality.*
Slant drilling starts to be used. *Dispersants, free water and fluid loss agents were seldom used due to shallow depths.*	• *Increased free water leads to increased likelihood of issues with hydraulic isolation due to channels on the upper side of the wellbore.*
Thermal cement blends introduced.	• *Reduced the risk of cement degradation in wells with high temperatures.*
Foam cement introduced.	• *Improved probability of achieving hydraulic isolation because it allows for single-stage operations across weak formations.* • *Significantly increased the complexity of the cementing operation because foam cement has very specific pump rate requirements for the ratio of cement slurry to nitrogen for foam quality. Increased complexity increases the risk of poor execution and therefore poor bond.* • *Increased risk of misleading bond log information if logging tool is not calibrated for foam cement.*

Table 23. 1986 - 1997

Consideration	*Impact(s)*
Poor economic climate due to NEP program remains through the late 1980s. Companies still minimizing costs, sometimes at the expense of quality cementing practices.	• *Decreased probability of achieving hydraulic isolation due to inconsistent or improper cement slurry properties for the well conditions (e.g., use of additives, fluid loss, etc.).*
New coupling thread designs for thermal wells.	• *Reduced the risk of pipe separation at joints in high temperature wells.*
Drilling rig mud pits replaced with mud tanks.	• *If mud pits were used for wells with oil based drilling fluids there could be contamination of the soil around the well that will require additional surface reclamation work.*

Table 24. Post 1998

Consideration	*Impact(s)*
Monobore tubular production strings introduced.	• *It is more difficult to place cement properly (i.e., keeping the casing centralized) in the smaller annular spaces which can lead to poor hydraulic isolation* • *For slim hole applications difficulty is increased.*
Standards for cementing practices emerge (IRP25: Primary and Remedial Cementing (1995) and its successor IRP25: Primary Cementing.	• *Improved probability of achieving hydraulic isolation with improved cement slurry properties, practices and placement.*

B.3. Main Sources on Well Type / Reservoir Pressure as a Risk Factor

Main sources of information were the papers publications by G. King and collaborators (King and King 2013; King and Valencia 2014; King 2015; King and Valencia 2016). Additional information came from numerous field studies of leaking wells in the field, summarized in Appendix A, Section A.8. Of special significance are papers by Dussault (2000), Wojtanowicz et al. (2001), Watson (2004), Bachu and Watson (2008), Watson and Bachu (2009), and Slater (2010).

As stated earlier, in the "Guidelines on the Qualification of Materials for the Abandonment of Wells", Oil and Gas UK (2015) discuss the risk associated with reservoir pressure:

- ***Pressure and variation:*** *Pressure will change during the productive life of a field or due to recharging of a depleted reservoir to original pressure. (…) Wellbores under barriers may eventually become pressurized due to connectivity with deeper strata. (…) Fields may be charged for storage of gas or* CO_2*.*

Moreover, in the "Guidelines for the Abandonment of Wells", Oil and Gas UK (2018) reflect on the special considerations for abandonment of gas wells and high GOR wells:

- *Gas wells or high gas oil ratio (GOR) wells have the added complexity of potential gas migration through barriers. <u>This can be the case for over-pressured, hydrostatic or sub-hydrostatic reservoirs</u>. It is advised to carefully select the type of barrier material and the placement technique to counteract this condition.*

B.4. Main Sources on Cyclic Loads as a Risk Factor

The effect of cyclic pressure and temperature loading has been extensively studied in the laboratory, with key studies by Carpenter et al. (1992), Goodwin and Crook (1992), Boukhelifa et al. (2005), Teodoriu et al. (2008), Yuan et al. (2013), Du et al. (2015), Manceau et al. (2015), Shadaravan et al. (2015), Vrålstad et al. (2015), De Andrade et al. (2016), Taylor et al. (2016), Therond et al. (2017), Giesler and Schubert (2019), Vrålstad et al. (2019), Zeng et al. (2019), Kuanhai et al. (2020), Anya et al. (2020) and Zhao et al. (2021). Key findings and observations of these studies are summarized in **Table B-5**, with some representative results shown in **Figures B-3, B-4 and B-5**.

General findings are that temperature cycling and pressure cycling can lead to cement-casing and cement-formation debonding, as well as cement cracking and disking failures in severe cases. Factors of importance include the cement formulation and its material properties, with flexible/expandable/ductile cements with low shrinkage tendencies performing markedly better than neat/higher-strength/brittle cements. Addition of admixtures such as SBR latexes (Carpenter et al. 1992, Anya at al. 2020) improve bonding by mitigating cement shrinkage, but this does not eliminate it. Formation properties are important as well: high-stiffness rock formations allow less cement deformation than soft formations, resulting in a lower degree of cracking in response to applied cyclic loads. Cement debonding and cracking typically start from existing flaws / defects at the cement interfaces with casing and rock formation, with fractures subsequently radiate throughout the cement interface or bulk material. Radial crack propagation can extend into the rock formation when cement is well-bonded to this formation.

Table B-5 – Overview of key studies into the effects of pressure and temperature cycling on annular cement sheath integrity and casing integrity.

Source	Experiment details	Key findings & observations
Carpenter et al. (1992)	Cement curing at 180ºF (82ºC), 1,500 psi (10.3 MPa)	Important early cement-to-casing bond strength study on effect of thermal cycling (cooling) on cement with admixtures. Cement subjected to colling cycles with temperature lowered from 180ºF to 100ºF. Bond strengths improved with addition of surfactant, polyvinyl alcohol (PVA) and SBR latex. Shear bond strength was found to be strongly reduced (as much as 69%) by thermal shock, with effects already apparent within one 100ºF thermal cycle.
Goodwin and Crook (1992)	Cement curing at 350ºF (177ºC), 500 psi (3.4 MPa)	Important early study into effects of pressure and temperature cycling on annular cement sheaths. Casing pressure cycles of 2000 psi, 4000 psi and 6000 psi caused progressively worse radial cement cracking and permeability increase for all cement formulations tested. More brittle cement performed worse than more ductile formulations. Dedicated field trials of pressure cycling substantiated the lab results (failure in more brittle cement system, more ductile system remaining intact).
Boukhelifa et al. (2005)	Ambient temperature / atmospheric pressure conditions	Dedicated set-up developed with annular cement geometry with a central core that can be expanded/contracted and outer rings simulating flexible or stiff formation, testing 7 cement formulations. Air permeability as a function of cyclic loading measured. Ability to handle loads, prevent tensile cracking and close micro-annulus ranked as Flexible & Expanding Cement > Flexible Cement > Foam Cement > Neat Cement. Stiffer rocks leads to fewer cracks.
Teodoriu et al. (2008)	± 9,300 kN axial loads on casing, ambient temp. / atm. press.	Casing fatigue study with cycled loads close to yield stress of 18 5/8 in. N80 casing with API buttress connections. Failure (rupture) observed in 1 of 3 casing samples after 10 cycles. Fatigue behavior of buttress and premium connections compared.
Yuan et al. (2013)	Cement curing at room conditions, 167ºF & atm. press., 212ºF and 2,610 psi	Study into low cycle cement fatigue using cyclic pressure loading (30 cycles) of unconfined cement cylinders (to 55,115 lbf and 77,162 lbf). Failure was observed within ~15 cycles for 55,115 lbf loading, and within ~4 cycles for 77,162 lbf. ANSYS modeling study used to investigate the beneficial effect of confining pressure on cycles to failure. Effect of temperature considered minor below 300ºF. Temperature may have more significant effect on cycles to failure above 300ºF.
De Andrade et al. (2014)	Sample curing: 66ºC (150ºF), atm. press. Thermal cycling 6 – 106ºC (43 – 223ºF)	First experiment with dedicated set-up, later refined (see next entry). Monitoring of acoustic emission and visualization by CT of debonding during temperature load cycling. Crack initiation and propagation found to be most important failure mode during thermal load cycling. Casing eccentricity (50% standoff) led to easier crack formation and formation of radial cracking along full sample length.
De Andrade et al. (2015, 2016)	Sample curing: 66ºC (150ºF), 500 psi (35 bar). Thermal cycling 4 – 110ºC (39 – 230ºF)	Set-up for curing cement under temperature and pressure, and submitting it to cyclic temperature loads. CT scanning to visualize debonding from casing and formation. Casing surface shown to influence degree of bonding, but effect of thermal cycling similar for all surfaces. Thermal cycling does show progressive cement debonding and cracking. Debonding starts from already-present defects. Results on different formations confirm that stiffer rocks lead to fewer cracks.
Du et al. (2015)	Ambient temperature / atmospheric pressure conditions	Cement analysis after thermal cycle loading using transmission electron microscopy (TEM) and micro-indentation. Changes in cement micro-structure and strength parameters observed with load cycling, which were formulation- and additive-dependent.

Table B-5 continued – Overview of key studies into the effects of pressure and temperature cycling on annular cement sheath integrity and casing integrity.		
Manceau et al. (2015)	17 – 52ºC (63 – 126ºF), 10 -28 bar (145 – 406 psi)	In-situ experiment reproducing a small well section at 1:1 scale in the Opalinus Clay formation in Switzerland, measuring permeability evolution over time in response to pressure and temperature cycling. Effective well permeability, dominated by flow at cement interface bypassing the low-permeability cement matrix, was found to be strongly dependent on temperature and pressure loads. Well temperature and pressure increase (causing casing expansion) reduced well permeability.
Shadravan et al. (2015)	Base temp. and pressure: 330ºF (166ºC) 15,000 psi (103 MPa)	16.4 ppg cement subjected at 330ºF temperature and 15,000 psi pressure to pressure load cycles of 5000 psi, 3,000 psi and 1,000 psi. Effect of number of load cycles observed, while extent of damage differs for different load cycles: 1,000 psi cycles caused radial cracking at failure cycle, 5,000 psi cycles caused more severe radial and disking failures at failure cycle.
Vrålstad et al. (2015)	Sample curing: 125ºC (257ºF), 500 psi (35 bar). Thermal cycling 5 – 125ºC (41 – 257ºF)	Continuation of the studies by De Andrade et al. (2014, 2015, 2016). Large difference observed in debonding behavior of cement sheath cured in shale (minimal debonding/cracking) and sandstone (significant debonding/cracking) related back to stiffness of rock formations (and fluid loss behavior - EVO). Continuous leak paths forming with increasing number of thermal cycles. Micro-annuli formed were found to be neither straight nor uniform.
Taylor et al. (2016)	Ambient temp., atm. pressure. Cycles up to 3750 psi (25.9 MPa)	Dedicated apparatus to evaluate effect of pressure cycling (typically 50 cycles), using CT to visualize cracking and displacement. Preliminary results communicated. Initial debonding and cracking of cement observed prior to pressure cycling, with CT image showing no visible changes after 50 cycles. Permeability, however, appeared to be increased after pressure cycling.
Therond et al. (2017)	Cement cured at 190ºF (88ºC), 500 psi (35 bar).	Combined cement integrity simulation (CIS) and large-scale experimental study (using apparatus by Therond et al. 2016) into well integrity under water injection conditions with ~200 full thermal cycles. Five types of cement failure were considered: inner & outer microannulus, shear failure, radial cracking and disking. Pressure-only cycles with pressure ramp, mixed pressure/temperature cycles and severe pressure cycles (200 cycles from 0 to 6000 psi) tested experimentally. Pressure cycling with ramp did not produce a microannulus, mixed pressure/temperature cycling generated an inner micro-annulus of 11 µm width and 10 mD permeability, severe pressure cycles had no further effect on permeability. Post-mortem analysis showed radial cracks, disking and inner micro-annuli formation. Test results predicted with good accuracy by CIS.
Giesler and Schubert (2019)	Curing and fatigue testing at 250ºF (121ºC) 6,000 psi (41 MPa)	Experiments using equipment by Shadravan et al. (2014). Radial cracking, disc cracking and debonding all observed in experiments with pressure load cycling. Use of polypropylene fibers increased number of load cycles in one set of samples, but decreased it in another set, hence unclear benefits of fiber addition to resist negative effects of pressure cycling.
Vrålstad et al. (2019)	Cement curing at 110ºC (230ºF), atm. pressure	Continuation of earlier studies (De Andrade et al. (2014, 2015, 2016), Vrålstad et al. (2015), confirming earlier results, including that rock stiffness and casing stand-off affect radial cracking behavior. New results: cracking in cement well-bonded to formation may extend into formation, behavior not observed when cement is poorly bonded to formation (due to filter cake presence).
Zeng et al. (2019)	80ºC (176ºF), 50 – 110 MPa (7,250 – 15,950 psi)	Study focused on cement sealing integrity during hydraulic fracturing. Experimental investigation using large-scale equipment coupled with modeling study. Cement sealing failure was observed after 13 repeated pressure cycles 0 – 70 MPa, with gas flow through the annular cement sheath detected during unloading.

Table B-5 continued – Overview of key studies into the effects of pressure and temperature cycling on annular cement sheath integrity and casing integrity.		
Kuanhai et al. (2020)	30 – 150ºC (86 – 302ºF) 0 – 70 MPa (0 – 10,150 psi)	Experimental study into cement-casing sealing integrity failure to be expected on hydraulically fractured wells, quantifying the number of cycles necessary for sealing integrity failure as a function of temperature cycling (for regular cement: 5/3/1 cycles for variations of 30-90ºC, 30-120ºC, 30-150ºC respectively, 18/7/2 cycles for variations of 0-50 MPa, 0-60 MPa and 0-70 MPa respectively). Improved results with high-strength cement. Reduction in interface mechanical properties (shear force, shear strength, cement force and lateral strength) characterized as a function of load cycling.
Anya et al. (2020)	Cement curing at 76.7ºC (170ºF), atm. pressure	CT study into effects of cyclic casing pressures. Casing pressure cycling in range 40 – 310 bar (580 – 4,500 psi). A total of 4 cement formulations tested with different levels of bentonite extender. Interfacial debonding on both casing-cement and cement-rock interfaces observed for all cement formulations, with casing-cement debonding being more severe. Cements exhibiting a large degree of shrinkage during setting showed more severe debonding. Addition of latex and having a more ductile formulation improved bonding.
Zhao et al. (2021)	Cement curing at 90ºC (194ºF), pressure cycles of 0 - 70 MPa (10,150 psi) and 0 - 90 MPa (13,050 psi).	Casing deformation study using P110 casing, probing response to cyclical pressure loads. Work of importance to hydraulic fracturing and casing failures caused by repeated frac stages. Casing exposed to cycling loads generates residual strain, of a magnitude proportional to the inner pressure applied. Casing collapsing strength appears to be linearly lowered with number of pressure cycles because of increasing unrecovered residual strain with each cycle. This explains casing deformations observed in the last fracturing stages of horizontal shale wells (e.g., Barreda et al. 2018).

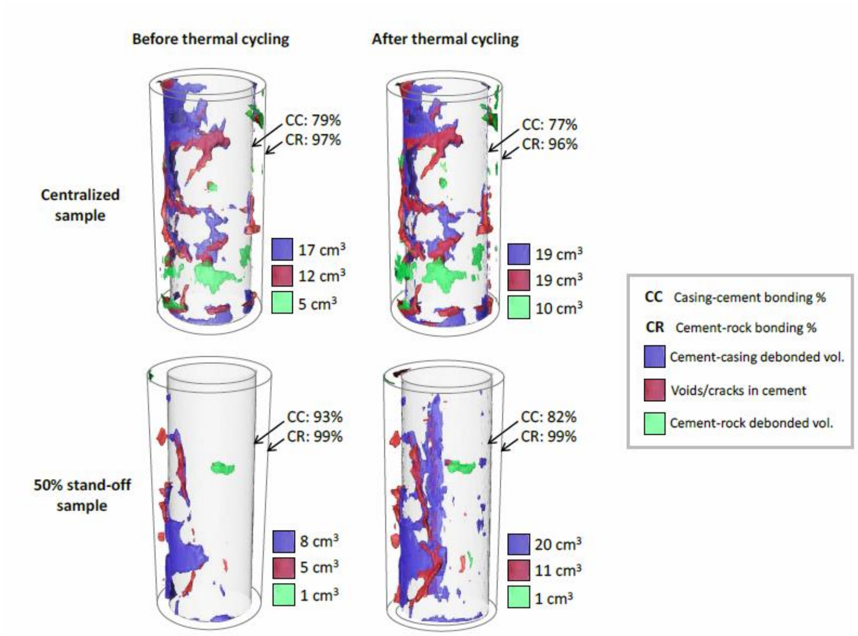


Figure B-3 – CT scan results with 3D volume reconstructions of void, cracks and debonding before and after thermal cycling of fully centralized casing (on top) and casing at only 50% standoff. Note the formation of what appears to be a continuous flow path for the 50% standoff case after thermal cycling. From De Andrade et al. (2014). Copyright Society of Petroleum Engineers (SPE), reproduced by permission.

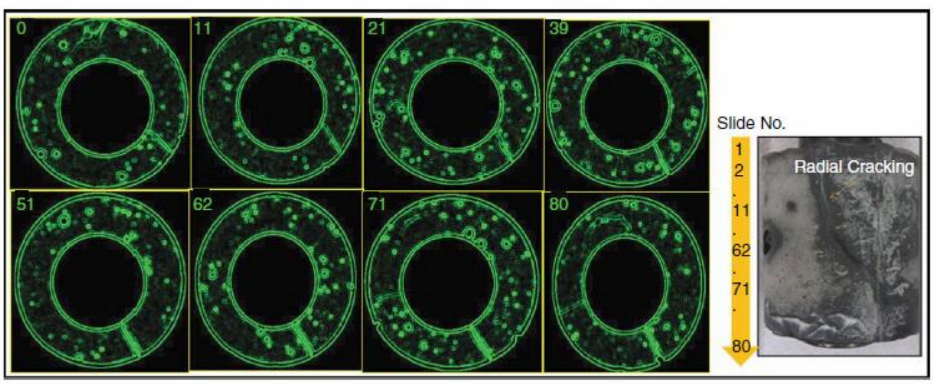


Figure B-4 – CT-scanned sample shows a radial crack in the cement sheath along the length of the sample after HPHT cyclic loading. From Shadravan et al. 2015. Copyright Society of Petroleum Engineers (SPE), reproduced by permission.

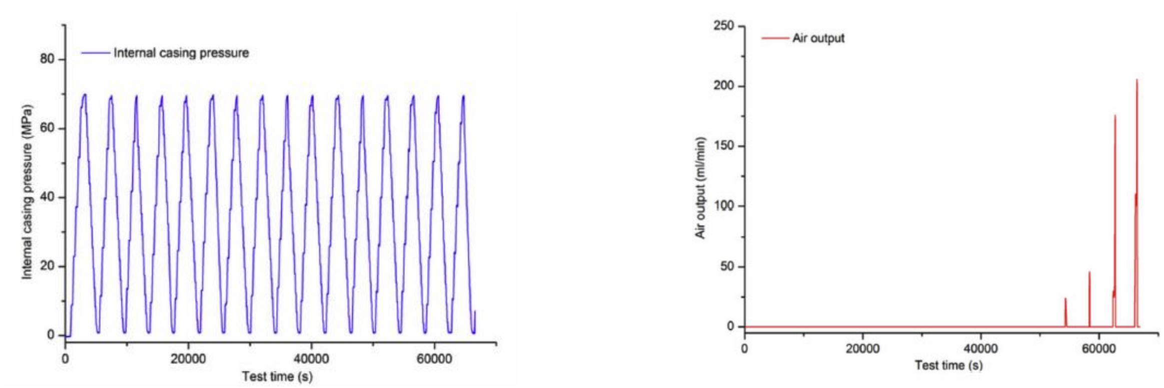


Figure B-5 – Data from study by Zeng et al. (2019) – (left) cyclic pressure loading and unloading cycles; (right) air flow channeling through cement after repeated pressure cycles, as indicated by air flow spikes appearing during later cycles. Copyright Elsevier, reproduced by permission.

In addition to the experimental studies, there are several relevant modeling studies as well. Wang and Taleghani (2017) modeled the fracturing behavior in hydraulically fractured vertical, inclined and horizontal wells using coupled 3D fracturing models. Numerical failure patterns were matched with radio-active tracer surveys to confirm model accuracy. Simulations show that pressurized fluid may cause annular fractures (in addition to transverse fractures) during hydraulic fracture stimulation, leading to an annular leak path that compromises well integrity. The study does not address the effects of cyclic pressure and temperature loads during hydraulic fracturing (noting that temperature-induced stresses are much smaller than the net excess pressures applied during hydraulic fracturing – this does, however, leave the effect pressure cycling during repeated frac stages unaddressed).

Orlic et al. (2018) modeled the risk of cement debonding for the life of a well with late-stage CO_2 injection using finite element techniques. Their probabilistic study looked primarily at the formation and evolution of a micro-annulus during injection of fluids (such as CO_2) at different temperatures, with micro-annular width increasing with an increasing temperature difference between the injected fluid and the rock formation.

A study on casing failure due to fatigue from cyclic pressure loading during multi-stage hydraulic fracturing was published by Barreda et al. (2018). A case study for two hydraulically fractured wells (A and B) in the Southern Midland Basin, completed with 22 and 19 fracturing stages, was analyzed. After hydraulic fracturing, the casing of Well A was found to exhibit excessive casing deformation and collapse at various locations making it impossible to drill out the fracturing plugs. For well B, 17 out of 19 fracturing plugs could be drilled out but excessive casing distortion was found while attempting to drill out the remaining 2 plugs. An attempt to explain the effect of cyclic loading on casing stability using “static” triaxial stress analysis with WellCAT™ software was not successful. Analysis using fatigue failure criteria (Goodman and Soderberg criteria) yielded a good explanation of the observed failures in wells A & B. Recent papers by Noshi et al. (2018, 2019) highlight the usefulness of using data analytics and machine learning techniques to predict casing failures, illustrated with examples of hydraulically fractured wells in the Granite Wash play / Western Anadarko Basin located in Texas and Oklahoma, USA. Logistical regression showed the most important variables (TVD, operator, frac start month, MG of most severe dogleg in well, heel TVD, hole size, bottomhole temperature, total mass of proppant, cumulative dogleg severity in lateral and build sections) correlating with casing failures after hydraulic fracturing.

Wu et al. (2020) recently presented an elasto-plastic 2D finite element study of the effect of cyclic pressure loading on cement sheath failure for ductile and brittle cements under hydraulic fracturing conditions. Risks of tensile failure as a result of higher radial and hoop stresses during pressure loading – and higher residual hoop stresses during unloading - were higher in brittle cement compared to ductile cement, as expected. The threshold for internal casing pressure causing damage to the casing-cement interface was also lower in brittle cement than in ductile cement. Moreover, the threshold for damaging the casing-cement interface is significantly lower in both brittle and ductile cement than the threshold for damaging the cement-formation interface, meaning that the casing-cement interface is the “weak link” that is the first to rupture and fail before the cement-formation interface fails.

B.5. Main Sources on Elevated Temperature as a Risk Factor

The supporting evidence for selecting elevated in-situ temperature as a risk factor for well integrity failure and leakage comes from:

- **References dealing with cyclic temperature loading at elevated / HPHT conditions**, including De Andrade et al. (2015), Du et al. (2015), Vrålstad et al. (2015, 2016), Giesler and Schubert (2019), and Zeng et al. (2019).
- **References concerned with the chemical/mineralogical changes of cement at elevated temperature**, including Saunders and Walker (1954), Eilers and Root (1976), Eilers and Nelson (1979), Nelson et al. (1981), Eilers et al. (1983), Krilov et al. (2000), Fabienne et al. (2002), Le Saout et al. (2006a,b), Kutchko et al. (2007, 2008 & 2009), Lin and Meyer (2009), Sauki and Irawan (2010), Salim and Amani (2013), Deshner et al. (2013), Omosebi et al. (2015) and Reddy et al. (2007, 2016).
- **References dealing with the challenges of well construction at elevated temperature / HPHT conditions**, including Oudeman and Bacarezza (1995), Oudeman and Kerem (2006), Shadravan and Amani (2012), Salim and Amani (2013), and Imrich et al. (2016).

B.6. Main Sources on Geological / Geomechanical Factors as a Risk Factor

Sources for geological and geomechanical factors as risks for well integrity failure and leakage include:

- **References on reservoir subsidence and compaction, causing well / casing shear failures**, including Bruno (1992, 2001, 2002), Hamilton et al. (1992), Schwall and Denney (1994), Schwall et al. (1996), Dusseault et al. (2001), Jinnai and Morita (2009), Robertson and Chilingar (2017), Kristiansen (2020), Arjomand et al. (2021), and Ewy (2021).
- **References on fault slip and induced seismicity**, including Frame 1952, Zoback et al. 2001, Zoback and Zinke (2002), Zoback (2010), Yuan et al. (2018), and Kang et al. (2019).
- **References on the effects of formation creep / formation loads causing casing deformation (ovalization and collapse)**, **and the effect of cement on casing collapse resistance** including the work by Last et al. (2006), Jammer et al. (2015), Lavery and Imrie (2017), Kristiansen et al. (2018), Xie et al. (2018), Lavery et al. (2019), Noble et al. (2019), and Govil et al. (2021).

B.7. Main Sources on Chemical Factors as a Risk Factor

Sources for chemical factors as risks for well integrity failure and leakage falls into two broad categories, one dealing with corrosion of casing strings and the other with chemical degradation of cement as follows:

- **References on casing corrosion:**
    - <u>General introduction / overview texts</u>: Brondel et al. (1994), Scrivener and Young (1997), Abdallah et al. (2013), Choi et al. (2013), Robertson and Chilingar (2017).
    - <u>Case studies</u>: Dethlefs et al. (2008), Blakney et al. (2010), Nengkoda et al. (2011), Al-Twaiqib et al. (2016).

    - Cementing and corrosion: Watson and Bachu (2009), Brandl et al. (2011), Kamgang et al. (2017), Carey et al. (2018), Li and Radonjic (2019).
    - Corrosion detection: Al-Yateem et al. (2013), Al-Ajmi et al. (2016), Cedeño et al. (2018), Al-Dhafeeri et al. (2020).
    - Corrosion mitigation and recovery: McDonald et al. (2014), Narhi et al. (2015), Yugay et al. (2017).
- **References on interaction of CO_2 with cement:**
    - General introduction / overview texts: Benge (2009), Smith et al. (2011), Zhang and Bachu (2011), Boise wt al. (2013), Loizzo et al. (2011), van der Kuip et al. (2011), Loizzo (2014).
    - Experimental & combined experimental-modeling studies: Bruckdorfer (1986), Duguid et al. (2005), Barlèt-Gouedard et al. (2006), Kutchko et al. (2007, 2008, 2009), Huerta et al. (2008), Bachu and Bennion (2009), Carey et al. (2009, 2010, 2018), Strazisar et al. (2009), Garnier et al. (2010), Laudet et al. (2011), Huerta et al. (2013, 2014), Um et al. (2014a,b), Elbakhshwan et al. (2021).
    - Field / leakage detection studies: Carey et al. (2007), Huerta et al. (2009), Watson and Bachu (2009), Crow et al. (2010), Gasda et al. (2011), Nygaard et al. (2014), Tao and Bryant (2014), Tao et al. (2014).
    - CO_2 and HPHT conditions: Shen et al. (1989), Krilov et al. (2000), Aiex et al. (2015), Omosebi et al. (2015 & 2017), Mainguy et al. (2019).
    - Self-healing / self-limiting reaction: Huerta et al. (2012), Brunet et al. (2013, 2016), Carroll et al. (2016).
    - Wellbore re-use for CO_2 storage/ old wells and CO_2 storage: Nordbotten et al. (2005), Loizzo et al. (2010, 2013), Miersemann et al. (2011), Nogues et al. (2011, 2012), Zulqarnain et al. (2017), Vielstädte et al. (2019), Patil et al. (2021).

- **References on interaction of H_2S and mixed H_2S / CO_2 with cement**, including Krilov et al. (2000), Benge and Dew (2006), Moroni et al. (2008), Lécolier et al. (2008 & 2010), LeNevue (2011), Garnier et al. 2012, Wilkie et al. (2014), Zhang et al. (2014), Vrålstad et al. (2016) and Omosebi et al. (2017).

- **References on interaction of brines with cement**, including Duguid et al. (2006, 2011), Duguid (2009), and Schwotzer et al. (2016)

- **References of cement (re-)formulation for chemical resistance**, including Heathman et al. (1993), Watson at al. (2002), Lécolier et al. (2007, 2008), Teodoriu et al. (2016), and Kamgang et al. (2017a,b).

B.8. Main Sources on Wellbore Deviation as a Risk Factor

The supporting evidence for wellbore deviation as a risk factor for well integrity failure and leakage comes from three statistical data studies conducted in Canada (Watson and Bachu 2009, Hardie and Lewis 2015, and Bachu 2017), and a very recent study conducted in three US states (Colorado, New Mexico, and Pennsylvania) by Lackey et al. (2021).

B.9. Main Sources on Combination of Factors as a Risk Factor

The supporting evidence for considering the combination of high risks as a separate risk factor for well integrity failure and leakage combines from papers by Shen and Pye (1989), Krilov et al. (2000), Ravi et al. (2003), Lécolier et al. (2010), Salim and Amani (2013), Teodoriu et al. (2013), Yuan et al. (2013), De Andrade et al. (2014), Aiex et al. (2015), Shadravan et al. (2015), de Andrade and Sangesland (2016), Ichim et al. (2016), De Gennaro et al. (2017), Omosebi et al. (2015, 2017), Mainguy and Innes (2019), and Vrålstad et al. (2019).

B.10. Main Sources on Additional (Minor) Factors as a Risk Factor

The additional factors that may be of importance to for well integrity failure and leakage come primarily from Watson and Bachu (2009), and also from Oil and Gas UK (2018).

Appendix C. Second Stage Questions Sources and Additional Details

C.1. Question 2 Sources

The following were the main sources for answering second stage question 2 of the KEM-18 study dealing with cement permeability:

- **Oilfield publications on cement permeability**, including Goode (1962), Parcevaux and Sault (1984), Nelson and Eilers (1985), De Rozières and Ferrière (1991), Jackson and Murphey (1993), Nelson and Guillot (2006) and references therein, Lécolier et al. (2010), Le-Minous et al. (2017), and Bauer et al. (2019)
- **Civil engineering publications on cement permeability**, including Morgan and Dumbauld (1952), Powers et al. (1954), Watson and Oyeka (1981), Dhir et al. (1989), Bamforth (1991), Cui et al. (2001) and Yang et al. (2019).
- **Field observations of cement and well permeability, with associated modeling**, including Celia et al. (2005), Nordbotten et al. (2005), Carey et al. (2007), Gasda et al. (2008, 2011, 2013), Huerta et al. (2009), Crow et al. (2010), Tao et al. (2013, 2014), Tao and Bryant (2014), Kang et al. (2015), Manceau et al. (2015), Nowamooz et al. (2015), and Gasda (2020)
- **Influence of CO_2 and H_2S on cement permeability**, including Bachu and Bennion (2009), Kutchko et al. (2009), Wigand et al. (2009), Garnier et al. (2010), Lécolier et al. (2010), Duguid et al. (2011), Laudet et al. (2011), Huerta et al. (2013, 2015), Luquot et al. (2013), Newell and Carey (2013), Walsh et al. (2013, 2014a&b), Wenning et al. (2013), Cao et al. (2016) and Carroll et al. (2016)

C.2. Question 3 Sources

The following were the main sources for answering second stage question 3 of the KEM-18 study dealing with casing corrosion:

- **General overview / review publications on corrosion**, including Brondel et al. (1994), Abdallah et al. (2013), Choi et al. (2013), and Robertson and Chilingar (2017).
- **Field cases on corrosion, detection and management**, including Carey et al. (2007), Dethlefs et al. (2008), Watson and Bachu (2008, 2009), Bachu and Watson (2009), Blankney et al. (2010), Henderson and Hainsworth (2012), Al-Yateem et al. (2013), Dusseault et al. (2014), Loizzo et al. (2015), Narhi et al. (2015), Alsaiari et al. (2017), Kamgang et al. (2017), Yugay et al. (2017), Blade Energy Partners (2019), and Beltrán-Jiménez et al. (2021).
- **Corrosion-related technology (detection / identification, cementing solutions):** including Brandtl et al. (2011), McDonald et al. (2014), Al-Ajmi et al. (2016), Al-Twaiqib et al. (2016), Alsaiari et al. (2017), Cedeño et al. (2018), Li and Radonjic (2019), and Al-Dhafeeri et al. (2020).

C.3. Question 4 & 5 Sources

The formation and presence of a micro-annulus between either casing and cement and cement and formation is very well studied and reported in literature. A significant amount of applicable literature was discussed in Sections 2.4 and B.4 dealing with the influence of cyclic pressure loading on micro-annulus formation, in Sections 2.7, 3.2 and 3.3 and on the interaction of a micro-annulus with corrosive brines and gases, and in Section A.6 on the identification and remediation of a micro-annulus and other flow paths in cement sheaths. The reader is referred to these sections for further details. The following were the main additional sources for answering second stage questions 4 and 5 of the KEM-18 study dealing with micro-annuli and filter cake.

- **General overview presentations**, including Bonett and Pafitis, (1996), Bellabarba et al. (2008), and Sweatman et al. (2015)
- **Micro-annular modeling studies**, including Bois et al. (2009, 2012, 2019), Lecampion et al. (2011), Nowamooz et al. (2015), Wu et al. (2016), Asala and Gupta (2019), Lavrov and Torsæter (2016, 2018), Liu et al. (2018a&b), Orlic et al. (2018), Rice (2018), Rice et al. (2018a&b), Zhang et al. (2018), Lackey et al. (2019), and Wise et al. (2019).
- **Cement formulation and experimentation to deal with micro-annular challenges**, including Evans and Carter (1962), Carter and Evans (1964), Parcevaux and Sault (1984), Stewart and Schouten (1988), Marlow (1989), Goodwin and Crook (1992), Jackson and Murphy (1993), Justnes et al. (1995, 1996), Baumgarte et al. (1999), Le Roy-Delage et al. (2000), Ladva et al. (2004), Carey et al. (2010), Newell et al. (2013), Li et al. (2015), Stormont et al. (2015), Torsæter et al. (2015), Li et al. (2016, Skorpa and Vrålstad (2016), Khalifeh et al. (2018), Stormont et al. (2018), Mwang'ande et al. (2019), Skorpa et al. (2019), Stroisz et al. (2019), Szewczyk and Opedal (2019), Corina et al. (2020), Kamali et al. (2021), Moghadam et al. (2021), and Yang et al. (2021).
- **Field studies (including field sample studies) and annular evaluation / logging**, including Issabekov et al. (2017), Nair et al. (2017), Gupta et al. (2019), Noble et al. (2019), Obando Palacio et al. (2020), Beltrán-Jiménez et al. (2021), Gardner et al. (2021), Kalyanraman et al. (2021), and Skadsem et al. (2021).
- **Filter Cake and cement-formation interaction**, including Dusseault et al. (2000), Nelson and Guillot (2007), Yong et al. (2007), Agbasimalo and Radonjic (2014), Aughenbaugh et al. (2014), and Opedal et al. (2014, 2015).

C.4. Question 6 Sources & Additional Details

C.4.1. Literature Sources

The following data sources, including various active parties in the investigation, further development and application of SAAB technology both in the laboratory (with experiments and computer modeling) and in the field, were consulted to answer Question 6 and provide the background presented in this section:

- **SINTEF Norway** – SINTEF has led a joint-industry program into the nature of shale barriers ("Shale as a permanent barrier after well abandonment") that was originally sponsored by the Norwegian Research Council (NRC), BP, ConocoPhillips, Det Norske Oljeselskap, Shell, Statoil (Equinor) and Total E&P Norge, and is currently sponsored by the Norwegian Research Council (NRC), Aker BP, BP, ConocoPhillips, Equinor, Lundin, Petrobras and Total E&P Norge. Although the results of the program are confidential, results have been published in open literature by Fjær et al. (2016), Holt et al. (2017), Bauer et al. (2017), Fjær and Larsen (2018), Fjær et al. (2018), Holt et al. (2019), Xie et al. (2019) and Gawel et al. (2021). SINTEF has also been involved in graduate studies (master's degrees) at the Norwegian University of Science and Technology (NTNU) by Austbø (2016) and Stavland (2017).
- **CODA Group, the University of Texas at Austin** – The shale barrier work by the well Construction, Decommissioning and Abandonment (CODA) research group led by Dr. Juenger and Dr. van Oort In Austin, Texas is sponsored by ConocoPhillips, BP, TotalEnergies, Cenovus and PQ, with results published in open literature: Enayatpour et al. (2019), van Oort et al. (2020), Thombare et al. (2020).
- **NORCE Norwegian Research Centre** – The Norce research institute (formerly named Rogaland and IRIS) has an active investigation in the quality of annular cement sheaths, including analyses of recovered casing strings and their apparent corrosion, with recent papers by Skadsem et al. (2020), Gardner et al. (2021), Skadsem et al. (2021), and Beltrán-Jiménez et al. (2021).
- **PUC-RIO Brazil** – The research group by Dr. Roehl specializes in the modeling of salt deformation behavior, primarily looking at evaporite formation offshore Brazil drilled by Petrobras. See Firme et al. (2014), Firme et al. (2016a&b), and Pereira et al. (2018).
- **Industry** – SAAB technology is of evident importance to industry companies, with several active parties including both oil and gas operators as well as service providers:
  - **Aker BP** – Aker BP is active as sponsor of the SINTEF program (see above) and with its own in-house program investigating the nature of naturally forming and artificially stimulated shale barriers, with papers by Kristiansen et al. (2018), Kristiansen et al. (2021) and Bauer et al. (2021)
  - **ConocoPhillips** – ConocoPhillips has been an active sponsor of both the SINTEF and UT Austin JIP programs, focusing with Schlumberger on barrier identification through advanced cased hole logging application (Govil et al., 2021) as well as multi-string logging (Zhang et al., 2019).
  - **Equinor** (formerly Statoil, StatoilHydro) – a seminal paper on shale barrier identification and testing in the field was written by Williams et al. (2009) in collaboration with Schlumberger.

- **Halliburton** – insightful papers on barrier identification and casing evaluation were written by Lavery and Imrie (2017), and Lavery et al. (2019).
- **Schlumberger** – As noted, Schlumberger has published jointly with Aker BP, ConocoPhillips and Equinor, and published a notable paper on the bonding behavior seen in well in the Varg Field by Noble et al. (2019), with Norce (Govil et al. 2020), as well as joint work with Norce and Aker BP (Obando Palacio et al. 2020).
- **Archer** - Stokkeland et al. (2020) recently published a paper on a one-trip system to qualify creeping shale barriers.

- Additional general information about shale and salt creep behavior can be found in Fabre and Pellet (2006), Jaeger et al. (2007), and Zoback (2010). Useful standards documents are NORSOK-D010 (2021) and Guidelines on Qualification of Materials for the Abandonment of Wells (Oil and Gas UK 2015).

C.4.2. Evidence for Shale/Salt Creep Mechanism

Shale and salt can behave as excellent natural barrier materials, as evidenced by the fact that they can function as competent cap rocks, trapping hydrocarbons in their reservoirs for millions of years. With the work on shale by Williams et al. (2009) and on salt by Lavery and Imrie (2017) it became clear that these materials could also act as excellent barrier materials in annular spaces without cement, thereby helping to establish a double-barrier to surface (as currently required by regulation for all nations around the North Sea, e.g. Norwegian Continental Shelf (NCS)), thereby simplifying well abandonments considerably. This is illustrated in **Figure C-1**: if a shale or salt formation can form a competent annular barrier that can be identified and qualified, then this may eliminate the need for casing cutting and pulling or casing milling before setting an open hole abandonment plug. This efficiency gain may also allow abandonments to be done rigless, at considerable time and cost savings to the operator abandoning offshore wells in particular.

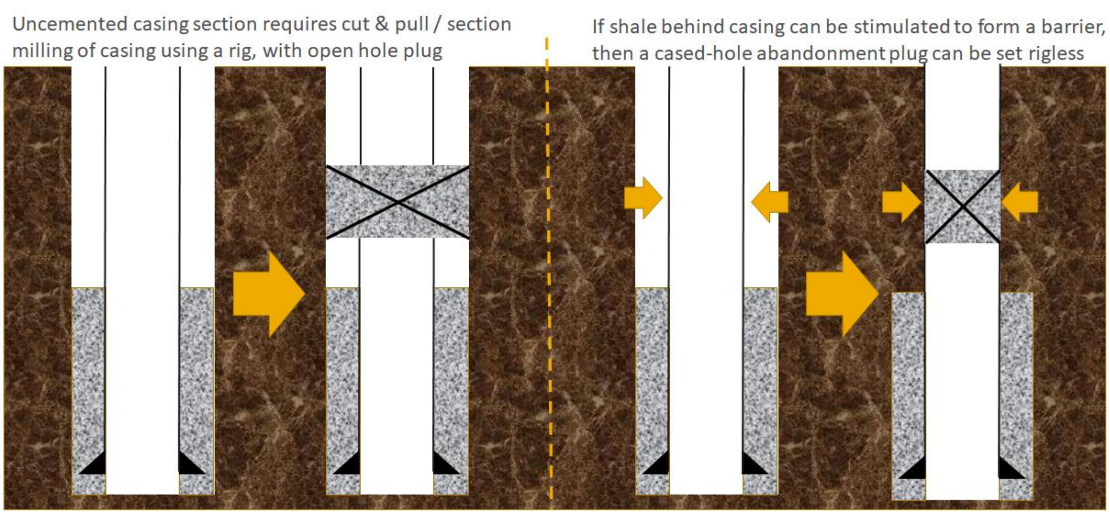


Figure C-1 – in order to establish two annular barriers to surface the view on the left shows conventional casing cutting & pulling or milling to set an open-hole cement plug in case of a surface string with an uncemented annulus. The view on the right shows that only a cased-hole abandonment plug is needed in case creeping shale or salt forms an annular barrier in the uncemented annular section. Copyright Society of Petroleum Engineers (SPE), reproduced by permission.

The SAAB phenomenon was apparent in bond logs (CBL/VDL sonic logs and ultrasonic logs, see Williams et al. 2009, Noble et al. 2019, Govil et al. 2021), showing bonding to casing above top of cement (TOC) in what should have been fluid-filled annular spaces (see **Figure C-2**). The bonding sites correlated in depth with shale formations, and showed sinusoidal patterns in ultrasonic bond log response indicative of dipping formation bedding planes (bond logging is discussed further in Section C.6.3), see **Figure C-3**.

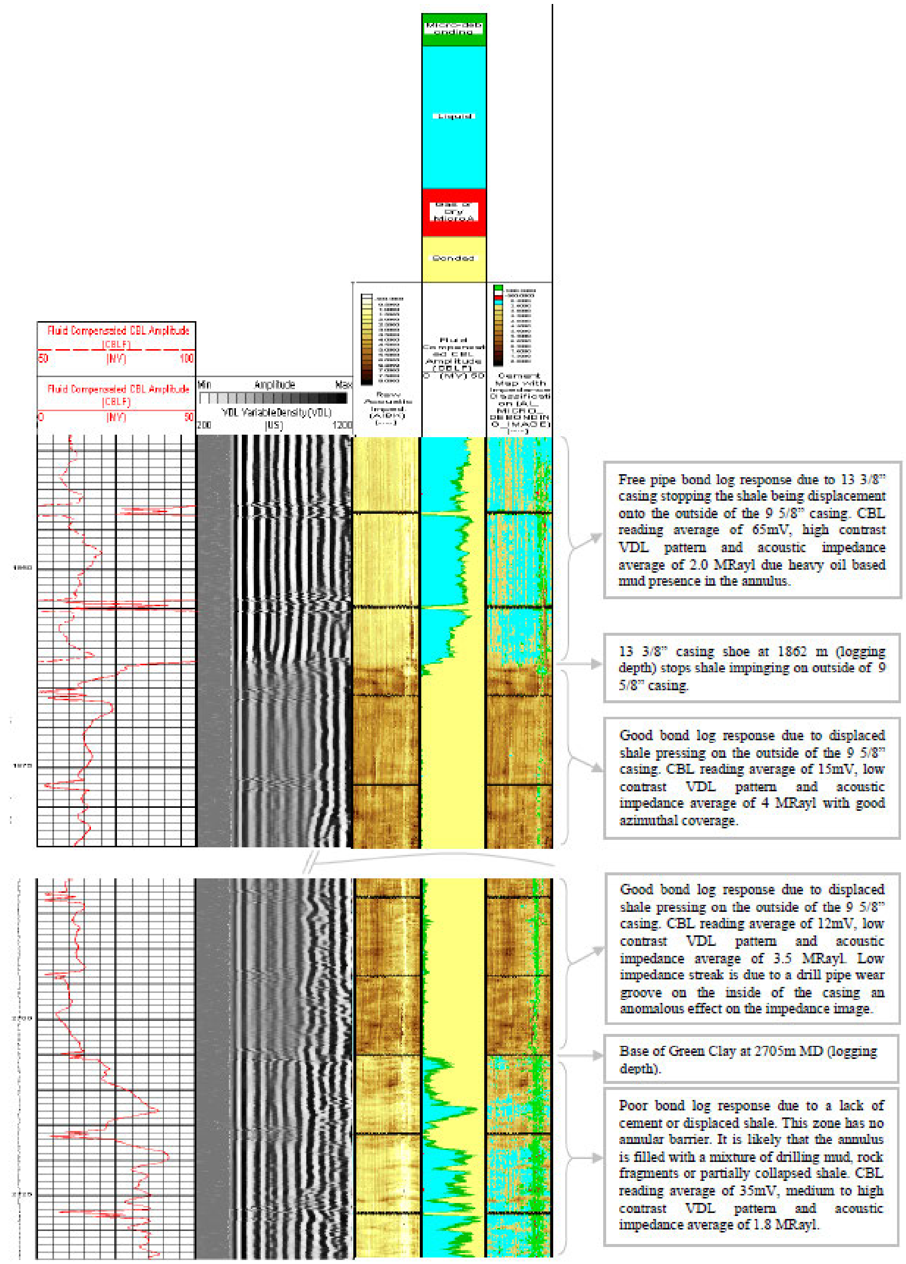


Figure C-2. – CBL/VDL and ultrasonic azimuthal bond logs, showing good bonding over an interval in the Hordaland "Green" Clay (adopted from Williams et al. 2009). Copyright Society of Petroleum Engineers (SPE), reproduced by permission.

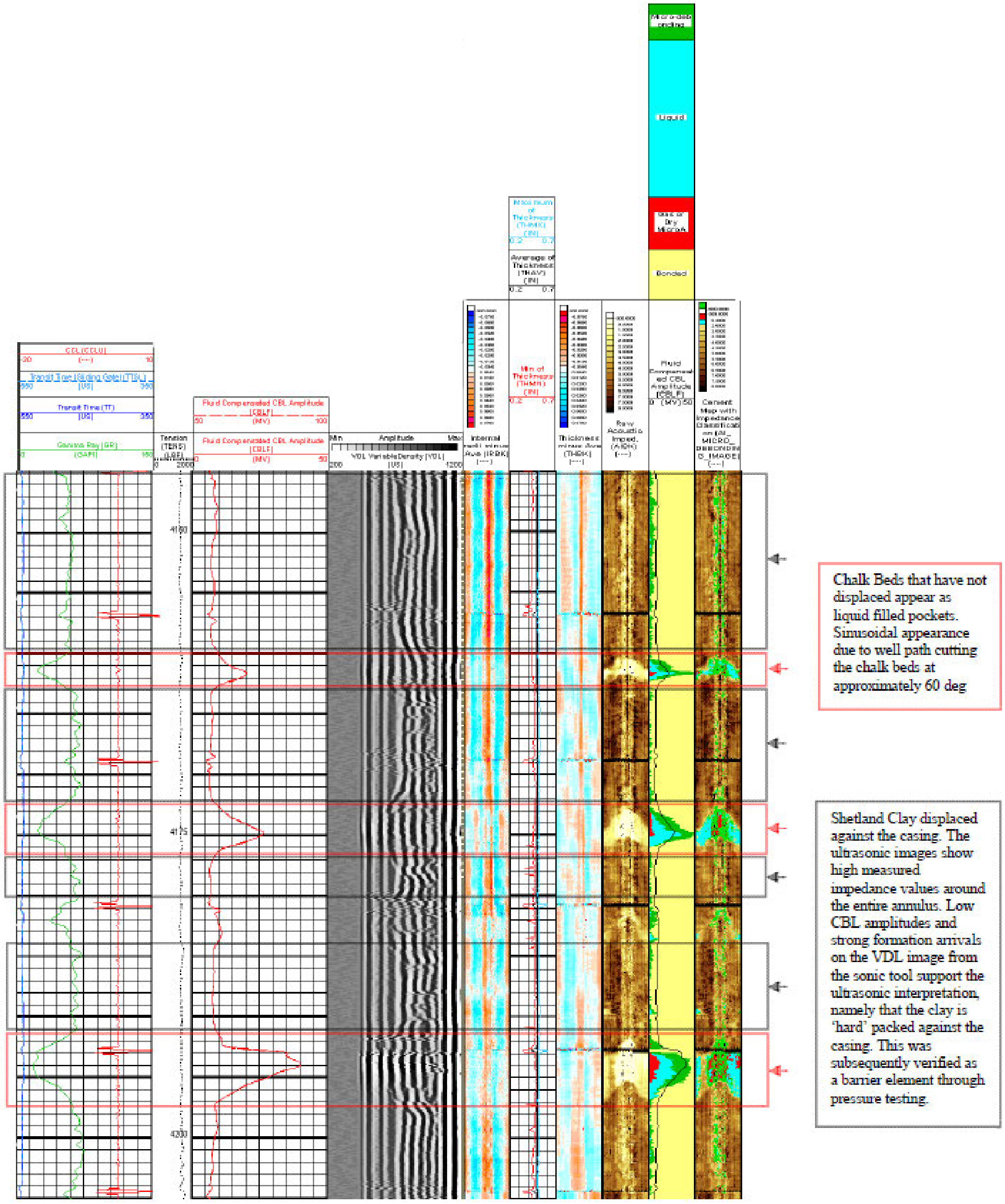


Figure C-3. – CBL/VDL and ultrasonic azimuthal bond logs over an interval of the Shetland Clay, with well-bonded areas (indicated by brown arrows) but also clear indication of chalk beds (indicated by red arrows) that do not exhibit barrier formation and show an open annular interval across them (adopted from Williams et al. 2009). Copyright Society of Petroleum Engineers (SPE), reproduced by permission.

To explain the bond log observations of shale contacting – and bonding to - casing, several mechanisms were considered:

- Elastic and elasto-plastic deformation
- Shear/tensile failure
- Compaction/consolidation
- Liquefication
- Thermal expansion
- Chemical effects
- Creep

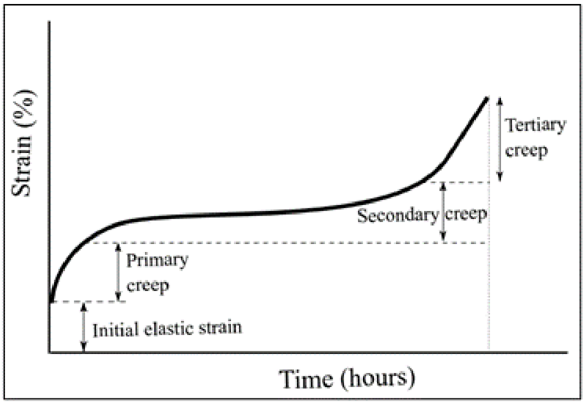
Elastic and elastoplastic deformation as well as compaction/consolidation were discussed by Kristiansen et al. (2018) and deemed unlikely mechanisms to cause annular closure with sealing ability. Williams et al. (2009) showed that only solid material pressed up to / bonded to the casing can cause the observed bond log response. Their bond log observations eliminated shear/tensile failure and thermal expansion as viable explanations, because these mechanisms were not consistent with the observation of open annular spaces in chalk layers intersecting well-bonded shale sections (see Figure C-3). Chemical effects appeared unlikely because barriers have been observed for different annular fluids (e.g. OBM and WBM muds left behind casing, see Noble et al. 2019 – note that chemical effects can play an important role in creep barrier activation, as discussed below).

This leaves creep as the predominant mechanisms for the SAAB phenomenon. Creep is the time-dependent deformation of a material under constant stress conditions (Griggs, 1940; Jaeger et al. 2007). It typically occurs in three stages (Jaeger et al., 2007; Lavery et al. 2019):

- **Primary (transient) creep** – a fast initial rise in deformation rate decreases with time. The deformation would eventually decrease to zero if the applied stress / load would be removed.
- **Secondary (steady-state) creep** - this stage is characterized by a constant deformation rate. This will lead to permanent deformation of the material, even if the applied stress / load is taken away.
- **Tertiary (accelerating) creep** – deformation rate may increase during the stage, potentially leading to rapid material failure.

The three creep stages are shown in schematically in **Figure C-4**, which also includes actual radial creep data obtained in the laboratory for the North Sea Lark shale.

The scientific evidence in support of shale creep as the dominant SAAB mechanism has been building over the past 5 years. In support of creep, SINTEF have published a numerical creep study (Fjær et al. 2016, see also Austbø 2016), an investigation into the ultrasonic properties of creeping shales (Holt et al., 2017), a study into temperature-acceleration of creep (Bauer et al. 2017, see also Stavland, 2017), shale barrier laboratory testing (Fjær et al. 2018, Fjær and Larsen, 2018), a comparison in the brittle and ductile deformation behavior of shales (Holt et al., 2019), and most recently a study into attempt to accelerate creep in Pierre I shale through acid treatment (Gawel et al. 2021).



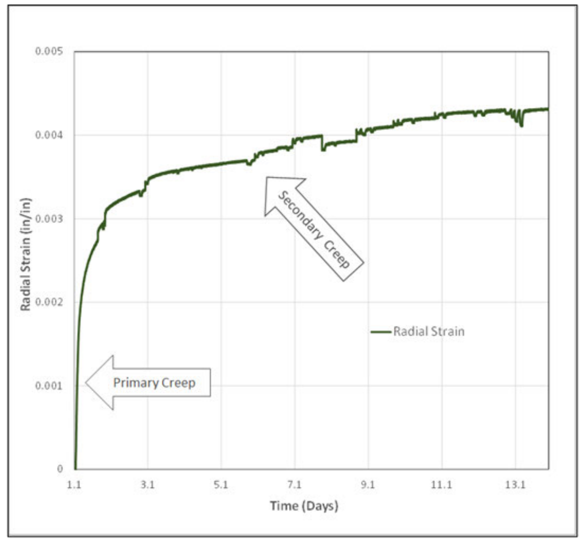
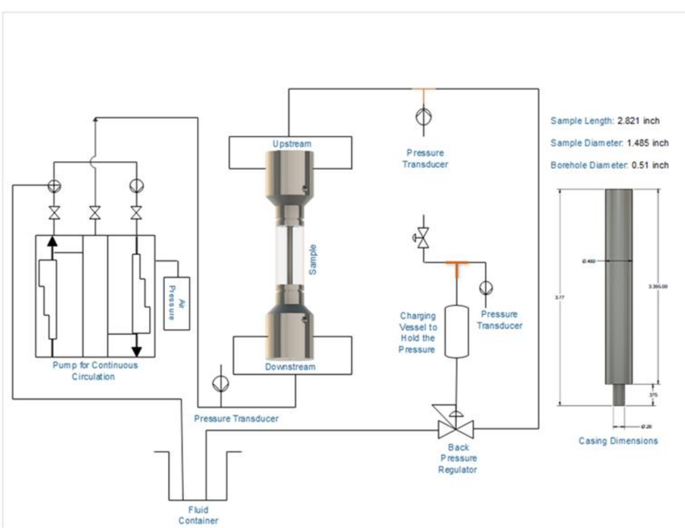


Figure C-4 – (top) theoretical creep behavior, showing primary, secondary, and tertiary creep stages; (right) Primary and secondary radial creep behavior observed for North Sea Lark shale, a member of the Hordaland Group, at in-situ effective stress and temperature conditions. After van Oort et al. (2020). Copyright Society of Petroleum Engineers (SPE), reproduced by permission.

The UT-CODA group has had access to well-preserved core of the Lark-Horda shale, one of the shales that has displayed creep barrier formation in the field. These core samples were provided by Maersk/Total (currently TotalEnergies) for SAAB studies. Special equipment was developed to measure annular creep rates under downhole stress and temperature conditions, with the ability to pressure-test the creep barrier after it has formed. Its ability to hold differential pressure and permeability were determined. **Figure C-5** shows a schematic and photograph of the equipment, with **Figure C-6** showing the core holder with mounted cylindrical shale sample and casing insert, leaving an annular space between the inner diameter of the shale sample and the casing in which shale deformation occurs during testing.



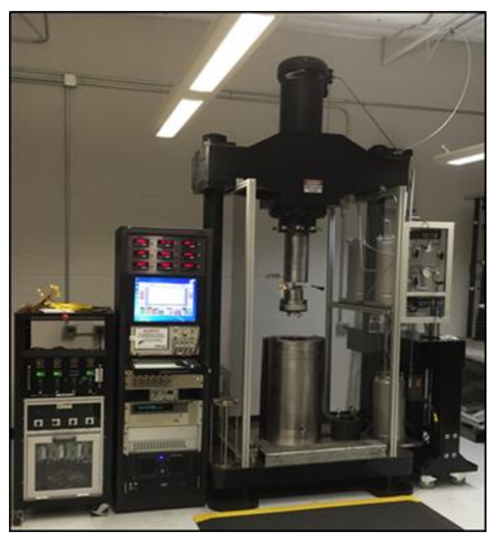


Figure C-5 – (left) schematic of SAAB test equipment; (right) full-scale triaxial equipment with temperature control used for SAAB testing. Copyright Society of Petroleum Engineers (SPE), reproduced by permission.

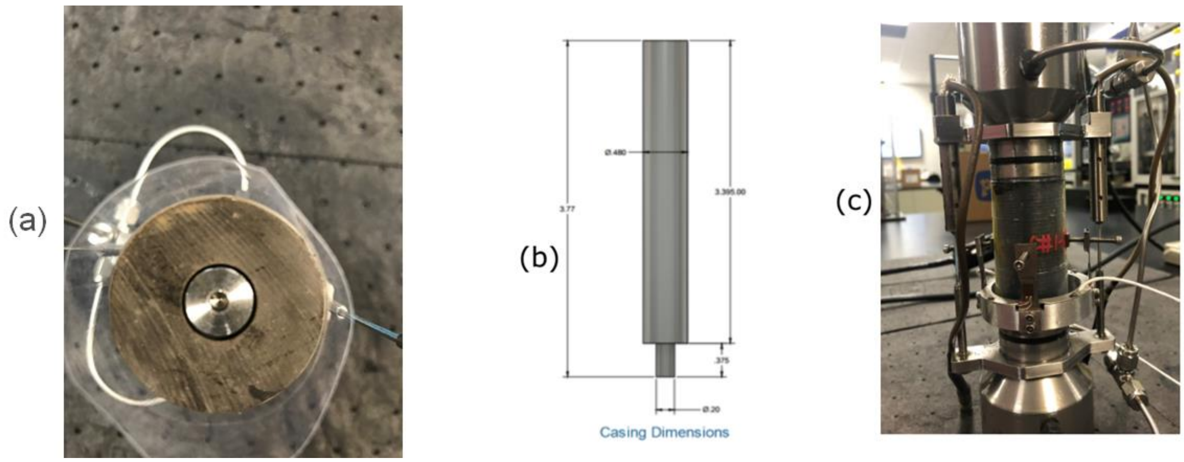


Figure C-6 – (a) Cylindrical shale sample with casing insert, (b) casing insert, (c) mounted sample, strain gauges and pressure lines for insertion in triaxial equipment. Copyright Society of Petroleum Engineers (SPE), reproduced by permission.

Figure C-7 shows a sample after testing, when the annulus has been filled in by shale creep and formed a barrier. The sample is CT scanned before testing, direct after testing before removal of the inner casing insert, and after casing insert removal, as shown in Figure C-7. The latter procedure usually damages the sample.

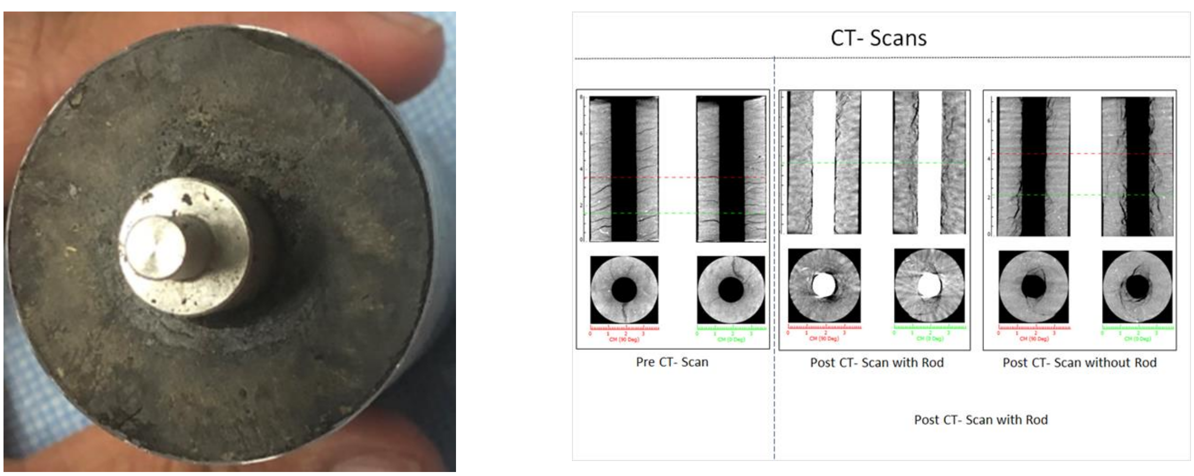
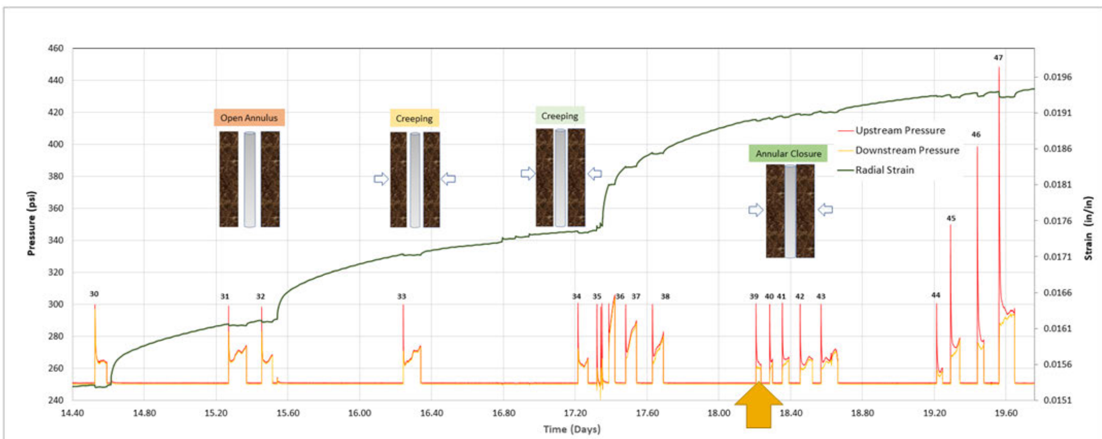


Figure C-7 – (left) Cylindrical shale sample with fully formed annular creep barrier after testing, (right) micro-CT scans of cylindrical shale sample before and after testing. Copyright Society of Petroleum Engineers (SPE), reproduced by permission.

Figure C-8 shows the behavior of the shale sample during the SAAB test. Indicated are the radial strain displacement indicating creep, and the behavior of pressure pulses to monitor closure of the annulus. During the test, the pressure on the top (upstream) side of the sample is pulsed up by 50 psi. If the annulus is open, the pressure is communicated immediately to the bottom (downstream) side, as illustrated in Figure C-8. However, when the annulus closes, there will be a lag in the transmission of pressure from the top to the bottom. From these "pressure transmission" signatures, it is possible to determine the permeability of the shale barrier. The permeabilities measured for the Lark shale were in the range of 1 – 12.5 µD after a few days of barrier formation (van Oort et al. 2020), which is in the same range as competent cement permeability. Moreover, shale barrier permeability was found to be progressively reducing to smaller values over time. It is speculated that given enough time, the barrier will reduce its permeability to the native permeability for the shale formation, which for the Lark shale is 3.5 nD. If this happens, then the barrier will obtain a permeability that is some three orders of magnitude smaller than a cement barrier. Fjær and Larsen (2018) measured the barrier permeability of a North Sea shale after annular closure to be 20 µD, with micro-CT scan showing reduced density and minor fractures in a limited region around the wellbore.



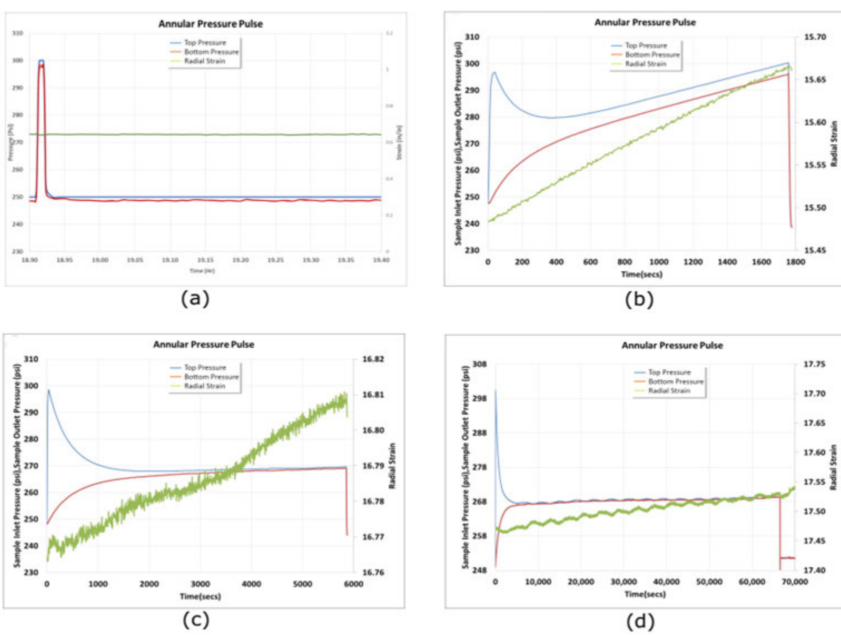


Figure C-8 – (top) creep behavior (green curve) of Lark shale sample with pressure transients characterizing annular closure. Separation of top and bottom pressure response shows annular closure at 18.2 days; (left) pressure transients from pulse measurements during Lark shale creep testing: (a) immediate response of bottom pressure following top pressure increase, indicating an open annulus. (b,c,d) pressure transients indicating annular closure, with bottom pressure (red curve) lagging behind top pressure increase (blue curve). The pressure signatures can be used to determine the permeability of the newly formed shale barrier, which reduces with time from graph (b) to (d) – note the lengthening timescale. Copyright Society of Petroleum Engineers (SPE), reproduced by permission.

Kristiansen et al. (2018) calculated that the expected gas leakage rate would be 2.5 10^{-3} – 2.5 10^{-6} m^3 / year for gas leaking through a shale barrier of 30 m (~100 ft) in length. This is a hundred to a hundred thousand times (10^2-10^5) times lower than for cement. This estimate indicates that a few meters of shale will have similar sealing effectiveness as several hundred meters / feet of cement. This is one of the reasons why there is considerable interest in the use of clay/shale barriers for nuclear waste storage (Horseman et al., 1996).

At the end of SAAB testing a pressure breakdown test can be conducted. Pressure at the bottom of the sample is ramped up until communication to the top side is observed, indicating a rupture of the new shale barrier. It was found that a shale sample of only 3 inch in length with a newly formed barrier could hold several hundreds of psi, in some cases up to the value of the effective minimum horizontal stress (1,500 psi in case of the Lark tests). An example is shown in **Figure C-9**. It shows the extra-ordinary barrier qualities of even small lengths of shale.

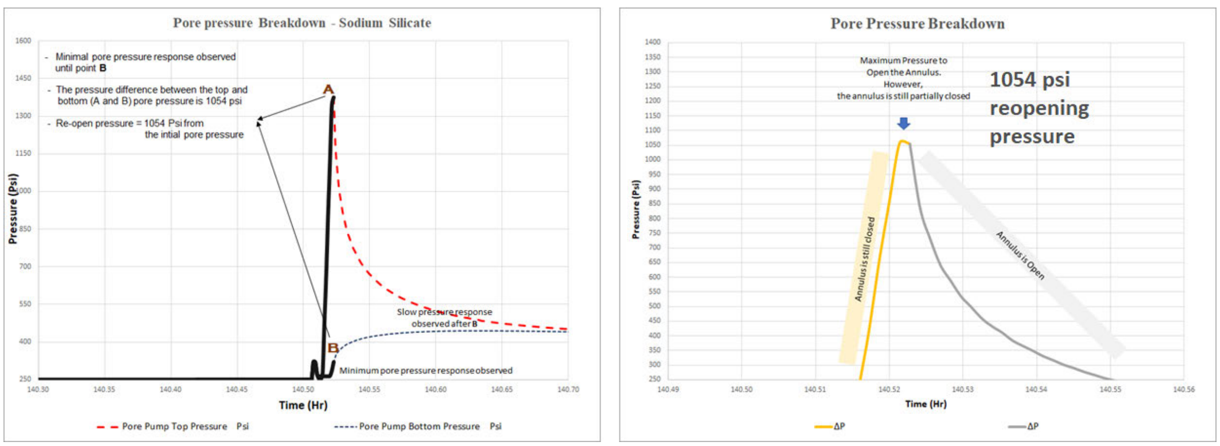
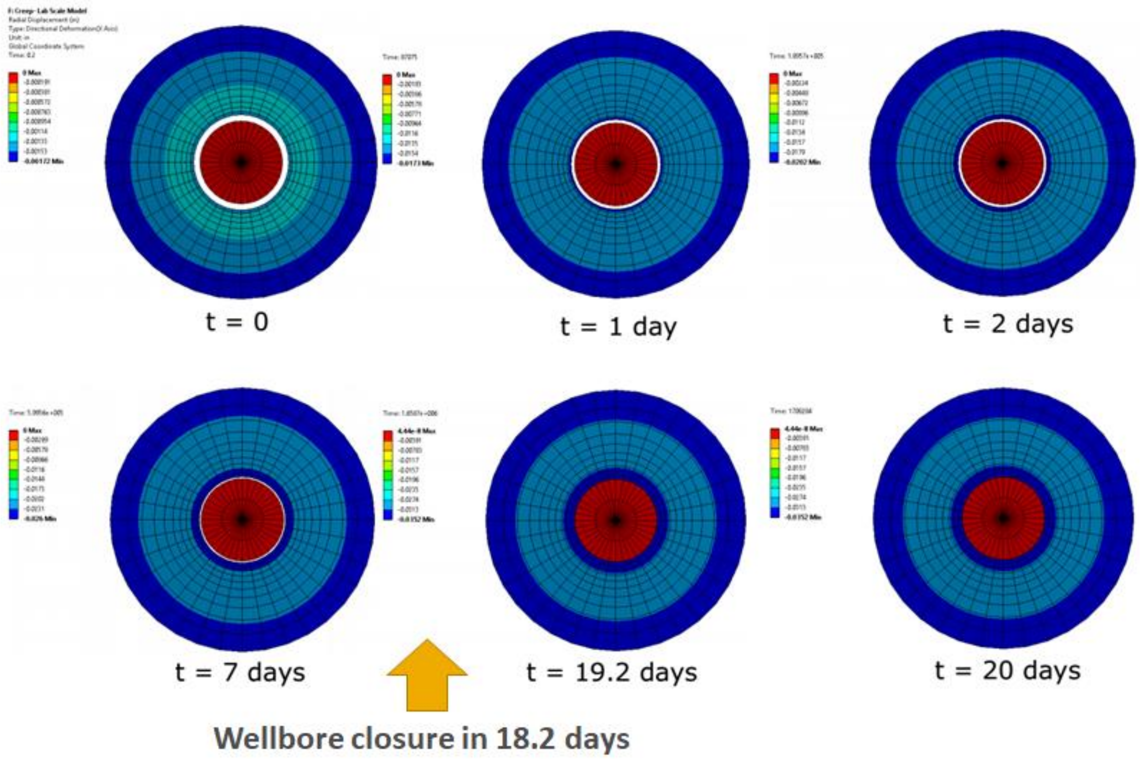
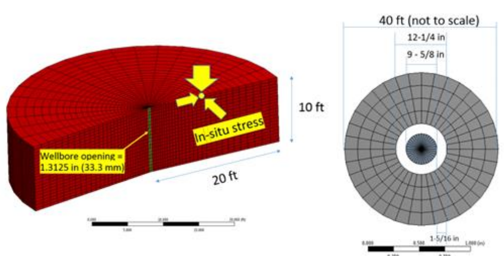


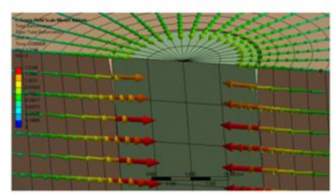
Figure C-9 – Pressure breakthrough test after barrier formation. The 3 in. Lark sample used for this test was able to resist more than 1,000 psi differential fluid pressure before the new barrier failed. Copyright Society of Petroleum Engineers (SPE), reproduced by permission.

The work by Enayatpour et al. (2019) extended the laboratory experiments to the field scale. Laboratory experiments were used to calibrate a creep model for the field scale, simulating annular barrier formation for a 9 5/8 in. casing in 12 ¼ in. hole. The laboratory sample showed barrier formation after 18.2 days (see Figure C-8). This result was simulated using ANSYS Fluent, implementing the creep model shown in **Figure C-10**. The numerical parameters obtained by simulating the lab results were then used for the field scale model. This model showed that in the field case, one can expect annular closure within 87 days ~ 3 months. This result is in good agreement with field observations on North Sea wells where barriers have formed (Noble et al 2019; Kristiansen et al. 2021), showing barrier formation on the timescale of weeks to a few months.





(a) (b)

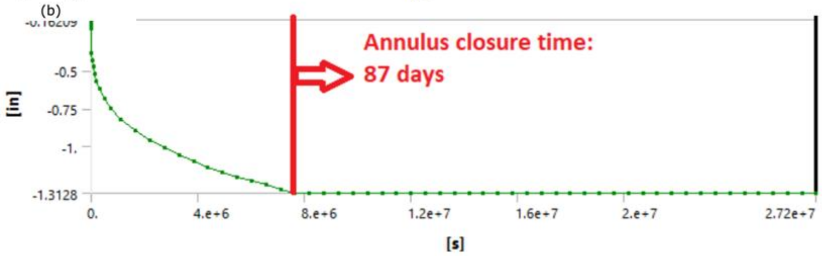


(c)

$$\dot{\varepsilon}_{cr} = f_1(\sigma) f_2(\varepsilon) f_3(t) f_4(T)$$

$$\varepsilon_{cr} = \frac{C_1 \sigma^{C_2} t^{(1+C_3)} e^{-C_4/T}}{(1+C_3)}$$

Parameter	Value
Young's Modulus, E	827 MPa (120,000 psi)
Poisson's ratio, ν	0.27
Creep model parameter, C1	1.7×10^{-6}
Creep model parameter, C2	1.7
Creep model parameter, C3	-0.641
Creep model parameter, C4	0



(d)

Figure C-10 – Simulation results by Enayatpour et al. (2019); (top) ANSYS finite element simulation of the experimental result shown in Figure C.6.8. (bottom) Experimental result extended to the field scale, simulating the closure of the annular space between a 9 5/8 in. casing and a 12 ¼ in. hole. Closure time was determined to be 87 days (~ 3 months). Creep model as indicated. Copyright Society of Petroleum Engineers (SPE), reproduced by permission.

C.4.3. Which Shales/Salts Will Form Barriers?

The understanding of which shales/salts will – and will not – form barriers is still evolving. The key question appears to be if the creep rate, predominantly in the secondary stage, and associated deformation will be sufficient to close the annulus and form a pressure-tight seal. The time horizon available to form a creep barrier in any well, from the time of construction until P&A, will typically be decades, but for most formations the creep deformation will probably be too low even for this lengthy timescale. It is, however, possible to accelerate barrier formation in certain cases, which is discussed in Section C.4.5. Here, focus is on formations that form barrier naturally without external activation.

Williams et al. (2009) gave the formation criteria for shale barrier formation simply as: sufficient strength, low permeability. In a more recent study, Kristiansen et al. (2021) identified the target shale material as: high clay content and especially high smectite content (for ductility and low permeability), high porosity, low content of cementing materials (such as quartz and carbonates which may inhibit ductile deformation and creep), and a low acoustic velocity on (ultra-)sonic logs correlating with low rock strength. These qualitative criteria were largely adopted in the recent NORSOK-D010 (2021) standard, which lists desired formation characteristics as: low permeability, ductile, high smectite and clay content or salt, low content of cementing materials (quartz, carbonates), low friction angle, low cohesion, and low UCS.

More quantitative information (**Table C-1**) for shale comes from a study by Holt et al. (2019), comparing different shales for their ability to form barriers. They found that only 2 of the 4 shales investigated formed barrier in laboratory testing. These "B" and "J" shales obtained from North Sea field cores were characterized by high porosity, high clay content, low strength, and low acoustic velocity. There is a marked difference between these shales and the "H' and Pierre I shales, which did not for barriers spontaneously.

Table C-1. – Properties of shales investigated by Holt et al. (2019) for creep and annular barrier formation. Only shales B and J formed creep barriers in the laboratory tests. Copyright American Rock Mechanics Association (ARMA), reproduced by permission.

Property \ Shale	B	J	H	Pierre I
Porosity	0.40	0.39	0.24	0.21
Clay Content	0.85	0.62	0.49	0.48
UCS (MPa, psi)	6.5 , 943	6.3 , 914	12.6 , 1827	9.7 , 1407
Friction angle (degrees)	5	15	20	30
V_{pz} (m/s)	2044	2038	N/A	2881
V_{pr} (m/s)	2429	2381	N/A	3009

The laboratory studies by Enayatpour et al. (2019), van Oort et al. (2020) and Thombare et al. (2020) were performed on North Sea Lark shale (**Table C-2**), a shale with a strong tendency to form creep barriers.

Table C-2. – Properties of North Sea Lark shale investigated by Enayatpour et al. (2019), van Oort et al. (2020), Thombare et al. (2020). This shale has a strong tendency to form creep barriers. Copyright Society of Petroleum Engineers (SPE), reproduced by permission.

Property	**Value**
Porosity	N/A
Clay Content	0.70 – 0.73 (3-4 % Smectite, 9-12% Illite / Smectite, 37-40% Illite / Mica, 18 – 21% Kaolinite, 1% Chlorite) – other minerals: 19-21% Quartz, 5-9 % Pyrite, 1-2 % Carbonates (Calcite and Dolomite)
CEC	58 – 78 meq/100g
Cohesion	778 – 857 psi (5.4 – 5.9 MPa)
Friction angle	4.3 – 9.4 degrees
V_{pr} (m/s)	2000 – 2100 m/s

Based on this very limited dataset, it appears that the desired quantitative values for relevant properties for shales are:

- High clay content (> 50%), with significant free and mixed-layered smectite content (> 10%).
- High porosity (> 25%-30%).
- High CEC (> 50 meq/100g).
- Low matrix cementation, low quartz and carbonates content (<30% combined).
- Low strength (UCS and cohesion (S_o) below 1000 psi - 7.0 MPa), and low stiffness (lower Young's modulus value, see Sone and Zoback 2011).
- Low friction angle (< 15 degrees).
- Low compressional wave velocities (< 2500 m/s - 8,200 ft/s).
- Noble et al. (2019) mention that the tendency of certain formations to cause shale-related borehole instability during the drilling phase is a good indicator for the likelihood that such a formation is going to for a well-bonded barrier. An example is indeed the North Sea Lark shale, which is known for its wellbore instability problems while drilling (see van Oort et al. 2018).

This list of formation property criteria will undoubtedly be further refined as more data becomes available. In addition to these criteria, there are other external factors that may determine whether a barrier forms or not, as studies by Noble et al. (2019) and Govil et al. (2021) demonstrated:

- **Mud Type**. Influence of mud type (OBM or WBM) left behind casing. Noble et al. (2019) conclude that mud type has limited influence on barrier formation, while Govil et al. (2019) conclude that OBM behind casing interferes with barrier formation (with inhibitive, high-performance WBMs having the same effect). The latter observation agrees with lab observations by van Oort et al. (2020), who did not see any barrier forming in Lark shale with OBM after waiting more than twice the amount of time needed for a barrier to form in WBM. Note that Noble et al. (2019) studied predominantly wells drilled with OBM (of the 14 Varg wells reported on, only one was drilled with WBM), with the barrier being evaluated after many years of well production or injection during the P&A phase, i.e. very significant time passed for the barrier to form. Note that they observed that the older the well, the higher the degree of bonding, i.e., timing is important. One explanation for the observations could be that OBM interferes with forming a barrier if it becomes pressurized in the annulus due to shale creep when it has no opportunity for escape and depressurization. However, if in the annular interval there is a ”sink” available, i.e., a permeable or fractured zone through which the OBM can escape and depressurize the annulus, then the barrier can form. With WBM, the fluid can be incorporated into the shale matrix, likely weakening it and thereby accelerating the creep rate. Inhibitive WBM would interfere with shale hydration and weakening, thereby interfering with barrier formation.

- **Well Azimuth**. As indicated, Noble et al. (2019) connected barrier-formation with a tendency to cause wellbore instability problems during drilling. An effect of hole azimuth on barrier formation was therefore expected but not found. Specifically, it was expected that in the normal faulting environment of the North Sea, stronger barrier formation would be seen in wells drilled parallel to the maximum horizontal stress than drilled parallel to the minimum horizontal stress. The former wells tend to suffer more from wellbore instability problems due to higher stress concentrations around the wellbore (requiring higher mud weight for wellbore stability). Noble et al. (2019) attributed the absence of any influence of azimuth on barrier formation to a stress environment with weak horizontal stress anisotropy (i.e., minor difference in magnitude between maximum and minimum horizontal stress) in the shallow shale formations. Note that the effect of formation strength anisotropy was not considered (i.e., wells drilled parallel to maximum horizontal stress could have encountered stronger shales, with the effects of higher stress concentration and stronger shales cancelling each other out where creep is concerned).
- **Hole deviation**. Noble et al. (2019) did find that less-deviated sections of wells showed less bonding. They explained this by noting that deviated wellbore see a component of the vertical stress, which is the maximum principal stress in a normal faulting environment. It is the reason why deviated wells are less stable and require higher mud weights for stability in such a faulting environment. Simply put, the shale forming the annular barrier experiences a higher stress concentration at the borehole wall, accelerating the creep rate.
- **Temperature**. Temperature accelerates creep for both shales and salts. Increasing temperature enhances both the mobility of the material and leads to increased thermal stress in the rock, accelerating the creep rate.
- **Temperature**: **producing wells vs. injector wells**. Noble et al. 2019 found that there were high levels of formation bonding to casing in hydrocarbon production wells, but reduced bonding in water injector wells. Their very plausible explanation invoked the temperature mechanism: hydrocarbon production heats up shallow casing strings during production, leading to accelerated creep behind those strings, whereas injection actively cools the well, leading to reduced creep rates. The difference between the two well types led to very discernable differences in observed cased hole log and bonding behavior. Noble et al. 2019 speculated that the cooling effect would be reduced for gas injectors compared to water injectors, but lacked the data to confirm this.
- **Well age, duration of production**. Noble observed that the older the well, the higher the formation bonding, but only for producing wells. Prolonged well age, of course, provides a longer time horizon for a creep barrier to form.

C.4.4. Shale/Salt Creep Barrier Identification and Testing

Creep barriers can be identified on logs (Williams et al. 2009; Noble et al. 2019; Govil et al. 2021):

1. **Sonic omnidirectional cement evaluation** using cement bond log (CBL) and variable density log (VDL) evaluation (see Figures C-1 & C-2). Reduction in the CBL's reading in millivolts or an increase in decibel attenuation are direct indications of higher-quality bonding of the material behind the casing. The X-Y waveform of the VDL helps in assessing the bond quality between the annular material and the casing by showing wave amplitude suppression, indication of formation responses, etc.
2. **Ultrasonic azimuthal cement evaluation** using a rotating measuring tool head fitted with transducers for pulse-echo and flexural attenuation measurements. The ultrasonic pulse-echo technique measures the acoustic impedance of the annular material in direct contact with the casing's external surface through characterization of the resonance decay of an exited compressional casing wave node. The acoustic impedance (expressed in units of mega-rayls (Mrayl)) is determined by the properties of the material behind casing. Flexural attenuation (expressed in units of decibel/meter (dB/m) is also a function of material properties behind casing, with excellent sensitivity to low-impedance materials, such as gas, liquid and light cements, in particular.
3. A particularly powerful analysis tool is provided by **cross-plotting the acoustic impedance measurement from the pulse-echo technique against flexural attenuation**. **Figure C-11** shows that such crossplots, interpreted with machine learning analysis techniques, can clearly delineate between gas, liquid, sagged-out barite and formation behind casing.

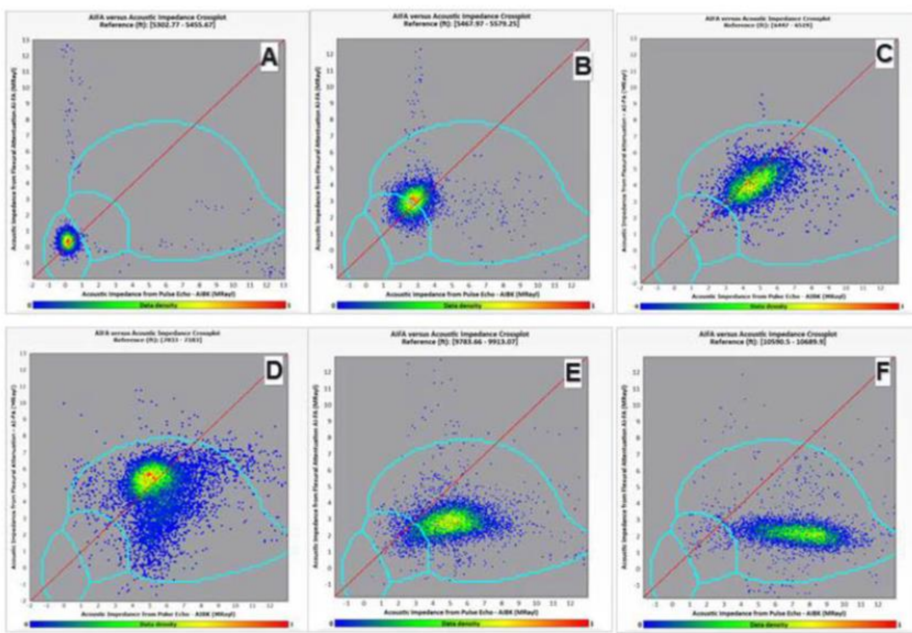


Figure C-11 – Crossplot of acoustic impedances (flexural (Y-axis) vs. pulsed echo (X-axis)) indicating various types of material behind casing: A – gas; B – solids-laden liquid; C – formation barrier material; D – light cement; E – wet micro-annulus; F – standard Class G Portland Cement. Image from Govil et al. (2021). Copyright Society of Petroleum Engineers (SPE), reproduced by permission.

Various examples and case histories showing different log responses and interpretations of data are given in the papers by Williams et al. (2009), Noble et al. (2019), Lavery et al. (2019), Kristiansen et al. (2021) and Govil et al. (2021) for shale, and by Lavery and Imrie (2017) for salt. Williams et al. (2009) laid out best practice log characterization and acceptance criteria for creep barriers as follows:

- *Recommended identification methodology:*
    - *Position and length of potential shale barrier behind casing shall be identified through appropriate logs.*
    - *Two independent logging measurements (e.g. CBL/VDL and ultrasonic) shall be applied.*
    - *Logging tools suitable for applicable well conditions, e.g. number of casing strings, casing dimensions and conditions, fluid types and densities.*
    - *Logging tools properly calibrated.*
    - *Logs interpreted by competent personnel.*
    - *Log criteria for good bonding established.*
- *Recommended log interpretation:*
    - *Both log measurements show good bonding of a minimum length of 50 m.*
    - *Less than 50 m continuous good bonding or ambiguous log response requires verification of shale barrier through pressure testing.*
    - *No/poor bonding identified requires further action, to be determined.*

Specific log criteria are given in **Table C-3**, providing specific cut-off values for CBL and ultrasonic AI variables. The classification obtained by Noble et al. (2019) from analysis of 14 wells in the Varg field on the Norwegian Continental Shelf is given in **Table C-4**. Their log indicators indicating formation bonding are:

- High-impedance solids observed far above the theoretical top of cement, with these solids not attributed to settlement of mud solids (e.g., barite).
- Uniform distribution of solids on acoustic impedance and ultrasonic flexural maps.
- Recognizable bedding planes on acoustic impedance and ultrasonic flexural correlate with gamma ray (GR) signatures obtained during the drilling phase. This includes bedding planes of the shale itself, but also of interbedded stringers of e.g., limestone / dolomite that do not show annular closure.
- CBL amplitude shows moderate to low values, although amplitude values for bonded shale tend to be higher than for cement, attributed to the higher stiffness of the latter.
- Some degree of casing ovalization may be noticeable on an internal radius map image, indicative of squeezing formation deforming the casing
- Flexural attenuation critical point is not reached, attributed to the fact that in shale zones both components of a wavefront, i.e., compressional and shear, are present.
- Areas of high impedance occur on the low side of the casing because, depending on formation stresses, formation bonding can develop first on the narrower annular side (due to eccentric

placement of the casing in the hole). This is usually opposite from cement bonding, where high impedance occurs on the high side of the hole in case of casing eccentricity.

- Top of high-impedance solids behind casing correlates with previous outer casing shoe, which is halting the shale from being displaced on the outside of the inner casing.

Table C-3 – Log characteristics indicating either a good barrier or no barrier (after Williams et al. 2009). Copyright Society of Petroleum Engineers (SPE), reproduced by permission.

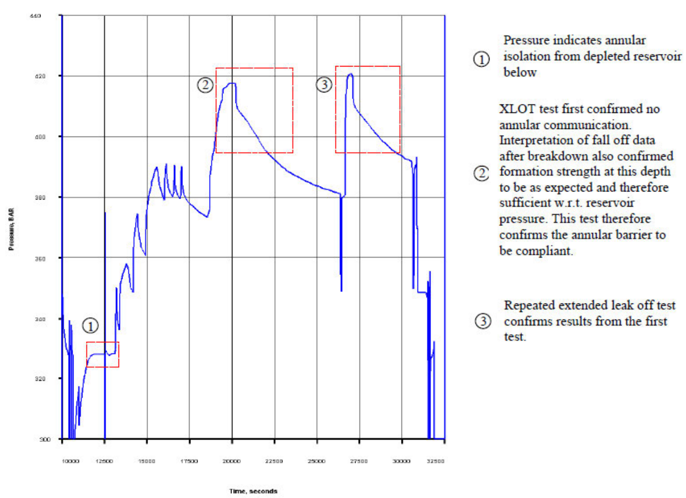
	CBL Amplitude	VDL Characteristics	Ultrasonic Acoustic Impedance (AI) Scanner
Good Barrier	CBL less than 20 mV over 80% of interval	Low contrast casing signal and clear formation arrivals	AI reading greater than 3 MRayl on all azimuthal readings
No Barrier	CBL reading within 20% of free pipe	High contrast casing signal and weak formation arrivals	AI reading less than 2MRayl on some azimuthal readings

Table C-4 – Classification of annular bond quality based on sonic (CBL/VDL) and ultrasonic log data, using the third interface echo (TIE) from the ultrasonic pulsed echo technique as an additional parameter (after Noble et al. 2019). Copyright Society of Petroleum Engineers (SPE), reproduced by permission.

Bond Quality	Acoustic Impedance and Flexural Attenuation	Third Interface Echo (TIE)	Cement Bond Log (CBL)	Variable Density Log (VDL)
Low	Annular space mainly filled with fluids	Normally strong and visible	Close to free pipe CBL response	Strong casing arrivals, clear chevron patterns
Low-to-Moderate	Mostly fluids in annular space, some scattered disconnected solids	Weaker response, still visible	Lower than free pipe values, but generally still on the high side	Slightly attenuated casing arrivals, chevron patterns visible
Moderate	Solids and fluids in annular space, presence of liquid-filled pockets and channels	Very weak or absent response	Mid-range CBL amplitude values	Attenuated casing signals, formation arrivals possible
Moderate-to-High	Close to 360° azimuthal coverage of solids in the annular space, presence of mostly disconnected small-scale fluid-filled pockets. Flexural attenuation in cemented areas could be past critical point	Response usually absent	Low CBL amplitude values, but higher within formation influence zone than within cemented zones	Attenuated casing signals, formation arrivals
High	Full 360° azimuthal solids coverage, absence of fluid-filled pockets or channels. Flexural attenuation in cemented areas could be past critical point	Response usually absent	Low CBL amplitude values, but higher within formation influence zone than within cemented zones	Attenuated casing signals, formation arrivals

Pressure testing of the barrier can be accomplished in different ways (Williams et al. 2009):

- Perforate casing at the base of the potential creep barrier identified from logs, and apply pressure until either a pressure response is seen on the casing annulus at surface, or a formation leak-off response is observed (based on drilling information regarding formation fracturing pressure). A typical leak-off example is shown in **Figure C-12**.
- Perforate the casing both at the base and the top of the potential barrier identified. Run a test string with packer, the latter to be positioned between the perforated intervals (typically right above the lower perforations). A schematic representation is shown in Figure C-12. Apply pressure until either a pressure response is seen on the casing annulus at surface, or a leak-off response is observed. Raaen and Fjær (2020) consider this the more accurate test of the options available.
- Use a cased hole formation tester with pump-in capability. Make a hole at the base of the potential barrier, and monitor pressure to ensure no connectivity with other pressurized zones. Pump into the hole until a leak-off response is observed.



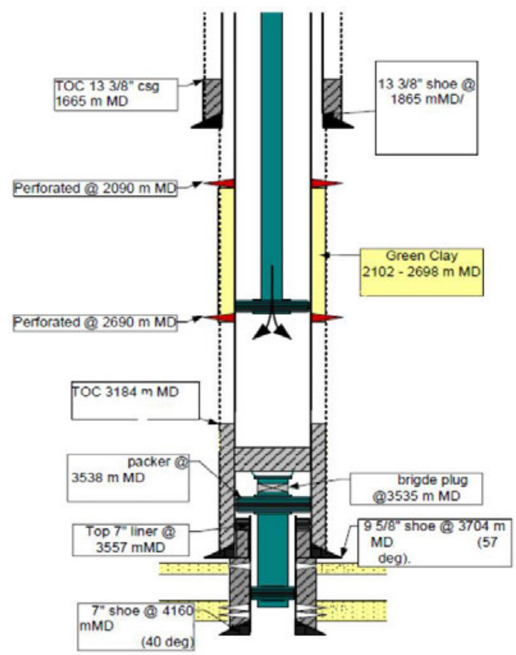


Figure C-12 – (top) example of an extended leak-off test (XLOT) used to test a North Sea shale barrier generated by the Shetland Nise Clay formation; (right) Example of set-up with test string, packer and perforations above and below the annular barrier for testing North Sea Green Clay barrier integrity. Images from Williams et al. (2009). Copyright Society of Petroleum Engineers (SPE), reproduced by permission.

Logging and pressure testing of creep-generated barrier zones in a number of wells allows the bond log response to be correlated with the integrity of the barrier. Inversely, if the barrier shows all the desired log characteristics of good bonding, then it may be possible to qualify and accept the barrier without any pressure testing. Williams et al. (2009) already indicated that at the time, bond log qualification was successfully employed for non-destructive barrier qualification on 40 wells, resulting in elimination of costs associated with pressure testing and complex remedial work.

The use of using bond log responses only for accepting creep barriers has now made it into regulation, as shown for example by the NORSOK D-010 (2021) requirements (compare by Williams et al. (2009) requirements given above):

1. *Position and length of the (barrier) element shall be verified by bond logs:*
    a. *Two (2) independent logging measurements/tools shale be applied. Logging measurements shall provide azimuthal data.*
    b. *Logging data shall be interpreted and verified by qualified personnel and documented.*
    c. *The log response criteria shall be established prior to the logging operation.*
    d. *The minimum contact length shall be 30 m MD for a single well barrier element or 2 x 30 m MD when the same formation will be a part of the primary of secondary well barrier, with azimuthal qualified bonding.*
2. *Pressure integrity shall be verified by application of a pressure differential across the interval. The interval should be no more than 30 m MD long.*
3. *Formation integrity at the base of the interval shall be verified in accordance to Table 3, in order to qualify as a well barrier element (WBE). The results should be in accordance with the expected formation strength from the field model.*
4. *<u>If the specific formation is previously qualified by logging and FIT, logging is considered adequate for subsequent wells. Differential pressure testing is required if the log response is not conclusive or if there is uncertainty about geological uncertainty.</u>*

C.4.5. Stimulating Barriers Artificially

There is considerable work ongoing into stimulating barriers artificially, either to accelerate barrier formation by shales/salts that tend to from them naturally (going from months/years down to weeks/days and possibly hours), or to activate barriers in formations that creep very slowly. There are three main mechanisms for artificially accelerating creep:

- **Thermal stimulation through temperature elevation** – This mechanism has been studied by Bauer et al. (2017), Stavland (2017), Kristiansen et al. (2018) and Xie et al. (2019). An increase in temperature of a creeping rock formation has two main consequences (Chu and Chang, 1989, Sone and Zoback, 2011; Bauer et al, 2017): (1) an increase in total mean stress, dependent on the thermal expansion coefficient of the rock; (2) an increase in pore pressure in according with poro-elastic theory, governed by thermal expansion of the pore fluid. As argued by e.g. Bauer et al., the increase in pore pressure is expected to be twice as large as the increase in mean stress. This means that the effective stress is reduced with a temperature increase ($\sigma_{eff} = S - P_{pore}$, where σ_{eff} is the effective stress, S is the total stress, and P_{pore} is pore pressure). A decrease in effective stress drives a material towards the failure envelope, with an increased tendency for plastic yielding and failure. Materials loaded close to failure conditions typically observe accelerated creep (Sone and Zoback 2019). **Figure C-13** shows the results of a creep acceleration study by Kristiansen et al. (2018) on shale cores of the Sele formation in the Rogaland group obtained at the Valhall prospect. A 30% increase in creep rate was observed by raising temperature from 25 ^{o}C to 95^{o}C. For the North Sea Lark shale studied by van Oort et al. (2020), a reduction in annular closure time from 18.2 days down to 11.5 days (37% reduction) was observed by raising test temperature from 55ºC to 85ºC. Thermal stimulation can be practically accomplished by using a downhole heater, as discussed by Kristiansen (2015), see **Figure C-14**. In general, sizeable increases in downhole temperature (from several tens of degrees to more than two hundred degrees, as indicated by the work by Xie et al. 2019) may need to be achieved in order to have meaningful thermal stimulation effect, which places certain requirements on the capacity and efficiency of downhole heaters. Potential negative implications of downhole heating, e.g., temporary compressive stresses induced in the casing by significant temperature elevation, remain to be studied.

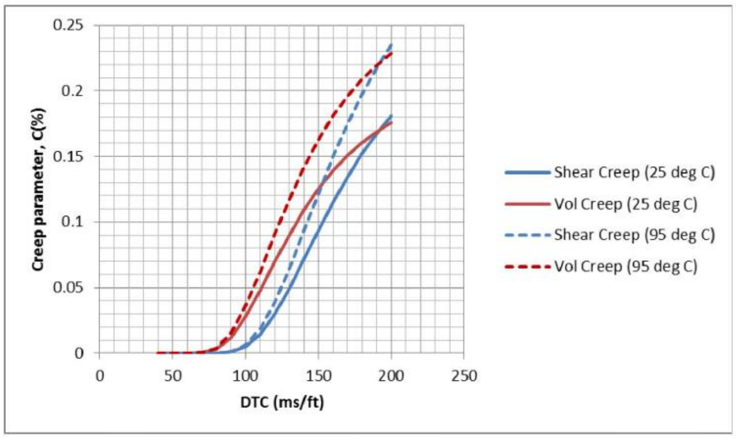


Figure C-13. – Trend lines derived from curve fitting of shear and volumetric strain creep rate parameters vs. DTC for 25 ºC and 95ºC based on data from the Sele formation at the Valhall prospect. Image from Kristiansen et al. (2019). Copyright Society of Petroleum Engineers (SPE), reproduced by permission.

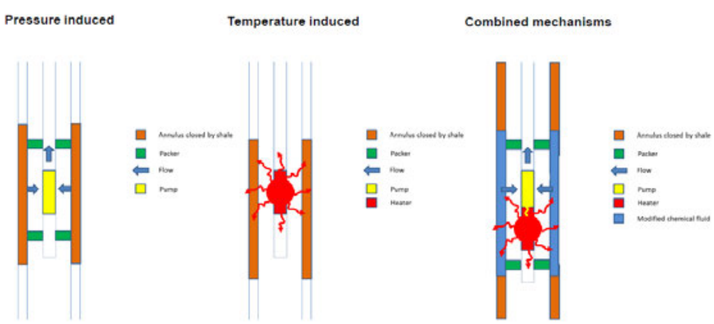


Figure C-14 – Schematic representation of barrier stimulation by pressure shock, temperature increase, and a combination of both. Image from Kristiansen (2015). Copyright Society of Petroleum Engineers (SPE), reproduced by permission.

- **Pressure shock by wellbore pressure drawdown** – The SAAB stimulation efforts championed by Aker BP (Kristiansen et al. 2018; Bauer et al. 2021; Kristiansen et al. 2021) are primarily concerned with this mechanism. The effect is illustrated in **Figure C-15**, showing a hollow cylinder test described by Kristiansen et al. (2018) conducted on Miocene shale from the Valhall prospect. Reducing borehole pressure by 1090 psi (7.5 MPa) at the start of the test leads to an immediate deformation of the shale at the inner wall, with much smaller deformation at the external wall. Similar results were obtained by Fjær et al. (2018). Kristiansen et al. (2018) argue that shock loading of a creeping formation by exposing it to a rapid external pressure reduction can lead to either "liquefaction" of the material or to "ductile / plastic" failure without macroscopic cracks and fractures. Further R&D is necessary to substantiate these claims. Alternatively, the mechanism may simply be that a pressure shock experienced by a creeping formation may lead to significant weakening of the near-wellbore material (experiencing microscopic failure) that accelerates the creep process. Modeling work by Enayatpour et al. (2019) predicts a significantly accelerated creep rate if the near-wellbore Young's Modulus, characterizing the material's stiffness, is artificially reduced, see **Figure C-16**. Pressure shock barrier activation has been extensively tested in the field by Aker BP, with case histories described by Kristiansen et al. (2018), Bauer et al. (2021) and Kristiansen et al. (2021). A typical example is shown in **Figure C-17**, showing the establishment of a shale barrier behind a liner over a 45 days period, as indicated by the signatures in repeated ultrasonic logs. Case histories are shared where barrier formation was successful and unsuccessful. Aker BP has also started to use the shock-induced barrier formation on new wells, by drilling out of casings/liners with low mud weight to stimulate the shale to form a barrier (Kristiansen et al. 2021). Pressure shock can be implemented in the field by perforating the casing and exposing the formation to low pressure in the wellbore, achieved either by a low hydrostatic head or using a pump in combination with isolation packers, as shown schematically in Figure C-14.

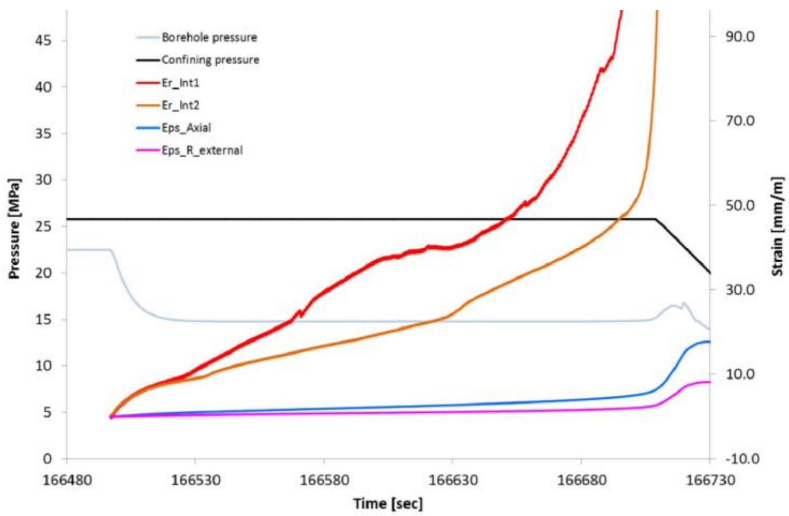


Figure C-15 – Valhall Miocene shale creep response, showing strain deformation (red and orange curves for internal wellbore, blue and purple curves for external wall) after a pressure drop simulating an annular pressure shock. Image from Kristiansen et al. (2019). Copyright Society of Petroleum Engineers (SPE), reproduced by permission.

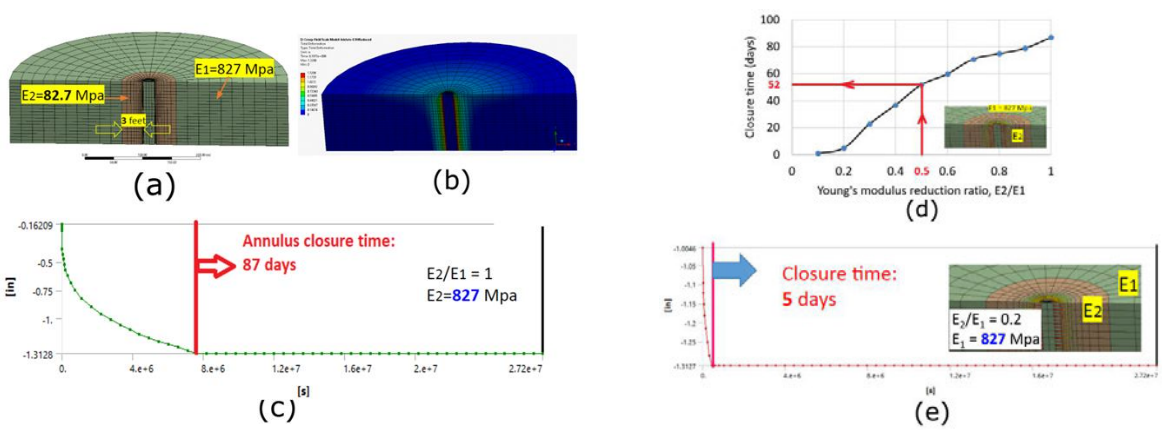


Figure C-16 – Simulation results by Enayatpour et al. (2019), showing that a reduction in near wellbore stiffness (characterized by Young's Modulus E) by a factor 10 reduces the annular closure time from 87 days (see also Figure C-10) down to 5 days. Copyright Society of Petroleum Engineers (SPE), reproduced by permission.

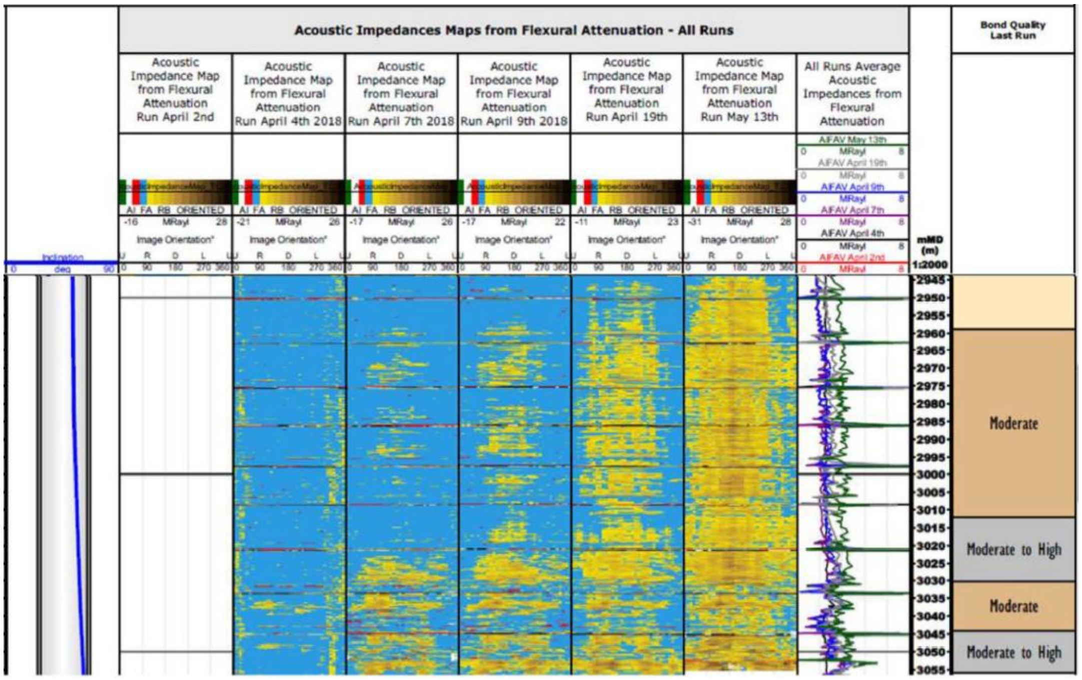


Figure C-17. – Ultrasonic echo time-lapse data by Kristiansen et al. (2019), showing the formation of a shale barrier with bonding to the casing developing over a 45 day time period. Copyright Society of Petroleum Engineers (SPE), reproduced by permission.

- **Chemical stimulation through shale chemistry alteration** – This mechanism was discussed by Kristiansen et al. (2018) and is the primary focus of study by UT Austin (Enayatpour et al. 2019; van Oort et al. 2020; Thombare et al. 2020) and Gawel et al. (2021). Shales are complex materials in which a range of physico-chemical processes take place. A comprehensive overview of these processes is beyond the scope of this document, but an overview is given by van Oort (2004). A well-known process is the change in hydration stress (also known as the “Swelling Pressure”) of clay-rich shales through e.g., ion exchange. The reduction of hydration stress in smectite-rich formations by e.g., potassium-rich salts is known as “inhibition” and is generally considered favorable for the stability of cuttings and boreholes. However, unfavorable ion exchange can drive an increase in hydration stress and associated hydration of the shale material. This weakens the material and drives it towards a state of plastic yielding and failure, thereby leading to an accelerated creep rate. Kristiansen et al. (2018) considered the chemical stimulation mechanism less effective than thermal stimulation and pressure shock (based on field observation of exposing creeping shales to water-based fluids), but the work by van Oort et al. (2020) shows that chemical stimulation can strongly accelerate barrier formation. **Figure C-18** shows the result of a SAAB test using a 10% v/v lithium silicate solution as the annular fluid. This reduced the annular closure time from 18.2 days (see Figure C-8) to only 2.9 days (a reduction by 84%), with the barrier having one of the lowest permeabilities measured (k = 1.7 μD) and the 3 in. plug being able to withstand almost 1000 psi differential pressure. Chemical stimulation can be implemented in the field by perforating the casing in two places and circulating in the desired annular fluid for stimulating the barrier in an experimental set-up similar to the PWC technique.

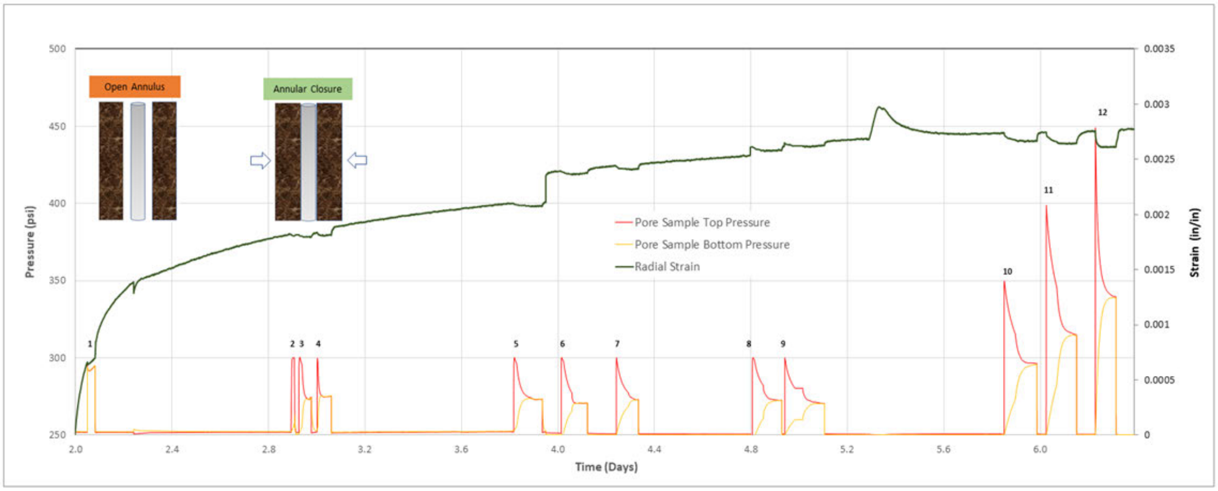


Figure C-18 – SAAB test by van Oort et al. (2020) using a 10% v/v lithium silicate solution as annular fluid, showing annular closure after only 2.9 days (compare with 18.2 days when using shale pore fluid as shown in Figure C-8. Copyright Society of Petroleum Engineers (SPE), reproduced by permission.

C.4.6. Risks and Concerns

Main risks and concerns associated with SAAB technology include:

- Creep causing casing ovalization and negatively affecting casing connections. Mild casing ovalization, as noted and observed by Lavery and Imrie (2017), Kristiansen et al. (2019), Lavery et al. (2019), should not pose significant problems as long as the casing body and the casing connections can resist any non-uniform collapse loads imposed on them.
- Leaving gel- or solids-filled micro-annulus of a small fraction of a millimeter due to thixotropic properties of mud when stimulating a barrier.
- Well control challenges when using pressure shock stimulation on new wells, as noted by Kristiansen et al. (2021).

C.4.7. Comparative Barrier Material Ranking

In a recent paper, Rios et al. (2021) comparative scored cement and cement alternatives (using the subdivision of Oil and Gas UK (2015), see Table A-4 in Appendix A) in terms of NASA technology readiness level (TRL), applicability and limitations, risks, costs and benefits. The scores for all materials are given in **Table C-5,** and graphically represented in **Figure C-19** for cement, thermosetting materials, metals and deformable formation. Higher scores indicate more favorable properties, characteristics, risks and costs. Apart from SAAB being not as mature in terms of TRL as other barrier approaches, it compares very favorably in all other categories, with none of the apparent weaknesses shown by the other approaches.

Table C-5 – Comparative barrier material ranking, according to Rios et al. (2021). Copyright Offshore Technology Conference (OTC), reproduced by permission.

Type	Material	Maturity TRL	Applicability / Limitations	Risks	Costs	Benefits	Strengths	Weaknesses
A	Cements & ceramics (setting materials)	10.0	8.7	7.5	9.2	4.7	7.3	8.1
B	Grouts (non-setting materials	8.9	6.0	7.5	6.7	4.7	5.6	7.2
C	Thermosetting polymers and composites	8.9	8.0	7.5	7.5	6.0	7.3	7.5
D	Thermoplastic polymers and composites	4.4	6.7	3.1	6.7	2.7	5.3	4.3
E	Elastomeric polymers and composites	10.0	6.0	6.9	5.8	3.3	5.1	6.5
F	Deformable rock formations (SAAB)	5.6	9.3	8.1	8.3	8.7	9.1	8.2
G	Gels	8.9	6.0	6.3	8.3	4.0	5.3	6.9
H	Glasses	4.4	6.0	5.8	5.8	3.3	5.1	5.3
I	Metals	7.8	6.0	7.5	7.5	7.3	6.4	6.3
J	Modified in-situ materials	4.4	10.0	8.3	8.3	8.7	10.0	7.8

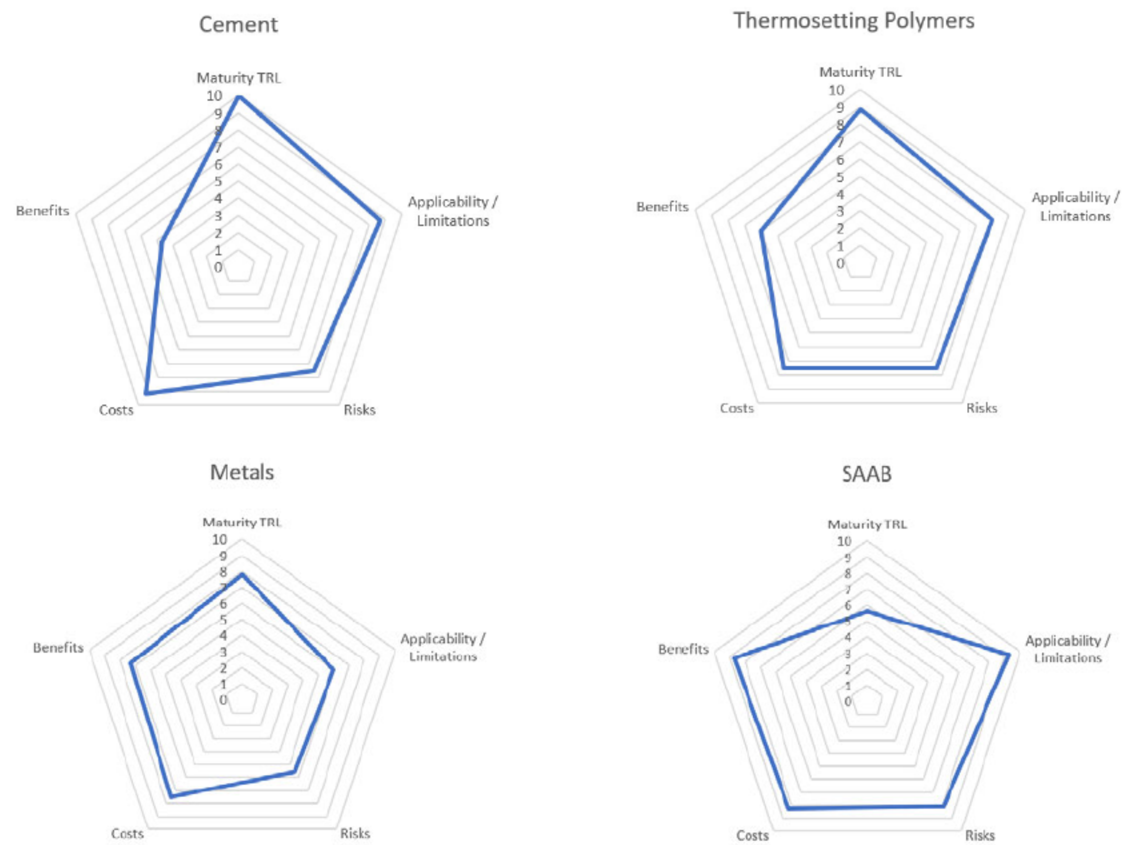


Figure C-19 – Radar plots showing comparative scores for cement, thermosetting polymers, metals and SAAB as indicated on maturity TRL, applicability / limitations, risks, costs and benefits. Data according to Rios et al. (2021). Copyright Offshore Technology Conference (OTC), reproduced by permission.

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