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Understanding Fluid Migration from Offshore Well Sites

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Drilling and Wells

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Abstract

Approximately 5000 wells on the Norwegian Continental Shelf (NCS) have either been decommissioned or are currently planned for decommissioning. This scenario raises concerns about potential methane leaks and their environmental impact. Methane, a potent greenhouse gas, offers immediate climate benefits when emissions are reduced. Addressing major sources, including plugged and abandoned wells, is crucial. Studies are important to assess if there is any significant methane emissions from plugged and abandoned wells in terms of seepages and leakage.

This thesis examines the integrity and efficacy of Plug and Abandonment (P&A) designs in mitigating leaks from these oil and gas wells, with a particular focus on natural seeps and their connection to wellbore structures. It reviews P&A strategies for main reservoirs, emphasizing barrier establishment and verification methods. The study also explores designs for the overburden, detailing techniques for barrier establishment, verification processes, and abstraction of Sources of Inflow (SOIs), along with assessing the depth and effectiveness of surface plugs in various geological contexts.

The findings affirm the importance of dual-barrier systems in reservoir abandonment, highlighting their effectiveness as artificial cap rocks in mitigating leakage risks, emphasize on complexity of overburden and subsequently complexity of P&A operations. The research distinguishes well seeps from leaks, identifying many supposed leaks as natural microseepages may not be caused by wellbores. It also finds no direct correlation between the type of gas (biogenic or thermogenic) and wellbore presence, suggesting that the natural seepage landscape is largely unaffected by wellbore interventions. The thesis concludes that many "leaking wells" are more accurately described as "wellbore-induced natural seepage" underscoring the need for precise terminology to improve regulatory and operational frameworks in managing geological seepage.

Nomenclature

ALARP	As Low As Reasonably Practicable
BOP	Blow Out Prevent
DPZ	Distinc Permeable Zone
EZSV	Expandable Zonal Isolation Valve
GHG	Green House Gas
GPW	Global Potential Warming
H	True Vertical Depth of Reservoir
h_{MSD}	Minimum Setting Depth (ft)
ISO	International Organization for Standardization
LOT	Leak Off Test
LWIV	Light Well Intervention Vessele
MSD	Minimum Setting Depth
NCS	Norwegin Continental Shelf
NMR	Nuclear Magnetic Resonance
NPD	Norwegina Petroleum Director
OBF	Overburden Formation
P&A	Plug and Abandonment
P_{Fluid}	Fluid Gradient Pressure (psi/ft)
P_{FP}	Final Reservoir Peressure (psi)
P_{Frac}	Fracture Pressure Gradient (ppg)
PP&A	Permanent Plug and Abandonment
PPG	Pound Per Gallon
PWC	Perforate, Wash, Cement
RIH	Run In Hole
RKB	Rotary Kelly Bushing
ROV	Remotely Operated Vehicle
RP	Recommended Practice
SMOW	Standard Mean Ocean Water (SMOW)
SOI	Source Of Inflow
TOC	Top Of Cement
TVD	True Vertical Depth

UKCS	United Kingdom Continental Shelf
VEC	Valuable Ecosystem Component
VPDB	Vienna Pee Dee Belemnite (VPDB)
WBAC	Well Barrier Acceptance Criteria
WBE	Well Barrier Element

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1. Introduction

The environment is at significant risk due to the discharge of noxious substances. Greenhouse gases exert a detrimental influence on the environment, a fact that is widely recognized as climate change. The emissions of greenhouse gases, whether from natural seeps in the deep sea or from hydrocarbon wells (oil and gas wells), pose a threat to the seas through acidification and atmosphere which play a crucial role in the ecosystem. The consequences of these leakages might be irreversible, such as the occurrence of climate change, air pollution, water contamination, and so on.

Methane is the second most prevalent human-caused greenhouse gas (GHG) in the atmosphere, behind carbon dioxide (CO_2). It contributes to around 16 percent of world emissions. Methane is almost 28 times more effective than carbon dioxide in retaining heat in the atmosphere. Human-related activities have significantly contributed to a more than twofold increase in methane concentrations in the atmosphere during the past two centuries. Due to its potent greenhouse gas properties and relatively short lifespan compared to carbon dioxide, reducing methane emissions would have a swift and substantial impact on the overall warming potential of the atmosphere (EPA, 2023).

The Global Warming Potential (GWP) quantifies the capacity of a greenhouse gas to retain heat in the atmosphere compared to carbon dioxide for a specified timeframe. The GWP may fluctuate based on the selected time window. As an example, the global warming potential (GWP) of methane is 34 over a span of 100 years but increases to 86 within a period of 20 years. This indicates that methane possesses significant power as a greenhouse gas in the immediate term, however it has a somewhat shorter residence time in the atmosphere. (Wilkerson, 2015).

1.1 Source of Leakage

The bottom of the sea and oceans have many natural seeps and vents that release methane (or natural gas). Some of this methane reaches the atmosphere by rising and escaping into the sea-air interface. This is called 'natural seepage'. Some of it undergoes physical and biogeochemical changes or gets trapped. Some of it dissolves in seawater and either stays there, increasing the methane concentration or gets released into the air later. Methane (or natural gas) also leaks from the seabed due to human activities. This happens when gas flows from underground layers of methane along or through offshore oil and gas wells. This is called 'man-induced leakage" (Griffioen & Geel, 2023).

1.1.1 Natural seepage

Shallow gas accumulations-This type of natural seepage will be explained in Chapter 7.

Pockmarks-Pockmarks are geomorphological features that form in response to (explosive) venting of natural gas from the seafloor. Böttner et al. (2020) documented more than 1500 pockmarks over an area of 225 km^2 in the North Sea where a limited number have active vents. They showed a direct relation to shallow gas accumulations in the subsurface. All these findings indicate natural leakage.

Gas chimneys-Seismic chimneys are zones of columnar shape that appear as anomalies in the seismic reflection profile (Kang, et al., 2016). They are common in the North Sea and suggest the presence of vertical channels for gas accumulations from shallow or deep sources (Wilpshaar, et al., 2021). In marine sediments, seismic chimneys are fluid migration routes and are closely related to gas hydrate formation. Gas hydrate is a solid material that resembles ice, where water molecules form cages that enclose methane or other light hydrocarbons, under low temperatures and high pressure. The amount of methane available, more than the water solubility, determines the occurrence and distribution of gas hydrates under these conditions. Therefore, fluid flow through seismic chimneys is a key factor for gas hydrate research, as it can move enough gas to form gas hydrate within the gas hydrate stability zone (Kang, et al., 2016).

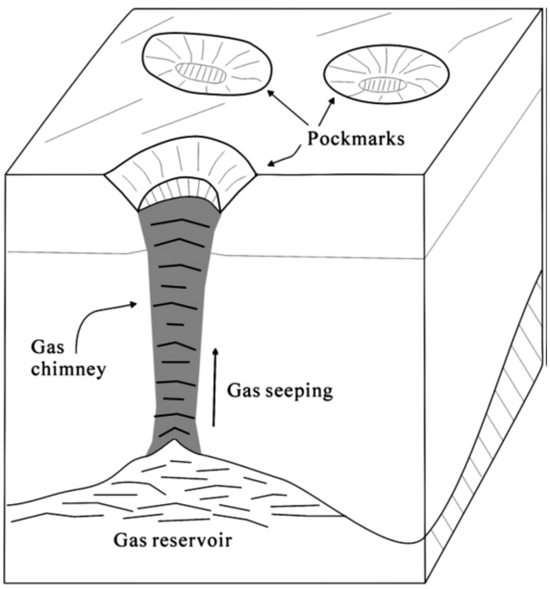


Figure 1-1 Pockmark and Gas chimney (Cathles et al.)

Pockmarks are frequently located atop gas chimneys. Slow, continued gas leakage through the chimneys sustains vent communities which produce carbonate mounds in the pockmarks, see Figure 1-1.

Subsurface salt domes-The well-known Tommeliten seep area, above a subsurface salt dome, is in the southern part across the Norwegian border concession block 1/9 (Wilpshaar, et al., 2021). Subsurface salt domes like Tommeliten are leaky geologic megastructures that often have surface seep manifestations on land and the seafloor (Hovland, 2007). Römer et al. (2021) also demonstrated a seafloor methane seepage link to salt diapirism in the German North Sea.

Figure 1-2 displays a seismic picture of a vertical 2D segment of the Auger Diapir at the bottom. The salt diapir is observable on the seabed surface in the northern area of the Gulf of Mexico, as seen in the bathymetry pictures released by the BOEM (2020). The salt rose, creating a conspicuous protrusion or dome (Google Earth upper right).

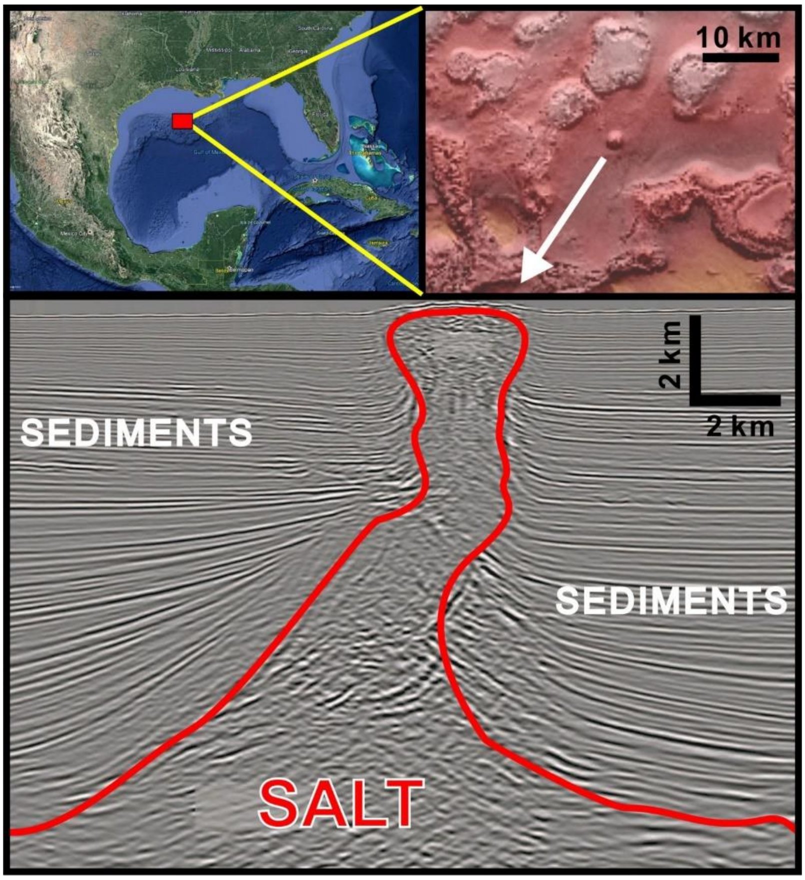


Figure 1-2 Salt dome(Lopez)

Peat layers-In addition to the natural seeps or leaks discussed earlier, shallow layers such as buried Holocene peat can also release gas and act as a potential source (Wilpshaar, et al., 2021).

1.2 Man-Induced Leakage

According to a report published by Vielstädte et al. (2017), in 2011 there were 11112 wells in the North Sea, not counting sidetracks and multilateral wells. Of these, 2818 were active, meaning they were either producing or injecting. However, more recent information suggests that there are 20,507 offshore wells in the North Sea, according to EMODnet bathymetric data. These wells are clustered in regions where the subsurface has rich hydrocarbon resources. The wells belong to five countries: the UK (11,672 wells, blue dots), Norway (6,254 wells, red dots), Denmark (269 wells, yellow dots), Germany (204 wells, black dots), and the Netherlands (2,108 wells, orange dots), see Figure 1-3. The maritime border (red dashed line) separates the wells by country (Böttner, et al., 2020).

It is crucial to have a solid understanding of well integrity when evaluating man-induced leaks in wells. Davies, et al. (2014) summarized how the integrity of offshore wells has been addressed at the national level. They concluded that well integrity issues are common for these wells, but they cannot be directly linked to active well leakage. These well integrity issues are mainly listed as sustained casing pressure, casing corrosion, no pressure reading at wellhead, leakage in wellhead components, erosion of production tubing.

Several studies have examined the leakage of gas from gas wells in the North Sea. Many articles focus on the blowout in the UK well known as UK22/4b in some literature that occurred in 1990. This blowout resulted in the largest release of methane at a single site in the North Sea: 15,000 – 41,000 tones y^{-1} from the seabed (at a depth of about 90-96 m) in 2011. The direct release to air was less than 5,000 - 7,500 tonnes y^{-1}, some of which was through gas bubbles. An earlier investigation published in 1998 estimated this as 7,008 tonnes y^{-1}. Some of the leakages may have dispersed laterally by seawater flow (Griffioen & Geel, 2023). These numbers suggest that the release has not changed much over time, as Leifer & Judd (2015) also concluded, so the gas reservoir has not been fully depleted since the 1990 event. The leakage fluctuates overtime at short (minutes) and long (days/years) time scales, showing elastic behaviour that causes eruptions (Leifer & Judd, 2015).

The data presented above accounts for this fact that the asserted leakages from the wells suggest that the release of has not changed much over time.

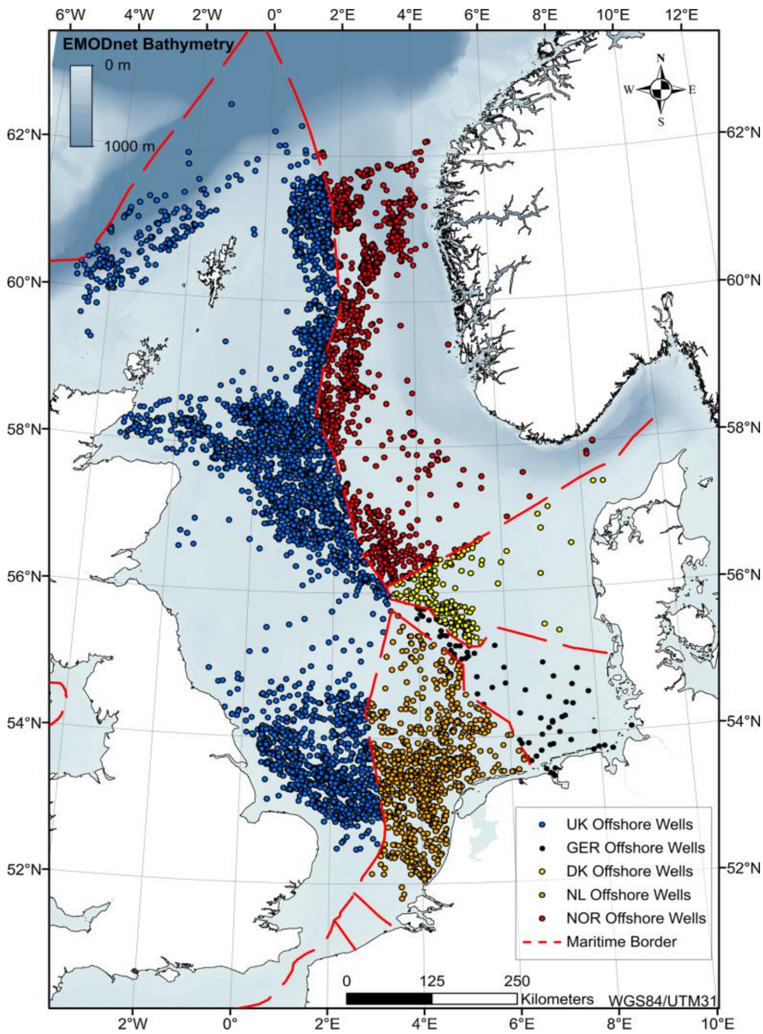


Figure 1-3 The North Sea comprises of 20,507 documented offshore wells (Böttner et al.)

Three other blowouts have been reported for the North Sea. In 1980, Norwegian well 34/10–10 had a blowout from a reservoir located 230m below the seafloor (Hovland, 2007). Another blowout happened at Norwegian well 2/4-14 in 1989, which was investigated by Landrø et al. (2019). The underground gas blowout lasted for almost a year before it was stopped by a relief well. The released gas kept flowing to the shallow subsurface and probably still does. A third blowout occurred in the early stage of gas exploration at the North Sea during an exploratory drilling in the German Bight. The well was successfully killed using heavy mud and cement. However, no flux measurements are available for these three blowout sites, so it is unclear whether they still leak natural gas (Griffioen & Geel, 2023).

Vielstädte et al. (2015) conducted a study to quantify the release of methane from three abandoned wells located in the Norwegian Central North Sea. All three wells targeted the Paleocene Heimdal Formation. One well was permanently plugged and abandoned as a dry well, while the other two boreholes intercepted gas in the Heimdal Formation but were later plugged and abandoned. The calculated fluxes were 1, 4 and 19 tonnes y^{-1}. The source was thought to be shallow, biogenic gas and the flow was assumed to happen along the outside of the abandoned well and not through the well itself. The highest flux was observed at a well that was drilled through a bright spot with a seismic chimney above the seismic anomaly. The lowest flux was detected at a well where there was a bright spot but no seismic chimney. The middle value was obtained at the dry well where the seismic layering was disrupted but without a seismic chimney (Vielstädte, et al., 2015).

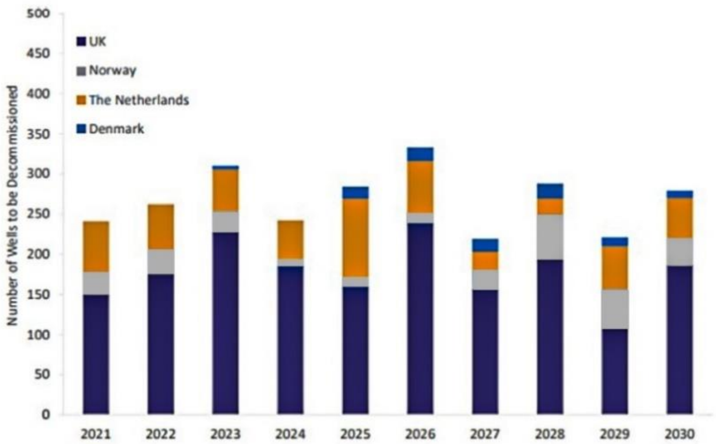
Böttner et al. (2020) assessed 43 decommissioned wells in the UK Central North Sea., which also covered the Scanner pockmark area. They found that 28 of these wells released gas, likely of biogenic origin, which is two-thirds of the wells studied. However, they did not consider the potential presence of natural seepage around these wells, even though the area contains natural seeps as noted by Wilpshaar et al. (2021).

Vielstädte et al. (2017) and Böttner et al. (2020) assessed the human-induced leakage of shallow gas along wells for two scenarios: the entire North Sea (with both active and inactive wells) and the UK Central North Sea (only decommissioned wells). They estimated a total leakage from the seabed of 3,000 – 17,000 tonnes y^{-1} for the first scenario and 700 – 4,200 tonnes y^{-1} for the second scenario. The first scenario had a lower range than the UK22/4b blowout and was 4-5 orders of magnitude smaller than the total natural seepage across the UK Continental Shelf (UKCS). They also calculated the emission of methane to the air for the first scenario as 1,000 – 7,000 tonnes y^{-1}. This was similar to or 1-3 orders smaller than other estimates on sea-air fluxes for the North Sea or UKCS, where the latter had very high maxima. It was slightly less than 1 promille of the oceanic emission of methane to air from geological sources.

1.3 The Fate of Hydrocarbon Wells in North Sea

When the activities of an injection or production is ceased, the condition of the well must be clarified. Depending on the situation, there are three possible scenarios: suspended, temporarily abandoned, or permanently abandoned (NORSOK-D010, 2021). The first scenario called suspension refers to the case where a well undergoes construction or intervention and the operations are halted without removing the well control equipment. This may happen for various reasons, such as waiting on weather, working in another well, waiting for equipment, skidding the rig to do short-term work in another well or batch drilling (top hole only), or carrying out piping activities in the field. Temporary abandonment occurs when the well is abandoned and the well control equipment is removed, but there is a plan to either re-enter at a later time or permanent abandonment. This might instead be referred to long-term suspension. Temporary abandonment can result from a long shutdown, waiting for workover, waiting for field development, re-development, etc. A temporary abandoned state starts when the main reservoir is completely isolated from the well and may last from a few days to several years. Permanent abandonment implies that a well or part of a well is permanently plugged and abandoned without the intention of re-use or re-entry (Khalifeh & Saasen, 2020).

The chart in Figure 1-4 presents a 10-year forecast for well abandonment projects in the North Sea. By the end of 2021, the UKCS, where drilling began in 1964, had a total of 7,385 development wells. Additionally, there were 2,535 explorations and 1,894 appraisal wells drilled over the same timeframe. In this region of the North Sea, 1,782 wells are anticipated to be decommissioned between 2021 and 2030, representing 67% of all wells decommissioned in the North Sea during this period. The remaining 33% of wells scheduled for decommissioning will be in Norway, the Netherlands, and Denmark. Based on this agreement, Norway has reported to decommissioning 278 wells out of a total of 2679 wells. This number of wells is almost equivalent to 10% of the total number (Chukwuemeka, et al., 2023). Close to half of the roughly 29,000 wells drilled in the North Basin of Germany have been plugged and abandoned. From this overall figure, between 80% and 90% of the wells intended for hydrocarbon extraction have been decommissioned, leaving around 3,500 wells still accessible (Bai, et al., 2015).



Country	Number of wells	
UK	1,782	67%
The Netherlands	528	20%
Norway	278	10%
Denmark	91	3%
TOTAL	2,679	100%*

Figure 1-4 A decade forecast of number of wells to be decommissioned in the North Sea (Oil and Gas UK)

1.4 Past, Present, and Future of Plugged and Abandoned Wells on the NCS

An accessible database including information on permanently plugged and abandoned wells would be advantageous for the industry, government, and taxpayers. This has the potential to lead to the exchange of information, improved coordination of plans, and enhanced comprehension of tactics and advancements in technology pertaining to the plugging and abandonment of wells (Khalifeh & Saasen, 2020).

Figure 1-5 depicts the overall quantity of wells in the Norwegian Continental Shelf (NCS). According to this statistic, there are injection, production, temporarily plugged with monitoring, and temporary abandoned wells in this region, with a total of +/- 2245 wells. According to NORSOK D-10 (2021), temporary plugged with monitoring refer to wells where both the primary and secondary barriers are continuously monitored and regularly tested. There is no time limit for this modus.

Temporary abandonment without monitoring refers to the state of wells that have been left without monitoring. During this period, both the primary and secondary well barriers are not subject to continuous monitoring or routine testing. The duration of abandonment must not exceed three (3) years.

Figure 1-6 displays a clear classification system based on colour coding for well integrity.

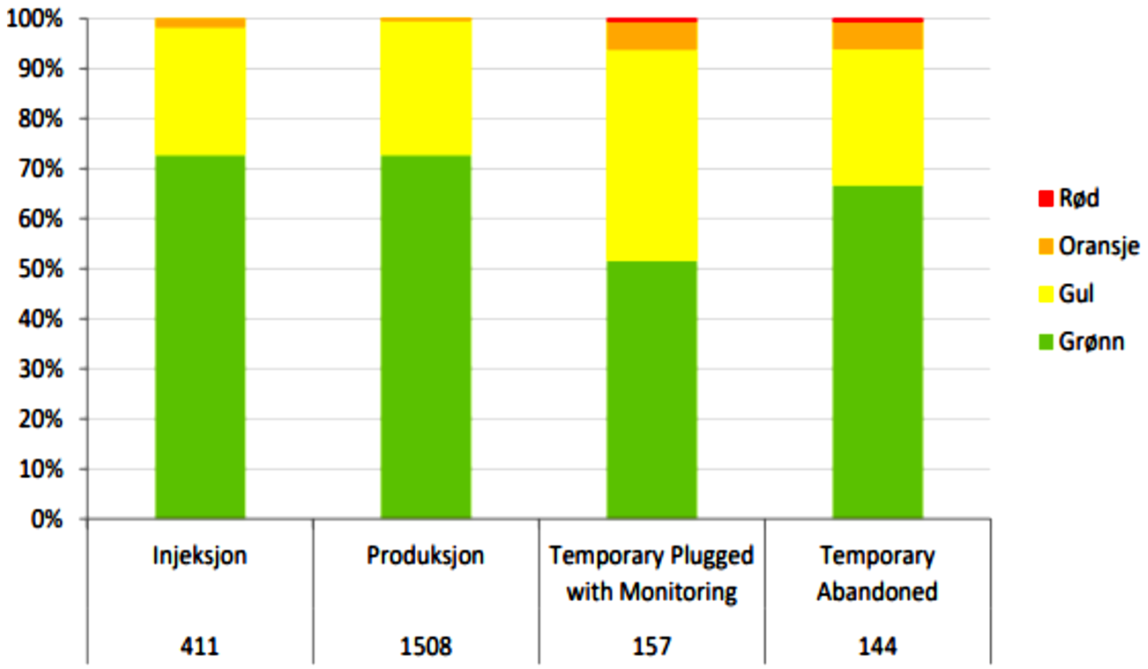


Figure 1-5 Total number of wells in NCS (Havtill 2024)

Category	Principle
Red (Rød)	One barrier failure and the other is degraded/not verified, or leak to surface
Orange (Oransje)	One barrier failure and the other is intact, or a single failure may lead to leak to surface
Yellow (Gul)	One barrier degraded; the other is intact
Green (Grønn)	Healthy well - no or minor issue

Figure 1-6 Well integrity colour codes (Offshore Norge)

Figure 1-7 presents the number of permanently plugged and abandoned production wells in the NCS region from 1978 to 2023. This figure shows that a total of 461 production wells on the NCS have been permanently plugged and abandoned (PP&A) between 1978 and 2023. Furthermore, there have been around 2000 exploration wells permanently plugged and abandoned. Each colour is denoted by unique operators.

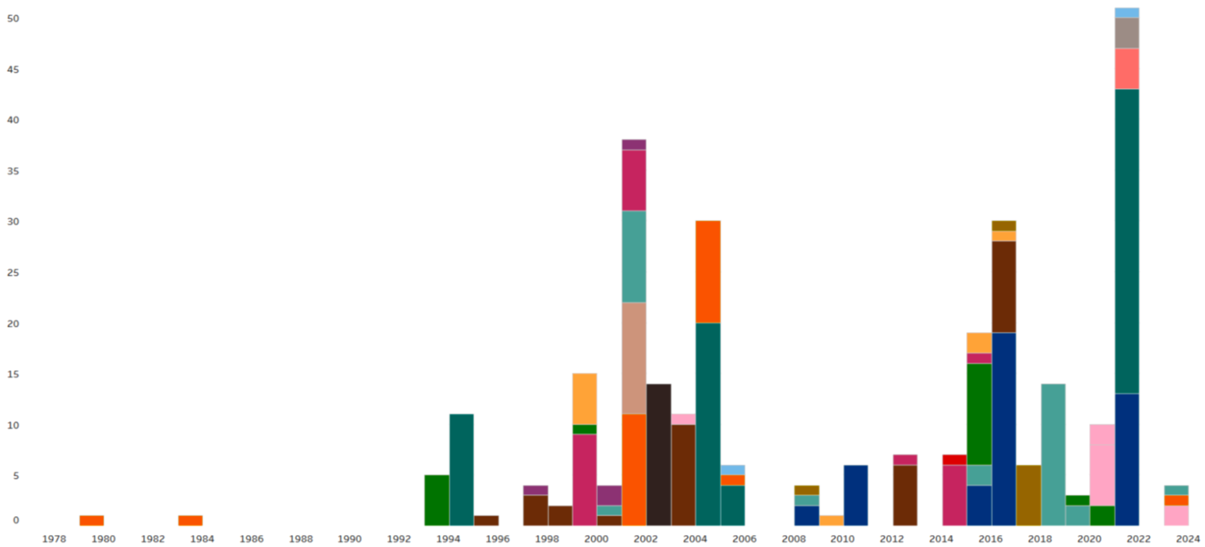


Figure 1-7 Permanent P&A of production wells NCS 1978 – 2023 (NPD)

The projected number of permanent plug and abandonment wells from now to 2050, broken down by year is shown in Figure 1-8. Based on these predictions, it is anticipated that about 1900-2000 wells would undergo permanent plug and abandonment operations between the years 2033 and 2050. However, there is a need to properly define “well” and “wellbore.

The annual count of various well types that are scheduled to be permanently plugged and abandoned categorized by operational units is depicted in Figure 1-9. This graphic facilitates comprehension of the scheduled decommissioning operations for both platform and subsea wells within the designated timeframe. Based on this data, there are a total of 250 platform wells and 50 subsea wells in the NCS that are scheduled to be permanently plugged and abandoned by 2032.

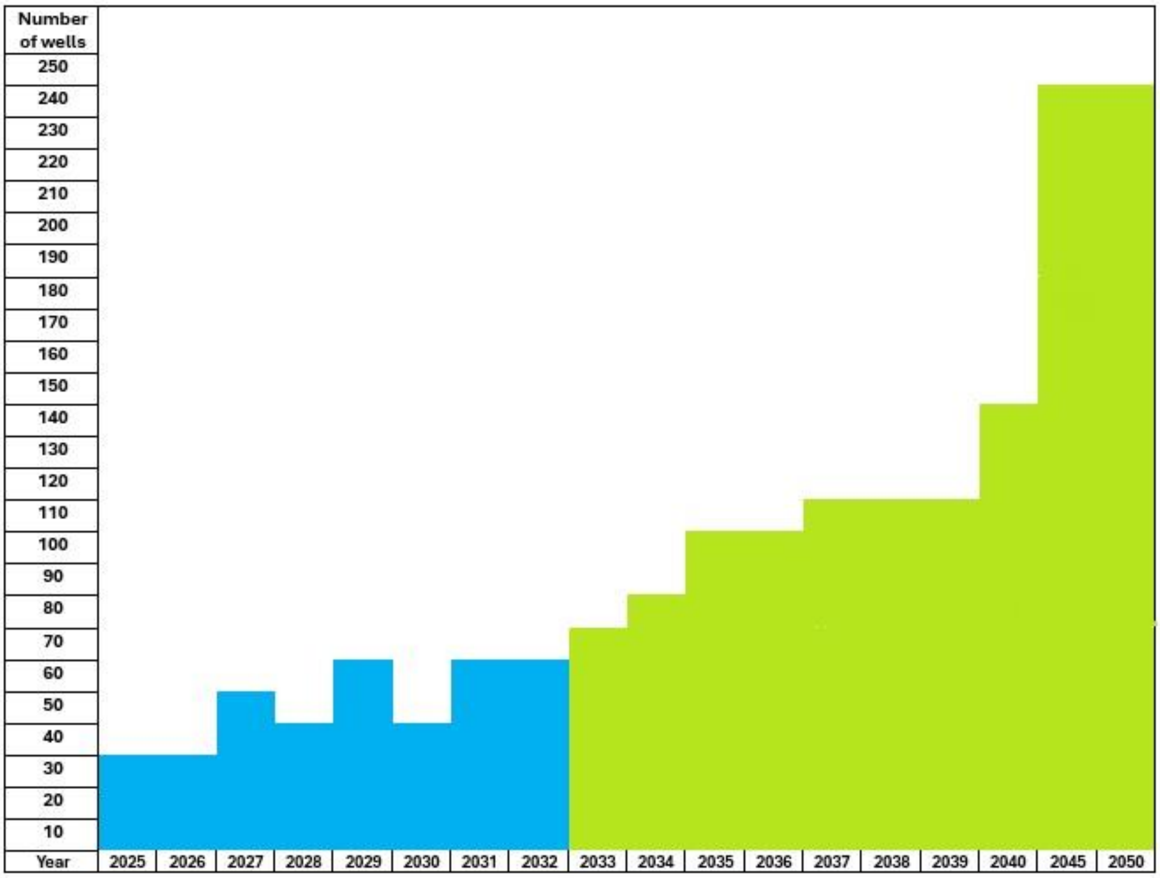


Figure 1-8 Predicted PP&A projects in the Norwegian sector of the North Sea (Havtil)

The industry is expected to experience a significant increase in well decommissioning in the near future. However, it is crucial to acknowledge that the projected number of wells to be plugged and abandoned is uncertain and can be influenced by factors such as oil and gas economics, environmental conditions, government policies, and disease outbreaks, as observed during COVID-19. The increasing price per barrel of oil may result in operators having additional funds to allocate towards P & A initiatives. However, it may also lead to some wells that were previously deemed uneconomical and potential candidates for decommissioning during periods of low oil prices being financially feasible for continued production over a defined timeframe (Chukwuemeka, et al., 2023). Moreover, these projections fail to consider the influence of manpower availability on future decommissioning operations. The oil and gas

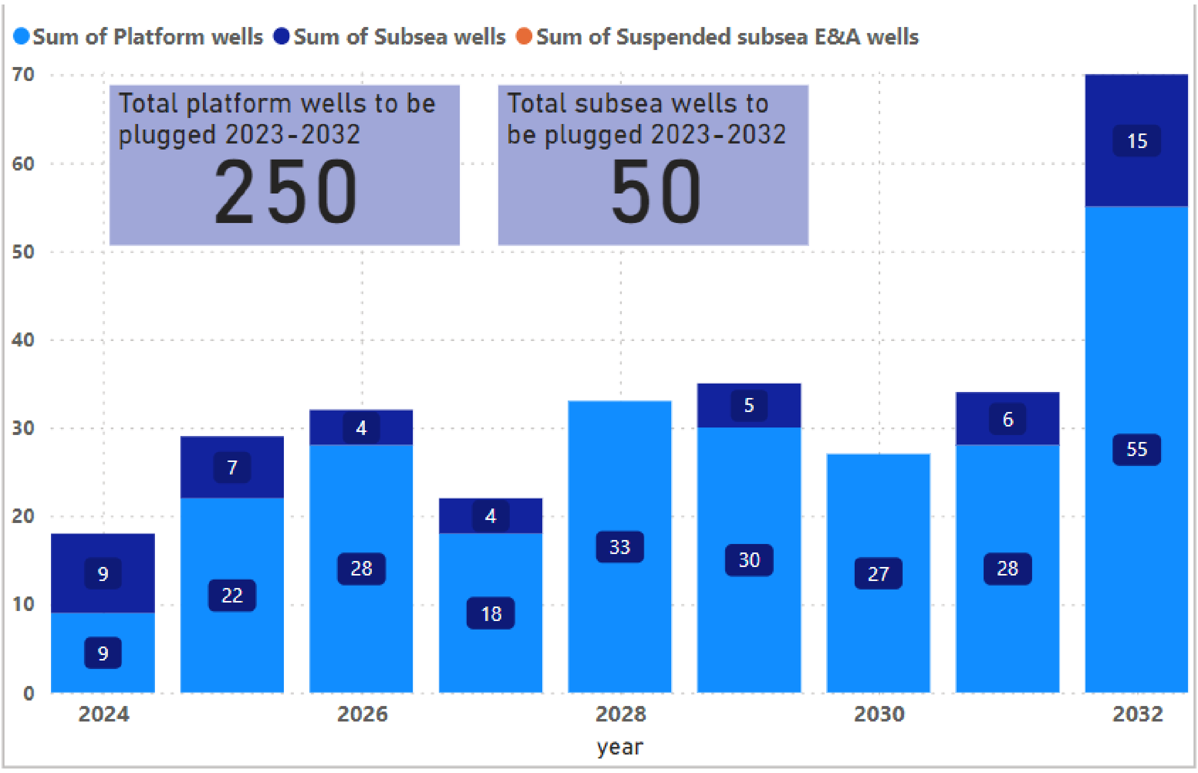


Figure 1-9 Well abandonment outlook 2032 in Norwegian sector of the North Sea (Offshore Norge)

sector may encounter a shortage of trained workers if present trends persist, since the experienced workforce is aging, and the younger generation is increasingly pursuing professions in data science and renewable energy (Chukwuemeka, et al., 2023).

1.5 Permanently Plugged and Abandoned Wells

According to the definition provided in the EU rules published in November 2023.

" *Permanently plugged and abandoned well' means an oil or gas well or well site, onshore or offshore, which has been plugged and will not be re-entered, in which all operations have been terminated and in which all installations associated with the well have been removed in accordance with the applicable regulatory requirements and where documentation can be provided as established in Annex IV, Part 1, point 3*." (Council of the European Union, 2023). This definition is aligned with NORSOK D010 (2021) and Oil and Gas UK Guidelines (2015).

1.6 P&A Phases

The operational procedures for plug and abandonment (P&A) of wells can vary significantly based on the well type and specific conditions. However, there are common steps involved, and a typical P&A operation can be summarized in three phases.

Oil and Gas UK Guidelines categorizes the sequence of P&A operations into three primary phases. Phase 1, "Reservoir abandonment," involves setting up primary and secondary barriers against the main reservoir. Phase 2, "Intermediate abandonment," includes the installation of potential barriers to prevent flow from zones above the reservoir. Additionally, an open hole-to-surface plug, also known as the "environmental plug," is placed below the seabed to prevent any residual fluid contamination. Phase 3, "Wellhead and conductor removal," involves the cutting and retrieval of casing strings and conductors, along with the removal of the wellhead. Beyond these, Moeinikia et al. (2015) propose a preliminary Phase 0, "Preparatory work," which entails pre-P&A activities such as killing the well and placing deep-set mechanical plugs.

Table 1-1 outlines these phases and summarizes their key actions. Segmenting the P&A operations into distinct phases helps underline the potential for using simpler, less costly rigless methods for parts of the operation, rather than relying solely on traditional, more expensive rig-based approaches (Vrålstad, et al., 2019).

Table 1-1 Different phases of P&A operations for typical well with vertical Xmas tree (Vrålstad et al.)

Operational Phase	Contents
Phase 0: Preparatory work	Retrieve tubing hanger plugs, kill well, install deep set mechanical plug, punch/perforate tubing, circulate well clean
Phase 1: Reservoir abandonment	Rig up BOP, pull tubing hanger and tubing, install primary barrier with its base at top of influx zone (i.e. reservoir), install secondary barrier where the base of barrier can withstand future anticipated pressures
Phase 2: Intermediate abandonment	Remove casing strings (if necessary), install primary and secondary barriers towards potential flow zones in overburden, install surface plug ("environmental barrier")
Phase 3: Wellhead and conductor removal	Cut conductor and casing strings below seabed to avoid interference with marine activity, retrieve casing strings, conductor and wellhead

1.7 Well Abandonment Approval

Once the abandonment design is completed, the operator proceeds to submit the program to the local regulatory authority. Subsequently, the authority evaluates the program, asking any needed modifications or granting permission. After receiving approval for the program, the operator is authorized to proceed with the P&A activity. It should be emphasized that the approval of the program does not inherently confer any duty onto the local authority. The operator retains all duties throughout the P&A and post-abandonment stages. (Khalifeh & Saasen, 2020).

1.8 Post Abandonment Era

During the last phase of a permanent plug and abandonment operation, the conductor and wellhead are cut off under the surface or seabed and then retrieved. This step is implemented to mitigate any potential disruption to upcoming maritime operations, such as fishing. In the Norwegian area of the North Sea, this duty is often classified as a maritime operation rather than a drilling activity.

Once the wellhead has been taken out, re-entering the wellbore becomes nearly impossible since the well control system can no longer be set up. The cutting and extraction process can be accomplished using a rig, a conductor jack, a vessel for subsea wells, or a heavy lift vessel for offshore wells (Khalifeh & Saasen, 2020).

Certainly, preventing post-abandonment leaks is paramount. There could be potential leak paths, such as micro annuli within plugged wells that must be addressed (Vrålstad, et al., 2019). Furthermore, annulus leakage outside the casing can occur, especially in older wells where annulus cement may be compromised. Cracks and microannuli (debonding) can form due to operational forces during pressure testing, injection, stimulation, and production (Bois, et al., 2011; Therond, et al., 2016).

To maintain integrity post-abandonment, permanent barriers must span the entire well cross-section, including all annuli. However, this process can be time-consuming and costly (Vrålstad, et al., 2019). On the other hand, in permanently abandoned wells, the well barrier elements (WBEs) face prolonged exposure to various mechanical and chemical stresses. Mechanical stresses are overburden and potential tectonic stress while chemical stress is exposure to various chemical substances include crude oil, brine, hydrogen sulfide, hydrocarbon gas, and carbon dioxide. While not every well encounters all these chemicals post-abandonment, the selection of barrier materials should align with the specific chemical composition of the target reservoir. For instance, sour wells which commonly found in regions like the Republic of Azerbaijan and Russia. In these countries, ensuring the durability of WBEs in the presence of corrosive elements is a top priority (Khalifeh & Saasen, 2020).

According to what was said above, it seems obvious that after the abandonment operation, it might be necessary to control and monitor permanently abandoned wells in terms of leakage or other factors. These actions should be in accordance with the rules and regulations that have been published and have the efficiency in addressing these concerns.

1.9 Recent Regulations

Methane Emissions Reduction Regulation (EU) 2019/942 is proposed regulations for reducing methane emissions in the energy sector were published by the commission on December 15, 2021, aimed at addressing global methane emissions. It introduces strict requirements for the oil, gas and coal sectors, including the measurement, reporting, and verification of methane emissions. In addition, it proposes rules for detecting and repairing leaks, limiting ventilation and flaring, and monitoring imports (Council of the European Union, 2023).

Article 18 of this document involves emission from inactive wells i.e., temporarily plugged wells and permanently plugged and abandoned wells.

Methane released from inactive and permanently plugged and abandoned oil and gas wells can present risks to public health, safety, and the environment. As a result, it is imperative to continue monitoring these emissions through quantification and pressure assessment where the necessary equipment is available, and to fulfill reporting requirements. Such wells and their sites must be permanently plugged, reclaimed and remediated as needed. In these situations, it is crucial for Member States to take a leading role, especially in creating comprehensive listings and developing mitigation strategies with definitive timelines when responsible entity is identified (Council of the European Union, 2023).

For wells that have been permanently plugged and abandoned, it is necessary to provide sufficient documentation proving the absence of methane emissions for all wells plugged and abandoned up to 30 years before this Regulation takes effect, and where possible, for those plugged before that period. This evidence should at minimum include quantification based on emission factors or samples, or solid proof of permanent below-ground isolation, adhering to ISO 16530-1, the global standard for well integrity in the oil and natural gas sectors (Council of the European Union, 2023).

1.9.1 Challenges in new regulation

Should methane leaks or integrity issues be detected at a P&A well after the removal of the wellhead, implementing mitigation measures becomes more complex. Without direct access to the wellbore, options for remediation may be limited to indirect methods, such as surface-based remote sensing or subsurface geophysical techniques, which may have limitations in sensitivity, accuracy, or spatial resolution and can be less effective and more costly. Implementing a monitoring system, including the installation of cabling and the need for battery replacements, poses logistical and financial challenges. These factors necessitate a.

considerable budget, making the monitoring process after P&A operations a complex issue that requires careful planning and resource allocation.

Dealing with the matter of monitoring and observing how often permanently plugged and abandoned wells are checked within regulatory frameworks has extra difficulties, particularly when rules lack definition.

2 Objective

The objective of this thesis is to evaluate the effectiveness of plug and abandonment designs in preventing leaks from wells. This leakage could be through stablished barriers during PP&A phases. Subsequently contemporary procedures which are utilized to establish potent barriers toward primary reservoirs, overburden layers, and surface plugs will be assessed.

The following study emphasizes the critical role of dual-barrier systems in ensuring well integrity and examines the challenges faced during abandonment operations, particularly near the surface.

Shallow depths are assumed to be associated with natural seeps and emissions. Hence, it is of a great importance to investigate the potential methane emission in shallow depths. Another technical aim of this study is to determine whether these seeps are influenced by wellbores or occur independently. Additionally, efforts are focused to evaluate the effect of wellbores on the behaviour and distribution of natural seeps. The thesis seeks to differentiate between natural seeps and wellbore-induced leaks in terms of emission. Additionally, efficient literature review is done to develop a better perspective of the term ‘Leak’ when it comes to assess the emissions from P&A wells. The proposed efforts might assist in improving regulatory views and optimizing future P&A initiatives.

3 Reservoir Abandonment-Phase 1

In Phase 1, during reservoir abandonment, primary and secondary permanent barriers are established to effectively restore caprock or it's functionality for the main reservoir (Moeinikia, et al., 2015).

The first stage in abandonment reservoir involves checking the wellhead and installing a wireline equipment. This device is utilized to verify the accessibility of the wellbore by performing drift tests and evaluating the condition of the production tubing using a caliper log. Phase 0, sometimes referred to as well intervention, is a critical step in minimizing the duration of P&A operations. In addition, methods are implemented to manage both liquid and solid waste. Following this, an injection test is conducted to assess the well's integrity. Should the well remain undamaged, a cement slurry is injected to effectively seal the primary reservoir. Once the cement has solidified and achieved sufficient durability, its efficacy is confirmed through the process of pressure testing. A rig is not necessary for this part of the procedure. Nevertheless, in the case that the well's integrity is compromised, it becomes essential to mobilize a rig and install a blowout preventer (BOP). Essentially, Phase 1 concludes once the main reservoir is securely sealed by the permanent primary and secondary barriers and the sealing has been verified. The production tubing might be removed or left in place, contributing to the well's barrier system. This stage is considered complete when the reservoir is entirely isolated from the wellbore (Moeinikia, et al., 2015).

3.1 Barrier

The fundamental concept of well integrity focuses on ensuring well control through the establishment of adequate barriers (Khalifeh & Saasen, 2020). In the context of well integrity, a barrier is an impenetrable object that prevents the uncontrolled release of fluid. A Well Barrier Element (WBE) refers to a physical component that may not independently prevent fluid flow but, when combined with additional WBEs, creates an effective well barrier envelope (NORSOK-D010, 2021).

It is important to design a well barrier such that the well integrity is ensured, and the well barrier is secured throughout the lifetime of the well. They should as far as possible be independent of each other with no common WBE (NORSOK-D010, 2021).

Optimal practices for permanent plugging and abandonment are installation of a cross-sectional barrier, referred to as a rock-to-rock barrier. This entails establishing a barrier that spans from one geological formation to another, covering all annular spaces, see Figure 3-1. It is crucial that this barrier is positioned at a depth where the geological formation has the capacity to withstand the highest expected pressure. This depth is known as “critical depth”. Consequently, a permanent barrier should be engineered to endure the greatest foreseen stresses, including the maximum differential pressure and temperature it could encounter, besides tectonic stresses, considering a long-term perspective (NORSOK-D010, 2021).

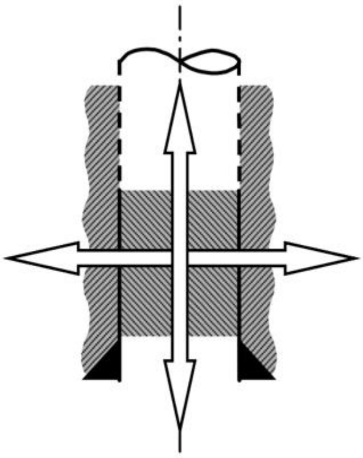


Figure 3-1 Cross sectional barrier(NORSOK-D010, 2021)

3.2 Two-Barrier Philosophy

There is a generally accepted philosophy for well barriers that the well should be equipped with sufficient well barriers to prevent uncontrolled flow from the potential sources of flow. In addition, it is generally accepted that no single failure of a well barrier component should lead to unacceptable consequences (Siddiqui, et al., 2018).

The two-barrier theory involves the use of two independent well barrier envelopes: a primary well barrier and a secondary well barrier. Primary well barrier is the first enclosure that prevents flow from a potential source of flow. Secondary well barrier is the second enclosure that also prevents flow from the potential source of inflow. The secondary well barrier is a back-up to the primary well barrier, and it shall not be engaged in use unless the primary well barrier fails. This is also known as “hat-over-hat” principle as shown in Figure 3-2 (Siddiqui, et al., 2018).

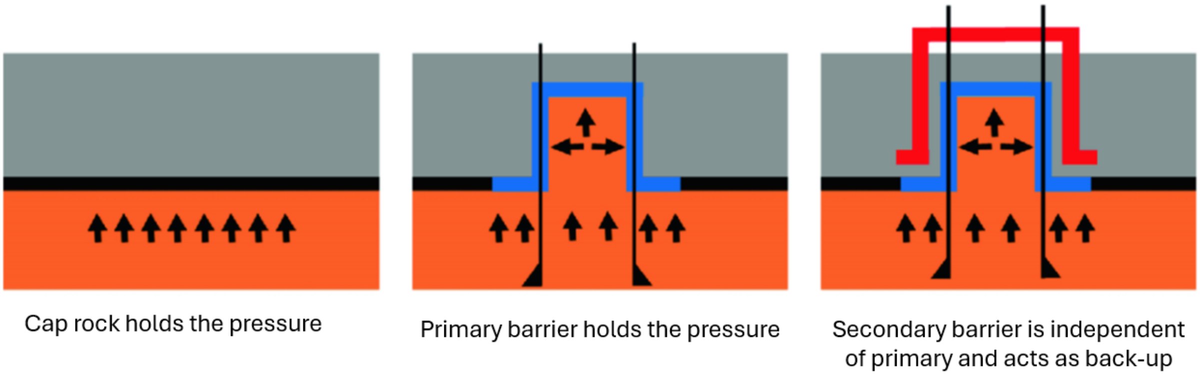


Figure 3-2 Two-barrier philosophy using the “hat-over-hat” representation(Khalifeh & Saasen)

To control the well, two independent qualified well barrier envelopes are necessary to be present for all activities in a well like drilling, testing, completion, production and when plugging and abandoning the well (NORSOK-D010, 2021).

Figure 3-3 illustrates the two-barrier philosophy of a well throughout its lifecycle, and Table 3-1 presents examples of the barrier elements through lifecycle of the given well. Primary well barrier shown as blue line and secondary well barrier as red. During a permanent P&A operation, in addition to primary and secondary barriers, a supplementary plug is installed close to the surface. It is the shallowest well hindrance that isolates open hole annuli from the external environments that broadly is known as the environmental plug. This plug is shown in green.

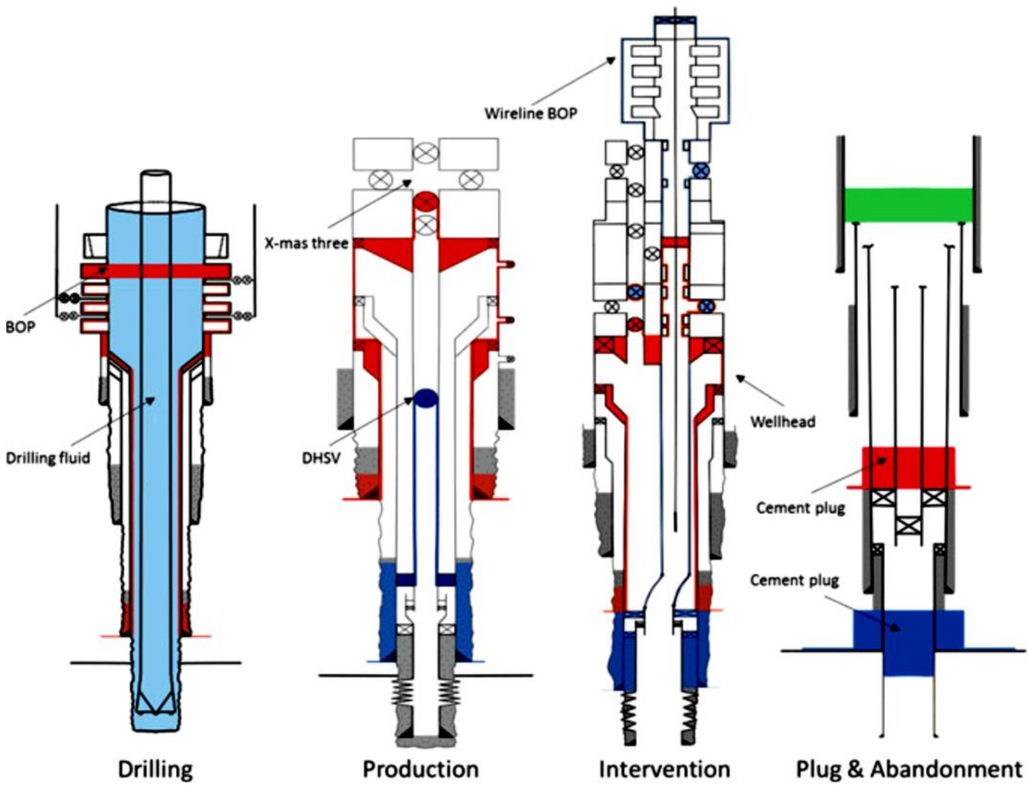


Figure 3-3 Depiction of the dual-barrier concept across the whole lifespan of a well (Anders, et al.)

Table 3-1 Examples of barrier systems through the lifecycle of the well given in Figure 3-3 (Khalifeh & Saasen).

Example	Primary Barrier	Secondary Barrier
Drilling	Overbalanced mud with filter cake	Casing cement, casing, wellhead, and BOP
Production	Casing cement, casing, packer, tubing, and DHSV (Downhole Safety Valve)	Casing cement, casing, wellhead, tubing hanger and Christmas tree
Intervention	Casing cement, casing, deep-set plug, and overbalanced mud	Casing cement, casing, wellhead and BOP
Plug & Abandonment	Casing cement, casing, and cement plug	Casing cement, casing and cement plug

3.3 Well Barrier Acceptance Criteria

To ensure the appropriate qualification of well barriers for their specific applications, it is essential to establish certain standards. These standards, referred to as Well Barrier Acceptance Criteria (WBAC) outlined in (NORSOK-D010, 2021). According to these criteria, a well barrier must be engineered to:

- Withstand the highest differential pressure and temperature scenarios it might encounter, considering the potential effects of depletion or injection activities in neighboring wells.
- Undergo leak and functionality testing or be validated through alternative approaches.
- Guarantee that the failure of a single well barrier or Well Barrier Element (WBE) does not result in the uncontrolled escape of formation and well fluids throughout the well's operational lifespan.
- Have the capacity to repair a compromised well barrier or set up an alternative barrier solution.
- Function effectively and withstand the specific environmental conditions it will face over its expected service period.
- Maintain independence from other well barrier systems, minimizing shared WBEs as much as feasible.

The key functional attributes of materials used for permanent barriers are (NORSOK-D010, 2021):

- Extremely low or zero permeability.
- Sustained durability under subterranean conditions.
- Non-shrinkage property.
- Flexibility or resistance to fracturing.

- Compatibility with subterranean fluids and gases.
- Adequate bonding to both the casing and the geological formation.

3.4 Position of Well Barriers

The formation adjacent to the permanent plug must be robust enough to sustain the highest anticipated pressure, which may arise from the inflow source. This anticipated pressure could either be the original pressure found in reservoirs supported by strong aquifers or a lower pressure anticipated at the end of the reservoir's operational phase, as determined by simulations. (NORSOK-D010, 2021). This is critical for determining the Minimum Setting Depth (MSD) or also known as critical depth of the plug, which is the shallowest depth at which the formation can withstand this pressure without fracturing. The MSD is crucial for the placement of the secondary plug, which acts as a backup to the primary plug. Placing the plug close to the source of inflow is standard practice to ensure optimal effectiveness. The MSD can be estimated using methods such as pressure-gradient curves for quick and dependable results, or the fluid gradient concept, which is useful when multiple leak-off test data points are available. These methods help ensure the integrity of the plug placement against formation pressures (Khalifeh & Saasen, 2020).

3.4.1 Minimum setting depth—gradient curves

In the approach to setting well plugs, initial pore pressure, fracture pressure, and minimum horizontal stress are graphed, and a gas gradient line is drawn from the reservoir pressure upward, factoring in the gas column's hydrostatic effect, see Figure 3-4. The intersection of this line with the minimum horizontal stress curve sets the MSD for the plug. This method also allows for installing new barriers if the initial ones fail, ensuring adaptability in maintaining well integrity (Khalifeh & Saasen, 2020).

3.4.2 Minimum setting depth—fluid gradient

In this methodology, the intersection of the fracture pressure and the gas column is determined through calculations. MSD is the variable to be solved for, while the final reservoir pressure, fracture gradient, fluid gradient, and true vertical depth (TVD) of the reservoir are established inputs. The formula provided defines MSD based on these known parameters:

$$h_{MSD} \geq \frac{P_{FP} - P_{Fluid} \times H}{(\frac{12}{231} \times P_{Frac} - P_{Fluid})}$$

P_{FP}: final reservoir pressure (psi),
P_{Fluid}: fluid gradient pressure (psi/ft)
H: TVD of reservoir (ft)
h_{MSD}: minimum setting depth (ft),
P_{Frac}: fracture pressure gradient (ppg).

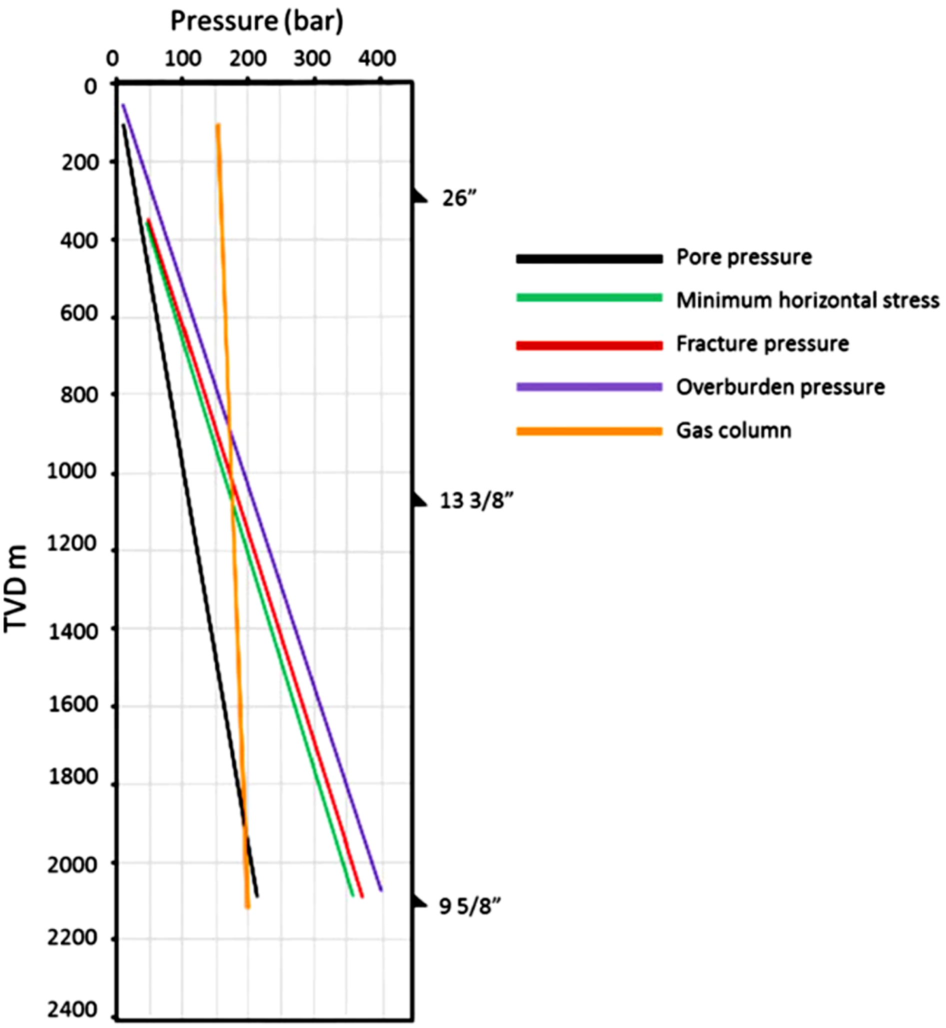


Figure 3-4 Fracture and pore pressure gradient curves (Khalifeh & Saasen)

3.5 Potential Leak Paths in Plugged and Abandoned Wells

The integrity of the cement plug may be compromised at any point in the life cycle of a well. Gas migration during curing, cement shrinkage, mud channelling, thermal and mechanical stresses during well operations, and faulty cementing during plugging and abandonment are a few of the several factors that can compromise the integrity of the cement (Ogienagbon & Khalifeh, 2023).The casing-cement and cement-formation interfaces have been identified as preferential flow paths for the migration of fluids in a wellbore system, see Figure 3-5 (Oil and Gas UK, 2015).

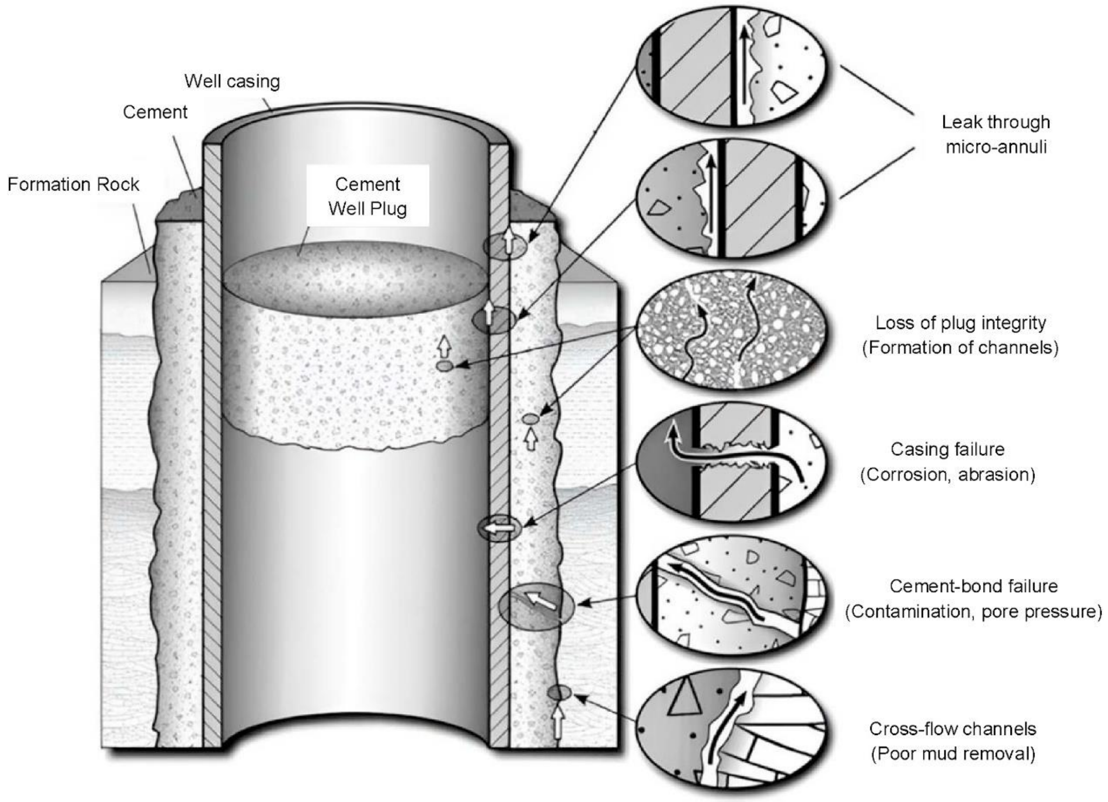


Figure 3-5 Possible pathways for leakage of cement plug and/or annular cement (Oil and Gas UK)

3.6 Verification of Permanent Barriers

Three primary modes of barrier failure exist: leakage occurring within the material itself, leakage circumventing the material, and changes in the barrier's location. These modes of failure, along with their underlying causes, are relevant to both annular cement and cement plugs (Vrålstad, et al., 2019).

The confirmation of a barrier's effectiveness is essential once it has been established. Various testing methodologies exist to assess the integrity of permanent barriers. These methods vary, including assessments of the annular barrier, evaluations of permanent plugs placed inside the casing, and examinations of barriers within openholes (Khalifeh & Saasen, 2020).

3.6.1 Verification of cement in casing/ open hole

Prior to being placed at downhole temperature and pressure, it is necessary to conduct strength testing on the cement. Volume pumped, return fluids while cementing, water-wetting pills, etc. should be documented during cementing operation (Tveit, 2018).

Pressure testing, also known as pump pressure testing or hydraulic testing, is utilized for evaluating plugs situated within the casing, open hole plugs extending to the casing, or plugs entirely placed in open holes, see Figure 3-6 (Khalifeh & Saasen, 2020).

Based on the direction of the applied hydraulic pressure, pressure testing can be categorized into positive or negative pressure testing. In positive pressure testing P_1 is greater than P_2, while in negative pressure testing P_2 is greater than P_1. (Figure 3-6). Positive pressure testing is done for scenarios which plug is inside casing or extended to casing and negative pressure testing (i.e., inflow test) is done for plugs placed in openholes (Khalifeh & Saasen, 2020). The positive pressure test shall be 70 bar above estimated LOT below casing/ potential leak path, 35 bar for surface casing plugs and not exceed casing pressure test (NORSOK-D010, 2021).

Weight testing is a technique to evaluate the plug's stability, its bonding to adjacent materials, and its position. In situations where a cement plug is positioned entirely within an open hole, conducting positive or sometimes even negative pressure tests may not be feasible (Khalifeh, et al., 2017).

3.6.2 Verification of cement in annulus

The top of cement (TOC) position should be accessed by documentation from the initial cementing process, which details operational data like the volume of cement used, flow returns, differential pressure, slurry velocity, and density, etc. Acoustic logging, noise logging and temperature logging techniques are used to determine the TOC and sealing capability of the casing cement (Khalifeh, et al., 2017).

Absence of sustained casing pressure during the life cycle of the well, absence of anomalies during the original cementing operations, acceptable leak off test when the casing shoe was drilled out are other indications of qualified sealing capability of cement in annulus (Henriksen, 2013).

When logging techniques for annular barrier verification is not practical, hydraulic pressure testing offers an alternative. It is especially useful for checking casing cement integrity with production tubing installed, inspecting barriers beyond the second casing, or when using the Perforate Wash Cement (PWC) technique for internal and external barrier setup (Khalifeh, et al., 2017).

Cemented casing is a sufficient barrier to vertical flow in the annulus as long as there is sufficient confidence in the quality of the cement in the annulus (Khalifeh, et al., 2017).

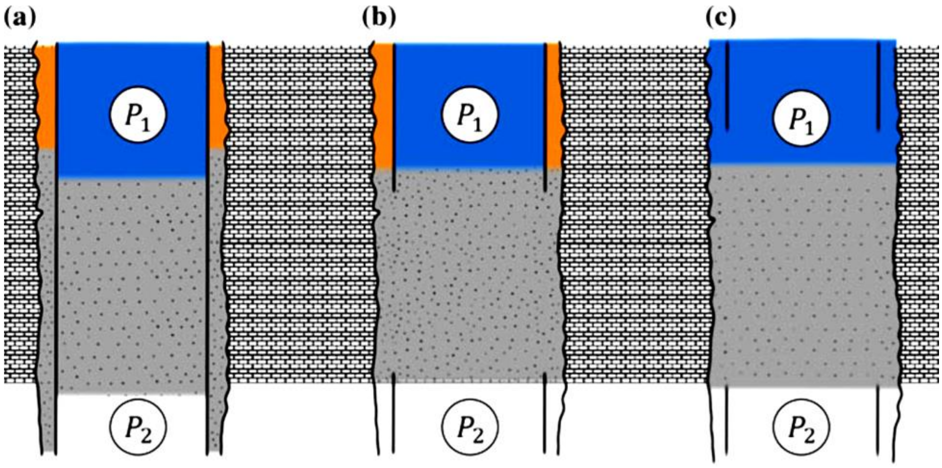


Figure 3-6 Cement plug installed in wellbore; a) cement plug is installed inside casing across a qualified annular barrier, b) cement plug installed in an open hole but extended to casing, c) cement plug entirely installed in an open hole(Khalifeh & Saasen).

3.7 Human factor in well integrity

The present requirements for energy necessitate reliable and secure operations in the oil and gas sector. With the shift towards more challenging environments and the introduction of novel systems, there is an increasing demand for systemic resilience. Given that most P&A activities utilize human-machine interface systems, the significance of human factors cannot be overstated in ensuring operational success. Neglecting various aspects of human factors can lead to catastrophic outcomes (Hal, 2015).

The human factor in P&A operations is a critical aspect to consider for ensuring the safety, efficiency, and effectiveness of these activities. It includes a wide range of considerations, including regulation and standard development, safety, skill, decision-making, error mitigation, teamwork, compliance, and technological adaptation. Addressing these human factors comprehensively is essential for the successful and safe conclusion of P&A activities.

Human performance is shaped by various factors, including physical, mental, and behavioral attributes. Deficiencies in areas such as sleep, hearing, motivation, skills, and vision can hinder performance and decision-making, affecting the ability to achieve task goals (Bailey, 1996).

The context of work significantly impacts human performance, emphasizing the need for suitable working conditions to minimize distractions and maintain system safety and efficiency. It is crucial to align the system with the operators' mental and skill levels (Bailey, 1996).

Bailey (1996) outlines three critical context considerations: physical, psychological and social, which are fundamental in shaping performance outcomes.

The physical context refers to the environment and conditions like noise, temperature, and lighting. The social context involves factors impacting human performance related to interpersonal interactions, including the presence of others, crowding, isolation, and grouping dynamics. The psychological context impacts behaviour, with emotions and variability shaping reactions to work culture (Bailey, 1996).

The impact of human factors on the establishment and evolution of engineering standards and regulations is significant, particularly in the context of well abandonment and related operations. The evolution of standards such as NORSOK D010 demonstrates how regulatory frameworks are subject to continual revision based on accumulated industry experience, technological advancements, and varying regional practices.

For instance, revisions in NORSOK D010 over time reflect a progressive understanding and adaptation to the practical and economic realities of well abandonment. Initial requirements, such as setting the top of the surface plug 5 meters below the seabed before removing the wellhead, have been reassessed and adjusted in subsequent revisions. Such changes highlight how standards evolve in response to operational feedback and changing industry needs.

This evolution is further influenced by regional differences in engineering practices and resources. For example, engineers in the United States and the Middle East may bring diverse perspectives and experiences to standard-setting processes, primarily due to differences in geographical and operational conditions such as the prevalence of land wells and the availability of different tools.

The dynamic nature of regulatory standards is also evident in how new regulations can initially increase operational costs. This is observed between NORSOK revisions, where newer, more stringent regulations aimed at enhancing safety and environmental protection can inadvertently raise the costs of compliance. Such regulatory changes prompt continuous efforts within the industry to optimize operations and reduce costs through innovative solutions and risk-based approaches.

In other words, the development of regulatory standards in well abandonment is not only a reflection of technical and scientific advancements but also deeply intertwined with human factors. These include experiential learning, regional operational practices, and the industry's response to economic pressures. Standards are therefore not static; they are living documents that evolve to balance safety, efficiency, and practicality considering ongoing industry feedback and changing operational contexts.

4 Intermediate Abandonment-Phase 2

During Phase 2 (intermediate abandonment), the goal is to isolate all identified areas with potential for overburden flow. Hydrocarbon flow potential is protected by permanent primary and secondary barriers. For hydrocarbon zones without flow potential and water-bearing zones, one permanent barrier is sufficient. However, if the water-bearing zone is of high pressure, permanent primary and secondary barriers become necessary, see Table 4-1. In the later part of Phase 2, a top plug, often referred to as an environmental plug, is installed (Moeinikia, et al., 2015).

The decision to use a rig in Phase 2 depends on a variety of factors, including the presence of hydrocarbons or overpressure at the depth of the reservoir barrier, limited access to casing, the absence of aquifers or isolated freshwater zones, presence of sustained casing pressure and/or the presence of non-isolated shallow gas. In addition, poor cement or uncemented casing at the barrier depth, inability to penetrate casing cement behind the second casing string, and presence of control lines (if not recovered in Phase 1) may require rig deployment (Moeinikia, et al., 2015).

Table 4-1 Origin of influx and minimum quantity of well barriers (NORSOK-D010)

Source of inflow	Minimum number of well barriers
a) Undesirable cross flow between formation zones b) Normally pressured formation with no hydrocarbon and no potential to flow to surface c) Abnormally pressured hydrocarbon formation with no potential to flow to surface (e.g. tar formation without hydrocarbon vapor)	One well barrier
d) Hydrocarbon bearing formations e) Abnormally pressured formation with potential to flow to surface	Two well barriers

4.1 Distinct Permeable Zone: DPZ

As per GP 10-60, a permeable zone is a zone that possesses sufficient permeability to facilitate the movement of fluids (such as oil, water, or gas) if there is a notable difference in pressure.

DPZ refers to either a single region or many sections that are permeable, and do not require isolation from each other for the operation or abandonment of a well (GP 10-60, 2008).

Prior to permanently plug and abandon a well, it is essential to assess previously established different permeability zones (DPZs) in order to ascertain whether isolation is necessary. Any newly detected DPZs during well abandonment must be isolated according to the same rules as the already identified ones (GP 10-60, 2008).

4.2 Reservoir and potential source of inflow

In drilling and well activities, any formation shall be a potential source of inflow with overpressure and/or HC present, unless otherwise can be concluded (Röser, 2014).

A reservoir is defined as a permeable formation or group of formation zones originally within the same pressure regime, with a flow potential and/or hydrocarbons present or likely present in the future, where the requirement is two permanent well barriers (Röser, 2014).

Source of inflow is defined as formation with the potential for flow (NORSOK-D010, 2021).

A formation shall be a potential source of inflow and consequently must be regarded as a reservoir if (Röser, 2014):

1. The formation contains free gas

2. The formation contains movable hydrocarbons (Hydrocarbons are typically mobile, unless they are residual or possess exceptionally high viscosity. (i.e., tar))

3. The formation contains movable water with overpressure, unless the risk (probability and consequence) of an inflow is insignificant.

An assessment of risk shall include a quantitative evaluation of (Röser, 2014):

- Flow potential; volume, matrix permeability and fractures
- Potential consequences associated with flow to overlaying formations and/or the environment.

Some major operators define "flow potential" as a formation with permeability and overpressure, meaning that a reservoir can be:

- Formation containing hydrocarbons
- Formation with permeability and overpressure
- Combination of both

4.3 Complexity of Intermediate Abandonment

4.3.1 Regulation in intermediate abandonment

The assessment of the overburden formation, including shallow inflow sources, must be conducted in alignment with the criteria for well abandonment (NORSOK-D010, 2021).

According to NORSOK-D010 "*all*" potential source of inflow shall be thoroughly identified and documented. Therefore, conducting a thorough exploration to accurately detect *all* potential source of inflow is necessary. Furthermore, "*Permanently abandoned wells shall be* *plugged with an eternal perspective taking into account the effects of any foreseeable injection, drainage, chemical and geological processes*". This raises pivotal questions: how can we adequately define the concept of *"eternity"* within the scope of these operations? And how can we ensure that our strategies are comprehensive enough to address "any eventuality" scenario?

Strict requirements regarding potential permeable zones in the overburden will lead to extra barriers and subsequently additional cost and risk to personnel involved in operation.

4.3.2 Identification of flow potential in overburden

The complexity of managing overburden in oil and gas fields is unpredictable behavior of gas traps. Initially, one might not find any gas, or the identified gas is at such low pressure that it is hard to detect. However, things change while constructing wellbore. The once hard-to-detect gas can become pressurized and easier to identify because of sustained casing pressure or finding leaks. This situation shows that there has been gas in the overburden, which was not obvious before (Röser, 2014).

A critical component of intermediate abandonment is the comprehensive evaluation of these zones to determine their flow potential accurately. Flow potential depends on various properties such as permeability, pressure, volume available, fluid type and time. Each parameter needs specific tools and technique to be determine. Additionally, uncertainties in pore pressure estimates in the overburden, which can significantly affect the assessment of flow potential (Röser, 2014).

Data must be gathered at various operational stages (drilling, production, P&A) to identify potential flow zones, which may not be apparent in standard datasets. Advanced logging tools and techniques, such as Nuclear Magnetic Resonance (NMR) logging, are critical in these efforts (Röser, 2014).

Some zones with flow potential are identified accidently, as was the case with a zone detected through NMR logging intended for other purposes. This highlights the importance of thorough and sometimes broader data acquisition strategies than initially planned (Röser, 2014).

A sensitivity study should be conducted to understand how flow potential varies with different reservoir sizes and fluid types. The study should model scenarios involving reservoirs of varying dimensions and thicknesses, filled with either oil or gas (Röser, 2014).

By accurately assessing the flow potential, operators aimed to optimize the placement of plugging materials, thereby reducing the cost and increasing the efficacy of P&A operations (Röser, 2014).

4.4 Risk-based abandonment, DNV GL-PR-E103

Finding the balance between the number and type of well barriers versus the cost of well P&A is a challenge in an environment when oil and gas prices are relatively low. In order to address this challenge, a risk-based approach to well P&A has been developed and successfully applied (Fanailoo, et al., 2017).

In April 2016, DNV GL introduced a new recommended practice (RP) for the permanent abandonment of wells, adopting a risk-based perspective that diverges from traditional prescriptive methods. This approach acknowledges the uniqueness of each well, suggesting that the requirements for the number, type, and size of barriers should vary based on specific safety and environmental protection needs. The risk-based strategy allows for customized design solutions, optimizing the abandonment process for each well and facilitating cost reductions for those considered less critical. The goal of this method is to systematically evaluate well abandonment designs against set acceptance criteria, ensuring environmental safety and upholding safety standards (Buchmiller, et al., 2016).

The methodology presents several benefits, including (Buchmiller, et al., 2016):

- Clearly defined criteria for safeguarding the environment
- Focused allocation of P&A resources on wells posing higher risks
- Enhanced capacity for tailoring well abandonment designs
- Adaptability for incorporating emerging plugging technologies
- Consideration of unique site-specific factors

The RP is comprised of two distinct sections. The first section serves as an introduction, while the second section presents a comprehensive risk assessment methodology specifically designed for well abandonment.

4.4.1 Introduction

Generally, the RP serves as a foundation for decision-making and provides guidelines and concepts for:

- Developing criteria for accepting environmental risks relevant to a particular place.

- Verifying adherence to safety standards for the installation/field.

- How to ascertain the functional specifications for materials utilized in permanent well barriers

- How to distinguish the level of environmental danger associated with different hydrocarbon compositions

The RP pertains exclusively to the permanent abandonment of offshore wells and does not apply to onshore wells, suspended wells, or temporarily abandoned wells. The provided standards are meant to be added to local rules.

The RP distinguishes between the three verbal forms shall, should, and may. The verbal forms' definitions are identical to the definitions of the same words in the NORSOK D-010 (DNV GL-RP-103, 2016).

4.4.1.1 System description

The RP provides a detailed account of the systems mentioned in the RP, which involve offshore wells, the geological formations around them, and the marine ecosystem in which they exist. This is seen in Figure 4-1, which is a reproduction from RP-E103.

Marine environment includes the sea surface, the water column and the seafloor. Geology is defined as the geological layer located above an oil or gas reservoir is known as overburden, which may contain varying amounts of hydrocarbons in certain formations. Wellbore is a conduit for injection to a reservoir or production from a reservoir.

The RP serves as a foundational guide for decision-making, outlining practices and principles for (DNV GL-RP-103, 2016):

- Developing criteria for accepting environmental risks relevant to a particular place.
- Verifying in accordance with safety standards for the installation/field.
- Defining the functional requirements for materials in permanent well barriers.
- Assessing environmental risk-based on the composition of hydrocarbons.

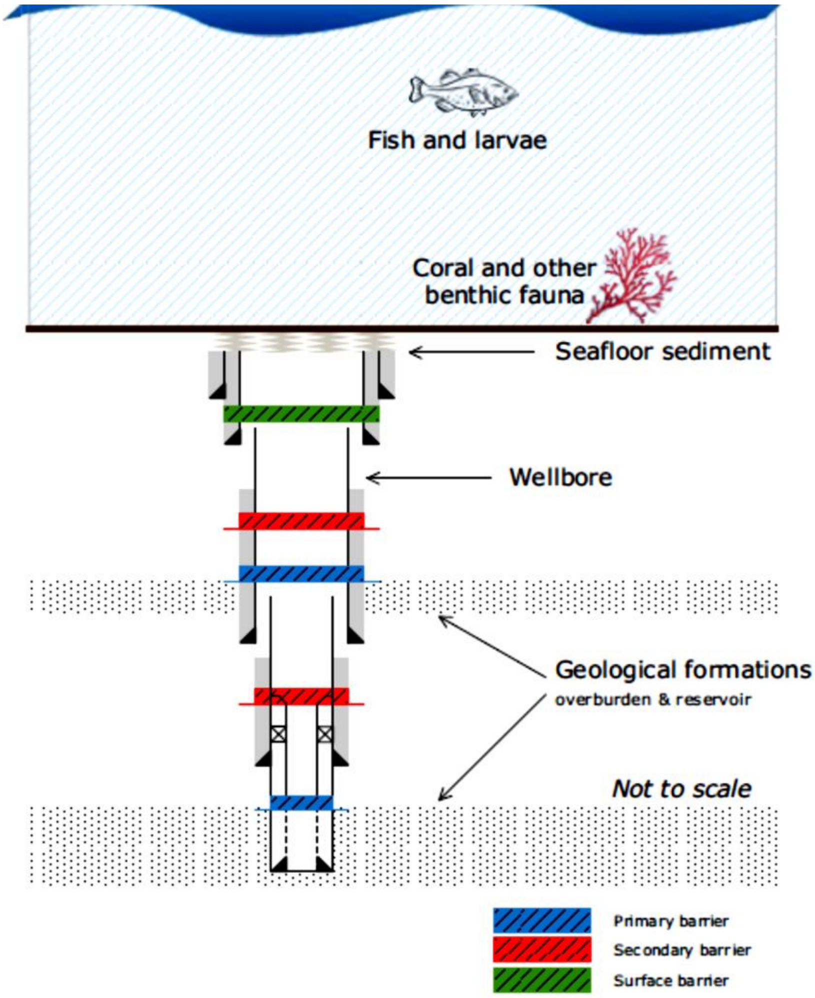


Figure 4-1 **The primary components of P&A wells (DNV GL-RP-103)**

4.4.2 Risk assessment framework for well abandonment design

Global standards are gradually recommending the use of a risk-based approach to ensure the integrity of wells. This approach focuses on evaluating wells based on their probability of experiencing containment failure. DNV GL expands the application of their approach to include the permanent decommissioning of offshore wells in RP-E103. This includes addressing long-lasting risks to well integrity. This method allows for a customized evaluation and reduction plan, concentrating on the distinct hazards that each well poses to ensure its safe abandonment (DNV GL-RP-103, 2016).

4.4.2.1 Establishing the risk context

The risk assessment process for well abandonment involves establishing, analysing, and evaluating the potential risks. This systematic approach identifies key risk factors and determines whether the proposed well abandonment design is adequate or if additional mitigation measures are necessary. This process, which is crucial for gaining insights, can be either qualitative or quantitative but must account for both environmental and safety risks. RP-E103 prioritizes a quantitative method. It is essential to define the context at the beginning and update it throughout the risk assessment to ensure relevance and accuracy. For P&A activities, it is recommended to assess the flow potential within the reservoir, surrounding formations, the possibility of crossflow between formations, and the efficacy of permanent well barrier solutions (DNV GL-RP-103, 2016).

Figure 4-2 illustrates the key components of a risk assessment for well abandonment. Identifying the well specific, environmental, met-ocean and geology data are primary types of data required for analysis (DNV GL-RP-103, 2016). In Appendix A, a sample input of data is shown.

4.4.2.1.1 Well abandonment design

RP-E103 points out that the main aim for well abandonment plans should be to stop any harm to the environment until natural geological barriers are back in place, all while keeping safety at the forefront. The plan should be as thorough as possible, tailored to the specific risks and highest expected flow. It also notes the importance of treating each well as unique, especially when dealing with several at once (DNV GL-RP-103, 2016).

4.4.2.1.2 Flow potential sources

A comprehensive analysis of formations that detects, investigates, and characterizes hydrocarbon-rich formations along with their corresponding flow capacity should be conducted. Flow potential, in this context, refers to formations that contain hydrocarbons capable of moving and are of such size to pose a possible risk to the environment or safety (DNV GL-RP-103, 2016).Table 4-2 presents the appropriate categorization of flow potential.

Table 4-2 Classification of flow capacity in deposits containing hydrocarbons (DNV GL-RP-103)

Categories of flow potential	Definition
No or limited flow potential	Hydrocarbon-bearing formations where moveable hydrocarbons present or in the future cannot under any circumstances have an environmental or safety impact
Moderate flow potential	Hydrocarbon-bearing formations where moveable hydrocarbons present or in the future may have an environmental impact, but no safety impact
Significant flow potential	Hydrocarbon-bearing formations where moveable hydrocarbons present or in the future may have both environmental and safety impact

The procedure entails assessing the anticipated capacity for fluid flow, considering variables such as natural recharging, utilization for hydrocarbon extraction, and participation in geothermal resources or storage projects including CO_2. To mitigate possible environmental hazards associated with formations exhibiting moderate or high flow potential, it is crucial to employ permanent well barriers and adhere to the ALARP (As Low As Reasonably Practicable) principles. To get more comprehensive instructions, the RP recommends consulting the UK Oil & Gas Guidelines for Well Abandonment (DNV GL-RP-103, 2016).

If many formations exist inside the same pressure region, they can be consolidated into a single formation for the purpose of management, if this does not violate environmental safety regulations. Nevertheless, it is typically advised against letting the flow between various forms to mitigate potential hazards (DNV GL-RP-103, 2016).

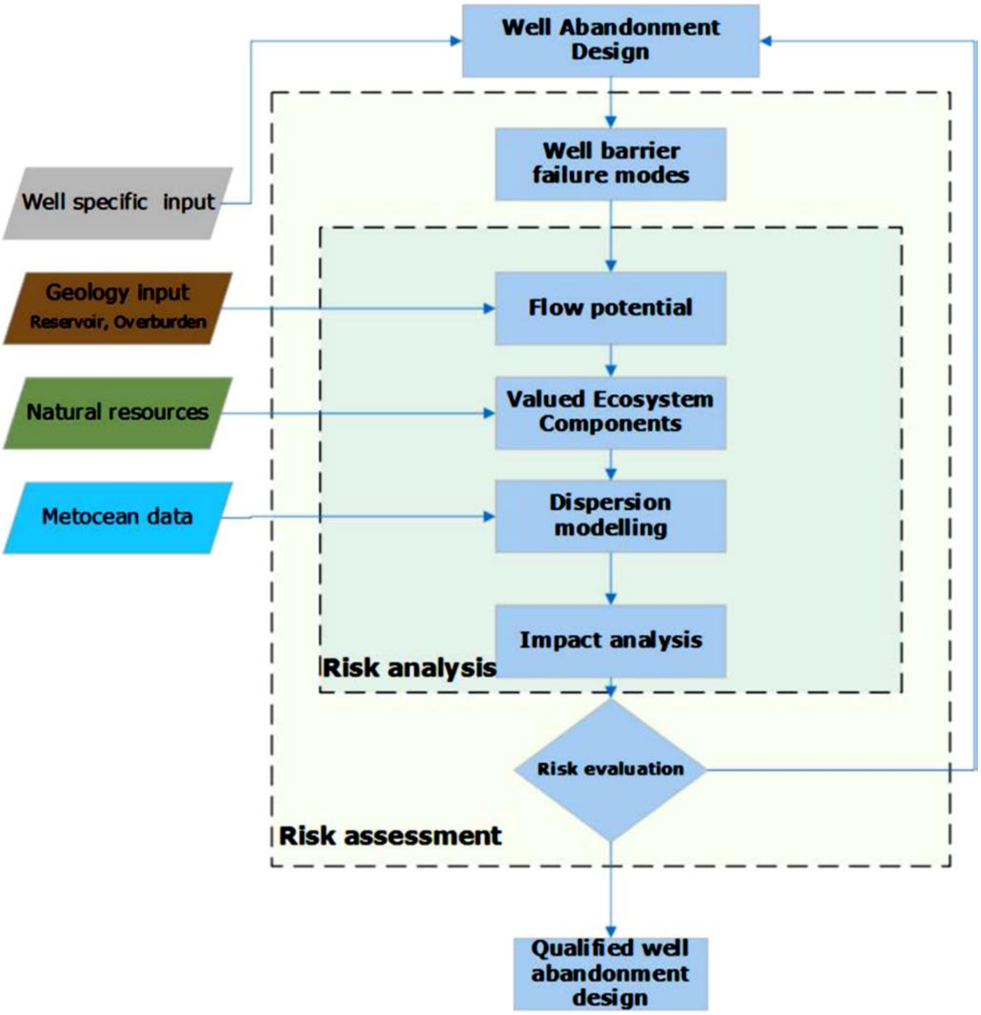


Figure 4-2 Risk Context for P&A (Janbu)

4.4.2.1.3 Permanent well barrier principles

When constructing a permanent barrier, it is crucial to be designed fit-for-purpose and consider any effect of potential chemical and geological variations. The primary purpose of a permanent well barrier is to manage formations that have a moderate or large potential for fluid flow. The lifespan of the barrier should be adapted to the individual site and dependent on its design. An essential component of the permanent well barrier is the surrounding formation, which must possess more integrity than the potential pressure underneath it and be impermeable at the depth of the barrier.

The barrier must possess sufficient depth to safely hold any hydrocarbons originating from the underlying deposits. It may be produced from any substance or combination of substances, if it satisfies these certain criteria (DNV GL-RP-103, 2016):

- It must withstand the highest expected pressures and forces.
- It should work as planned under the conditions it will face, including various pressures, temperatures, fluids, and physical stresses.
- It must block any unwanted flow of hydrocarbons to the outside environment.

The RP utilizes the term "any reasonably foreseeable" for characterizing the design of permanent well barriers, whereas NORSOK applies the term "eternity" to describe the longevity of these barriers. It also specifies that the duration of the barrier should be determined based on site-specific conditions, rather than an eternal perspective (DNV GL-RP-103, 2016).

4.4.2.1.4 Number of well barriers

Figure 4-3 presents different designs for the abandonment of wells, with each design customized based on the individual risk of flow associated with the well. The diagram demonstrates that the number of barriers employed is dependent upon the evaluated flow potential, established by risk analysis. The RP recognizes the advantage of employing many autonomous barriers to augment safety. It is possible to combine a primary and a secondary barrier into a single barrier if it maintains the same level of effectiveness and reliability as having two independent barriers. Furthermore, there is a requirement for a surface barrier that functions in conjunction with the main and secondary barriers to ensure that no fluid escapes from the wellbore (DNV GL-RP-103, 2016).

4.4.2.2 Permanent well barrier failure modes

Every well abandonment design must go through a failure mode identification process, in which all relevant failure modes are carefully examined and threats, events, and impacts are systematically recorded. This procedure evaluates not just possible cost reductions and advantages but also integrates many essential stages specified in DNV GL-RP-E103, including (DNV GL-RP-103, 2016):

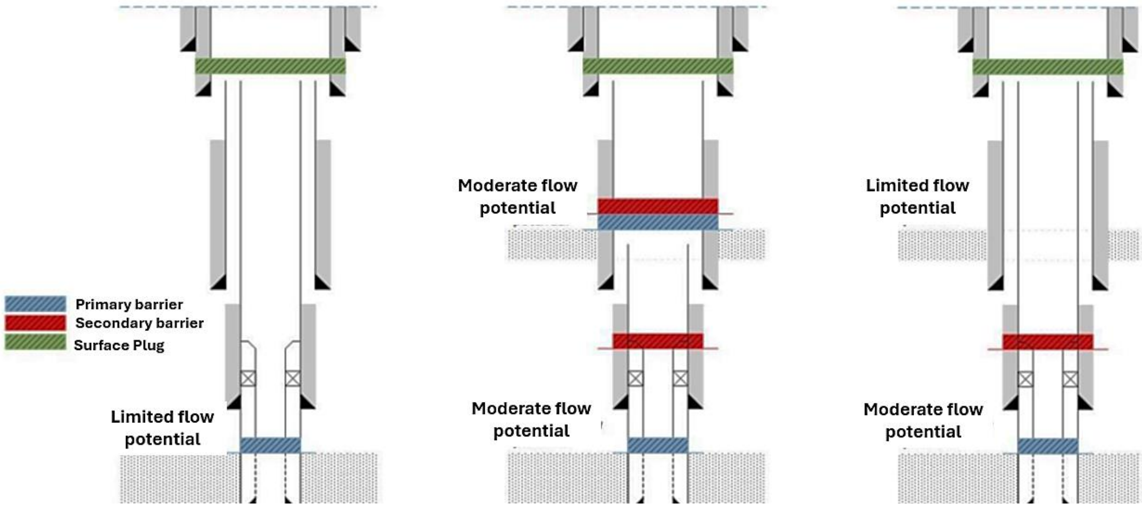


Figure 4-3 Examples of efficient well abandonment designs in DNV GL- RP-E103 (DNV GL-RP-103)

- Analyzing the causes of failure and degradation and categorizing threats according to predetermined levels of severity.
- Identifying more risks arising from the distinctive characteristics of the well abandonment strategy.
- Understanding the interaction between many forms of failure, particularly the possibility of one failure causing a chain reaction of others.
- Determining the elements that might increase the likelihood or severity of these failures.

Appendix B lists potential failure modes for analysis.

4.4.2.3 Risk analysis

The objective of risk analysis in P&A is to enhance our comprehension of hazards, with a specific emphasis on their characteristics, probability of occurrence, and the magnitude of their consequences. Risk analysis in P&A operations includes both safety and environmental hazards, relying on previously known failure mechanisms. It utilizes reliable data when accessible or relies on conservative assumptions when data is limited or uncertain (DNV GL-RP-103, 2016).

The study for P&A involves evaluating the well's flow potential by measuring the maximum achievable flow rate and the properties of hydrocarbons in the formations. This aids in assessing the possible consequences of any hydrocarbon flow. The research also examines the probability of such flows occurring, which helps in recognizing the risk associated with each failure scenario (DNV GL-RP-103, 2016).

The analysis can be either qualitative or quantitative, depending on the chosen strategy. ISO 31000 provides recommendations on both methodologies. Additionally, it involves examining the valuable ecosystem components (VECs) in the vicinity to the well, mapping significant resources and habitats to have a deeper understanding of environmental hazards (DNV GL-RP-103, 2016).

To assess the transport of identified hydrocarbon flow potential, three-dimensional dispersion modeling is essential. This method calculates and records the mass distribution and concentration of hydrocarbons in water and sediments. Employing a probabilistic approach provides insights into potential seepage behavior under various ocean conditions.

The final phase of risk analysis involves an impact analysis. This analysis integrates the results of flow potential analysis and dispersion modeling to understand the consequences. The likelihood component, derived from the flow potential analysis, is also incorporated.

Building the environmental risk picture involves evaluating the potential impact based on the overlap between hydrocarbon concentrations and defined Valued Ecosystem Components (VECs). For safety risks, the assessment considers the likelihood and consequences associated with the well abandonment design.

The combined output of consequence analysis (including flow potential, VEC mapping, and marine dispersion) and likelihood analysis, yields the overall risk assessment for each specific well abandonment design (DNV GL-RP-103, 2016).

4.4.2.4 Risk evaluation

Once the risk analysis is finished, it is necessary to compare the results with established criteria for accepting risk in order to make well-informed judgments. If the analysis indicates that the existing well abandonment plan is unsuitable and presents excessive risk, it may be necessary to alter the plan to mitigate such risks (DNV GL-RP-103, 2016).

Acceptance standards for risk are established for both environmental and safety factors. These criteria assess the potential impact of hydrocarbons on valuable ecosystem components (VECs) and the likelihood of this impact exceeding a specific threshold, with a focus on environmental concerns. The standards for safety vary depending on whether the well is located on a platform or underwater (DNV GL-RP-103, 2016).

Next, it is necessary to evaluate the findings of the risk analysis with the acceptability criteria for both environmental and safety hazards. This comparison can facilitate the determination of the optimal abandoning strategy, or whether modifications are necessary for the plan. Any modifications to the strategy should be reevaluated to comprehend their impacts. Additionally, these insights can assist in making informed judgments on the costs and benefits involved (DNV GL-RP-103, 2016).

4.4.2.5 Treatment of uncertainties

Similar to any risk analysis, there will inevitably be a certain degree of uncertainty in the outcomes. It is crucial to guarantee the utmost precision of these outcomes. When there are substantial uncertainties, doing sensitivity or scenario assessments can aid in understanding the influence of factors such as pressure, hydrocarbon quantity, and temperature on the risk assessment (DNV GL-RP-103, 2016).

Quantitatively addressing uncertainty can be facilitated by constructing a probability distribution containing weighted probabilities. The selection of the appropriate distribution model is dependent on the existing information and its potential evolution in the future.

Prior to P&A of each well, it is essential to undertake a comprehensive examination of the available data. The purpose of this is to find and record any crucial information that might aid in minimizing uncertainty in the risk assessment procedure (DNV GL-RP-103, 2016).

4.5 Risk-based approach to P&A advantages/disadvantages

So far, the P&A projects that have been carried out utilizing DNVGL-RP-E103 have achieved cost savings of 50% or more. The technique has also facilitated compliance with or overcome regulatory requirements in the North Sea and complemented internal operator needs. The risk-based approach has effectively addressed stakeholders' concerns by offering reliable physical models and a clear risk acceptance threshold (Fanailoo, et al., 2017).

The risk-based approach to plug and abandonment (P&A) operations represents a departure from traditional prescriptive methodologies by tailoring the abandonment process to the specific characteristics and uncertainties of each well and field. Rather than applying a uniform set of guidelines, this approach utilizes quantitative risk assessment techniques to identify and address potential failure modes, establish well-specific acceptance criteria, and design abandonment procedures accordingly (Buchmiller, et al., 2016).

One of the key advantages of the risk-based approach is its ability to provide a more effective strategy for well abandonment. By considering sub-surface uncertainties and variability, operators can better understand the unique challenges posed by each well, leading to more robust and tailored abandonment designs. This approach also allows for the optimization of resources, as less stringent requirements may be sufficient for wells deemed "simple," resulting in considerable time and cost savings and safety for personnel (Vrålstad, et al., 2019).

Furthermore, the risk-based methodology facilitates a comprehensive evaluation of environmental and safety considerations throughout the abandonment process. By incorporating environmental mapping, quantitative risk calculations operators can assess the potential impact of abandonment activities on the surrounding environment and mitigate risks accordingly. This holistic approach helps ensure that environmental protection remains a priority throughout the P&A process (Buchmiller, et al., 2016).

However, there are also challenges associated with the risk-based approach. One notable disadvantage is the need for thorough and accurate data to perform meaningful risk assessments. Currently, there is a lack of sufficient experimental results to serve as reliable input for risk models, particularly regarding plug sealing ability. Without adequate data, operators may struggle to accurately assess and mitigate risks, potentially compromising the effectiveness of the abandonment process (Vrålstad, et al., 2019).

The complexity of using risk-based approach becomes more when old wells which are supposed to be plugged are coming to the picture. This is due to lack of data and uncertainty of available data on these wells.

5 Conductor and wellhead removal-Phase 3

The final step in permanent P&A a well involves the removal of the well control system, followed by the cutting and retrieving of the wellhead and conductor pipe. The approach to this process varies based on the geographical location of the well and the regulatory requirements of the local governing bodies. Options for dealing with the wellhead include either cutting and removing it or leaving it in place protected by a cover. Removing the wellhead significantly reduces the possibility of accessing the wellbore in the future, as reinstalling the well control system becomes nearly impossible. When a well is fully plugged and abandoned, it will resemble the well shown in Figure 5-1. The cutting and removal operations can be conducted using different methods, including rigs, conductor jacks for subsea wells, and vessels or heavy lift vessels for wells located offshore (Moeinikia, et al., 2015).

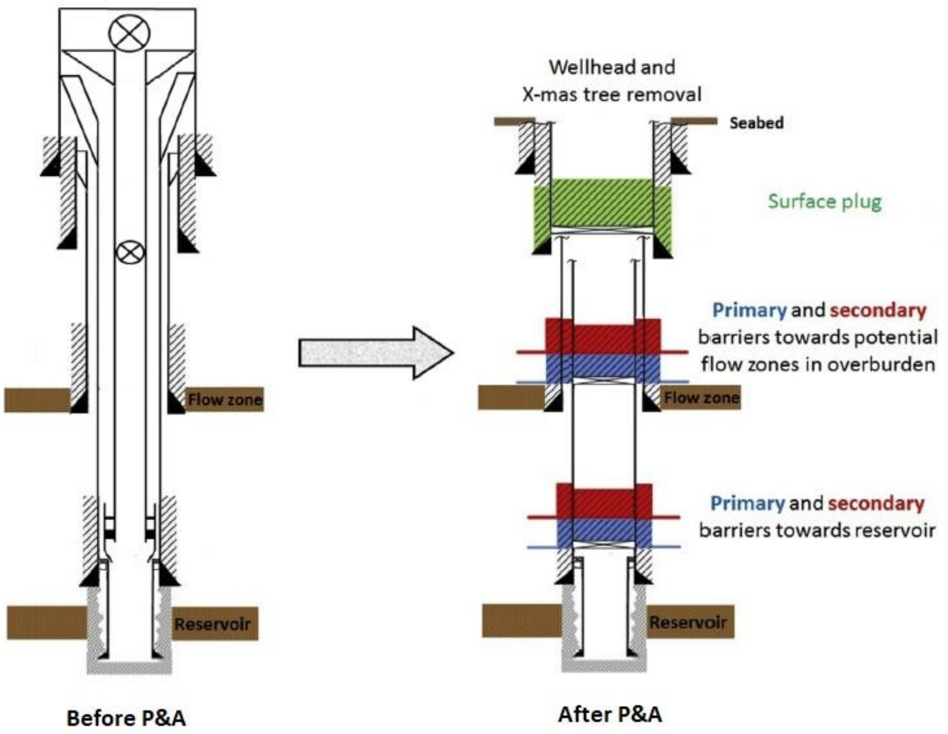


Figure 5-1 Simplified representation of an offshore production well before and after P&A (Vrålstad et al.)

Several conditions during Phase 3 may necessitate deploying a rig, such as when integrity of conductor is poor, if the offshore platform cannot support the weight of the conductor during its removal, or if the water is too deep for cutting to be done by anchor handling vessels or Light Well Intervention Vessels (LWIV) in the case of subsea wells. The weakening of the conductor could result from rust, frail connectors, or damage near the surface (Khalifeh & Saasen, 2020).

In situations involving deep or ultra-deep subsea wells, removing the wellhead might not be necessary if the area does not support activities like fishing. Nevertheless, for wells on land and those attached to platforms, it is a standard procedure to cut the wellhead below the seabed level and then remove it (Khalifeh & Saasen, 2020).

According to the regulations, the pipelines that are still there need to be cut below the surface of the sea and removed together with the wellhead, see Figure 5-2. The procedure of cutting and removing the wellhead, especially for subsea wells, can be complex and costly. This procedure may need the use of a movable offshore drilling unit, which is not usually a typical drilling rig. Different methods are used to cut the wellhead, including as explosive, hot, mechanical, abrasive, and laser cutting procedures (Khalifeh & Saasen, 2020).

Figure 5-2 Wellhead and multi string conductor removal (www.claxtonengineering.com)

6 Reviewed Case Studies

This chapter focuses on the analysis of actual data collected from different fields, where certain parts of the reservoir and intermediate zones have been plugged and abandoned.

6.1 Implementing a Risk-Based Approach for Intermediate abandonment: A Case Study of Valhall

The field was initially founded in 1975, received approval for development in 1977, and began production in 1982. The depth of the reservoir is approximately 2450 TVD RKB, and the primary reservoir is located inside the Tor formation, which is further separated into four distinct reservoir zones. The secondary reservoir is located inside the Hod formation, which is subdivided into six distinct reservoir zones. The two formations are separated by a hard formation with minimal porosity. The seal of the Valhall field consists of a claystone section that is 1000 meters thick. Microfractures are seen in this claystone due to overpressure in the chalk. Oil and gas have moved upward through these cracks and formed a significant gas cloud in the Miocene section, located at approximately 1350 m TVD RKB above the crest (Njå, 2012).

6.1.1 Potential sources of inflow

In their study of the Valhall field, BP Norway's specialists in overburden have found up to four areas at the crest of the field that might need to be plugged as per the guidelines for permanently abandonment wells. Figure 6-1 provides a basic look at what lies beneath the surface of the Valhall field. The guidance provided by experts in overburden is summarized as follows (Njå, 2012):

1) The layers from the Pliocene/Quaternary period contain aquifers close to the sea floor and sand containing biogenic gas under hydrostatic pressure. There are large networks of channels in the shallow parts, indicating that over time, there could be a natural flow of materials from these channels to the sea floor through cracks or breaks. To manage this, a plug is needed to cover the shallow areas above 450mTVD, extending as far to the surface as possible. This is to facilitate the removal or cutting of the conductor pipes.
2) Late Miocene is recognized as the dividing point between thermally processed hydrocarbon below it, and biogenic gas above it. The pressure starts to significantly rise

at around 900m TVD, which can be especially noticed in the G-10 area, known for its high-pressure gas within sand layers.

3) The diatomaceous sediments from the Intra-Mid Miocene period contain hydrocarbons, although their permeability is extremely low, measuring less than 1 millidarcy (mD). The potential of it becoming a viable reservoir has not been assessed, however, the anticipated in-place volumes, considering the thickness and fracture porosity, are around 550 million barrels. A plug is needed at a depth of 1430 mTVD.
4) The Tor/Hod reservoirs contain a substantial amount of residual hydrocarbons. Install the plug above and as near to the top of the Tor as possible. There is now a satisfactory flow between the Tor and Hod throughout the final well abandonment process.

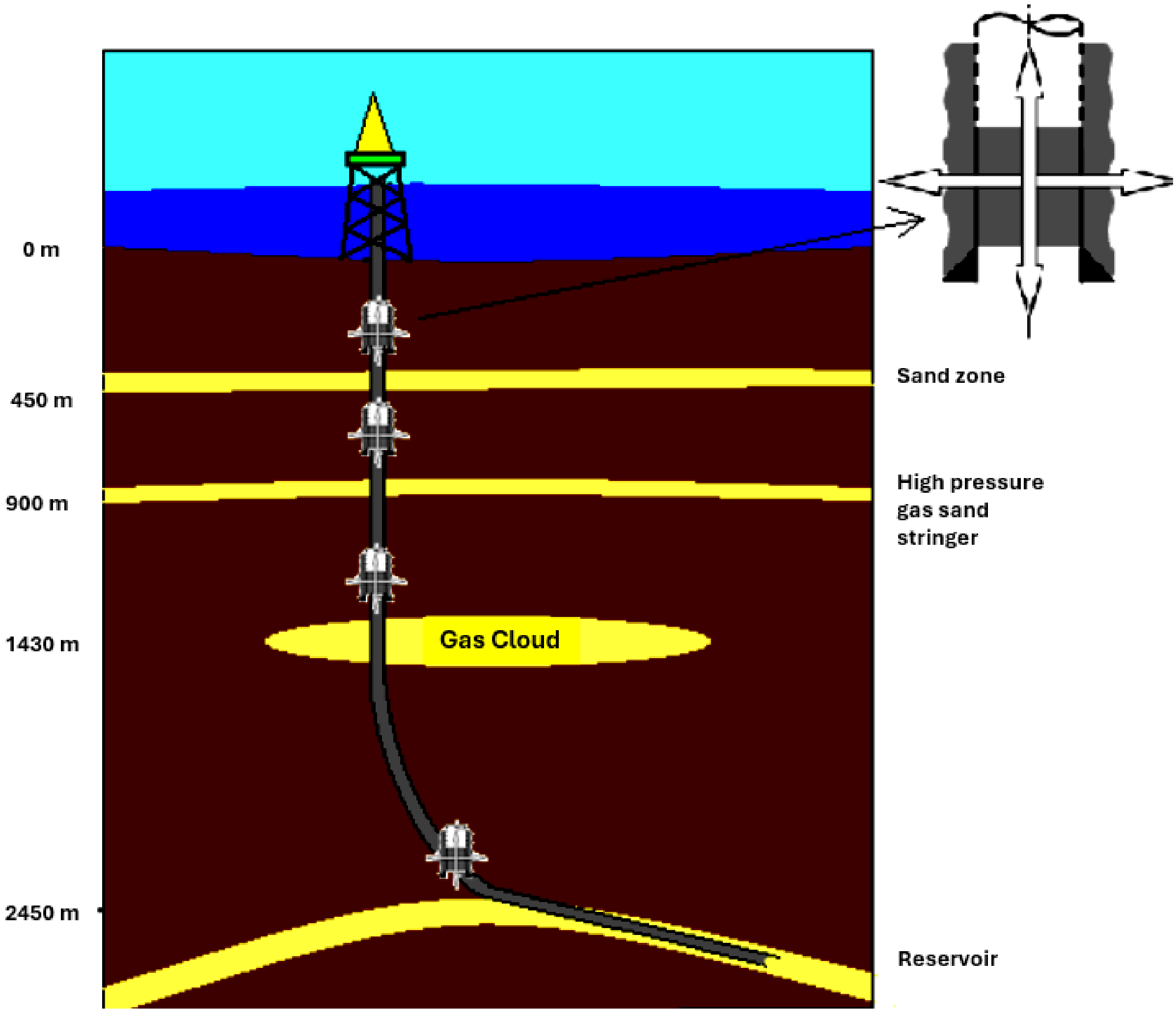


Figure 6-1 Areas that require plugging at the crest of the Valhall field (Njå)

6.1.2 Reservoir abandonment

For the Valhall DP wells, reservoir engineers have calculated that the peak reservoir pressure could reach 6665 psia at 2664 mTVD. The formation fracture gradient has been standardized across the field based on an analysis of leak-off tests (LOTs), detailed in Figure 6-2. Calculations for the placement of the top of the secondary reservoir plug are shown in Table 6-1 (Njå, 2012).

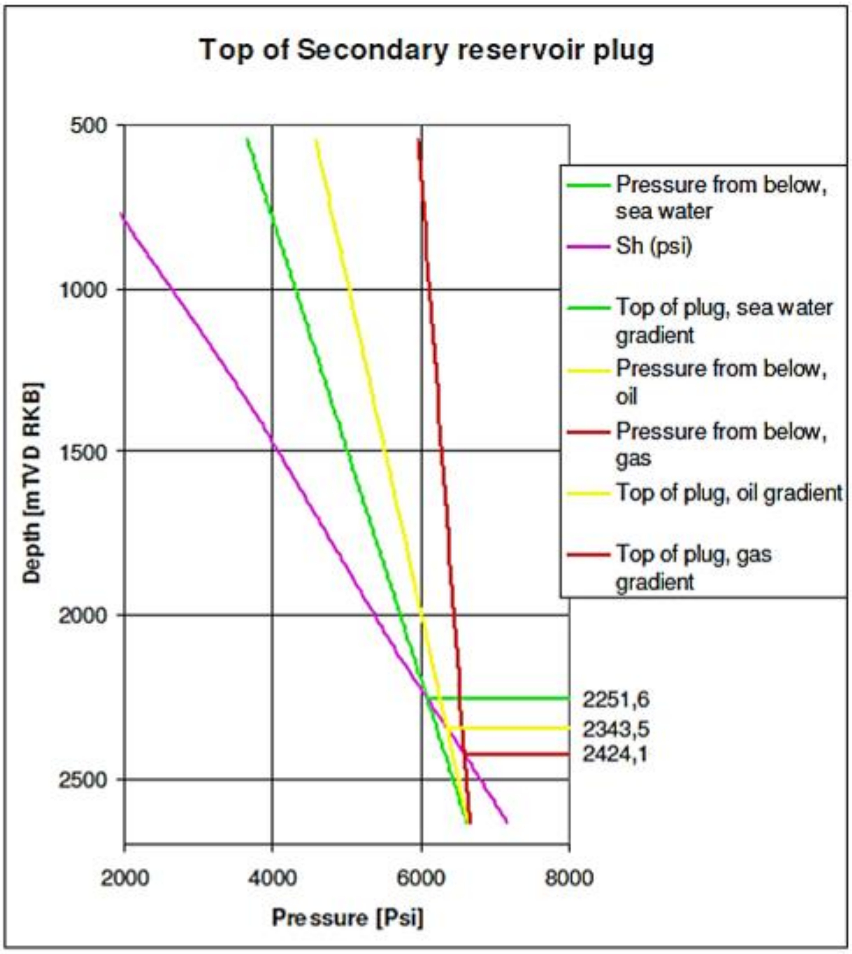


Figure 6-2 Minimum depth to top of secondary reservoir plug with different fluid gradients (Njå)

Table 6-1 Minimum setting depth of secondary reservoir plug for Valhall DP wells (Njå)

	- Resevoir Data	
- Maximum Reservoir Pressure	- 6665	- Psi
- Depth of Reservoir Pressure	- 2664	- mTVD,RKB
	- Fluid Data	
- Gas Gradient	- 0.33	- Psi/m
- Oil Gradient	- 0.98	- Psi/m
- Sea Water Gradient	- 1.42	- Psi/m
	- Top of Secondary Plug	
- Gas Gradient	- 2424.1	- mTVD,RKB
- Oil Gradient	- 2343.6	- mTVD,RKB
- Sea Water Gradient	- 2251.6	- mTVD,RKB

It is critical to confirm the presence of a sufficient annulus barrier before setting a permanent plug within the wellbore. If logging or drilling data confirms the barrier's adequacy, a permanent plug can be installed deep within the well, ensuring that the top of the secondary plug meets the minimum depth requirements (Njå, 2012).

If the annulus barrier is insufficient, remedial actions such as Perforate-Wash-Cement (PWC) or section milling must be taken. In contrast, wells with an uncemented heavy wall overlapping liner pose a greater challenge due to the current lack of tools capable of logging cement bonds through multiple metal strings and annuli, as well as performing remedial cementing through two metal strings. Current technology typically involves section milling to create a window in the casing, through which a well barrier plug can then be placed. Once a complete cross-sectional wellbore communication is established, well barrier plugs can be securely placed, sealing the entire wellbore, see Figure 6-3 (Njå, 2012).

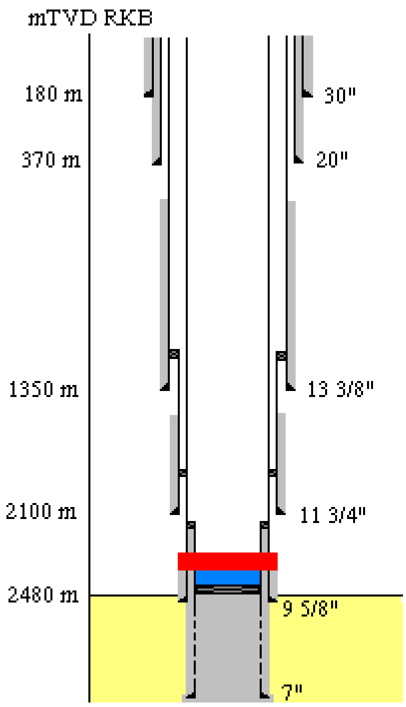


Figure 6-3 Reservoir abandonment (Njå)

6.1.3 Overburden Abandonment

During the life cycle of the field nine different distinct permeable zones were identified. All these zones contain hydrocarbons with different flow potentials, see Figure 6-4. According to the risk-based approach, three specific zones require the installation of primary and secondary well barrier plugs in addition to those in the reservoir. These zones, located at the Gas Cloud (1430m TVD), the high-pressure gas sand stringer (900m TVD), and the shallow sand zone (450m TVD), necessitate the sealing of the wellbore and all surrounding annuli. To effectively place these barriers, the 9 5/8" casing must be removed by cutting and pulling it out, due to its uncemented state at these depths. Additionally, in some instances, the 11 3/4" liner must also be cut and removed to facilitate the setting of competent gas cloud well barriers. The 13 3/8" casing, which is cemented in most Valhall DP wells, undergo logging and/or perforation and pressure testing to confirm the presence of an annulus barrier. If confirmed, competent well barriers is installed above a mechanical plug inside the casing (Njå, 2012).

Should the annulus barrier not be verifiable, the PWC method is employed to ensure the placement of effective well barrier plugs. At about 450m TVD, where the shallow sand zone is located, plugging must occur at depths where both 13 3/8" intermediate and 20" surface casings are present. Typically, the intermediate casing is uncemented at this depth, while the surface casing is cemented. To address this, the intermediate casing is removed. Following casing removal, a combination of open and cased-hole sections often exists, necessitating further actions based on the presence and verification of annulus barriers to ensure the effective setting of permanent plugs, see Figure 6-5 (Njå, 2012).

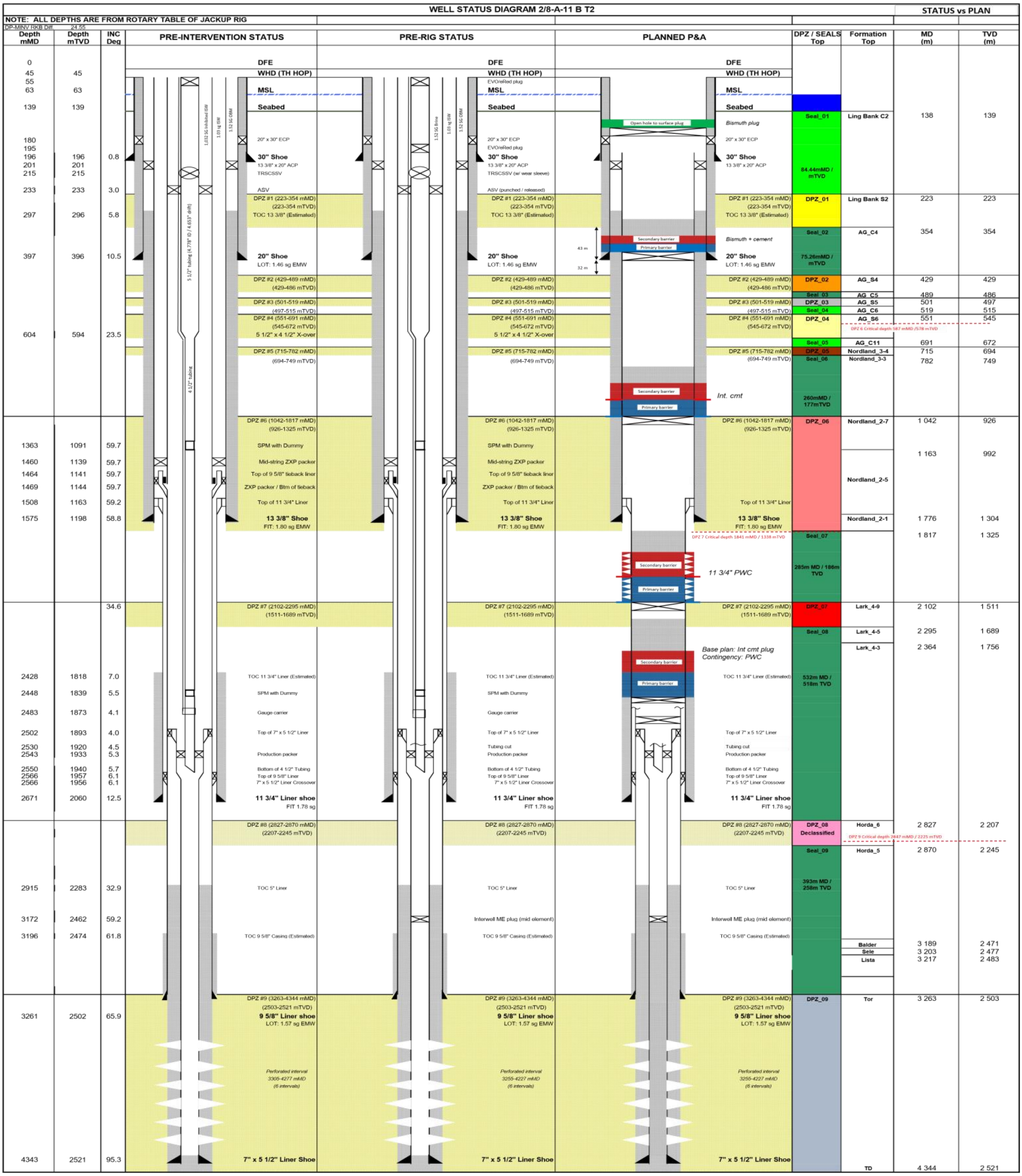


Figure 6-4 Nine DPZ in Valhall (Courtesy of Aker BP)

6.1.4 Setting surface plug

The surface plug was planned to be installed at a depth from the top of the secondary barrier situated above the 450m TVD sand zone to below the seabed. This installation occur within the 20" surface casing. Verification of the annulus barrier is not required for this plug, as it is not designed to resist pressure potential (Njå, 2012).

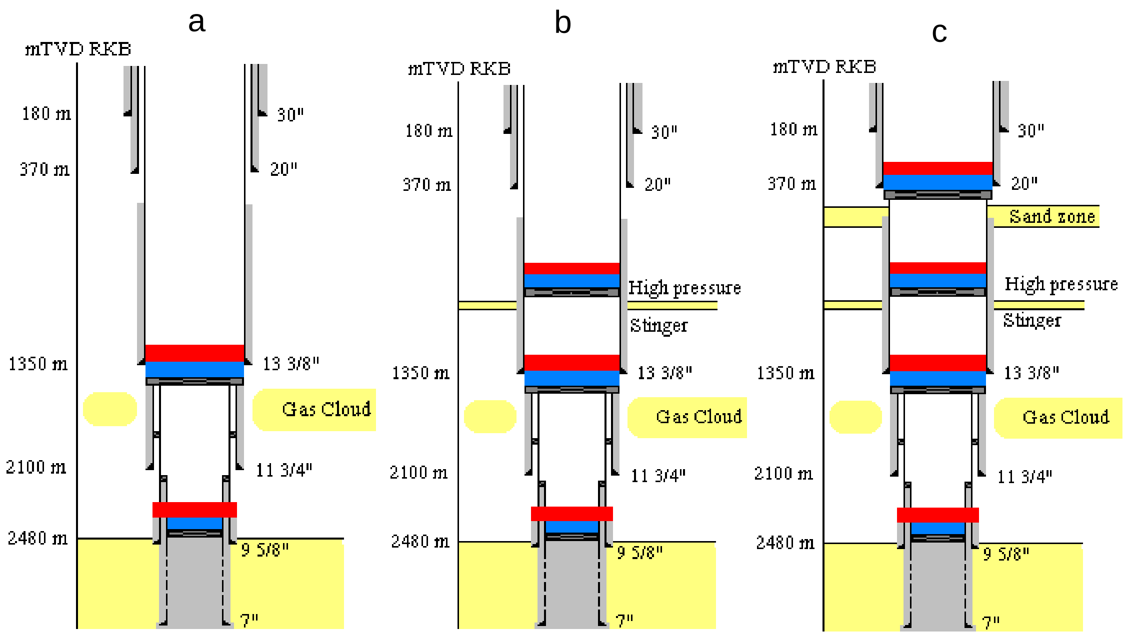


Figure 6-5 : a) Gas Cloud abandonment b & c) Plugging of the potential sources of inflow in the overburden.

6.2 Plug and abandonment in Ekofisk

In this section, the permanent plug and abandonment of a well will be examined as a case study. The well, contributed by operating companies on the NCS, has been anonymized in this thesis. This well has previously undergone plugging as part of batch P&A campaigns. This section will introduce this well and provide a short overview of the conventional approaches employed for their P&A activities (Wittberg, 2017).

Well A-1, initially completed for oil production in the Ekofisk field, was later shut down due to a high water-cut and subsequently designated for plugging during a batch P&A operation. Configuration details of the well are illustrated and summarized in Figure 6-6 and Table 6-2. The overburden formation (OBF) of well A-1 includes a water-bearing zone and a formation with the potential for fluid flow, which are systematically numbered for clarity in documentation (Wittberg, 2017).

The data package for well A-1 lacked gradient curves for pore and fracture pressure. Therefore, the minimum setting depth for the secondary reservoir barrier was estimated using available information. This involved calculating the pore pressure in OBF #1 by subtracting the hydrostatic head of seawater from the reservoir pressure.

While reservoir pressure pre-P&A was 320 bar, estimated MSD for secondary reservoir barrier is:

$$h_{MSD} \geq \frac{P_{FP} - P_{Fluid(gas)} \times g \times H}{\left(P_{Frac} - P_{Fluid(gas)}\right)} \qquad h_{MSD} \geq \frac{320 - 0.23 \times 0.0981 \times 2886}{1.64 \times 0.0981 - 0.23 \times 0.0981} = 1842.7m$$

Estimated MSD for secondary intermediate barrier:

$$h_{MSD} \geq \frac{P_{FP} - P_{Fluid(gas)} \times g \times H}{\left(P_{Frac} - P_{Fluid(gas)}\right)} \qquad h_{MSD} \geq \frac{285 - 0.23 \times 0.0981 \times 2540}{1.64 \times 0.0981 - 0.23 \times 0.0981} = 1646m$$

6.2.1 Operational steps

In the operation planned for Phase 1 and 2 of permanent plug and abandonment of the well A-1, a skid rig was utilized to adjust the XMT and set up the BOP. The operation then proceeded to retrieve the tubing to the designated P&A depth. This step was followed by cleaning the 9-5/8" casing to ensure the plug setting area was prepared properly. To ensure the integrity of the cement bond, an ultrasonic cement bond log was conducted to confirm the TOC. Continuing with the operation, a back-to-back cement plug was installed above the tubing cut. This plug acts as both the primary and secondary barrier for the reservoir and the first overburden formation (OBF #1). Once the cement was in place, it was dressed off and tagged, and the plug's effectiveness was verified through a pressure test to LOT + 70 bar (Wittberg, 2017).

Further steps include cutting the 9-5/8" casing above the 13-3/8" casing shoe, followed by setting and testing a casing bridge plug in the 13-3/8" casing. The well was then displaced to seawater. A cement plug wss installed above the 13-3/8" bridge plug to serve as the primary barrier for the second overburden formation (OBF #2) and as an open hole to surface barrier. This plug was also pressure tested to LOT + 70 bar to ensure its strength and integrity. Well schematic of well after these operations is illustrated in Figure 6-7 (Wittberg, 2017).

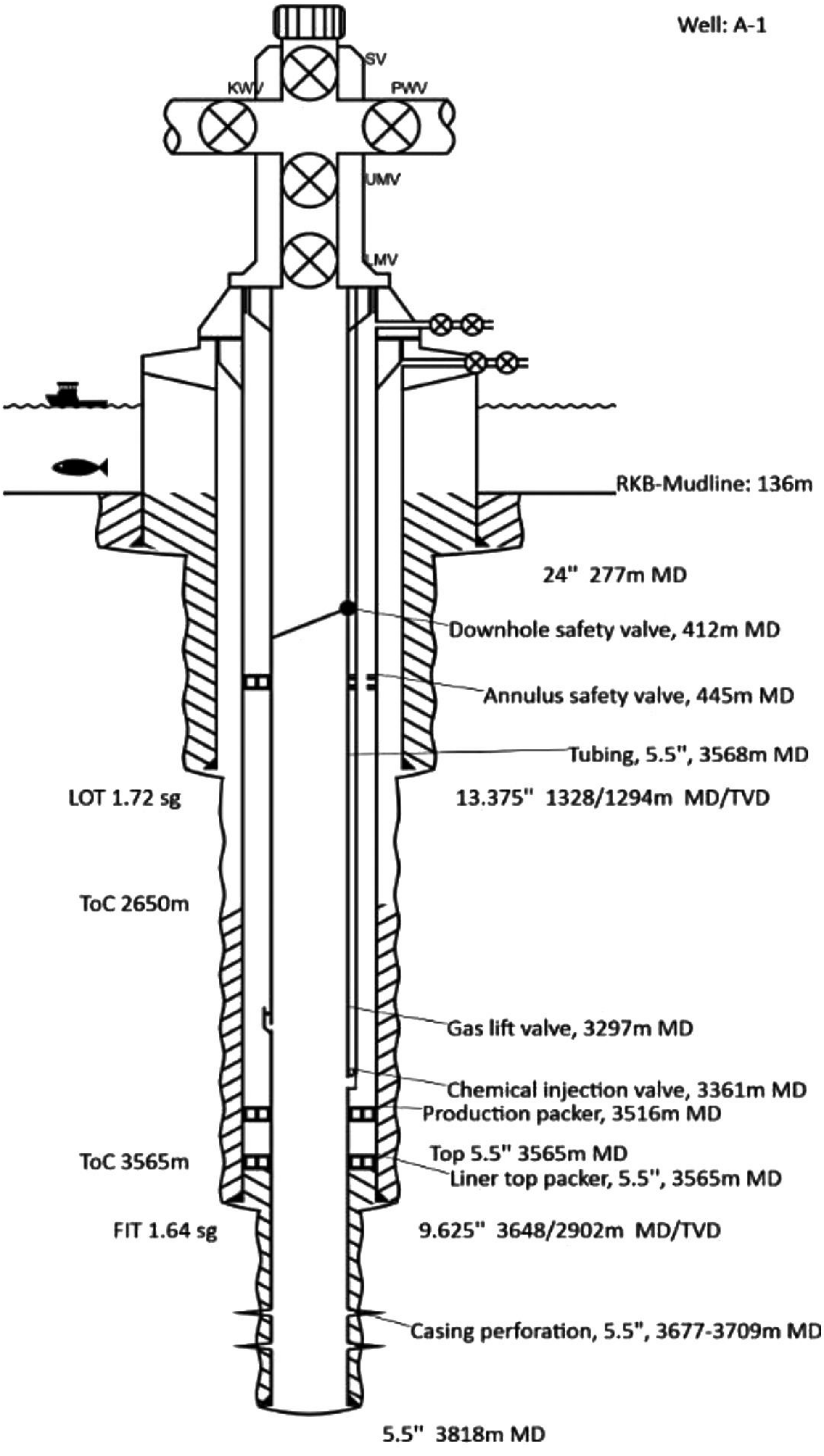


Figure 6-6 Well schematic A-1 (Wittberg)

Table 6-2 A-1 Well summary table (Wittberg)

Description		Depth
13-3/8" CSG	Shoe@ TOC@	1328m/1294m TVD 136m
9-5/8" CSG	Shoe@ TOC@	3648m/2902 TVD 2650m
5-1/2" Prod.Tubing	DHSV@ ASV@ GLV@ DHPG@ CIV@ Prod. Packer@ WEG	412m 445m 3297m 3329m 3361m 3516m 3568m
Reservoir Perforation Interval	top@	3677m/2886m TVD 3677-3709m
Formation (Fm) with potential in overburden. OBF#1	Fm top@	3320m/2540m TVD
Formation without potential, but water bearing. OBF#2	Fm top@	1070m
Estimation of minimum setting depth based on: Gas density LOT FIT	 0.23 s.g 1.72 s.g 1.64 s.g	 1294mTVD 2902mTVD

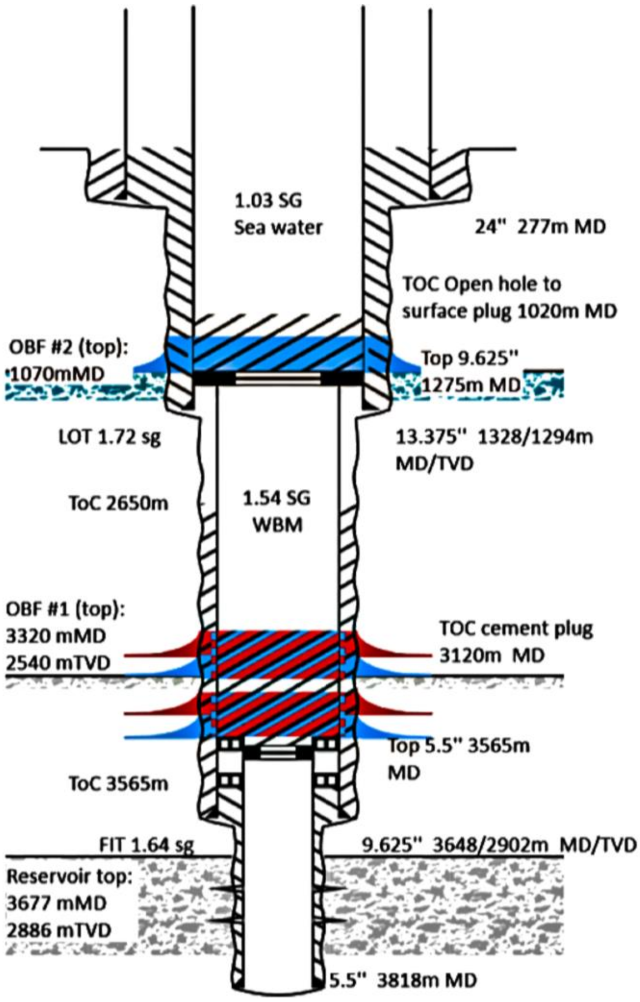


Figure 6-7 Well A-1 schematic after P&A (Wittberg)

6.3 Gyda plug and abandonment

The Gyda field, situated 280 km southwest of Stavanger in North Sea block 2/1, began production in 1990, a decade following its discovery in 1980. Currently, there are 32 wells in the Gyda field that require permanent plugging and abandonment. Two primary inflow zones have been identified in the Gyda field that necessitate isolation.

Two inflow zones have been identified in the Gyda field that necessitate isolation:

- Gyda reservoir, Farsund and Lower Åsgard (in 7 wells) which are Hydrocarbon bearing zones.
- Sele/Forties/Lista which are water bearing zones with flow potential.

The subsurface department has provided the following reservoir pressures for use in the P&A design.

Gyda Main:589 bar @datum 4112m TVD RKB.

Gyda South:325 bar @ datum 3984,5 m TVD RKB.

Forties:435 bar @ datum 2916m TVD RKB.

Although it is technically feasible to integrate both the Forties and Gyda formations into a single well barrier at the top of the Forties—where either a robust cement job or a creeping formation behind the casing can withstand future maximum anticipated pressures and provide as a cross-sectional barrier—the strategy was to implement a more conservative approach. Specifically, the plan involved establishing a double barrier for the Gyda formation and adding another two barriers for the Forties formation. This approach surpasses the minimum barrier requirements outlined by NORSOK-D010 standards (Alhamoud, 2020).

6.3.1 Operational steps

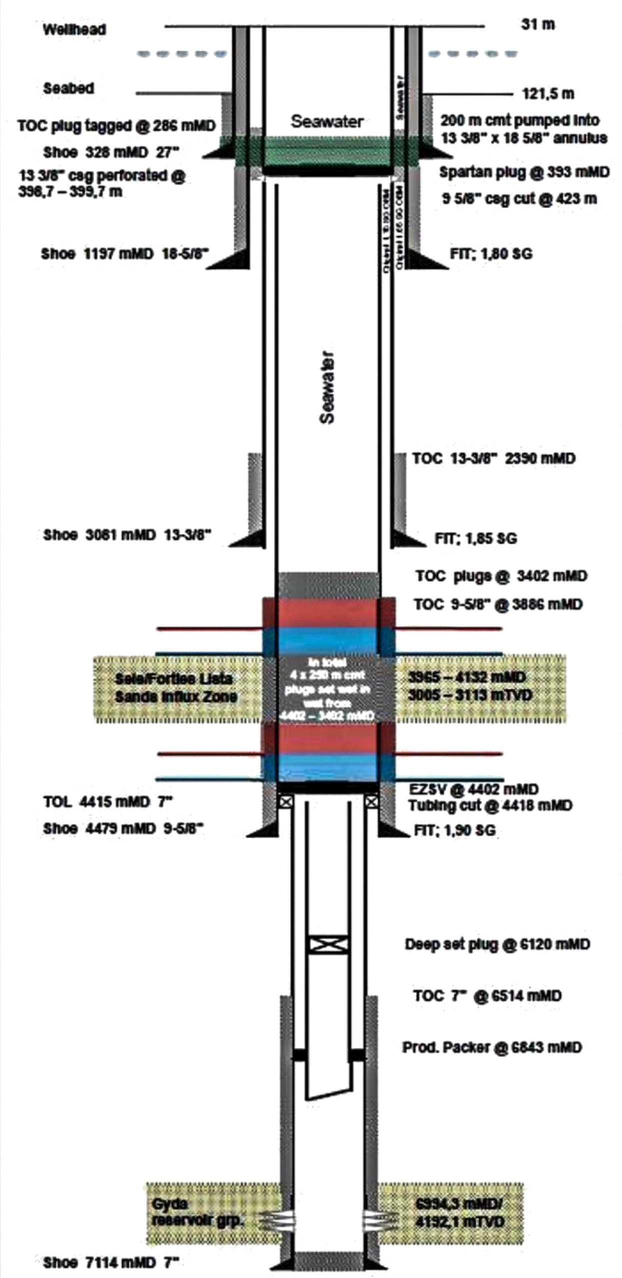
To conduct Phases 1 and 2 of the plug and abandonment process, the production tubing was pulled from the well, followed by well logging. The next steps involved permanently securing the Gyda reservoir and the inflow zones in the Forties formation with primary and secondary barriers. Finally, an environmental plug wss established to protect against contamination and ensure the well's integrity, aligning with environmental safety standards (Alhamoud, 2020).

To approach these objectives, the first step was to set up the blowout preventer (BOP). Once secured, the shallow tubing plug was pumped open. Following this, the tubing was retrieved from the well. If necessary, a scraper run is conducted, and the wellbore is displaced to weighted mud. To verify the integrity of the annulus barrier, a Bond Log was run. Subsequently, the EZSV (Expandable Zonal Isolation Valve) was run in hole (RIH), set, and undergone a pressure test to ensure proper sealing and functionality. Primary and secondary reservoir barriers, consisting of cement plugs, was then placed on top of the EZSV (Alhamoud, 2020).

The operation continued by setting additional EZSVs and placing primary and secondary barriers for the overburden. Once these steps were completed, the 9 5/8” casing was cut and retrieved at approximately 280 meters. An optional scraper run might be performed depending on the condition inside the casing. Another EZSV was run, set, and pressure tested, followed by the setting of a 100-meter environmental (surface) plug on top of the EZSV. To finalize the operation, the BOP was disassembled, and the rig was moved to the next well location, see Figure 6-8 (Alhamoud, 2020).

Well Barrier Diagram Gyda 2/1-A-25A	Phase II P&A

NOT TO SCALE



Well information		
Field:	Gyda	
Well no.:	2/1-A-25 A	
Well type:	Oil Producer	
Validity:	Post Phase II P&A	
Revision:	Final	February 2020
Prepared:	Stian Johnsen Dybvik	

Well barrier elements	Verification of barrier elements
PRIMARY BARRIER - RESERVOIR	
1. In-situ formation	Sb base frac strength at top of barrier: 2,05 sg EMW.
2. 9 5/8" casing cement	Barrier set inside qualified cement bond verified by SLB cement bond log
3. 9 5/8" casing	Pressure tested to 400 bar with 1,70 sg OBM
4. Cement plug	Job Performance. Set on pressure tested mechanical plug.
SECONDARY BARRIER - RESERVOIR	
1. In-situ formation	Sb base frac strength at top of barrier: 2,00 sg EMW.
2. 9 5/8" casing cement	Barrier set inside qualified cement bond verified by SLB cement bond log
3. 9 5/8" casing	Pressure tested to 400 bar with 1,70 sg OBM
4. Cement plug	Job Performance. Set on pressure tested mechanical plug.
PRIMARY BARRIER – SELE/FORTIES/LISTA SANDS	
1. In-situ formation	Sb base frac strength at top of barrier: 1,94 sg EMW.
2. 9 5/8" casing cement	Barrier set inside qualified cement bond verified by SLB cement bond log
3. 9 5/8" casing	Pressure tested to 400 bar with 1,70 sg OBM
4. Cement plug	Job Performance. Set on pressure tested mechanical plug.
SECONDARY BARRIER – SELE/FORTIES/LISTA SANDS	
1. In-situ formation	Sb base frac strength at top of barrier: 1,93 sg EMW.
2. 9 5/8" casing cement	Barrier set inside qualified cement bond verified by SLB cement bond log
3. 9 5/8" casing	Pressure tested to 400 bar with 1,70 sg OBM
4. Cement plug	Job Performance. Set wet in wet on top of transition plug.
OPEN HOLE TO SURFACE BARRIER	
1. 18 5/8" casing cement	TOC reported to be at surface. Visual verification.
2. 18 5/8" casing	Pressure tested to 90 bar with 1,30 sg WBM
3. 13 3/8" casing cement	13 3/8" csg perforated & cement pumped into the 13 3/8" x 18 5/8" annulus. Verified by job performance.
4. 13 3/8" casing	Pressure tested to 200 bar with 1,65 sg OBM
5. Cement plug	Cement barrier set on top of spartan plug pressure tested to 100 bar. Tagged at 286 mMD RKB.

General Comments

4 x 250 m cement barriers set "wet in wet" from 4402 to 3402 mMD RKB
Logging results:
Sele / Forties / Lista Sands Barrier
- 440 m Additional barrier formation (3930 – 3446m MD)
- 44 m Additional barrier cement (3930 – 3886m MD)
- 50 m Secondary barrier formation (3836 – 3786m MD
- 50 m Primary barrier formation (3886 – 3836m MD)

Reservoir Barrier
- 14 m Additional barrier cement (4306 – 4292m MD)
- 30 m Secondary barrier cement (4372 – 4306m MD)
- 30 m Primary barrier cement (4402 – 4372m MD)

Figure 6-8 Well barrier diagram post Phase II (Alhamoud)

6.4 Huldra PP&A project from five to one double barrier

The Huldra field is a gas/condensate field. Top reservoir situated at 3500 mTVD. The field, which began production in 2001 and stopped in 2014, initially had a reservoir pressure of 675 bar. This pressure has significantly declined, currently ranging between 85 and 95 bar, although in specific sections such as well A-11, it remains between 300 and 400 bar. Notably, the overburden gas pressures are higher than normal, indicating charged formations that add complexity to the field's management, see Figure 6-9 (Golberg & Johnsen, 2015).

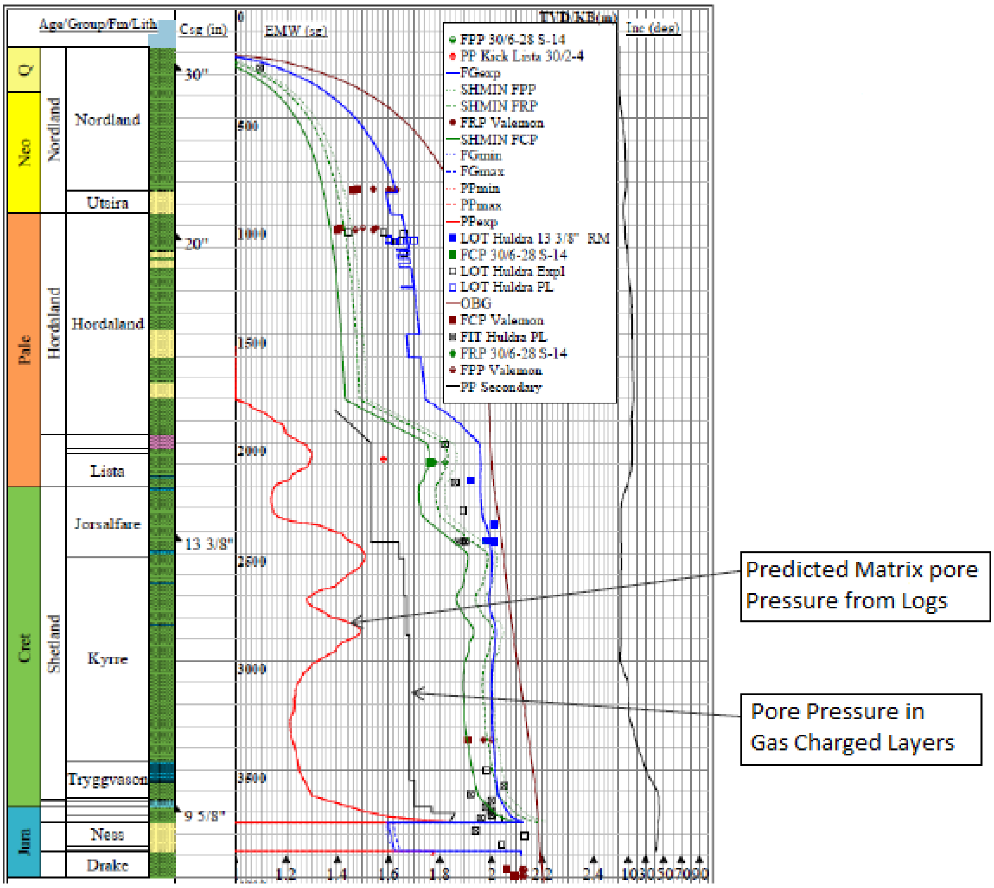


Figure 6-9 Pore pressure and formation strength (Audun Golberg)

Given the complex pressure dynamics and the need for secure abandonment, the field plans to transition from using five barriers to a more streamlined approach of one double barrier in its P&A operations, see Figure 6-10. This decision is driven by a variety of factors including the natural expansion and pressure dissipation of gas along the annulus, the effectiveness of the caprock and buffer sands above the overburden gas, the absence of leaks from old exploration wells, and the observation of low gas rates at the B-annulus. This strategy aims to enhance cost efficiency while maintaining safety and environmental integrity in the P&A process (Golberg & Johnsen, 2015). Challenges of Huldra P&A are illustrated in Figure 6-11.

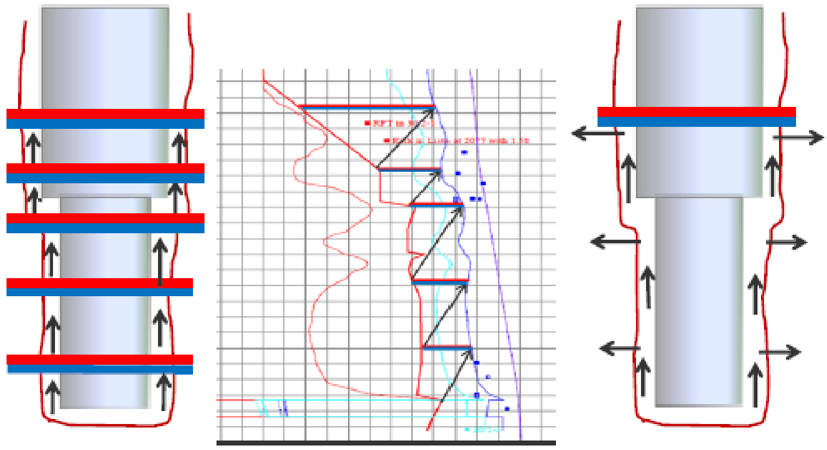


Figure 6-10 Traditional a recommended approach (Golberg & Johnsen)

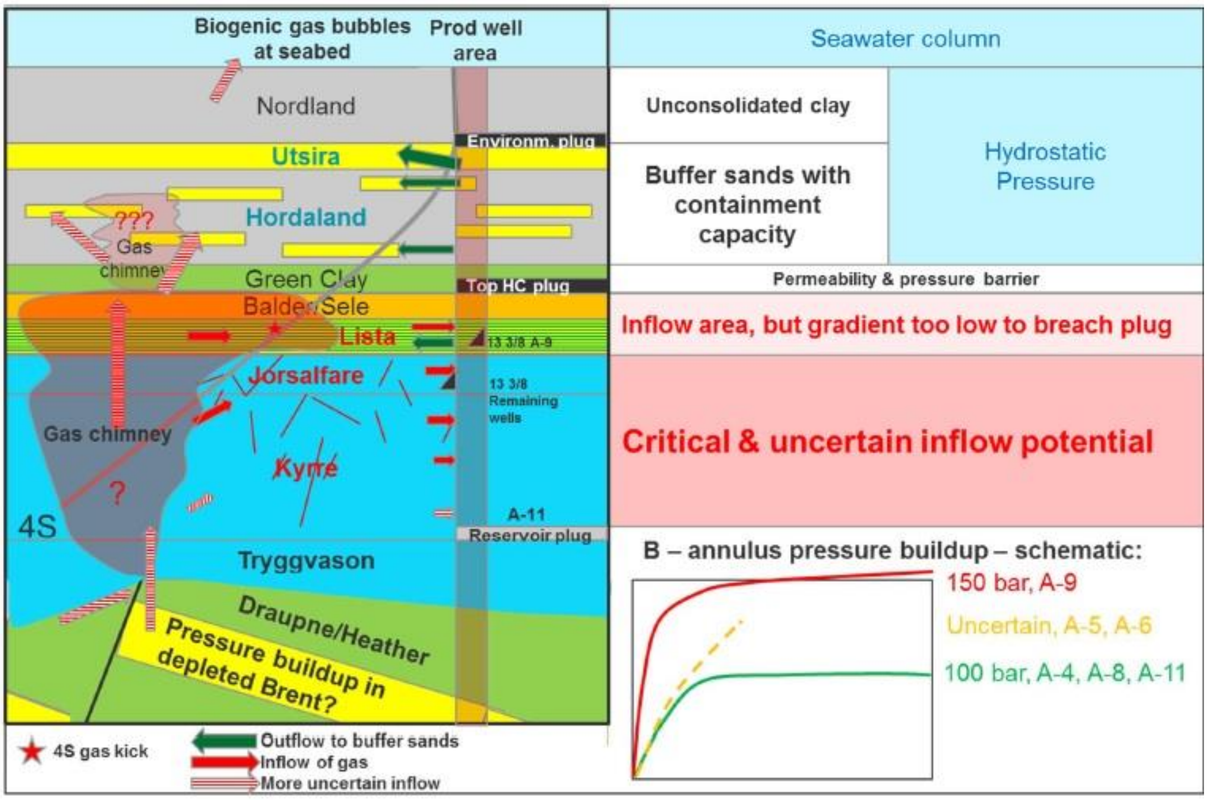


Figure 6-11 Schematic illustration of Huldra P&A challenges (Audun Golberg)

The subsurface evaluation of the Huldra field's plug and abandonment (P&A) solution has been informed by detailed cross-disciplinary studies analyzing all relevant data. These studies affirm the sealing capacity of the Green Clay caprock, ensuring its ability to act as an effective barrier. Additionally, it is determined that pressure buildup above the formation integrity of the Green Clay will not occur due to cross-flow dynamics within the subsurface structures (Golberg & Johnsen, 2015).

The evaluation further indicates that the pressure within the Brent reservoir will not surpass 150 bars over the next 500 years, a significant decrease from its initial pressure of 675 bars. This stability in pressure supports the decision to use a single dual barrier plug at the top of Rogaland, demonstrating that this approach does not increase the risk of leakage when compared to configurations involving multiple plugs. Dual plug at top Rogaland will withstand 320 bar, which is equivalent to a Brent pressure of 330 bar (Golberg & Johnsen, 2015). Moreover, as a precautionary measure against potentially higher pressures in the A-11 well, which taps into the Oseberg Formation, an additional dual plug will be placed above the reservoir. This strategic decision enhances the robustness of the well's sealing framework, ensuring long-term integrity and mitigating the risk of uncontrolled hydrocarbon releases.

Based on subsurface studies, the recommended solution Huldra. (l barrier plug solution which is both a safe and cost-efficient concept for PP&A on Huldra, see Figure 6-12 (Golberg & Johnsen, 2015).

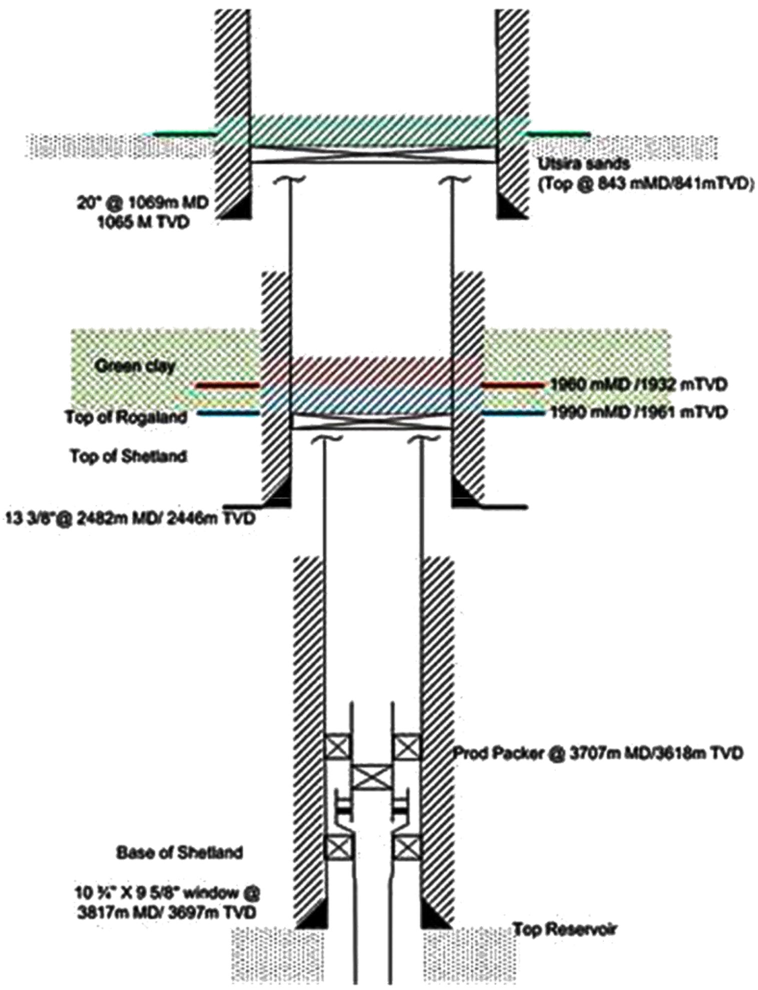


Figure 6-12 Recommended solution based on subsurface studies (Audun Golberg)

6.5 Discussion

In this chapter, as case study, the differences in reservoir and intermediate abandonment of Ekofisk, Valhal, Gyda and Huldra was highlighted.

The focus lies on reservoir abandonment practices, where it is common for operators to follow a standard procedure. In this practice, the minimum setting depth is calculated using the methods outlined in Chapter 3. Subsequently, two plugs are placed, and pressure testing is conducted in accordance with established standards.

This is contrasted with intermediate abandonment strategies, where differences among operators become apparent. For example, one operator adopts a risk-based approach in Valhall but for the other operator, although it is technically feasible to integrate both the Forties and Gyda formations into a single well barrier at the top of the Forties the strategy is to implement a more conservative approach. Specifically, the plan involved establishing a double barrier for the Gyda formation and adding another two barriers for the Forties formation This contrast illustrates that although the main reservoir abandonment strategies might align, intermediate abandonment practices can vary significantly.

The Huldra PP&A project suggests a need for the industry to re-evaluate intermediate abandonment practices to develop more unified procedures in other areas with comparable geological conditions, similar to those established for reservoirs. However, this recommendation must be based on a thorough field specific subsurface evaluation of both the reservoir and the overburden. This shift would ensure enhanced safety and integrity across different field operations, addressing the growing recognition that intermediate zones require more attention.

7 Shallow Gas

7.1 Challenges of zonal isolation in shallow depth

Zonal isolation in the North Sea area has specific challenges while operating at shallow depths.

7.1.1 Low temperature

The cold conditions found at these shallow levels can make standard cementing materials less effective, risking the breakdown of these barriers. When cementing the surface casing, the cement needs to extend all the way to the ocean floor, where it is exposed to cold temperatures. These low temperature conditions can negatively impact the cement's behavior, causing problems like weaker strength, prolonged curing time and static gel strength development of cementitious materials (Agista, et al., 2023).

In this situation, it is important for the cement to become strong enough quickly, even in cold conditions, so we can be sure it is safe to keep drilling the next parts of the well (Agista, et al., 2023).

7.1.2 Soft formation

Other issues at shallow depths include the loose, unconsolidated formations and low pore pressure which make designing the right materials for effective zone separation more complicated. To solve this, using a lighter type of cement material, made lighter by adding water, foam, or lightweight particles, is necessary. However, this lighter cement's weaker strength, especially in cold conditions, raises concerns about the well's long-term stability. Moreover, encountering areas with moving shallow gas and water adds to the difficulty of cementing, possibly reducing its success and leading to expensive problems that can harm the environment and pose safety risks (Agista, et al., 2023).

7.1.3 Present of Gas in shallow depth

Instances have occurred when the techniques employed to maintain distinct zonal isolation, particularly at shallow depths, have failed to meet expectations, highlighting the need of properly planning and executing this procedure (Agista, et al., 2023). Vielstädte et al. (2017) discovered the release of methane gas from three decommissioned wells located in the shallow regions of the central North Sea. In a study conducted by Böttner, et al. (2020), it was found that 28 out of 43 old wells located in comparable areas were releasing gas into the sea. The origin of this gas was determined by analyzing prior operation information, utilizing sonar technology, examining seismic data, and conducting gas tests. It was found to originate from shallow gas zones located at depths ranging from 400 to 800 meters. In a separate investigation, Tveit (2018) documented an incident where a substantial amount of gas dissolved into the ocean and subsequently being released into the atmosphere from 20 decommissioned wells. This highlights the necessity for effective zone separation. Choosing appropriate materials for zonal isolation is essential to minimize leaks and ensure long-term separation of different zones (Agista, et al., 2023).

7.1.4 Cementing shallow depth

Various types of cement materials specifically designed for cementing operations in low-temperature and shallow-depth environments have been developed and are widely utilized. Two examples of specialized cement are gas tight cement and rapid hardening cement. Recent study has demonstrated encouraging outcomes by using alternative materials to cement (Agista, et al., 2023). This shows that still there is room for developing tailored barrier solutions for shallow zones in the North Sea and permafrost areas.

7.2 Terminology

When examining literature on hydrocarbon seepages, it is crucial to clearly define some key terms. This ensures a thorough understanding and proper discussion of the concepts presented. These definitions will be essential for interpreting the information and contributing effectively to the field of study.

7.2.1 Seep and seepage

The terms "seep" and "seepage" are commonly used interchangeably but they have distinct meanings. Generally, "seep" refers to the emergence of a fluid from a specific point source, with the flow rate measured in mass per unit of time, such as grams per day. On the other hand, "seepage" describes the flow of fluid over a broader area, where the flow rate is measured as mass per area per time, for example, grams per square meter per day (Etiope, 2015). According to dictionary definitions, "seepage" is described as a geological process or phenomenon, whereas "seep" specifically refers to the act of fluid coming out at the seabed or ground surface. In practical terms, oil and gas might escape through a vent on the seafloor, which is a seep, while the overall activity in the region would be described as oil or gas seepage (Tveit, 2018).

7.2.2 Macro-seeps vs. Microseepage

Macro-seeps produce discrete flows of gas bubbles or oil droplets that ascend through the water, creating them observable and traceable by sound. (Hovland, et al., 2012). Microseepage, however, involves a more widespread, diffuse release of gas. This is typically identified by collecting and analysing samples from sediment pore water or seawater above the expected area of seepage to measure dissolved gas levels. Microseepage demonstrates a subsurface that is permeable enough to allow gas to move and spread within it. When this migration is more concentrated, leading to a macro-seep, it usually suggests the presence of subsurface fractures or faults that act as pathways for oil or gas migration .It is important to note that the term "seep" is exclusively used for oil; the concept of oil microseepage does not exist (Etiope, 2015).

7.2.3 Origin of hydrocarbon seepages (thermogenic/ biogenic)

In the petroleum industry, conventional oil and gas are formed from the burial of organic material, typically in sedimentary basins. When this organic matter is buried deeply, high temperatures underground break it down into lighter compounds, ultimately creating oil and gas. This transformation process is known as catagenesis, producing what are called thermogenic hydrocarbons. This process generally occurs at temperatures above 60°C, and the depth at which it takes place depends on the temperature at the seafloor and the geothermal gradient. However, not all seeping gas is thermogenic. Microbial communities in shallow sediments often generate a portion of natural gas at relatively low temperatures, typically ranging from 60 to 80°C. This process is referred to as diagenesis, and the gas produced is often called biogenic or microbial gas (Tissot & Welte, 1984). Figure 7-1 provides a summary of the temperature ranges in which different types of hydrocarbons form.

While both biogenic and thermogenic gases come from biological sources and are thus described as "biotic," methane can also be produced through chemical reactions, such as in magmatic processes, without any organic matter. These are referred to as "abiotic" gases (Etiope, 2015).

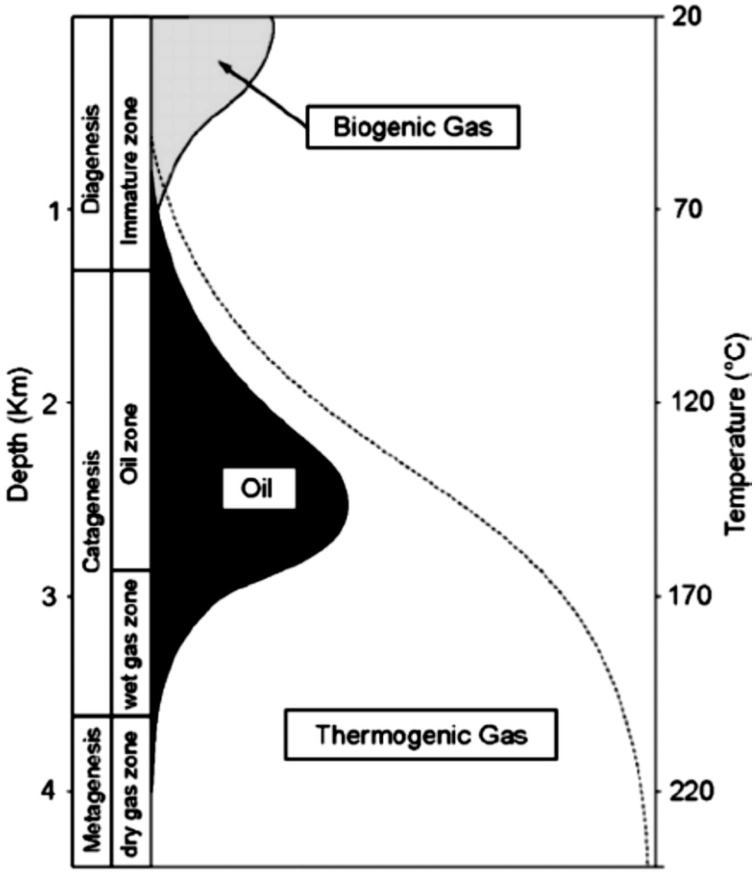


Figure 7-1 Temperature ranges to produce various hydrocarbons (Tissot & Welte)

7.2.4 Classifying seeping gas (biogenic / thermogenic)

When analyzing a natural gas seep, it is crucial to find out if the gas is derived from biological processes (biogenic) or from deeper subsurface sources (thermogenic). To determine the origin of methane, the first step is to analyze the stable isotopes of carbon (13C/12C) and hydrogen (2H/1H) present in it. The isotopes are often denoted as δ13C and δ2H (or δD, as 2H is also referred to as Deuterium), and their measurements are expressed in parts per thousand (‰) relative to the standard values derived from the Vienna Pee Dee Belemnite (VPDB) for carbon and Vienna Standard Mean Ocean Water (SMOW) for hydrogen. The isotopic patterns of thermogenic and biogenic gas exhibit clear distinctions and have been extensively documented worldwide (Schoell, 1980).

Biogenic gas generally exhibits δ13C values below -50‰, suggesting the presence of lighter carbon isotopes. Thermogenic gas typically ranges from -45‰ to -30‰, although gas from highly developed sources can reach as high as -20‰. The isotopic values are graphed on Schoell's diagram, Figure 7-2a which visually displays the distinct areas representing biogenic, thermogenic, and mixed-source gases (Schoell, 1980).

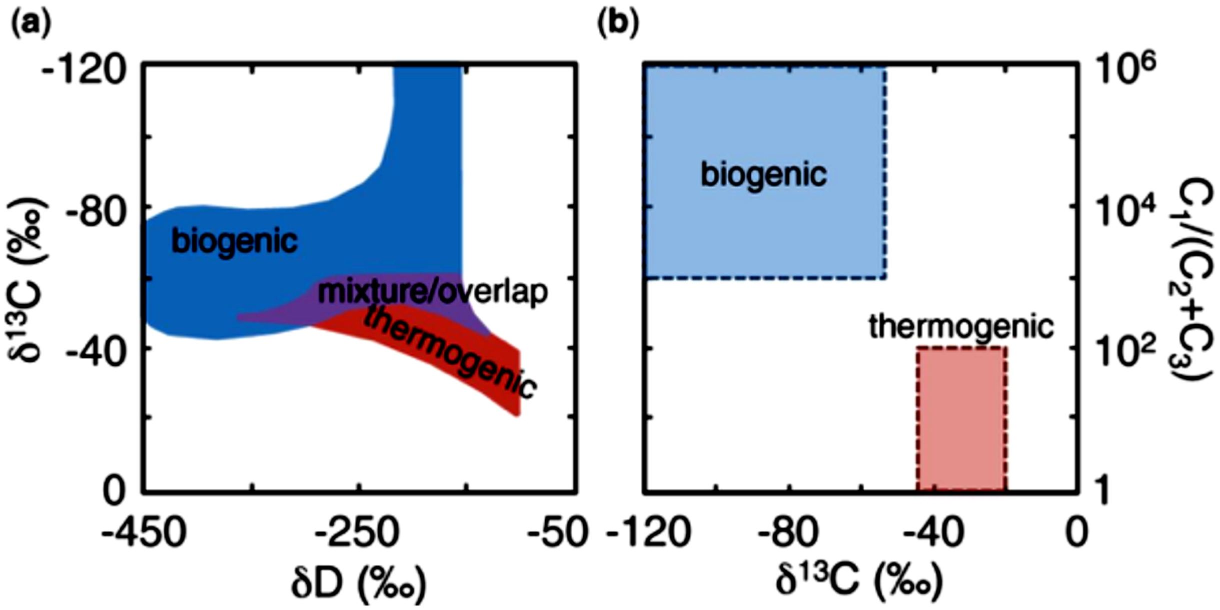


Figure 7-2 Using component ratios and isotopic fingerprints to categorize natural gas (Stolper et al.)

The second step in identifying the origin of gas is to examine the relative presence of light hydrocarbons. Biogenic gas, produced by microbes in shallow sediments, is predominantly methane (CH4) and is considered very dry. It may also contain small amounts of ethane (C2H6) and trace amounts of propane (C3H8). In contrast, thermogenic gas results from the breakdown of larger hydrocarbon molecules due to heat and often contains a higher proportion of heavier compounds, including butane (C4H10), pentane (C5H12), and hexane (C6H14) (Bernard, et al., 1978).

The differences in composition between biogenic and thermogenic gas can be quantified using the Bernard ratio, defined as C1/(C2+C3) (Bernard, et al., 1978). Normally, biogenic gas has a Bernard ratio greater than 500, while thermogenic gas has a ratio less than 100. It is important to note that the specific values can vary slightly in different studies, with some literature indicating biogenic gas ratios over 1000 and thermogenic gas ratios below 50 (Etiope, 2015). However, in certain cases, thermogenic gas might display a Bernard ratio high enough to be mistaken for biogenic gas. This usually happens when the gas is extremely dry and comes from a highly mature source, which means the source rock has been subjected to deep burial or very high temperatures during its formation, as shown in Figure 7-1. To reduce the risk of misinterpreting the Bernard ratio, it is often analyzed alongside the δ13C values of methane in a graphical representation known as a Bernard diagram, illustrated in Figure 7-2b. This diagram is also used to assess whether the seep includes a mix of deep, thermogenic sources and shallow, biogenic sources (Stolper, et al., 2018).

7.3 The shallow gas system in the North Sea

Natural methane presents in several geological layers in the North Sea. The uppermost 1000 meters of sediment from the geological layers referred to as the North Sea Group, which include biogenic gas accumulations. Most of the gas deposits in the region are in deeper geological formations. As a result, the gas accumulations in the North Sea Group are commonly known as shallow gas accumulations (Wilpshaar, et al., 2021).

The main accumulation of this natural gas is in unconsolidated marine to fluvio-deltaic deposits from the Plio-Pleistocene Eridanos delta, Pleistocene tunnel-valley fill deposits, and some volcanic debris at the base of the Paleocene (e.g., Basal Dongen Tuffite). The gas, mainly produced biogically found within these deltaic deposits, consists predominantly of methane (>99%). The process of gas generation began in the early Pleistocene-Calabrian period within the delta and continues today (Verweij, et al., 2018).

The gas is trapped within low-elevation anticlinal structures located on salt domes or in stratigraphic or depositional traps. The presence of clay at silt intervals between the silty and sandy reservoir layers creates excellent seals that restrict the gas within these reservoirs.

Shallow gas accumulations are seen in close near to hydrostatic pressure, see Figure 7-3, suggesting that the seals lack the ability to contain a significant volume of gas without causing leakage. A seal breach, often referred to as leakage, happens when the pressure exceeds hydrostatic pressure by a little margin, causing the gas to go upward. In addition, these gas accumulations are not filled to their maximum capacity and are occasionally found in many reservoir layers that are vertically stacked (Verweij, et al., 2018). This stacking phenomenon may be explained by the progressive reduction in the strength of the seal due to decreased compaction and the upward movement of gas, which increases its buoyancy. Eventually, natural methane leakage occurs when a portion of the gas escapes to the bottom and is discharged into the sea and atmosphere.

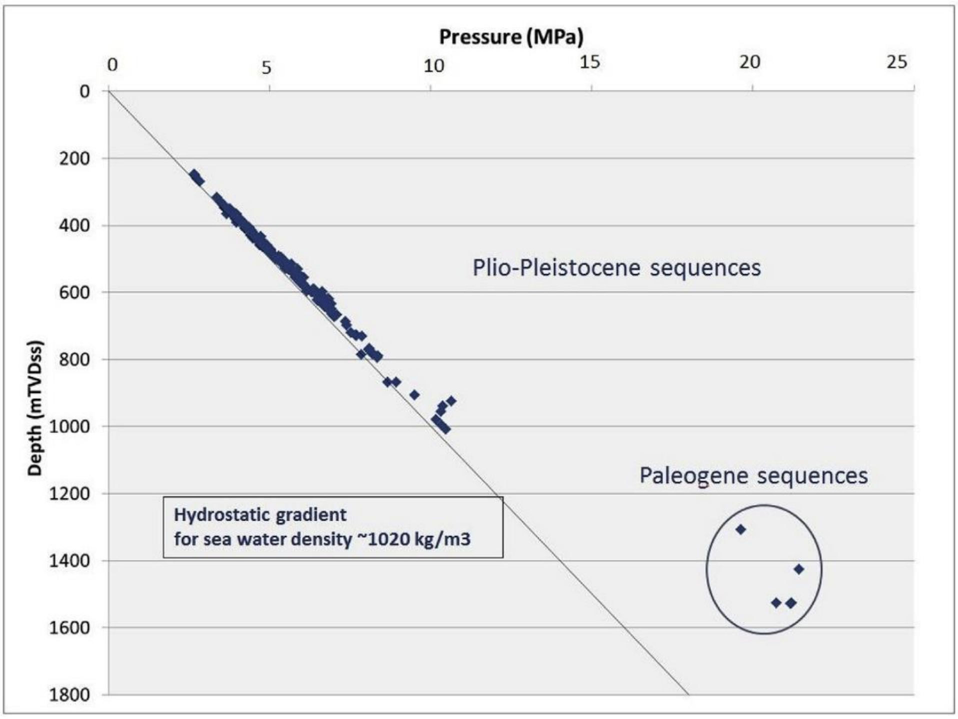


Figure 7-3 Cross plot of pore fluid pressure versus depth showing that the pressures in the Plio-Pleistocene Southern North Sea Delta sequences (Verweij et al.)

7.4 Definition of Shallow

Shallow gas refers to the accumulation of trapped gas in the highest layer of the stratigraphy, and this occurrence is observed globally. The precise definition of "shallow" varies depending on the actual depth of the gas. It is often defined as any gas incident that happens prior to the installation of the BOP. The term "shallow gas" is commonly defined as the first 1000 meters inside the subsurface, according to several sources (Davis, 1992; Floodgate & Judd, 1992; Grinrod, et al., 1988; Solheim & Larsson, 1987).

However, in the context of oil well drilling, the term "shallow" can be referred to the segment of the geological formation that extends from the mudline to the depth where the casing shoe of the surface casing is installed. This region is characterized primarily by its relatively soft formation, which is unsuitable for placing the casing shoe. The depth at which the casing shoe is set varies depending on geological conditions and typically marks the transition from softer, less stable formations to harder, more stable formations capable of withstanding subsurface pressures.

The definition of "shallow" depth can vary significantly from one field to another, influenced by local geological characteristics. For instance, in some fields, the casing shoe might be set at a depth of 500 meters, whereas in others, it could be as deep as 700 meters or more. This variability suggests that the term "shallow" should not be rigidly defined by a specific depth.

Instead, it is proposed that "shallow" be considered as the zone extending from the mudline to the depth just below where the casing shoe is placed, as this area typically encompasses formations too soft for the placement of the casing shoe.

7.5 Tommeliten Geology and Seepage

The Tommeliten seep area is in the Central North Sea, precisely on the European shelf, see Figure 7-4, and the detection of gas seepage occurred for the first time during a regular site examination in 1978 (Rehder, et al., 2011). Since oil companies have commenced the production of oil and gas from Tommeliten, we will conduct a detailed examination of this field.

This area undergoes considerable seasonal variations and has an average water depth of 74 meters, which is a rather shallow water depth. The site has a complicated geological formation called a graben, which is packed with layers of rock varying from the Permian to Tertiary eras. These rock layers act as reservoirs for oil, gas, and other fluids. These substances have the ability to migrate upwards and perhaps become stranded in shallow layers beneath the seabed, creating hydrocarbon reservoirs (Rehder, et al., 2011).

Beneath Tommeliten, there are three salt formations named Alpha, Gamma, and Delta. The Delta formation has pushed upwards through the layers above it, creating a dome-like shape. Because it breaks through these layers, it doesn't have a proper cap to contain gases (Hovland & Judd, 1988). Seismic investigations have detected indications of shallow gas in proximity to the Earth's surface and the release of gas throughout a region of around 120,000 square meters. Earlier research by Hovland & Sommerville (1985) and Niemann, et al. (2005) using seismic survey data has shown a dome-like feature in the shallow seafloor layers, which is thought to be a gas accumulation. When this gas accumulation reaches the seafloor, gas ebullition is often seen.

The seabed in the area of the gas seepage site at Tommeliten is predominantly level, gradually descending from a depth of 72.6 meters in the northeast to 73.4 meters in the southwest. Near this gas seepage site, there are minor, irregular depressions of approximately 3 meters in diameter and 0.2 meters in depth (Rehder, et al., 2011).

Hovland & Sommerville's (1985) investigation revealed that gas leaks were predominantly concentrated inside a limited region measuring 6,500 square meters, referred to as the "main seepage" zone. Within this area, they observed 22 locations on the bottom where gas bubbles, around 10 mm in diameter, were consistently emerging every 6 seconds. Their estimation suggested that there may potentially be around 120 gas release locations over the whole region.

In their 2002 study, Niemann, et al. (2005) noticed a formation of gas bubbles from a specific region measuring 3,500 m^2. In addition, they suggested another potential seepage site located at coordinates 56°29.56'N and 2°59.25'E.

The main gas seepage region at Tommeliten has been discovered to be 21 times more in size than previously documented, accommodating a total of 550 distinct gas vents. In addition, four additional seepage spots have been detected, resulting in a total of 185 additional vents. ROV observations show that gas ebullition is regular, with the release of gas bubbles of roughly 4.5 mm in diameter (Rehder, et al., 2011).

The combination of in-situ gas flux measurements, acoustic mapping of shallow gas distributions in the sediment, and the use of hydroacoustic methods to detect seepage in the water column, has revealed that the total amount of methane released into the water column in the main seep area of Tommeliten is 1.2 million moles of CH_4 per year, which is equivalent to 19.6 tons per year. The emission of methane from the new seepage sites produces an extra 0.3×106 moles of CH_4 each year (Rehder, et al., 2011).

Video recordings from 2006 confirmed the previous observations made by Hovland and Sommerville in 1985, revealing the presence of tiny, funnel-shaped cavities in the sandy seabed (Rehder, et al., 2011). The craters had a depth of around 10 cm and a width of 20 cm, appearing at each location where gas was being emitted. The apertures through which the gas was released had a diameter of approximately 1 cm. Occasionally, these cavities were occupied with a kind of algal remnant (Niemann, et al., 2005). Hovland & Sommerville's (1985) examination of the geochemical composition of gas bubbles revealed that the bubbles consisted of 99% methane gas, with a d13C signature of 45.6% VPDB. The coexistence of ethane, propane, and butane with methane indicates that the gas originates from the Earth's depths, through thermogenic mechanisms.

In close proximity to the gas emissions, the concentration of methane in the water reached levels as high as 500 nanomoles, much above the typical 5 nanomoles detected in areas unaffected by similar gas discharges (Niemann, et al., 2005).

According to the model's results, less than 4% of the methane emitted by the Tommeliten seeps reaches the surface layer of the water throughout the summer months. During the winter season, the process of stratification breakdown causes the water layers to mix more, resulting in a higher likelihood of increased methane transfer from the ocean to the atmosphere. This occurs due to the release of methane that was previously contained under the warmer surface layer known as the thermocline (Rehder, et al., 2011).

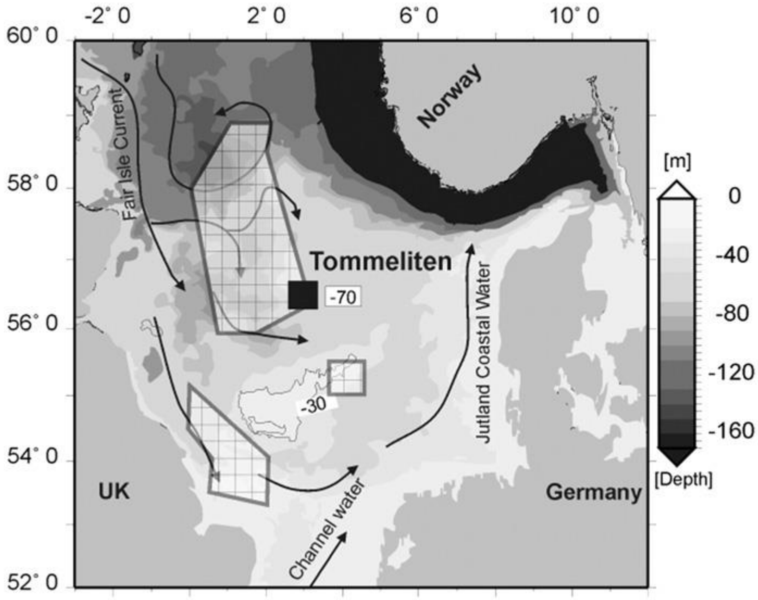


Figure 7-4 North Sea bathymetry from the GEBCO grid (**http://www.gebco.net)**

8 Plug and abandonment of shallow zones

Preventing shallow gas migration presents a considerable challenge due to difficulty in sustaining adequate hydrostatic pressure at shallow depths during the liquid phase of cement, intensified by lower temperatures that prolong the transition period from liquid to elastic-solid state. Identifying the root causes of this phenomenon and devising effective solutions are crucial in well integrity (Al-Buraik, et al., 1998).

8.1 Limitations

Given the shallow depths where formation strength is relatively weaker, it is advisable to utilize cement slurries with lower density (Agista, et al., 2023).

Historically, the industry has employed cement additives to achieve reduced slurry density. Most of these additives possess water-absorption properties, facilitating water addition without causing solids segregation. However, a decrease in slurry density often correlates with a compromised chemical and physical properties of the resulting cement (Nelson & Guillot, 2006).

In response to this challenge, advancements during the 1980s introduced hollow microspheres and foamed cements, enabling the formulation of competent cements at densities as low as 8 lbm/gal [960 kg/m^3]. Nevertheless, the preparation of foam cements necessitates specialized equipment at the wellsite (Nelson & Guillot, 2006).

Additionally, lightweight-particle extenders offer an alternative approach to reducing slurry density by virtue of their lighter composition compared to cement particles. These extenders encompass materials such as expanded perlite, powdered coal, gilsonite, and glass or ceramic microspheres (Nelson & Guillot, 2006).

The utilization of cement extenders such as glass beads and foam alongside water to achieve density reduction in cementing operations introduces complexities in the process. A notable challenge associated with glass beads lies in their inherent dissolution over time. Consider a scenario where cement contains pores filled with glass beads; upon dissolution, these pores become voids. When the beads are closely packed, the resulting voids may interconnect, potentially creating pathways for fluid migration.

Alternatively, foam serves as a connecting agent. However, its deployment necessitates the incorporation of glass beads, which, over time, also facilitate connectivity. Consequently, the choice between foam and glass beads poses significant challenges in managing potential leakage pathways. Furthermore, the inclusion of water as density extender in the system presents its own set of challenges, leading to increased permeability.

During the surface casing cementing process, it is essential to extend the placement of cement down to the seabed, subjecting it to temperatures as low as 4°C or even sub-zero (Agista, et al., 2023).

Temperature plays a significant role in influencing the hydration process of Portland cement. The rate of hydration, as well as the characteristics, stability, and structure of the resulting hydration products, are profoundly impacted by this environmental parameter (Nelson & Guillot, 2006).

8.2 Biogenic gas leak path

Figure 8-1illustrates the three scenarios of biogenic gas leakage, depicting the different pathways through which the gas escapes from the subsea infrastructure.

In Scenario A, biogenic gas migrates behind the conductor pipe and/or behind surface casing, reaching sea level without breaching the wellbore. This leakage is from the soft formation behind the casing or conductor pipe, which occurs naturally and cannot be effectively mitigated.

This scenario suggests that the formation surrounding the well structure is loose, allowing gas to migrate upwards. However, this condition does not necessarily indicate a failure in the established barriers in wellbore. Therefore, the risk associated with Scenario A is deemed lower as the leakage does not imply a direct compromise of the well's integrity.

In Scenario B, biogenic gas is released to seabed through barriers, such as the cement located behind the conductor pipe and/or the cement located behind the surface casing. This indicates a failure in the well's barrier systems.

In scenario C, it is not the barriers that are compromised, but rather the cement plug. The leakage through the wellbore is a critical indicator of poor sealing, necessitating attention

The leakage through the surface plug in scenario C implies that the primary barrier may also be compromised, as these components form a unified sealing mechanism against gas escape. The failure of this barrier necessitates a revaluation of the plug and abandonment procedures.

A recommendation is proposed to delay the cutting and removal of the wellhead and conductor pipe. Postponing these actions, aiding in determining whether the gas originates from behind the casing or through the wellbore. Seismic data indicating pre-drilling gas presence supports

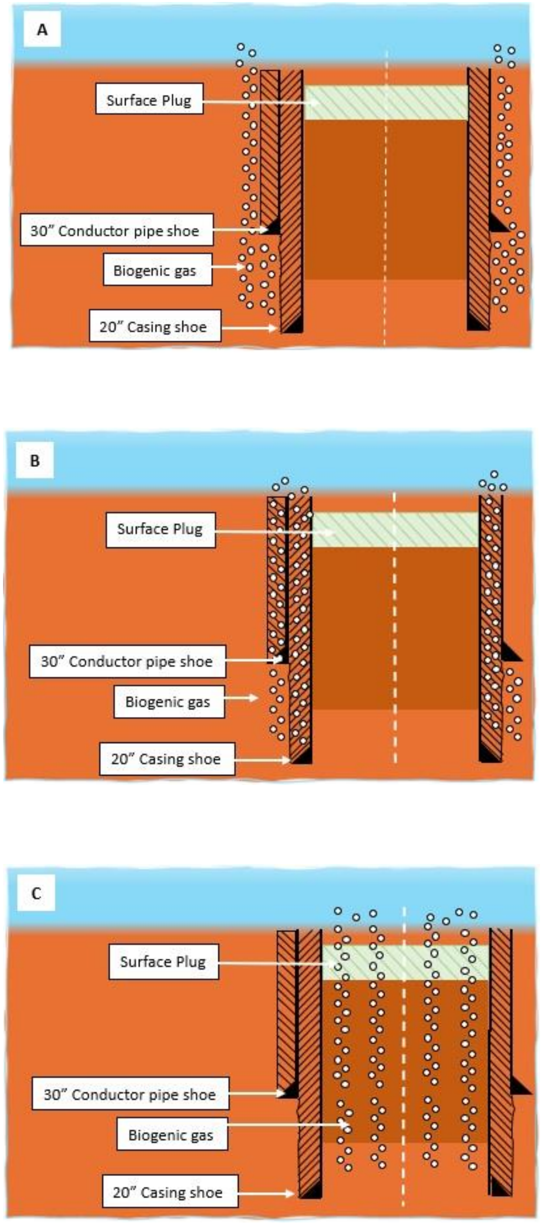


Figure 8-1 Biogenic gas leak path

the hypothesis that some leaks may be natural rather than due to operational failures.

In addition, Scenario A accurately depicts the occurrence of wellbore-induced natural seeps, when natural seepage is widespread and enters behind the wellbore casing. In regions such as Tommeliten, where there is a significant rate of seepage, the existence of seeps behind the casing does not have a substantial impact on the dynamics of leakage, as seepage happens equally.

Furthermore, in Scenario B and C, there is a well leakage, meaning that the well itself is leaking, not the surrounding region. On the other hand, in instance A, there is wellbore-induced seepage.

8.3 Complexity of reservoir, overburden and shallow depth

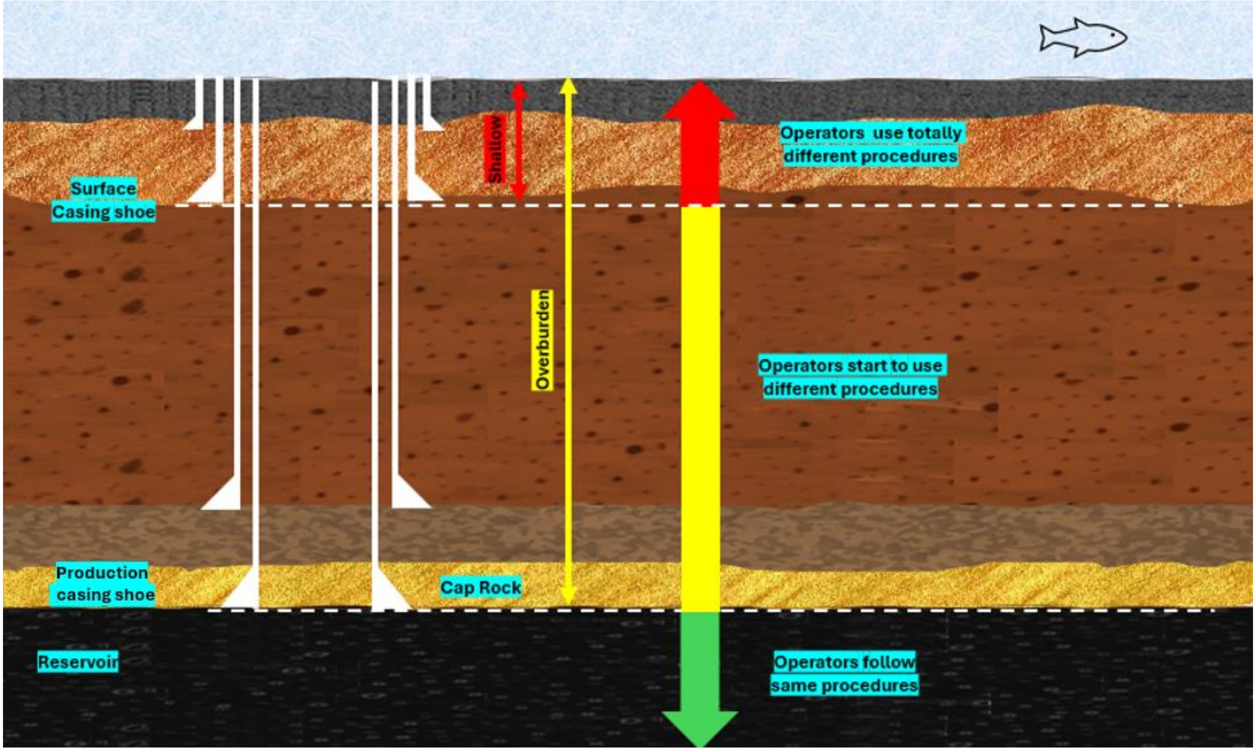


Figure 8-2 Complexity of reservoir, overburden and shallow depth

Figure 8-2illustrates the complexity of overburden concerning zonal isolation, with a particular emphasis on regions containing shallow gas. Shallow zones are situated above the surface casing shoe, overburden is extending from the mud line up to the cap rock, including shallow zone. During Phase 1 operations, standardized procedures are generally followed by all operators. However, when addressing the overburden, the complexity increases, and although shallow gas zones are a subset of the overburden, they present unique challenges requiring distinct consideration.

It is essential to differentiate between shallow gas zones and the broader overburden due to their specific difficulties. While reservoir abandonment procedures are standardized across operators, variations emerge when dealing with overburden complexities. In contrast, procedures for shallow gas zones differ significantly among operators due to the heightened complexities involved.

The complexity of reservoir abandonment primarily arises from the difficulty in accessing the reservoir rather than the plug and abandonment operations themselves. Once access is achieved, standardized P&A procedures are typically followed. The increased complexity is primarily geological, affecting the P&A process indirectly. In the illustration, the reservoir is marked in green to denote that the inherent geological complexity, rather than the P&A operations, is the primary challenge.

As operations progress upward from the reservoir, the complexity intensifies, particularly in areas with shallow gas. This increased complexity in the overburden, and especially in shallow gas zones, necessitates the adoption of more varied and specialized procedures to ensure effective zonal isolation and safe P&A operations.

9 Conclusion and further work

9.1 Conclusion

The current lack of sufficient direct observations and samples from leaking wells or surrounding restricts our ability to accurately determine the source of methane and establish correlations between geological factors and well construction in relation to the risks of leakage.

This study aimed to get a comprehensive understanding of fluid flow near wells, which is essential for the sustainable management of marine resources on the NCS.

The PP&A process consists of three distinct phases. An extensive examination has been conducted to determine the comprehensive method followed at each step to prevent potential leaks produced by the flow of fluids from primary reservoirs, overburden layers, and shallow depths. Afterwards, the shallow depth and complexity of the overburden were assessed to determine their impact on the extent of seepage and probable leakage following the PP&A operation.

Furthermore PP&A operation in different oil and gas field were reviewed to verify the differences in reservoir and intermediate abandonment practices. The findings of this thesis underscore the critical importance of dual-barrier systems in the process of reservoir abandonment, where these barriers function effectively as artificial cap rocks. Strategically positioned in carefully chosen areas to maintain integrity and successfully pass pressure tests, these barriers significantly reduce the likelihood of leakage, particularly in a depleted reservoir.

Considering the findings of this study in reservoir management, a leaking well does not mean all wells are compromised, as different personnel may handle operations. Thus, a single leak should be considered an isolated incident, not a systemic issue. However, the challenges intensify during Phases 2 and 3 of abandonment as activities approach the surface. In this context, the presence of softer formations and frequent natural gas occurrences complicate the abandonment procedures, making it more difficult to maintain structural integrity. Another challenge associated with overburden is the identification of the source of flow, even if some of these sources may not be commercially viable.

Case study reviews indicate that while main reservoir abandonment strategies may align, intermediate abandonment practices can vary significantly, highlighting the growing need for more attention to intermediate zones.

This research sum ups this fact that there is a lack of good terminology to differentiate between seepage and leakage among engineers. There is a comprehensive distinction between well seeps and leaks. Although initial observations may suggest the presence of well leaks, further investigation reveals that what are commonly referred to as leaks might be natural seeps. These micro-seepages occur in the same locations as wellbores but are not always produced by them. Distinguishing between seepages caused by well integrity issues and those resulting from natural geological processes is crucial in reshaping public and regulatory perspectives, especially among younger demographics who may not easily differentiate between the two.

Furthermore, the study outlined the relationship between biogenic and thermogenic gases and the integrity of the wellbore. Despite numerous reports of gas seepages, no definitive link was discovered between the specific type of gas discharged and the existence of wellbores. These findings suggest that the natural seepage landscape would remain largely unaltered regardless of wellbore involvement. This leads to an important conclusion: the observed occurrences are predominantly caused by natural seepage rather than leakage induced by wellbore activities.

This thesis proposes that the commonly used term "leaking wells" may often be inaccurate, suggesting instead that "wellbore-induced natural seepage" would be a more precise description. This understanding is crucial for future regulations and operational structures in the industry, emphasizing the importance of clear and accurate terminology to improve comprehension and control of both natural and human-induced impacts on geological seepage.

9.2 Further work

For further work it is recommended to follow up these topics:

- How can abandoned wells be repurposed for carbon capture.
- Develop guidelines and best practices to optimize well-decommissioning protocols.
- Introduce “wellbore-induced natural seepage” or “wellbore-stimulated natural seepage” as new term in NORSKOK D-10 or other regulatory.
- Precisely defining the term “shallow” by the use of drilling and surface casing shoe placement.
- Propose possible solutions to mitigate potentially leaking wells.

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APPENDIX

Appendix A: Listing of generic input needed for risk-based P&A (DNV GL-RP-103)

	Detail	*Notes*
General	Well details	number, field and location of wells type of well (production/injection) future usage plans for the well
	Field architecture	Subsea or platform, high level description
	Water depth	Water depth
Reservoir and overburden	Number of flow potential overburden formations	any formation which contains moveable fluids in the form of hydrocarbons or abnormally pressured water.
	Hydrocarbon-bearing formation 1	name & geological formation
		true vertical depth [TVD] range (top & bottom)
		contents of formation, including composition of hydrocarbons and volume capacity
		original, current and future pressures
	Additional hydrocarbon-bearing Formations	name & geological Formation, TVD range (top & bottom), contents formation, including hydrocarbon composition volume original, current and future pressures, cross-flow potential
	Subsurface factors	hydrogen sulphide [H2S], carbon dioxide [CO2], geological faults, pore-and fracture gradients
	Geological barrier formations	Formations that are or can be qualified as barrier
Wellbore	Well history summary	Well barrier diagram and schematic
		Annuli fluids and annuli operating limits
		Primary well barrier status including status of tubular/casing/liner
		Secondary well barrier status including status of casing/cement including cement quality
		Previous abandonment activities, including side-tracks
		Wellbore stability diagrams, temperature plots, mud logs, pressure tests, open hole logs
		Challenges during well construction – caving, losses, washouts, cementing problems, borehole instability issues/geological challenges
		known well integrity issues – leaks, degraded components pressure containment issues
	Current and previous well operational status	well status details including the well's 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 importance of environmental resources of special importance for life-history stages of species
	Site specific safety	General or site-specific safety requirements

Appendix B: Generic well barrier failure modes for P&A wells (DNV GL-RP-103)

	Potential failure mode	*Potential cause mechanism*	*Risk management strategy*
Mainbore	Insufficient barrier length in mainbore	— low top of barrier — barrier slippage — density miscalculation	include functional barrier length assessments into quantitative models
	Barrier function degraded in mainbore	— incorrect barrier density — operational issues — permeable barrier — high barrier shrinkage leads to increased porosity and stresses that may cause a microannulus to form	perform sensitivity studies as to the flow potential through and around these barriers
Casing	Corrosion of casing	— well fluids exposure or long-term exposure	perform sensitivity studies as to the flow potential through and around these barriers Include formation aspects and time perspectives
	Yielding of casing due to pressure in well	— well loading over time including geological forces — formation loads	
Annulus	Insufficient barrier length in annulus	— slippage due to inadequate density or losses — not able to perform squeeze job	include functional barrier length assessments into quantitative models with sensitivity studies
	Degradation of annulus barrier	— channelling/lack of bonding — CO_2 corrosion — H_2S corrosion — magnesium chloride degradation — thermal cracking and/or de-bonding (microannulus) due to Joule-Thomson effect during injection into, e.g., depleted gas reservoir — pre-existing channels — pre-existing micro-annulus	perform sensitivity studies as to the flow potential through and around these barriers
	Contamination of annulus barrier	— poor mud and filter cake removal leaves a route for hydrocarbons to flow up the annulus — high barrier shrinkage leads to increased porosity and stresses that may cause a microannulus to form	
Formation	Overpressure of formation	— build-up of pressure over time — injection nearby	evaluate the formation characteristics, the need for crossflow prevention and natural leakage/seepage
	Fluid exposure	— degradation effects over time	
	Geological barrier formation	— potential to use formations as an additional well barrier, if possible	identify if compacting formations or aquifers can be used as permanent barriers.