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Writer: Eskild Muri Bø	Eskild Muri Bø (writers signature)
Faculty supervisor: Mahmoud Khalifeh	
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Abstract

As more and more wells reach the end of their production life, the focus on permanent plug and abandonment has increased in interest. Cost-efficient abandonment of wells with ceased production is an important economic goal for the oil and gas industry. A dominant part of the plug and abandonment operation is the removal of steel tubular and casing to establish a rock-to-rock cross-sectional barrier in the well. This process is aggravated by settled barite and other mud solids accumulated at the bottom of the casing annulus, increasing over-pull and resulting in several cut and pull runs. If the settled barite, which is already in place behind the casing, could function as a part of a barrier envelope, it could significantly reduce such operations.

This thesis's primary objective is to investigate if industrial field data support the utilization of settled barite as a feasible annulus barrier element. A total of 307 wellbores were analysed for cut and pull operations, where attempts to circulate settled barite out of the annulus were performed. A three-layered model was suggested using theories of barite segregation and settling regimes in drilling mud. The model was used to calculate the hydrostatic pressure of an annulus column of drilling mud settlements to accurately predict the differential pressure excreted through the settled barite plug. Twenty-two of the investigated wellbores showed potential for further analysis, and four wells displayed plugs of settled barite that would prevent fluids from a re-pressurised reservoir to flow unintentionally to the surface or other formations.

"A standard is worth nothing - unless it is referred to"

– Knut Heiren, *Standard Norge 2004*

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Working on this dissertation has been both interesting and challenging. It has required more than academic support, and I have many people to thank for their support, facilitation and understanding. To enumerate all would be excessive, so I will instead express my gratitude to one and all who directly or indirectly have lent their hand in this venture.

Eskild Muri Bø
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Nomenclature

API	American petroleum Institute
BHA	Bottom hole assembly
CED	Closed-end displacement
DDR	Drilling data report
DHSV	Downhole safety valve
EAC	Element acceptance table
EOWR	End of well report
HSE	Health, safety and environment
mD	Milli darcy
mMD	Meter measured depth
mTVD	Meter true verical depth
NCS	Norwegian continental shelf
OGUK	Oil and Gas United Kingdom
P&A	Plug and abandonment
PSA	Petroleum saftey authority
TOC	Top of cement
TOS	Top of solids
TRL	Technology readiness level
TSW	Treated sea water
TTOC	Theoretical top of cement
TTOS	Theoretical top of solids
WBE	Well barrier element
WBS	Well barrier schematics
WOB	Weight on bit
XMT	Christmas tree

Definitions

Some important definitions from NORSOK-D010 are transcribed in the following.

A-annulus - annulus/space between the tubing and the production casing.

Abnormal pressure - formation or zones where the pore pressure is above the normal, regional hydrostatic pressure

B-annulus - annulus between the production casing and the previous casing string

Can - verbal form used for statements of possibility and capability, whether material, physical or casual.

Cement - collective term for cement and non-cementitious materials that is used to replace cement.

Cross flow well barrier - a well barrier which prevents flow between two formation zones

Formation integrity pressure - collective term to describe strength of the formation. This can be either FIT/PIT or the interval between fracture breakdown pressure and fracture closure pressure.

Fracture closure pressure - pressure at which the fracture closes after the formation has been broken down. Fracture closure pressure equal to minimum formation stress.

May - verbal form used to indicate a course of action permissible within the limits of the NORSOK standard.

Permanent well barrier - a well barrier which permanently seals a source of inflow.

Pressure/leak testing - application of differential pressure to detect leaks in a well barrier, well barrier element or other objects that are designed to confine pressurised fluids (liquids or gas).

Reservoir, source of inflow - a formation which contains free gas, movable hydrocarbons, or abnormally pressured movable water.

Shall - verbal form used to indicate requirements strictly to be followed in order to conform to NORSOK standard and from which no deviation is permitted, unless accepted by all involved parties.

Should - verbal form used to indicate that among several possibilities one is recommended as particularly suitable, without mentioning or excluding others, or that a certain course of action is preferred but not necessarily required.

Well barrier - envelope of one or several well barrier elements preventing fluids from flowing unintentionally from the formation into the wellbore, into another formation or to the external environment.

Well barrier element - a physical element which in itself does not prevent flow but in combination with other WBEs forms a well barrier.

Well barrier element acceptance criteria - technical and operational requirements and guidelines to be fulfilled in order to verify the well barrier element for its intended use.

Well control - collective expression for all measures that can be applied to prevent uncontrolled release of wellbore fluids to the external environment or uncontrolled underground flow.

1 | Introduction

1.1 General

Since the beginning of the Norwegian oil era, starting with the discovery of Ekofisk in 1969, more than 6900 wells have been drilled on the Norwegian continental shelf (NCS) [NPD, 2020]. The production started in 1971, and hydrocarbons have been produced from 112 fields, where 87 are still in operation. A total of 3382 wells have been decommissioned leaving more than 3000 active production or injection wells in addition to an average of 180 new wells drilled each year [NPD, 2020]. When a well reaches the end of its lifetime, it must be decommissioned and abandoned [Khalifeh and Saasen, 2020]. What dictates the end of a well's life cycle could be completed data gathering from exploration wells, depleted reservoir pressure for sustained production, integrity issues, water/gas coning, water break-through or other economic reasons [Khalifeh and Saasen, 2020].

As more and more wells reach the end of their production life, maximizing economic recovery and focusing on cost-efficient abandonment of wells with ceased production continues to be a goal for the oil and gas industry [Osundare et al., 2018, Wilkie et al., 2014, Liversidge et al., 2006]. A hydrocarbon well will inevitably transform from being an asset into a liability at the end of its lifecycle [Osundare et al., 2018]. An estimated 2000 wells on the NCS have reached the end of their lifecycle and are planned to be decommissioned in the upcoming decade. The decommissioning of a well is a major task for the operating company and is an operation with no financial return. Yet, it requires careful planning and execution to minimize risks, leading to an increase in operational expenditure and health, safety, and environmental (HSE) damages [Osundare et al., 2018].

Well decommissioning (not to be mistaken with field decommissioning) is often referred to as plug and abandonment (P&A) in the oil and gas industry. Such plug and abandonment operations usually consist of removing production equipment and sealing the wellbore with several rock-to-rock cement barriers. This is done to restore the cap-rock functionality and isolate the reservoir and other fluid-bearing formations, prohibiting any unintentional flow of hydrocarbons to the environment and securing the well integrity permanently. Plug and abandonment of a well can take an average of 35 days [Straume, 2013] and can easily contribute to 25% of the total cost of drilling exploration [Khalifeh and Saasen, 2020]. Depending on the state of the well, such an operation can be increasingly more time consuming and thus reach costs surpassing that of the actual drilling operation. With the number of active wells and the rate that new wells are being drilled, the Norwegian P&A campaign will last over 40 years and cost an estimated 900 billion NOK [Myrseth et al., 2016], assuming that the current technological status of the industry persists.

Well abandonment (i.e., permanent P&A) has always been an important sector in the oil and gas industry. The increased interest in the topic, over the last decade, is due to the large number of wells that are currently shut-in, suspended or have reached the end of their economic life and require permanent plugging and abandonment. According to Osundare et al. [2018], the rig cost is the largest expenditure element, contributing over 50% in many P&A operations. Consequently, the operating companies exert their effort to reduce the time of their P&A campaigns to an absolute minimum. The dominant part of a P&A campaign is associated with cutting and pulling casing to establish rock-to-rock cross-sectional barriers. The barrier requires a minimum setting depth in a suitable strong formation to handle the differential pressure created by expected reservoir pressure build-up. Therefore, this can result in long casing pulling operations in some situations.

A common problem in casing pulling operations is the presence of formation creep and settled drilling mud solids, resulting in excessive over-pull and the need for multiple cut and pull runs. When faced with this problem, the conventional method is to section mill the casing to access the formation for barrier placement. This method is also considered time-consuming, costly, and associated with increased HSE risks and operation uncertainty [Khalifeh and Saasen, 2020]. Thus, a growing interest has been put into finding new methods and solutions to reduce such operations' time and cost.

Numerous methods are currently being used or are experimented with to combat the challenges with casing removal. Upwards milling has in some situations shown promising results and several companies have developed perforate and washing tools that perforate the casing and enable the possibility of squeezing cement into the annuli to create an annulus barrier. Several new plugging materials and solutions have also entered the industry including unconsolidated sand slurries, thermosetting resins, geo-polymers, and bismuth-based alloys [Khalifeh et al., 2013, Kamali et al., 2021]. However, they are at different Technology Readiness Level (TRL) and have not merited widespread industrial adaptation.

1.2 Problem Formulation

To reduce the cost of P&A operations, existing technologies must be optimized and new time-effective methods needs to be developed. Barite is a mineral consisting of barium sulfate, a chemically inert mineral that is commonly used as a weighting material in drilling fluids. Weighting particles suspended in the drilling fluids will over time settle on the bottom of the fluid column and are called settlements. Barite settlement is an aggravating factor in the time-consuming casing pulling operation [Vrålstad et al., 2018], inducing excessive friction to the casing and generating disproportionate pulling force. If settled barite behind the casing could function as a part of the barrier envelope, it could greatly reduce time of P&A operations. Considering the settled barite is already in place behind the casing, an investigation for the utilization of settled barite as an annular barrier element could benefit the industry.

Preliminary experimental work conducted by well integrity research teams at University of Stavanger (UiS) has shown promising results with using settled barite as a permanent annular barrier. Acting as an unconsolidated slurry, the settled barite has proved to be diffusion tight against both gas and liquid with Bingham plastic properties. It creates a seal at the interface of formation to prevent dehydration of the settlements and retain the unconsolidated slurry abilities over time.

To analyse the feasibility of barite as a permanent well barrier element, this thesis will show if large scale industrial data supports the laboratory findings. A case study was proposed to investigate previous cut and perforate operations to analyse theoretical and logged length of settled barite related to circulating pressures. By doing so, one can establish if there are any relationship between the length of settled barite and observed circulating pressure and if these pressures are more prominent than expected. If a relationship is found, it could verify that the barite is diffusion tight and exerting friction on the formation and casing wall. A diffusion-tight material already in place, in the annular gap between formation and casing, could be utilized as a part of a barrier element, reducing time (i.e., cost) associated with casing pulling and milling operations.

1.2.1 Objectives

The primary objective of this project is to investigate if industrial field data supports the theory that settled barite could be a feasible annulus well barrier element that can be utilized in future plug and abandonment campaigns.

To address the objective, some research questions have to be answered through theory and empirical data analysis.

1. Is there any relationship between the height of settled barite and an increased differential pressure needed to establish circulation through the annulus in old wellbores?

2. Is there a maximum angle of inclination where the settling regime of barite particles prohibits a utilization of settled barite as barrier element?

3. Is there any credible verification methods to assure the location and suitability of the in-place settled barite as a barrier element?

4. Last but not least, is there any industrial guideline or governmental regulations prohibiting the use of settled barite as a part of well barrier envelope and how likely is it that the oil and gas industry will adapt the solution?

1.2.2 Limitations

Due to the time constrain of the MSc thesis and the accessibility of industrial data, this thesis will only analyze data related to 9 5/8-in casings in fields with similar lithology, casing programs and casing setting depths. This is to get data sets closely related with regards to dimensions, true vertical setting depth, and formation lithology.

2 | Well integrity

There are different definitions of well integrity, but NORSOK D-010 gives the most widely accepted definition: "Application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids and well fluids throughout the life cycle of a well" [NOROK-D010, 2013]. Similar wording exists in ISO 16530:2016 Well Integrity Standard: "Containment and the prevention of the escape of fluids (i.e., liquids or gases) to the subterranean formations or surface". Well integrity philosophy is an essential element in well management and refers to maintaining full control of all fluids within a well at all times. It defines commitments and obligations to safeguard health, safety, environment, assets and reputation by preventing unintended fluid movement or loss of containment to the environment.

There are several different requirements and procedures for well integrity and many countries establish their own standards. A range of international frameworks is available, but in this chapter the most important governing bodies for the NCS will be discussed. A more comprehensive list of standards and guidelines that cover well integrity, well control and well abandonment are listed in Appendix A, originally published by IOGP [IOGP, 2018]

2.1 American Petroleum Institute

American Petroleum Institute (API) is the largest US Petroleum association for the oil and gas industry. It is responsible for publishing hundreds of worldwide accepted standards for all aspects of the on- and off-shore oil and gas industry, known as API standards. Important API standards for well control and well integrity are the API RP 59 - Well Control Operations and API RP 65-2 Isolating Potential Flow Zones During Well Construction. A challenge with the API system is the share number of standards. There are no holistic collection of well integrity standards but are divided into different independent standards.

2.2 NORSOK

NORSOK is a Norwegian abbreviation for "Norsk Sokkels Konkurranseposisjon", "The Norwegian Continental Shelf Competitive Position". It is the result of a collaboration between the Norwegian government and the Norwegian petroleum industry started in 1993 with the aim to increase Norway's competitiveness in delivering field solutions. The NORSOK initiative was supported by the Norwegian Oil and Gas Association and the Federation of Norwegian Industries. Out of this initiative a number of standards were developed to make operations more safe and cost efficient through standardisation [Bizley, 2014]. NORSOK-D010 is revered as the only holistic well integrity standard in the world. It focuses on well integrity by defining the minimum functional and cost-efficient requirements and guidelines for well design, planning and execution of well activities. The standard also focuses strongly on establishing and controlling well barriers and their elements and covers well integrity management and personnel competence requirements.

NORSOK-D010 is a respected and functional standard that sets the minimum requirements for the equipment and solutions to be used in a well. However, it leaves it up to the operating companies to choose the solutions that meet the requirements. The operating companies have the full responsibility for being compliant with the standard [Thorbergsen et al., 2012] and have an obligation to ensure that equipment and solutions meet the minimum requirements to give the well a safe lifecycle. If a selected solution deviates from the standard, this solution needs to be equivalent to or better than the requirement stated [Thorbergsen et al., 2012]. It is, therefore, common for operating companies on the NCS to have their own requirements that are higher and more strict than that stated in NORSOK-D010 to be certain they are compliant with the standard.

2.3 Barriers and barrier philosophy

In the context of well integrity, a barrier is an impenetrable object that prevents the uncontrolled flow of well fluids [Khalifeh and Saasen, 2020]. A well barrier can be described as a pressure-containing envelope that prevents fluids from flowing unintentionally from one formation into another formation or to the external environment. The well barriers must ensure complete and reliable isolation of permeable formations, preventing flow both through the wellbore and the sub-surface formations. A well barrier envelope consists of several impermeable objects, referred to as well barrier elements (WBE). A WBE is a physical element, which in itself may or may not prevent flow, but in combination with other WBEs forms a well barrier [NOROK-D010, 2013]. The two-barrier philosophy was implemented in the oil and gas industry probably as early as the 1970's [Thorbergsen et al., 2012]. It simply states that any operations on high-pressurised systems that involve breaking containment must be isolated with two barriers separating the high-pressure fluids from the environment. NORSOK-D010 specifies: "There shall be two well barriers available during all well activities and operations, including suspended or abandoned wells, where a pressure differential exists that may cause uncontrolled outflow from the borehole/well to the external environment" [NOROK-D010, 2013, Thorbergsen et al., 2012].

Table 2.1: NOROSK-D010, section 4.2

Number of barriers		Source of inflow
One well barrier	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 vapour)
Two well barriers	d)	Hydrocarbon bearing formation
	e)	Abnormally pressured formation with potential to flow to surface

According to NORSOK-D010 the following number of barriers shall be in place at all times.

NORSOK-D010 uses the two-barrier philosophy considering two independent well barrier envelopes named primary well barrier and secondary well barrier. *"The primary well barrier shall contain the fluids at all times during the wells life cycle, and under all load conditions. The secondary well barrier shall contain the fluids in the event of a breach of the primary well barrier"* [Thorbergsen et al., 2012]. The primary well barrier is the one closest to the source of potential flow while the secondary barrier is a backup if the primary fails. This requirement is also referred to in The Petroleum Safety Authority (PSA) activities and facilities regulation, and it implies that operators have to adhere to the two well barrier philosophies and maintain sufficient adherence in all phases of their operation [Thorbergsen et al., 2012].

2.4 Well barrier requirements

According to NORSOK-D010, the well barriers shall be designed, selected and constructed with capability to;

1. withstand the maximum differential pressure and temperature it may become exposed to;
2. be pressure tested, function tested or verified by other methods;
3. ensure that no single failure of a well barrier or WBE can lead to uncontrolled flow of wellbore fluids or gases to the external environment;
4. re-establish a lost well barrier or establish another alternative well barrier;
5. operate competently and withstand the environment for which it may be exposed to over time;
6. determine the physical position/location and integrity status at all times when such monitoring is possible; and
7. be independent of each other and avoid having common WBEs to the extent possible.

2.5 Well barrier schematic

Well barrier schematics (WBS) shall be prepared for each well activity and operation as stated in NORSOK-D010. A WBS is a visualisation of the barriers in place in a well at the time of operation. NORSOK-D010 states that a WBS is a standardised illustration of the different well barrier elements creating the well barrier envelopes with annotations on the barrier location, status and tests details. The primary barrier envelope shall have elements marked in blue and the secondary envelope shall have elements marked in red. A standardised WBS will prevent misinterpretations of the operating engineers intentions and can help establish a common understanding and perception of the barrier elements. Well barrier schematics can be created for all situations throughout the life cycle of the well. A consistency in illustration annotation and barrier element listing will further strengthen the common understanding of the well barrier status.

2.6 Well abandonment activities

NORSOK-D010 covers four different well abandonment scenarios: 1) Suspension of well activities and operations, 2) Temporary abandonment, 3) Permanent abandonment, and 4) Permanent abandonment of a section in a well (sidetracking, slot recovery) to construct a new wellbore with a new geological well target [NOROK-D010, 2013]. Requirements for isolation of formations, fluids and pressures for temporary and permanent abandonment are the same, but choice of WBE may be different to account for abandonment time and the ability to re-enter the well [NOROK-D010, 2013].

2.6.1 Well abandonment design

When a well or well section is selected for P&A, the abandonment design phase is initiated [Khalifeh and Saasen, 2020]. There are two common categories for well abandonment design. The first is a complete P&A of the entire well with reasons described above. The second is when the targeted formation has reached its yield potential, was drilled dry or abandoned for other reasons, and a new geological well target is planned through the same wellbore. This is commonly called slot recovery in the petroleum industry and requires the same approach to abandonment design considering the formation and wellbore needs to be sealed off. The difference is that only the reservoir section is abandoned and the upper well section is re-used for a new geological well target in an undrained area of the reservoir.

Before the operation starts, the operator is required to know all potential sources of inflow and pressure regimes present or likely to be present in the future. A WBS shall be prepared for each well activity operations and a final verified WBS for the well status upon completion of operations shall be in place [NOROK-D010, 2013]. All WBE used for plugging of the well shall withstand the load scenarios and the environmental conditions they may be exposed to for the abandonment period. For permanent P&A, the abandonment period is defined as "eternity".

The design basis should include well configuration, stratigraphic sequence of each wellbore, logs, data and information of cementing operations, formations with suitable WBE properties and specific well conditions [NOROK-D010, 2013]. Typically, the well schematic (Fig. 2.1) will show the completion components and the casing configuration. The handover document shall include WBS that will show the barrier location, status and verification methods. The End of Well Report (EOWR) includes depths and inclinations, specification of formations with potential sources of inflow, casing strings, casing cement and wellbores. In addition, detailed information of all sidetracks and previously abandoned well sections are required to be documented. Completion reports and hole surveys can be sourced to verify this information.

Stratigraphic sequence of each wellbore showing reservoir(s) and information about their current and future production potential, with reservoir fluids and pressures (initial, current and in an eternal perspective) needs to be present [NOROK-D010, 2013]. There may be a field wide geological assessment conducted during field development that is the basis for the stratigraphic report, or there may be done individual assessments on the given well or rig. Adjusted pore pressures and fracture gradient along the wellbore are also needed to confirm suitable caprock formations and minimum setting depth for isolation barriers. Identifying an appropriate formation, for where to establish the primary and secondary well barriers, is a key factor in the design phase [Khalifeh and Saasen, 2020]. A suitable formation is typically an impermeable shale that possess caprock properties, with sufficient strength to hold the exerted hydrostatic pressure of the barrier material and the expected pressure from the formation. If a geological assessment with these key items is not available, the data will need to be collected from EOWR and drilling data reports (DDR) in addition to an analyses of adjacent wells completed in lithologically similar formations.

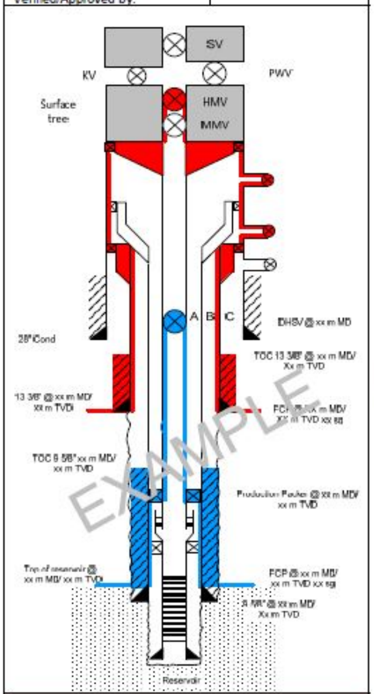
Casing cement and cement intervals are important information when planning barrier placement. During the drilling phase, this is estimated from displacement efficiency based on records from the cementing operation. Volumes pumped, wellbore and casing geometry, returns and pumping pressures are used to calculate top of cement (TOC) and the quality of the cement job. Detailed examination of EOWR, DDR and logs should give information about any losses during the cementing operation, over gauged holes caused during drilling and if the total volume of cement was displaced according to design. It is important to note that theory is not always corrolated to the real world and one should not be too confident in the cement calculations. Cement logging is one of the most commonly used and trusted verification methods in the petroleum industry to qualify cement [Khalifeh and Saasen, 2020]. TOC and cement quality should be logged if it is to be used as part of a barrier.

When the over mentioned data is controlled and verified, the attention can be turned to the production and intervention data. To establish barriers in the well, it is necessary to get access to the part of well where the barriers are to be placed. Specific well conditions such as casing wear and collapsed casing, evidence of deterioration due to corrosion or erosion, evidence of access restrictions due to scaling, sand production or component failure have to be documented. Sustained casing pressures implying loss of cement integrity, and evidence of communication behind tubing or across annuli must be investigated. Samples of the fluid build up should be taken as these can confirm the probable source of pressure and guide barrier installation design. In addition, there are specific well conditions such as H_2S, CO_2, hydrates, benzene or similar issues when present in the well that dictates contingency plans or HSE considerations.

2.6.2 Barrier material

All WBEs shall be designed for a combination of the functional and environmental loads they can be exposed to. Pressure induced by migration of formation fluid into the wellbore based on a worst anticipated reservoir pressure and lowest anticipated fluid density for the abandonment period is a required load condition for all permanent barriers. Increase of reservoir pressure due to a natural re-pressurization to initial/virgin level formation pressure, should be used in the design criteria for all permanent WBE [NOROK-D010, 2013]. NORSOK-D010 describe the permanent abandonment period as eternity taking

Well information (as built)	
Field/Installation:	
Well name:	
Well type:	Producer
Well status:	Shut-in
Well design pressure:	xx bar
Revision number:	Version 1.0
Date prepared/revised:	
Prepared by:	
Verified/Approved by:	



Note 1: Well shut-in due to tubing leak above DHSV.

Nomenclature:
PT: Pressure test
IT: Inflow test
FCP: fracture closure pressure
XLOT: extended leak off test
AC: acceptance criteria

Well barrier elements	EAC table	Verification / Monitoring
Primary well barrier		
In-situ formation (cap rock)	51	FCP: x.x s.g. Based on field model / n/a after initial verification
Casing cement (9 5/8")	22	Length: xx mMD Cement bond logs / Daily pressure monitoring of B-annulus
Casing (9 5/8")	2	PT: xx bar with x s.g. EMW / n/a after initial verification
Production packer	7	PT: xx bar with x s.g. EMW / Continuous pressure monitoring of A-annulus
Completion string	25	PT: xx bar with x s.g. EMW / Continuous pressure monitoring of A-annulus See Note 1.
Completion string component (Chemical injection valve)	29	PT: xx bar with x s.g. EMW / Periodic leak testing AC DHSV: xx bar/xx min
Downhole safety valve (incl. control line)	8	IT: xx bar (DHSV) PT: xx bar (control line) / Periodic leak testing AC DHSV: xx bar/xx min
Secondary well barrier		
In-situ formation (13 3/8" shoe)	51	FCP: x.x s.g. Based on XLOT / n/a after initial verification
Casing cement (13 3/8")	22	Length: xx mMD Method: Volume control / Daily pressure monitoring of C-annulus
Casing (13 3/8")	2	PT: xx bar with x s.g. EMW / Daily pressure monitoring of C-annulus
Wellhead (Casing hanger with seal assembly)	5	PT: xx bar / Daily pressure monitoring of C-annulus/ Periodic leak testing
Wellhead / annulus access valves	12	PT: xx bar / Periodic leak testing of valve AC: xx bar/xx min.
Tubing hanger (body seals and neck seal)	10	PT: xx bar / Periodic leak testing
Wellhead (WH/XT Connector)	5	PT: xx bar / Periodic leak testing
Surface tree	33	PT: xx bar / Periodic leak testing of valves AC: xx bar/xx min

Figure 2.1: Well barrier schematic example from NORSOK-D010 (NORSOK 2013)

into account any foreseeable chemical and geological processes. Eternity as a concept is hard to grasp, so many operating companies have defined this as 500 years. In this time frame, it is assumed that steel casings have eroded, mechanical plugs have lost their sealing abilities and that the reservoir pressure has returned to the initial level. Therefore, any WBE should be comprised of some other materials than steel.

Permanent well barriers shall be extended across the full cross section of a well, including all annuli and seal in both horizontal and vertical direction [NOROK-D010, 2013]. The well barrier(s) shall be placed adjacent to an impermeable formation with sufficient formation integrity for the maximum anticipated pressure and the suitability of the selected plugging materials shall be verified and documented. NORSOK-D010 does not state what material a WBE should consist of, but cement has been the most common in the oil and gas industry. The design and placement of WBE consisting of cement or alternative materials should account for uncertainties relating to downhole placement techniques, contamination of fluids, shrinkage of cement or plugging material, casing centralization, support for heavy slurry and degradation over time [NOROK-D010, 2013].

NORSOK-D010 states that a permanent WBE should have characteristics to provide a long-term integrity, be impermeable, non-shrinking, able to withstand mechanical loads, be resistant to chemicals, ensure bonding to steel and not be harmful to the steel tubular integrity. A well barrier element acceptance criteria (EAC) table shall be in place for all WBEs used. General technical and operational requirements and guidelines relating to WBEs are collected in the EAC tables in NORSOK-D010 section 15. A new EAC table shall be developed in cases where an EAC table does not exist for a specific WBE and the level and details shall be defined by the user [NOROK-D010, 2013, 4.2.4].

Table 2.2: EAC table description - [NOROSK-D010, Table 4]

Features	Acceptance criteria	See
A. Description	This is a description of the WBE	
B. Function	This describes the main function of the WBE	
C. Design (capacity, rating, and function), construction and selection	For WBEs that are constructed in the field (e.g. drilling fluid, cement), this should describe; a) design criteria, such as maximal load conditions that the WBE shall withstand and other conditional requirements for the period that the WBE will be used. b) construction requirements for the WBE or its sub-components, and will in most cases consist of references to normative standards. For all WBEs that are pre-manufactured the focus should be on selection parameters for choosing the right equipment and proper field installation.	
D. Initial test and verification	This describes the methodology for verifying the WBE being ready for use and being accepted as part of a well barrier.	
E. Use	This describes proper use of the WBE in order for it to maintain its function during execution of activities and operations.	
F. Monitoring (regular surveillance, testing and verification)	This describes the methods for verifying that the WBE continues to be intact and fulfils the design criteria.	
G. Common WBE	This describes additional criteria to the above when this element is a common WBE.	

Steel tubulars WBE shall be supported by cement or alternative plugging materials called an external well barrier element. The external well barrier element (e.g. casing cement) shall be verified to ensure a vertical and horizontal seal. The requirement for an external WBE is 50m with formation integrity at the base of the interval. If the casing cement is verified by logging, a minimum of 30m interval with acceptable bonding is required to act as a permanent external WBE. The interval shall have formation integrity. The internal WBE (e.g. cement plug) shall be positioned over the entire interval (defined as a well barrier) where there is a verified external WBE and shall be minimum 50m if set on a mechanical plug/cement as a foundation, otherwise 100m with minimum 50m above any source of inflow Figure 2.2 (C) and (D).

The same casing cement can become WBEs in both the primary and secondary well barriers. The acceptance criteria states there shall be 2x 30m intervals of bonded cement, obtained by logs which have been verified by qualified personnel Figure 2.2 (A). For some well activities, it is not possible to establish two independent well barriers. When a common WBE exists, a risk analysis shall be performed and risk reducing measures applied. The cement plug can be a common WBE in some situations, e.g. when a continuos cement plug is set inside casing and where the casing cement is verified Figure 2.2 (B).

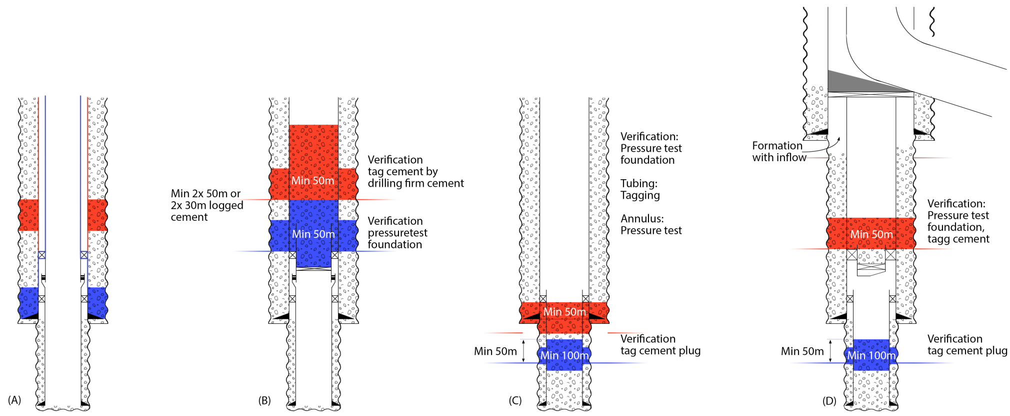


Figure 2.2: Barriers by cutting and pulling casing. Reproduced from NORSOK-D010

2.6.3 Verification and testing

When a WBE has been installed, its integrity shall be verified by means of pressure testing by application of a differential pressure, or when not feasible be verified by other specified methods [NOROK-D010, 2013]. A low pressure test to 15-20 bar for minimum 5 minutes stable reading should be performed prior to high pressure testing. The high pressure test value shall be equal to, or exceed the maximum differential pressure that the WBE may become exposed to. Static test pressure shall be observed and recorded for minimum 10 minutes with stable reading. Inflow tests should least for a minimum of 30 minutes with stable reading (or longer due to large volumes, high compressibility fluids or temperature effects).

2.7 Procedure for P&A operations

Generally, a P&A operation can be divided into three phases; Phase 1 - reservoir abandonment; Phase 2 - intermediate abandonment, and Phase 3 - wellhead and conductor removal. In the following section, a general procedure for P&A operations will be briefly described in its main components.

2.7.1 Killing the well

The first step in any P&A operation is to stop the production and thus cease the flow of hydrocarbons from the reservoir. For completed wells, this will be done through the Christmas tree (XMT), while for an exploration well it might be done through the blow out preventer (BOP) already installed. This section assumes the procedure is done on a rig with a top-side completed production well. The operation is called killing the well, and is done by pumping high-density fluids downhole through the XMT and the production tubing to the reservoir. This is normally done with bull-heading, which is the process of forcibly pumping fluids into a formation. Typically, the term bull-heading applies to any operation inducing reverse flow into the production well.

2.7.2 Wireline operations

Wireline is normally used in the pre-phase of P&A campaign to prepare the well for drilling operations. Wireline is used for pulling the downhole safety valve (DHSV), do scale removal and caliper runs if scale or debris are detected in the tubing. The hydrostatic pressure of the high density fluid, ensures overbalance against the reservoir and impede the hydrocarbons to flow into the wellbore. The high density fluid acts as the primary barrier against the reservoir and a mechanical deep set plug can be installed on wireline in the reservoir liner or the lower completion. Wireline equipment is then used to cut or punch the tubing above the production packer and displace the tubing and annulus to treated sea water (TSW). Finally, a shallow set plug is installed below the DHSV with a pump open sub to act as an additional barrier.

2.7.3 Pulling tubing

With two independent barriers installed and tested in the well, the XMT is removed and a BOP is installed on the wellhead and pressure tested. For subsea wells, completed with a horizontal XMT, the BOP is installed on top of the XMT that will be removed after the tubing is pulled. The production tubing is pulled through the BOP while control lines are removed. It is normal to do a clean-out / gauge run of the production casing to circulate out old completion fluid and potential cuttings or debris and to gauge the casing.

2.7.4 Logging cement

According to NORSOK-D010, a well barrier is required to be pressure tested, function tested or verified by other methods. For the annulus cement to be used as WBE, it must be verified by logging. It is required to log the annulus cement after the tubing is pulled if this was not done after the cement job. Using the data gathered during the well abandonment design phase, the operator has created a plan for where to install the barriers, including what depth, length and what materials they want to use. These intervals are logged using wireline to verify the cement integrity and bonding intervals. The requirements stated in NORSOK are two sections of 30m with logged cement where the cement has good bonding with formation and casing. Depending on the log results, the barrier length and placement may need to be adjusted.

2.7.5 Set and test plug

The lower barrier located closest to the reservoir is usually called the reservoir barrier. This barrier is typically installed deep in the reservoir liner or in the lower completion, expanding upwards past the production packer and into the production casing. If the plug is located in open hole, the requirements are 100m MD with a minimum of 50m MD above any source of inflow or leakage point. A plug in transition from open hole to casing should extend at least 50m MD above and below the casing shoe. For a plug in cased hole, the requirements are 50m MD if set on a mechanical or cement plug as foundation, otherwise, the requirement is 100m MD. There is a mechanical plug installed in the lower completion in the described scenario. A balanced cement plug is then typically installed with a length of a minimum 100m MD into the casing as long as there are two intervals of a minimum 30m MD with good bonding. This cement plug acts as a primary and secondary barrier to the formation.

For a permanent abandonment of the formation with a following slot recovery the P&A operation is complete if there are no other sources of inflow between the formation barrier and the kick-off point, Figure 2.2 (D). The following operation would be to install a mechanical plug below the kick-off window, install a whipstock, mill through the casing and drill the section to the new geological target. If there are other sources of inflow or the well is to be permanently abandoned, a second barrier may be required higher up in the well [NOROK-D010, 2013].

2.7.6 Expose formation

The production casing is normally installed with a deep shoe and is only cemented some several hundred meters above the shoe. If a second barrier is required to seal off shallower formations with flow potential, there may not be any annulus cement to act as WBE. Some formations, typically shale, can creep into the wellbore with time. The process is called shale creep and it is a complicated process dependent on multiple variables such as formation properties, annulus fluid, pore pressure, depth, wellbore inclination, permeability and several more. If the shale has crept into the bore hole and surrounds the casing, effectively sealing off the annulus, it is called shale potential and can be utilized as a WBE verified by logging. In other situations, the tubing has to be pulled or section milled to expose the formation and enable the instalment of a rock-to-rock barrier.

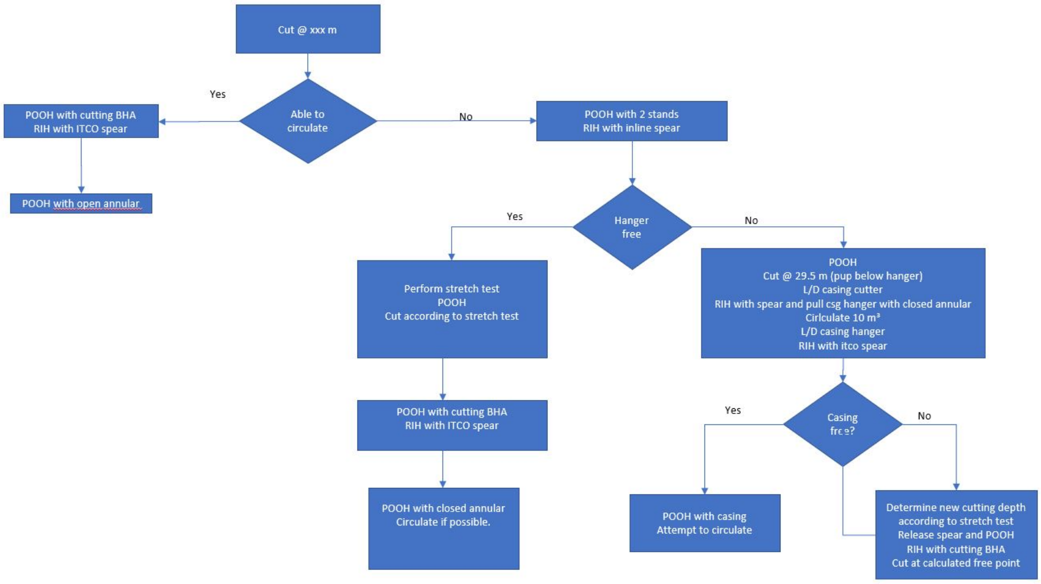


Figure 2.3: Cut and pull decision tree flowchart

2.7.7 Cut & pull operations

Depending on the depth of barrier placement, formation strength and casing conditions the operator has to decide to pull the casing or section mill a window to expose the formation. If pulling the casing is decided, a mechanical plug is installed typically 50m MD below the planned cutting depth. A bottom hole assembly (BHA) consisting of a casing cutter and inline spear are run into the well on drill pipe to cut and pull the casing. When the cutter is at the desired depth, the cutting knives are pumped open and rotation is initiated. Cutting parameters are achieved and the casing is cut. All cutting parameters are recorded and the cut is considered complete when the standpipe pressure and torque drops. An additional verification of the cut can normally be done by sound or vibration in the casing and drill pipe string at surface or at wellhead. The casing cut is verified physically by lowering the knives onto the casing stump and applying 10 tonnes on the string. The annular preventer on the BOP is closed around the string and pressure is applied in an attempt to break the annulus fluid gel strength and initiate circulation. This is called breaking the circulation and is a commonly used drilling term in drilling operations. If circulation is achieved, the annulus is circulated until there is homogeneous mud in the entire well system, namely that the mud in and out has the same properties. If the circulation is not broken a decision tree (Fig. 2.3) is used for future operations.

When circulation is not achieved the standard operation is to pull up and engage the inline spear in an attempt to pull the casing free before trying to establish circulation again. A frequently encountered challenge in casing pulling operations is that the casing is stuck and does not move when the spear is engaged and upward force is applied to the string. This is normally caused by the casing hanger being stuck in the wellhead. The standard operation procedure is to pull out and cut the casing below the wellhead hanger and then pull the hanger free. The spear is re-entered into the casing and upward pulling force is applied to free the casing. If the casing is pulled free, another attempt to circulate is done. If this fails, the casing is pulled out of the hole and circulation is attempted every couple of stands until it is achieved. All pressures used when attempting to circulate and the pressure used when circulation was achieved are recorded in the DDR. In addition, pulling force during freeing and pulling of the casing are also recorded.

2.7.8 Milling operations

If the operator decides to section mill the casing, a mechanical plug is installed below the bottom of the planned window. A BHA, with milling tools, is run into the hole to the top of the desired window. Cutting parameters are achieved and the casing is cut similarly to a regular cut and pull operation. When the casing is cut and the cut is verified with 10 tons on the casing stump, milling parameters are initiated. With weight and rotation on the string, the knife-mill the casing and the cuttings/metal shavings, called swarf, are transported to the surface. Normally the rig cutting handling equipment is not designed to handle swarf and external equipment called swarf handling units are used. This is typically modular machinery that utilizes magnets and rotating drums to remove the swarf from the fluid before it is reintroduced to the well. Swarf handling is a tedious process associated with downhole problems, HSE risks and damage to equipment such as the BOP. The operation causes excessive vibrations that could damage downhole equipment and the risk of getting stuck or tangled in long swarf string is a pressing concern. Section milling is time-consuming with typically 1-2 meters milled casing per hour. A standard 9 5/8-in casing generates 75-150 kg of metal swarf per hour that needs to be handled on the surface. The produced metal cuttings must be transported to shore and disposed of as hazardous waste. In addition, extensive swarf removal and cleaning of surface equipment, wellhead and BOP are mandatory to regain equipment operating standards and well control functionality.

When the window is milled, the swarf is circulated out of the well and all well control equipment are cleaned of swarf and function tested, the plug can be placed in the window. A balanced cement plug is typically installed with a height of a minimum 100m MD and extending 50m MD into the casing at the top of the window (Fig. 2.4). If two windows are milled the plug requirement is 50m MD extending 50m MD into the casing. Independent of the procedure used to expose the formation, the plug should be verified by tagging and/or pressure testing.

Dress off and tagging is a term used when drilling through the top of the cement plug until hard cement is reached. The top of the cement plug is normally contaminated with drilling fluids in the interface during pumping and does not set into hard cement. By dressing off the interface until hard cement is attained and weight on bit (WOB) increases, the operator knows the depth at the top of the cement plug. The plug is tagged by applying 10 tons on the drill bit to verify the cement is hard and has set according to design specifications. After tagging the well is pressurized to 70 bar / 1000 psi above leak of pressure to verify the plugs sealing ability.

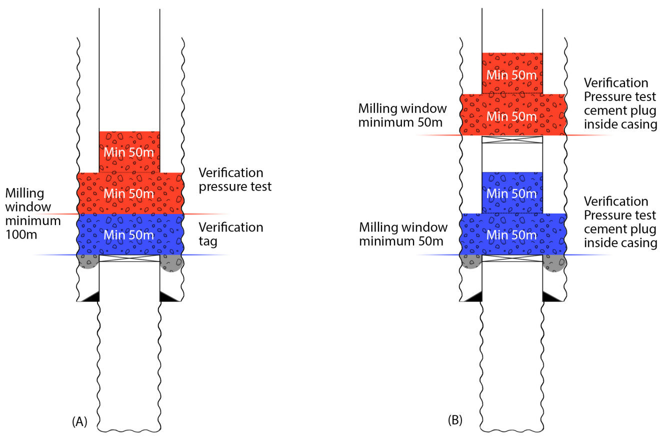


Figure 2.4: Barrier created by milling casing. Reproduced from NORSOK-D10

3 | Theory

3.1 Barite

Barite is a mineral consisting of barium sulfate ($BaSO_4$). In its pure form, barite has a specific gravity of 4.5 s.g and is one of few non-metallic minerals with a specific gravity above 4.0 s.g. High specific gravity, low toxicity, and insolubility in water and oil-based liquids make barite suitable for weighting material in drilling fluids. Barite powder used as weighting material normally contains traces of heavy metals and other lower density minerals, hence a specific gravity of 4.2 s.g is standardly used in the industry. Furthermore, barite is a thermodynamically stable and chemical inert mineral, making it unaffected by downhole conditions.

3.1.1 Barite sag

Drilling fluids are oil- or water-based fluid-solid mixtures were high-density minerals are used as weighting material to increase the fluid density. As the density of the weighting material is much higher than that of the fluid, gravitational forces act on these particles making them segregate and finally settle out of the fluid [Khalifeh et al., 2020]. Weighting material sag is a phenomenon directly resulting from the weighting material's physical properties, namely the particles' size and weight and the fluid thixotropic properties. The term "barite sag" is commonly used because barite has long been the traditional weight material for drilling fluids. However, sag can occur with any other solid weighting materials. In addition to barite, ilmenit ($FeTiO_3$), hematite (Fe_2O_3) and manganese tetroxide (Mn_3O^4) are also commonly used. Ofei et al. [2020] performed a light scattering (LS) particle size analysis that showed that API barite's particle size ranges from 0.04 μm to 200 μm. Fig. 3.1, reproduced from [Taugbøl et al., 2005], compares particle size distribution of a micronized barite slurry ($d_{50} < 2$ μm) with API barite (d_{50} 25 μm).

Barite sag is a major concern in the drilling industry. Some of the problems associated with sagging is the loss of hydrostatic pressure which can result in influx of gas or collapsed borehole, fluctuation in torque and drag, difficulty in running casing, displace-

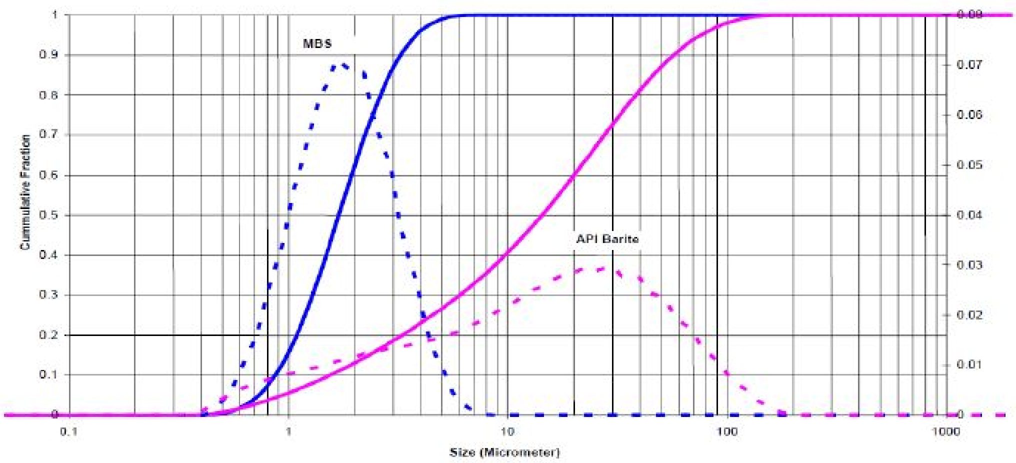


Figure 3.1: Particle-size distribution comparison of micronized barite slurry (MBS) and API barite (from Taugbøl et al. 2005)

ment inefficiency during cementing operation, lost circulation and stuck pipe [Saases et al., 1995, Therani et al., 2004, Zamora and Jefferson, 1994, Ofei et al., 2020]. Barite sag was originally thought only to be a static problem because sections with density stratifications were observed in directional wells after circulation was stopped for extended periods [Zamora and Jefferson, 1994]. The kinetics are illustrated in Figure 3.2 (left) in which suspended particles, substantially denser than the suspending fluid, settle vertically due to gravitational effects. The settling regime is divided into clarification, hindered settling and compaction regime, and the concentration of particles increases with depth. In the clarification section, particles settles individually according to Stokes law, affected only by gravity and friction forces. As the dense particles travel downwards, the less dense fluid travels upwards to preserve the fluid mass balance [Khalifeh et al., 2020]. In the hindered settling regime, the concentration is sufficiently high that surrounding particles crowd and interfere with the settling of individual particles, thereby slowing their settling rate [Zamora, 2009]. The counterflow of fluid may contain solid particles smaller than the sagging particles. Hence the sag velocity is reduced [Khalifeh et al., 2020]. In the compaction section, the particles are paced together and support each other mechanically and the fluid is squeezed upwards as the bed compacts [Zamora, 2009].

Studies with slant-tube flow loops performed by Boycott [1920] observed that settling of blood corpuscles in narrow tubes settled a good deal faster when the tubes were inclined rather than vertical. Later studies performed by Hanson et al. [1990] conclude that the same applies for barite sag in drilling fluids. Hanson et al. [1990] were among the first to identify barite sag primarily as a dynamic settling problem. Based on extensive laboratory studies, they proposed that barite beds formed while circulating, thickened when the flow was static and then slid downwards to create density variations in the fluid column [Zamora, 2009]. In a tilted pipe shown in Figure 3.2 (right), the sag will be accelerated by the so-called Boycott effect. Particles still settle vertically, although the travelling distance is reduced. The clarified layer forms quickly on the entire high side of the tube and flows upward, effectively creating an efficient and orderly means for the displaced fluid to collect and move out of the way of the settling particles [Zamora, 2009]. A study conducted by Dye et al. [1999] concluded that dynamic barite sag increased as hole angle increased from 45-60°.

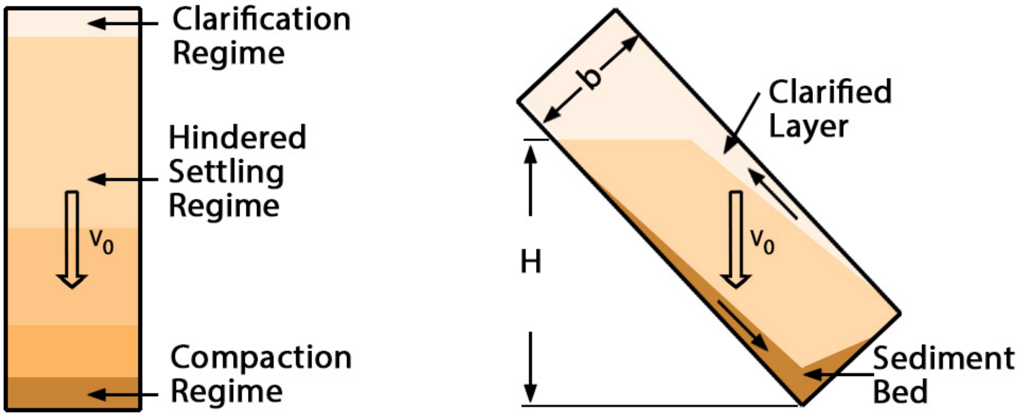


Figure 3.2: Hindered (left) and Boycott (right) settling kinetics under static conditions. (Reproduced from Zamora 2009)

Ribiero et al. [2017] performed a case study where segregation and sedimentation of barite was monitored to develop a simplified model for barite sag. The graduated cylinder methodology was used to record the evolution of the batch sedimentation process with time and are visualized in Figure 3.3. The sedimentation of a suspension initially generates four homogeneous sedimentation areas. A clear zone (A), a zone of constant initial concentration (B), a transition zone with varying concentrations (C) and a compression zone (D). Over time, the samples settled in two phases; a clear zone and a compression zone. Ribiero et al. [2017] used barite sizes ranging from 10-60μm suspended in water in order to better scan the interface decay and showed that increased particle size increased the settling velocity while increased viscosity slowed it. The study also showed that using a simplified model based on the mass and momentum conservation equitations adequately describes and simulates simplified static barite settling in vertical tubes.

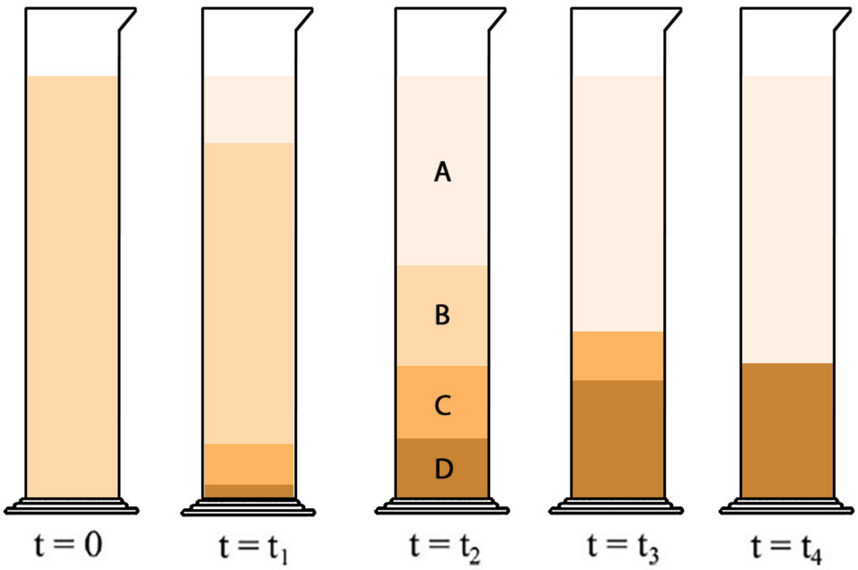


Figure 3.3: Sedimentation layers forming over time (reproduced from Ribiero et al 2017)

While barite settling has proven a complex subject to describe and model accurately, the operational result is that barite segregation and sedimentation is a challenge in several drilling operations. In the context of P&A, the static settling of barite in the annular gap between the casing and formation is a challenge in cut and pull and milling operations ref. 2.7.7. In vertical sections, the barite will eventually settle on top of the cement, and with maximum packing, the hydrostatic pressure through the column will be lost. Sedimentation of barite particles will over time accumulate with an overlaying clarified layer with density close to that of the carrier fluid. For a layer of sedimented barite particles, any force transmission will be conducted through direct particle-particle contact and may prevent pressure transmission from the overlaying fluid [Khalifeh et al., 2020]. Due to particle size and distribution, some of this force will be absorbed as friction acting between particles and the annulus wall.

3.2 Barite settlement

Saasen et al. [2011] showed using Darcy's law (Eq. 3.1) and the semi-empirical Blake-Kozeny equation (Eq. 3.2) that flow through a packed sand bed can be presented as Eq. 3.3. The factor 150 is an empirically adjusted factor that also includes the geometrical terms arising from treating flow around spheres [Saasen et al., 2011].

$$\frac{\Delta P}{\Delta L} = \frac{\mu}{\kappa} v \tag{3.1}$$

$$\frac{\Delta P}{\Delta L} = \frac{150\mu}{d_p^2} \frac{(1-\epsilon)}{\epsilon^2} v \tag{3.2}$$

In this equation μ is the viscosity, κ is permeability, v is fluid velocity, d_p is the particle diameter and ϵ is the bed non-solid fraction [Saasen et al., 2011].

$$\kappa = \frac{\epsilon^2}{(1-\epsilon)} \frac{d_p^2}{150} \tag{3.3}$$

In the unconsolidated slurry regime, the larger particles alone would leave a moderately permeable matrix, but the particle distribution results in the void being filled with smaller particles. Thus, the permeability of the system is defined by micron-sized particles. For a sand slurry, the permeability is reduced further by particles both larger and smaller. When considering a static sand slurry microstructure at a micro-scale, it acts as a liquid and will, at minimum, exert a hydrostatic head equal to the liquid phase. When considering the slurry at a macro-scale, it acts as a solid, and the pressure gradient in the liquid phase will only be "seen" by fluid entering into the pore space of the slurry [Saasen et al., 2011]. Saasen et al. [2011] explained that the slurry's resulting permeability is less than one millidarcy because the particles that control permeability are of submicron size.With such a low permeability, the migration rate through the plug is in the order of cm/yr and volumetric rates becomes negligible because of the slurry's very low effective porosity [Saasen et al., 2011]. Briefly said, the whole process is based on maximum packing, where particles create a seal and non-setting material.

A barite plug can be defined as a plug made from barite weighting materials placed at the bottom of a wellbore [Schlumberger, 2021]. Barite plugs have been used as temporary plugging material for several decades. Unlike cement, a barite plug does not set as a solid plug but can provide effective pressure isolation while regaining circulation, searching for a transition zone or tripping [Messenger, 1969]. In sedimentation theory, consolidation is defined as the process that convert sediments into rock by compaction and deposition of cement in pore spaces, or by physical and chemical changes in the constituents. Most consolidation processes are started by the precipitation of salt and other cementing minerals from the liquid phase within the voids and pores of the rock particles. These precipitations acts as a cementing agent that chemically adhere to the rock particles and locking them in place, transforming the settled particles into a solid rock. As settled barite is thermodynamically stable and chemically inert, barite does not set as a solid. After years of compaction, the settled barite may have the ability to "solidify" due to surface chemistry and electrostatic bonds but it does not set like cement. The internal electrostatic bonds increase particle to particle adhesion effectively holding the settlement together. Due to the particle size distribution of API barite, the compaction regime is defined by maximum packing and the permeability is defined by micron-sized particles similar to the sand slurry described above. When the term consolidated barite is used in this thesis, it is considered compacted based on maximum packing and electrostatic bonded but not transformed to a solid.

3.3 Identification of settled barite

Historically, three methods are used to verify isolation barriers. Pressure tests restricted to localized areas, communication tests for testing behind casing isolation and cement evaluation logs. Annulus barriers are generally located deep in the sub-surface and are impossible to retrieve to the surface for analysis [Govil et al., 2021]. Thus logging tools are utilized for this purpose. Cement evaluation logs are time-efficient, cover the majority of the casing, and are inexpensive compared to communication tests [Boyd et al., 2006]. Logging tools are the most commonly used methods to verify cement, but they are also used to determine other materials behind casings and to locate material bonding and location. A problem with logs is that interpretations do not accurately predict behind casing communications. There has been a prolonged discussion in the industry regarding the validity and reliability of such log evaluation.

Cement bond logs (CBL) is one of the earliest acoustic techniques that tried to establish the relationship between the amplitude of a sonic signal with the cement bond between casing and cement. This evolved into the variable density log (VDL), which analyses the sonic wave train received from the formation to establish an indication of the cement bond between formation and cement [Kyi and Wang, 2015]. CBL/VDL are usually run together in an attempt to evaluate the sealability of casing cement. A micro annulus is a very small annular gap between the casing and the cement that is typically caused by temperature, mud cake deposits, pipe coatings or constraining forces.

Since the introduction of ultrasonic tools in the early 1990s [Hayrnan et al., 1991], ultrasonic logging has been the preferred option because the measurement is a non-destructive technique and provides information on the cement placement behind casing and casing condition in the same run [Govil et al., 2020]. Traditional ultrasonic tools have been the Ultrasonic Imaging Tool (USIT) of Schlumberger and the Circumferential Acoustic Scanning Tool (CAST) of Halliburton. The technique delivers high-resolution images that offer the possibility to resolve narrow azimuthal features such as drill wear or narrow channels in cement present behind the casing [Govil et al., 2020]. The ultrasonic pulse-echo technique measures the acoustic impedance of the material in contact with the casing by analysing the resonance decay of an exited compressional casing node [Govil et al., 2021]. In the mid-2000s [Van Kuijk et al., 2005], the well-established ultrasonic pulse-echo technique was complemented with the addition of an ultrasonic pitch-catch configuration [Govil et al., 2021]. By angling the transducer, a flexural mode is generated which is a function of the material properties behind the casing.

"Combining the compressional and flexural modes in a cross-plot and processing the data using advanced interpretation software enables interactive zonation of log intervals and the measurement can be compared against modelled response" [Govil et al., 2021]. Case studies performed by Govil et al. [2021] show that the combined cross-plot distinguish annular material behind casing and can be visualized in a plot like shown in Fig. 3.4. The results have been validated by performing full-scale logging experiments by utilizing ultrasonic and sonic log data against reference barrier cells.

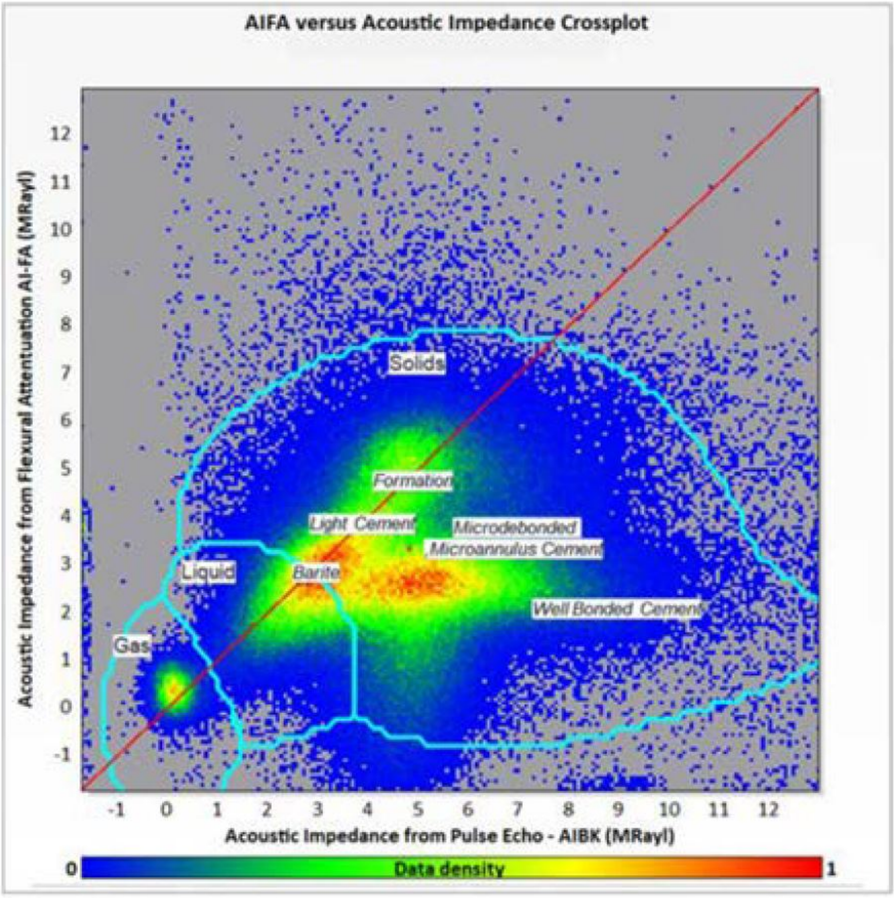


Figure 3.4: Acoustic impedance cross plot highlighting typical signature of different materials present behind the casing across a depth interval (from Govil et al 2021)

The utilization of the cross-plot technique has filled a knowledge gap that has persisted in the industry for years. By being able to differentiate the annular materials behind casing, more reliable identification and verification of potential barriers are now available to the industry. This enables operators to assess the suitability of annular barrier material and more accurately determine where to place them. If using settled barite as WBE, the innovative logging technique improves the identification of settlements and offers detailed information about compaction, density, and homogeneity.

3.4 Laboratory studies

In her thesis, Kljucanin [2019] introduced a test setup to perform pressure resistance testing of settled barite plugs. In cooperation with Equinor, she manufactured a transparent test tube of 3.5 meters consisting of 4 pressure sensors connected to two pressure gauges (in Fig. 3.5). The intention was to fill the pipe with the desired drilling fluid to simulate the natural segregation and settling processes. There was a pressure port connected to a pump in the bottom of the pipe, and the settled barite plug was to be exposed to differential pressures and analysed.

Well integrity research teams at University of Stavanger (UiS) have used the laboratory setup and test procedures proposed by Kljucanin [2019] at the University of Stavanger (UiS) to perform several tests on settled barite plugs. An article describing the findings was not yet published at the time of this thesis, but some preliminary results have been published individually. In a video posted by Khalifeh [2021], a barite plug is pressurized with gas from below in the transparent pipe setup.When the pressure exceeds the adhesive forces between the plug and the pipe's acrylic walls, the plug is moved upwards. What is interesting with this result is that it shows the settled barite moving upwards without breaking up (Fig. 3.6). This shows that the barite particles' internal adhesion is strong enough to hold the plug together.

The barite plug used by Khalifeh [2021] was composed of a barite and clay mixture similar to drilling fluids typically used in the field. The clay particles, intermixed in the plug matrix, hydrates and increases the other particles' adhesion, effectively gluing them together. With the presence of clay particles, Khalifeh [2021] has shown that a settled barite plug behaves as other plugging materials and that it is diffusion tight against gases. The low friction coefficient of acrylic glass was not enough to hold the plug in place for high pressures, but the experiment shows the suitability of settled barite. With a longer plug and materials with higher friction coefficients, such as steel and rock formations, the plug can hold higher pressures.

Figure 3.5: Test setup to analyse settled barite plugs at University of Stavanger (Kljucanin 2019)

Figure 3.6: Settled micronized barite acts as a plug when pressurized from below with gas (Khalifeh 2021)

4 | Methodology

4.1 Introduction

This thesis is written in light of methodological naturalism, namely that natural laws govern the natural universe's structure and behaviour. Methodological naturalism concerns itself with suitable methods in the acquisition and evaluation of knowledge and in identifying causal mechanisms responsible for the emergence of physical phenomena. Naturalism is based on the assumptions that the universe is objective and consistent and that reality can be accurately perceived by an observer. It is further based on the theory that rational explanations exist for elements of the real world and that humans can unlock and access these explanations with the use of rational logic and a scientific method. The methodology is the framework within which to conduct the scientific study. It is the cognitive approach to reality.

To be termed scientific, a method of inquiry is commonly based on empirical and measurable evidence subject to specific principle of reasoning [Newton, 2015]. The scientific method is a body of techniques for investigating phenomena, acquiring new knowledge, or correcting and integrating previous knowledge [Garland Jr, 2015]. It can be defined as a method or procedure consisting in systematic observations, measurements and experiments, and the formulation, testing and modification of hypotheses [Press, 2018].

A theory is a well-substantiated explanation or interpretation of the natural world based on general principles independent of the thing to be explained. Although theories can take a variety of forms, one thing they have in common is that they go beyond the phenomena they explain by including variables, structures, processes, functions, or organizing principles that have not been observed directly [Price et al., 2017]. A hypothesis is a specific prediction about a phenomena that should be observed if a particular theory is accurate [Price et al., 2017]. They are typically developed by considering existing evidence and using reasoning to deduce a specific study's outcome. For a hypothesis to have any credibility, it needs to be tested to prove its reliability.

4.2 Problem and research questions

To analyse the hypothesis that settled barite can act as a pressure barrier and eventually be qualified as a barrier element, some research questions were proposed. Two of these research questions have to be answered with empirical data.

1) Is there a relationship between the height of settled barite and an increased differential pressure needed to establish circulation through the annulus in old wellbores? To answer this question, one must identify wells where the casing was cut below top of settled barite and circulation was attempted. One can investigate the barite plug's pressure resistance using either casing logs or calculated top of barite to compare the circulation pressure to the height of barite settling. A systematic approach is needed to verify that the data does not contain errors and that there are no physical phenomena that could give pressure readings unrelated to the settled barite.

2) Is there a maximum inclination angle where the settled barite does not produce increased circulation friction due to the settling regime of barite particles in drilling fluids? By sorting the pressure data based on inclinations and comparing the results with the settlements theory in slanted tubes one can discover if there are significantly reduced circulation pressures in incline boreholes.

The theories that create this thesis's basis are the hydrostatic theories of static fluid pressure regimes in a U-tube pipe and the settling of solids in drilling mud described in the theory section. In a wellbore with drilling mud in the annulus, which has been static for several years, the barite's settling is assumed to be completed. The sedimentation regime above the top of cement is dehydrated and consolidated. The cement creates a solid foundation for the settled barite and the lower part of the settlement is assumed to be consisting of solids without a hydrostatic pressure differential. Above the settled barite a transition zone of varying density exists followed by a clear zone of light fluid going up to the wellhead. The transition zone is assumed to be small and negligible to simplify the situation.

The theory of hydrostatic says that there will be a pressure differential through the settled barite as a result of the difference in fluid density of the light fluid in the annulus and the drilling mud in the casing. In addition to the differential u-tubing pressure, there is the break-circulation pressure asserted on the standpipe resulting in increased differential pressure across the sedimentation. Data gathering from live wells where circulations were performed through cuts below barite settling is expected to give pressure data that can be related to the height of settlement. If the settled barite does not exert any adhesive forces, these pressures should not be higher than what could be expected to break a normal circulation of drilling mud with composition, density and viscosity as the one in the given annulus. On the other hand, if the barite particles do exert an adhesive force, this pressure should be higher and if the barite is moved as a plug, it should be related to the weight of the settlement.

4.3 Data gathering

The first step in data gathering for this thesis was to reach out to the petroleum industry and apply for a data acquisition license. Before an application was submitted, the data handling scope and intentions had to be determined, described, and justified. For this thesis, the data requested was slot recovery operations by cutting and pulling 9 5/8-in casings in a field where the casing program has been relatively unchanged during the field lifetime. An approval of a field with several decades of exploration and multiple rigs with more than 400 wellbores was given in December 2020. A total of 307 wells were primarily investigated for slot recovery with cut and pull operations where the 9 5/8-in annulus was circulated clean with reported pressure and circulation data.The operational wellbores were not considered because they are still in operations and no slot recovery has been started on them. The main criteria for exclusion in this phase was slot recovery by setting whipstock without cutting casing and cut and pull operations without circulations data. The first investigation revealed 72 wellbores matching these criteria.

In an attempt to follow the scientific method and be as systematic as possible and only gather data with a causal mechanism related to settlement friction, several wells needed to be excluded from the data set. A set of acceptance criteria was made to make sure the data was representative for the theories used in this thesis. The main exclusion criteria was missing data and cuts performed above top of the solids. For the 307 wellbores analysed, the average 9 5/8-in setting depth was 2400 mTVD and the length of cement was

1300 mMD. This assures that the casings were set in and cemented across similar formations with minor differences related to variations in the local lithology. The 13 3/8-in casings were primarily 72 lbs/ft P-110 with a capacity of 77.248 lpm. Some casings were of lower steel grades, but the capacity were the same. The 9 5/8-in casings were all 53.5 lbs/ft with P-110 or C-95 grade with capacity of 36.910 lpm and closed-end displacement of 46.945 lpm. Of the 22 wellbores used in the final data set, 2 of the 9 5/8-in casings were installed in water-based mud with an average density of 1.50 sg and the rest were installed in oil-based mud with an average density of 1.50 sg.

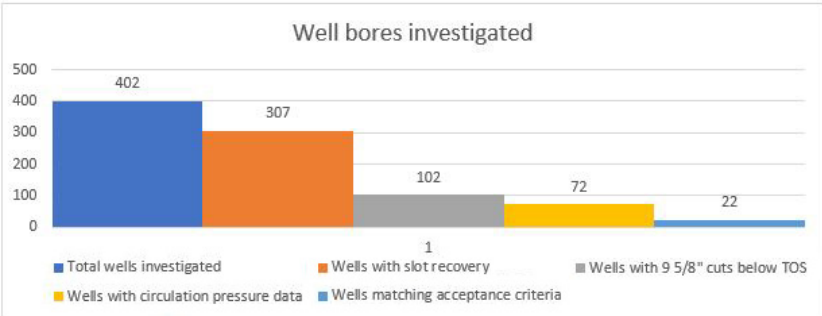


Figure 4.1: Number of wells examined during the data gathering categorized after acceptance criteria

4.3.1 Acceptance criteria

Considering the field in question has been in operation since late 1970, data reporting for several of the wells investigated were limited or non-existing. This is likely due to the fact that the reporting database was created in recent time and backlogging of old wellbores have had a low priority because they were already plugged and abandoned at this time. The data exists on old paper logs in archives but were not available for this thesis. There were also data logging of limited quality where pressures were not recorded. Due to this fact, one of the first acceptance criteria for a wellbore was the existence of casing installation data. Several data were needed to be able to calculate barite settling and top of cement, where logs are unavailable. The wellbore fluid specifications and density during casing installation are essential for barite content calculations and wellbores with missing fluid information were discarded. Cement data such as density and volumes were needed for calculation of top of cement, in addition to the casing tally detailing shoe track volumes, plug bumping and losses were also required. Wellbores without this information were also discarded.

For a wellbore to give any interesting information regarding sealability of settled barite, the cut used for circulation and differential pressure logging must be located below the top of barite or settled mud solids. Most of the wellbores investigated were missing top of solids logs and theoretical calculations were used to determine top of solids. Nevertheless, cuts above theoretical top of solids were discarded from the final data sets. However, they were used for verification of the theories and formulas used in U-tubing and circulation pressures because many of them had successful circulations.

Several data such as standpipe pressure, cutting torque, and hook-load are reported during cutting operations. The cut is normally verified with a drop in standpipe pressure and physical verification with sound or movement in the pipe at wellhead. As an additional verification, the cut is normally located with the cutting knives and several tons are set down on the cut. Cuts that were not verified and the following pulling operations showed excessive over-pull were discarded from the data set. After a verified cut, the drill pipe is withdrawn upwards in the casing before the spear is engaged and the casing is pulled free. It is normal to expect some over-pull from barite settling drag when pulling the casing free, but excessive over-pull or over-pull with no movement of the casing is associated with stuck casing or tight spots creating excessive drag. If the casing does not move, it is normally stuck in the wellhead hanger and this can be solved by cutting below the hanger and pulling this free before re-engaging the spear and pulling the casing. Wellbores with excessive over-pull and stuck casings that were unresolved by cutting and pulling the hanger were discarded from the data set. This was done to avoid inaccurate pressure data due to tight spots creating increased circulation friction. Such data could overestimate the settled barite's sealing capability and give unrealistic results. An exception to this rule was used when the clean-out run following a pulling operation did not show any tight spots or under-gauged holes, but instead reported large amounts of barite settling corresponding with stretch calculations. If down hole power tools were used, the wellbore was discarded nonetheless.

After a cut is verified and the casing is pulled free, the normal operating procedure is to close the BOP or annular around the drill pipe and pressurize the casing to establish circulation. To break the gel strength of the old annulus mud a given pressure is required. The casing is pressurized to a maximum allowable pressure, limited by the casing burst pressure, plug pressure or formation leak of pressure in an attempt to break circulation. This break-circulation pressure is normally reported regardless of whether circulation was broken or not. When circulation is broken the standard procedure is to report the break-circulation pressure and the circulation pressures used when cleaning out the annulus. The break-circulation pressure is the one used in the data set whether circulations were broken or not. If this pressure was missing in the reports, the wellbore was discarded because the differential pressure across the cut could not be calculated.

The final acceptance criteria was that settled barite was reported on the pulled casing or over shakers, no hard cement reported on the casing that could have produced tight spots during pulling and that there were no excessive drag during casing pulling.

4.3.2 Casing data

The well data used in this thesis were mainly gathered from the operators well databases, which is a composition of DDR, program records, operation reports and logs. The initial data gathering for a wellbore started with reading through the DDR and finding 9 5/8-in casing information. This information contains casing setting depth and year of installation. Casing dimensions were found in the casing program and drilling fluid used during installation was found in the DDR or the fluid reports. Casing depths are normally reported in meters measured depth (mMD) and to be able to correlate this to true vertical depth (mTVD), the gyro survey for the completed wellbore was downloaded and stored together with the casing data. A linear interpolation script was written, which used gyro data to correlate mMD to mTVD.

Start *	End *	Duration *	End Dep.. (m)	Conv	Activity code *	Hole	Downtime/ Waiting	Description
12 1/4" autogenerated TASK Previous day ➔ Next day								Drilling - 12 1/4" Duration: 459:00 Completed: 100 %
00:00	06:00	6:00	2772	DP	CASING - RUN CASING - U			CONT TO RIH WITH 9 5/8" CSG FROM 1983M TO 2772M. FILLED CSG EVERY 5 JNT AND BROKE CIRC AT 2593M.
06:00	16:30	10:30	3956	DP	CASING - RUN CASING - U			RIH WITH 9 5/8" CSG FROM 2772M, FILLED EVERY 5 JNT AND BROKE CIRC AT 3140M AND 3575M. P/U CSG HANGER AND LANDING STRING AND LANDED 9 5/8" CSG WITH SHOE AT 3956M.
16:30	17:30	1:00	3956	DP	CASING - RIG UP/DOWN TO R...			R/D CSG SLIPS, TAM PACKER AND M/U CMT HEAD.
17:30	00:00	6:30	3956	DP	CASING - CIRC/COND PRIOR ...			CUT MW FROM 1.63 SG TO 1.60 SG AND COND MUD.

Figure 4.2: DDR snippet from Equinor's DBR database. Well no.135 9 5/8-in casing installation record

Sample time	Sample depth (m)	Fluid system	Fluid type	Sample point	Mud weight (g/cm3)
06.11.1993 05:00		INTERD. MVO-FG	Oil based	Active pit	1,64
06.11.1993 14:00		INTERD. MVO-FG	Oil based	Active pit	1,64
06.11.1993 23:00		INTERD. MVO-FG	Oil based	Active pit	1,60

Figure 4.3: Fluid report from the day of 9 5/8-in casing installation in well no.135

4.3.3 Cementing

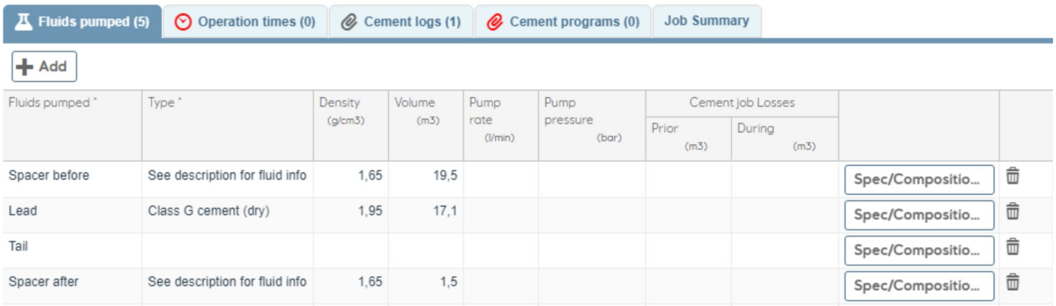
When casings are installed in the well, they are cemented to the formation. A barrier between the continuing wellbore and the annulus is created by the cement. This secures the casing in place and increase the stability of the shoe and integrity of the well. Cement is pumped down the casing, into the shoe track and up in the annular gap between the casing and the formation. During displacement, a pressure build-up is normally seen as the cement starts rising in the annulus due to the U-tube effect. Volume pumped and return from the annulus is closely monitored together with pump pressure to detect losses. For the 9 5/8-in surface casing investigated in this thesis, the cement was generally placed around the shoe and several hundred meter up the hole.

In P&A operations, TOC and cement quality are important information and are used in the decision-making process for barrier placement and cut or milling depths. There are several ways of determining TOC where calculations and logging are the most commonly used. Not all cement jobs are logged, especially if they are not part of the well barrier envelope on the finished well or the cement placement went in accordance with design specifications. Of the 22 wellbores used in the data set, only four were logged. TOC for the other wellbores was calculated. To be able to calculate the theoretical TOC, several sets of data are needed that can be found in the DDR, the casing program and cementing report. Hole dimensions, casing dimensions, capacity and closed-end displacements (CE)[1] are used in the volume calculations. Cement volume, volume of losses and pressure data are used in displacement calculations.

Wells drilled with current technology is normally in gauge, meaning that the diameter of the hole is in accordance with the bit diameter and the hole volume can be calculated with simple geometric formulas. Wells drilled before 1990 were generally drilled with mud motors and are typically over-gauged producing a larger hole volume than what would be expected from a gauged hole. All the 22 wellbores were drilled with 12 1/4-in bit producing a 12 1/4-in gauged hole or a 14-in over gauged hole for wells drilled prior to 1990 or with a mud motor. The reason for using 14-in over gauged hole diameter is that this was the commonly used empirical diameter according to the operating company.

Volume of cement pumped during a cement job can be found in the cement report. In

[1]Closed-end displacement is the total volume displaced by a closed-ended casing or pipe submerged in liquid. Closed-end displacement incorporates the steel displacement and the casing or pipe's internal capacity.



Fluids pumped (5) | Operation times (0) | Cement logs (1) | Cement programs (0) | Job Summary

Add

Fluids pumped *	Type *	Density (g/cm3)	Volume (m3)	Pump rate (l/min)	Pump pressure (bar)	Cement job Losses Prior (m3)	Cement job Losses During (m3)		
Spacer before	See description for fluid info	1,65	19,5					Spec/Compositio...	
Lead	Class G cement (dry)	1,95	17,1					Spec/Compositio...	
Tail								Spec/Compositio...	
Spacer after	See description for fluid info	1,65	1,5					Spec/Compositio...	

Figure 4.4: Cement log and report for 9 5/8-in casing in well no.135

addition, the density of the lead and tail cement, displacement volume, losses and pressure curves are also recorded. By using the reported volume of cement pumped (V_c) subtracting shoe track volumes (V_{ST}) and losses (V_L) an annulus cement volume is calculated. The available annulus volume is the open hole capacity (C_{OH}) with the closed end displacement (V_{CE}) of the casing subtracted, and thus the equivalent annulus cement column (H_c) can be decided.

$$C_{OH} = \frac{\pi}{4}(D_{Bit} \cdot 0.0254)^2 \cdot 1000 \quad [l/m] \tag{4.1}$$

Where C_{OH} [l/m] is the capacity of the open hole and D_{Bit} [in] is the outer diameter of the bit

$$H_C = \frac{(V_c - V_{ST} - V_L) \cdot 1000}{C_{OH} - V_{CE}} \quad [m] \tag{4.2}$$

$$TOC = W - \frac{(V_c - V_{ST} - V_L) \cdot 1000}{CAP_{OH} - CE} \tag{4.3}$$

$$TOC = W - \frac{(V_c - V_{ST} - V_L) \cdot 1000 - (S - W) \cdot (CAP_{OH} - CE)}{CAP_{13} - CE} \tag{4.4}$$

In Eq. 4.2; H_C [m] is the height of cement, V_c [m^3] is the volume of cement pumped, V_{ST} [m^3] is the shoe track volume, V_L [m^3] is the volume of the loss . Additionally in Eq. 4.3 and 4.4; TOC [mMD] is top of cement in , CAP_{OH} [l/m] is the capacity of the open hole from Eq. 4.1, CAP_{13} [l/m] is the 13 3/8-in capacity and CE [l/m] is the 9 5/8-in closed end displacement. W [m] is the depth of 13 3/8-in window, S [m] is 9 5/8-in shoe depth.

For cement columns that are longer than the open hole section and reach into the

13 3/8-in casing, the capacity of the 13 3/8-in casing has to be used to calculate a new annulus volume. The calculations are similarly straightforward, but the cement column has to be divided into two sections. If there are any losses recorded during the cement displacement, it must be evaluated if the loss was deep or shallow. Losses are reported when volume pumped are not in accordance with return from the well. A study of the pressure curve can determine if the expected U-tube pressure develops according to theory or breaks off during displacement, indicating a deep loss. A deep loss would happen if the cement column's hydrostatic pressure exceeds the fracture pressure of the formation at the shoe and thus, the formation fractures and cement is lost. A shallow loss are more common because the shallower formation generally has a lower fracture gradient and the spacer or shallow cement is lost to the formation higher up in the well. For a shallow loss situation the V_L is disregarded from the equation above and the loss is estimated to be mainly spacer and mud.

Theoretical cement calculations will never be exactly accurate and should only give an indication of where TOC is located. This is owning to the fact that the wellbore dimensions could vary throughout the drilled section, flow regimes during displacement will create a cement / mud interface that could result in cement higher than theoretically calculated and that there is no certain way to estimate the exact depth of losses. In view of this fact all cement jobs should be logged to correctly determine the TOC. However, the calculations used above have been verified with logged data and for wells without losses the calculated TOC is within a few percent of logged values. Only one of the wells used in the data set had losses during cementing, and the loss was assumed to be shallow in the drilling report.

4.3.4 Top of solids

Top of solids (TOS) is a term used to describe the height of accumulated settlements in the annular gap outside the casing. When the TOS is calculated, it is assumed that the solids have segregated and settled in the settling regime described in Sec. 3.1.1. Barite settlement can be identified with logging as described in Sec. 3.3, however logging of settled barite was not commonly done in the early oil and gas industry in Norway. Several of the wells examined in this study did not have TOS logged.

Theoretical TOS can be estimated to a certain degree with mass balance equations. As long as barite is the only solid in the liquid the mass balance equation takes a simple form, but when there are several solids and chemicals added to the fluid as is normal for drilling mud, detailed information about additives and amount is needed to do calculations. In a typical P&A design, light fluid density is taken to be that of the carrier fluid. The heavy fluid density is the average of the weighting agents and other added solids and chemicals that will segregate and settle over time. This is considered accurate enough to estimate the top of solids and coagulated mud in the planning phase. The initial TOS calculations used in this data set implemented the same assessment and used the density of the carrier fluid as light fluid density and a heavy fluid density of 2.00 s.g. This number is the commonly used high density number by the operator on the field investigated. Using a high fluid density of 2.00 s.g will encompass the barite, bentonite and other solids that may be present in the mud. However, it will also create a theoretically higher column of solids and coagulated mud than what can be used to evaluate consolidated barite.

There will be a mix of the individual solids, originally suspended in the drilling mud, in an annular column of settlements. As a result of the settling regime and density of the different solids, they will segregate and settle in a different time frame and the bottom of the column will hence be dominated by barite settlement. However, the sedimentation bulk will not reach densities as high as the pure un-grinded barite due to microporosity, particle distribution and heterogeneity. In the complex environment with mixtures of different solids, settling with different velocities, it is expected that the density increase with depth, but this is complicated and inconvenient to calculate within the scope of this thesis. Thus the top of solids were calculated in a two step process. Initially, the available annulus volume from the TOC was calculated using open hole and casing capacities. The volume was divided into a light clear layer using Eq. 4.5, which represents the clear layer in Fig. 3.2 $t=t_3$. With Eq. 4.6 the volume of heavy fluid is found, represented by the two lower layers in the figure. The process is done a second time using the heavy liquid volume to divide this into two new layers, one of consolidated barite with a density of 3.00 s.g and one with wet coagulated bentonite settlements with a density of 1.15 s.g.

$$V_L = \frac{\rho_H - \rho_m}{\rho_H - \rho_L} \cdot V_A \quad [m^3] \tag{4.5}$$

$$V_H = V_A - V_L \quad [m^3] \tag{4.6}$$

Where V_L [m^3] is the volume of the light fluid , V_A [m^3] is the annular volume from TOC to the wellhead hanger, ρ_H [s.g] is the density of the heavy fluid, ρ_L [s.g] the density of the light carrier fluid and ρ_m [s.g] is the density of the mud used during installation.

The result of the calculations are visualized in Fig. 4.5 where the bottom of each column represent the TOC. Though several cuts were performed, the deepest cut is that of primal interest because this is where circulation is done through the lower settlements. The mentioned data was gathered from all the 307 wells in an attempt to verify the calculations with logs. Several wells were logged both with TOC and TOS but only after all the data was gathered, and calculations were completed, the cut depth and wellbore suitability were evaluated.

4.3.5 Pressure data

When a casing is cut, the cut connects the casing and annulus creating a U-tubed system. Owning to the different composition of the fluid in- and outside the casing, a pressure differential exists across the cut. This pressure differential can potentially transfer pressure through the cut and if propagated to the surface and registered by pressure sensors, it is commonly termed U-tube effect. When the cut is completed, the driller observes the surface pressure sensor for a pressure increase to verify the U-tube effect. If no pressure is observed, it is recorded that the cut did not generate any U-tube effect, and similarly if pressure is observed, this is recorded in the drilling report.

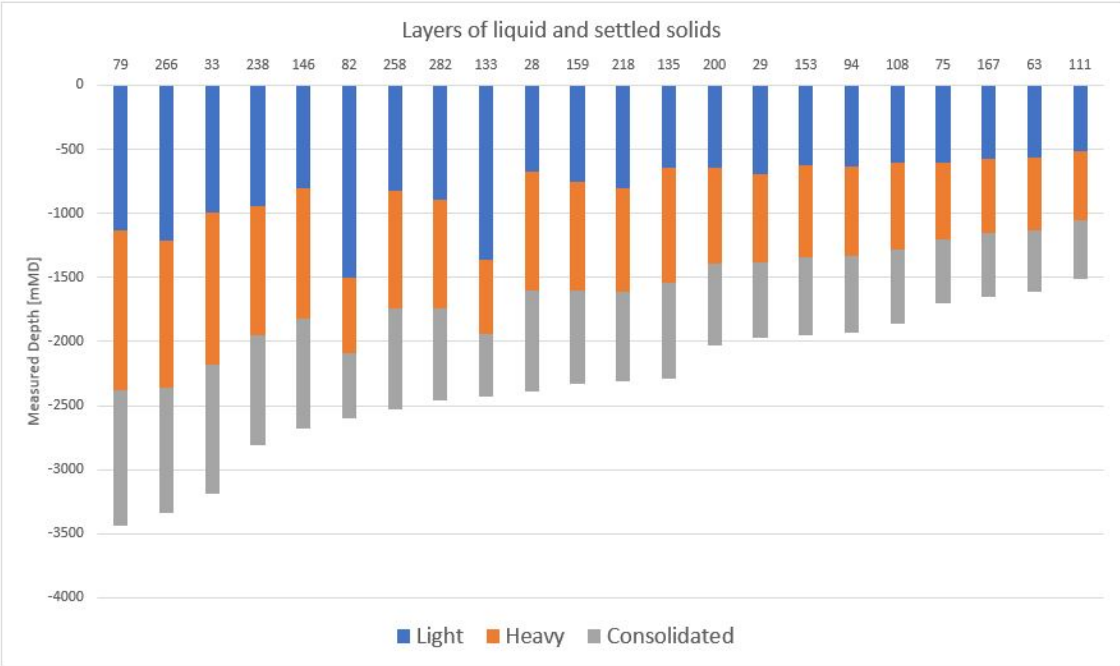


Figure 4.5: Annulus fluid divided into different settlement layers in the wellbores used in the final data set

The U-tube effect will always be present across the cut even though it is not propagated to the surface. The pressure can be blocked by settlements, tight spots or other phenomena hindering pressure propagation through the annulus. Nevertheless, the U-tubing effect applies pressure on the settlements and should be considered in the final pressure regime across the cut. Inside the casing, there exists a controlled environment with homogenous mud with know density. Thus, the hydrostatic pressure inside the casing is known. In the annulus, the mud is a mixture of the old installation mud and cementing spacer and several interfaces. In addition, the solids have segregated and settled over time creating a layered column of increased density with depth. To simplify the situation while simultaneously trying to have a high degree of accuracy the multi-layered model described above was used. The clear layer was given the density of the carrier fluid. This is verified by reports after circulation, where mud weight samples record the light density. The second layer or interface between the barite and the light fluid is given the density of wet bentonite, which is reported to be 1.15 s.g. The final layer, which is assumed to be consolidated barite, does not have a hydrostatic column.

The annulus hydrostatic pressure was calculated with the given densities and true vertical depths gathered from the TOS calculations and interpolated with the gyro data. In situations where a higher cut was performed, continued by a pulled casing and a clean-out run, the top of the column was adjusted and a new column of casing mud was introduced. This would be the same as to adjust the column top of both annulus and casing to the depth of the overlying cut. This is owing to the fact that the overlying column of casing mud would create the same hydrostatic pressure in both casing and annulus.

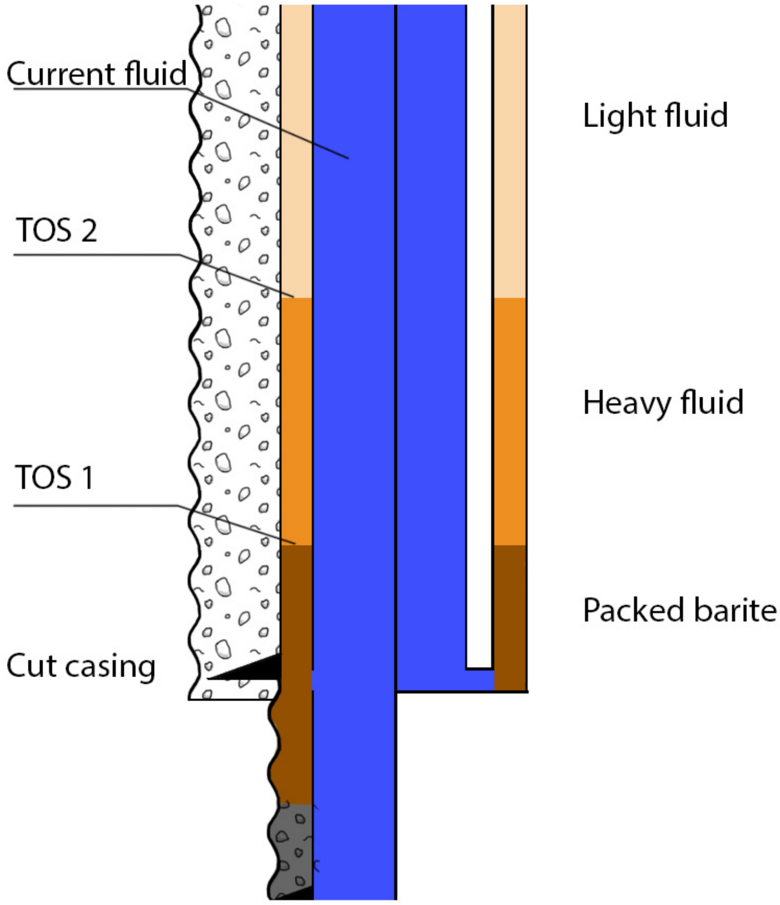


Figure 4.6: U-tube effect between casing and annulus divided into different layers of mud density

$$dP_U = g \cdot \left[\rho_m \cdot H_{cut} - (\rho_L \cdot H_L + \rho_H \cdot H_H + \rho_c \cdot H_c)\right] \tag{4.7}$$

Where H_{cut} [m] is the depth mTVD to the casing cut, ρ_L [s.g] is the density of the light fluid, H_L [m] is the depth (mTVD) of top of solid, ρ_H [s.g] is the density of the heavy fluid 1.15 s.g, H_H [m] is the depth (mTVD) of the consolidated barite minus top of solid, ρ_c [s.g] is the density of the consolidated barite 3.00 s.g and H_c [m] is the depth of cut (mTVD) minus top of consolidated barite.

After the casing has been cut and potential U-tubing effect have had time to propagate and be registered, the casing is pressurized in an attempt to break circulation. This is done by closing the BOP and applying pressure to the casing. The maximum pressure is dictated by the weakest part of the well, being the deep set plug pressure, the formation leak off pressure or the casing burst pressure. Typically, the maximum pressure is limited by the fracture pressure of the formation exposed in the annulus and thus pressures high enough to break circulation can be challenging to reach. Often the casing is pressurized to maximum pressure without any effect on the settlements in the annulus. Due to the limitations listed any other pressure data points are unavailable. The barite settlements could potentially hold pressures much higher than what is seen in the data set. If circulation is not achieved, the casing is pulled several joints before a new break-circulation is attempted. The cut bottom and cut top is therefore moved and a new hydrostatic column is calculated. In the calculations it is assumed that the settlements do not move with the casing reducing the hydrostatic pressure of the settlements. This is not hundred percent accurate, and in real life some of the settlements that has adhered to the casing wall is pulled out of the hole as seen in Fig. 4.7. However, this is impossible to calculate and thus any additional pressure readings have uncertainties. It is important to note that this uncertainty is in the favour of the plug because removal of solids would reduce the pressure, while a calculation would not. This means that the break-circulation pressure is calculated lower than what would be realistically accurate.

The pressure used in the break-circulation attempts are recorded in the DDR and are used as an additional pressure on the casing side. Together with the U-tube pressure it gives the total differential pressure acting across the consolidated barite. This pressure data was plotted together with height of settlements (mMD) in an attempt to find any correlation between differential pressure and plug length.

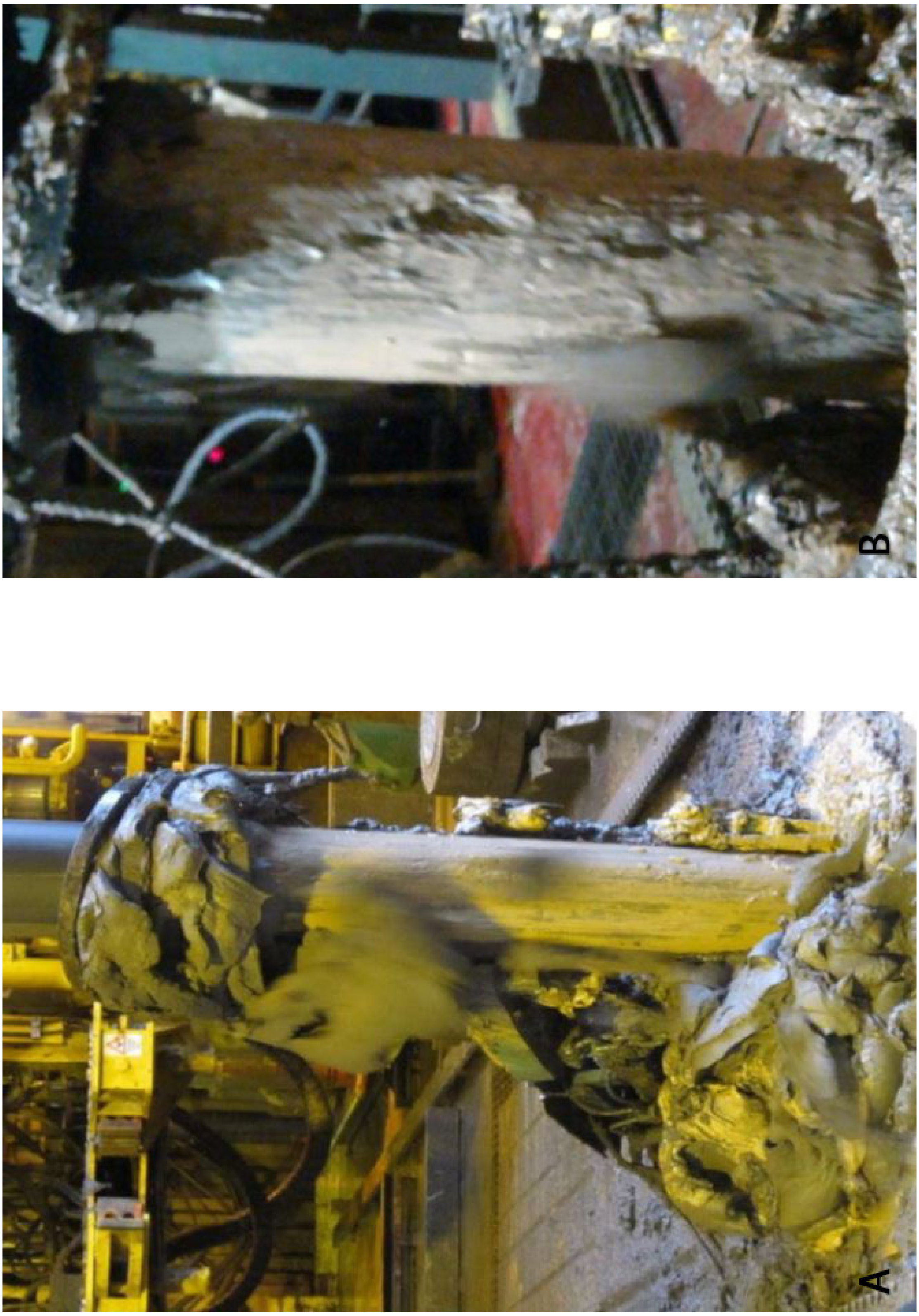


Figure 4.7: A: Consolidated barite seen sticking to the casing wall during pulling casing to surface. (Equinor 2011). B unconsolidated barite sticking to casing (Equinor 2020)

5 | Analysis, results and discussion

5.1 Data analysis

5.1.1 Challenges with segmentation

One of the challenges with the initial data analysis was determining the length of settlements used in the pressure calculations. This information is important because it gives inputs to the U-tube effect, that for some of the wellbores constituted a considerable pressure. The settlements' initial segmentation used a heavy fluid density of 2.00 s.g, which was the operators' preferred number for the field in question when doing TOS calculations. This number corresponded well to USIT/CBL log interpretations of TOS but does not separate the solids into layers of different densities. By initially using this number a scatter plot (Fig. 5.1) of circulation length vs pressure was created where break circulation pressures were marked in blue and unsuccessful circulation pressures marked in orange.

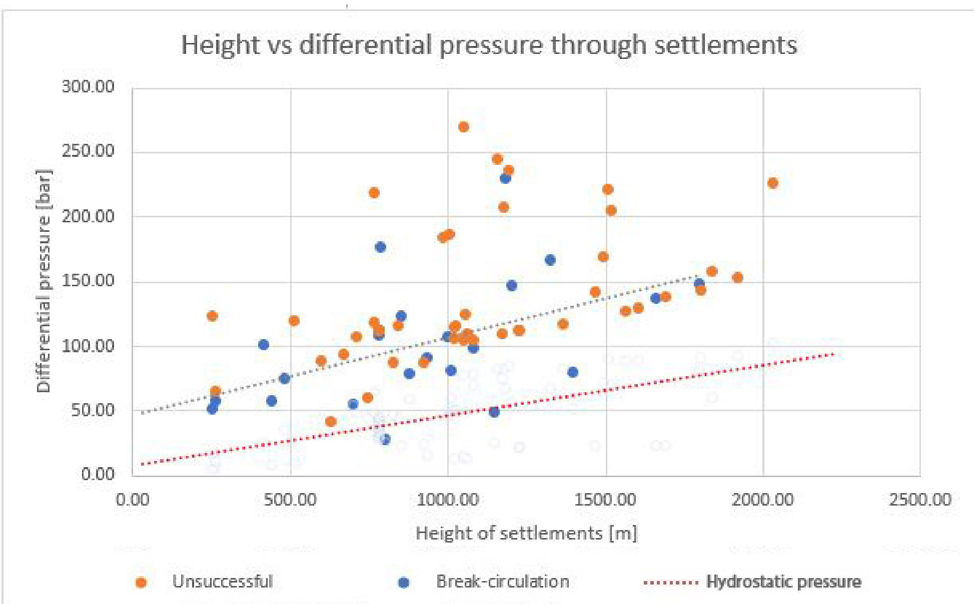


Figure 5.1: Data points of circulation pressures vs height of settlements using 2.00 s.g as heavy fluid in settlement calculations

The plot in (Fig. 5.1) shows pressure differential through the entirety of the settlements. It offers a clear trend that the pressure needed to break circulation is noticeable higher than the hydrostatic pressure exerted by the solids (red line). This confirms that friction forces exist between the settled solids and the casing wall but do not give any information about the pressure resistance of the packed barite. Using the three-layer model and assuming an average density within each of the layers, a more comprehensive picture was achieved. After years of compaction, the settled barite may have the ability to solidify due to surface chemistry and electrostatic bonds. This was verified by records where casings pulled to the surface had dry and hard barite sticking to the casing surface. An example of logged packed barite can be seen in Fig. 5.11 label B. There certainly exists a hydrostatic pressure gradient through the two upper layers, but if and where the hydrostatic column stops is hard to predict for the wellbores that were un-logged. Therefore, it is assumed that the paced barite, represented by the grey layer in Fig. 5.2, does not have a hydrostatic column through it. Future calculations assume maximum packing and consolidation, prohibiting a continuous hydrostatic column through this layer. The hydrostatic pressure through the light fluid used the light fluid density and the hydrostatic pressure through the heavy fluid used the density of wet bentonite. As earlier described, settled barite that is not compacted acts like an unconsolidated sand slurry. Mixed with bentonite and other precipitated mud solids, this layer is composed of even finer particles enhancing that effect. Even though there is a hydrostatic column acting through the slurry, the permeability due to maximum packing is negligible and it could potentially be used as a barrier. Therefore, circulations through only these layers are still considered in the data set. The black line in Fig. 5.2 represents the deepest cut done on the individual casing.

5.1.2 Correlation between length and pressure

The initial question postulated in this thesis was whether there exists a relationship between the length of a settled barite plug and the maximum pressure the plug can withstand. It would be interesting to investigate if there existed a linear relationship between the plug length and pressure resistance. With this information, it would be able to predict a plugs pressure resistance based on its length. To be able to achieve this, pressures should be applied until the plug fails and then the length of settlements and pressure applied recorded. Ideally, the circulation path should only go through the settled solids and

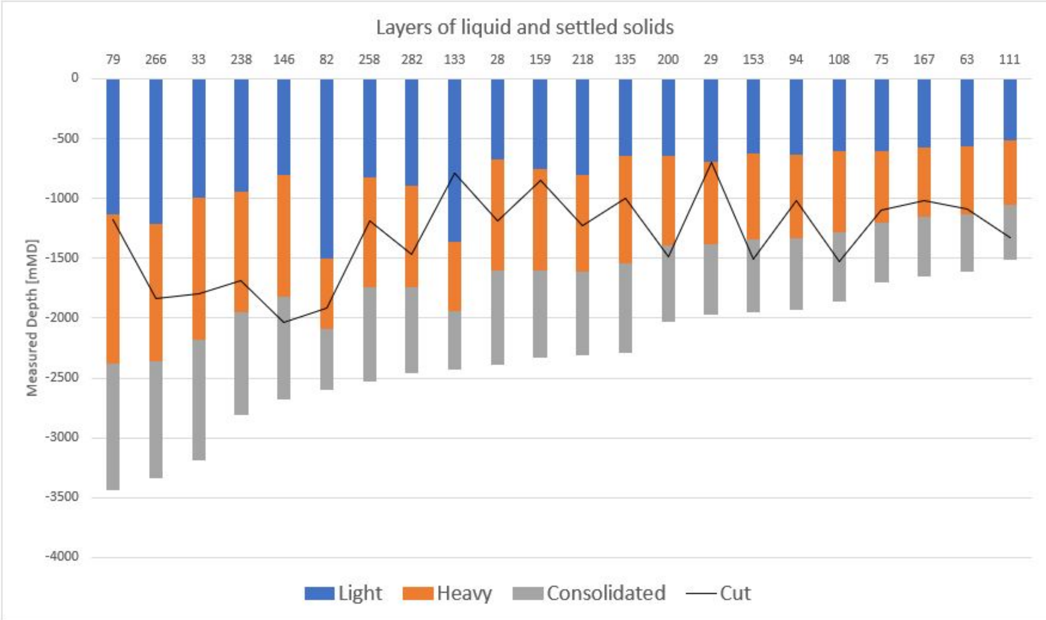


Figure 5.2: Each wellbore divided into a three layer model with a clear layer, coagulated mud and solids and packed barite at the bottom.

not extend into the clear layer. Field circulations through cut casing are limited by where the cuts are performed and the maximum allowable circulation pressure that typically represents the formation fracture pressure. Owing to this fact, most of the circulation pressures obtained in the data gathering did not initiate circulation of the behind casing settlements. Additionally, they often extended hundreds of meters through the clear layers. Whenever a field circulation failed, the casing was pulled several joints before pressure was reapplied and a new circulation attempt initiated. This operation creates two data entries, one where the length was measured from the original cut to TOS and one where the cut was moved upwards, reducing the column's height to be circulated through. However, pressure points that did not break circulation do not give any information of the maximum pressure the plug can withstand, but only proves it can withstand the pressure applied to it. The plug's pressure resistance could be much higher than what was recorded in the data set, and thus correlating pressure resistance per unit length of the plug makes no sense for the unsuccessful circulation attempts.

Using the three-layered model, all the circulation attempts were segmented and calculated. Fig. 5.3 presents the composition of the different circulation attempts and the total circulation length. Black dots represents the circulation pressure above hydrostatic in the annulus. This pressure can be viewed as the pressure needed to overcome the friction between the settlements and the annulus walls. This is because the hydrostatic pressure from the column of settlements has been subtracted from the casing pressure. Fig. 5.2 clearly shows that most of the cuts were done above the packed barite, which is not surprising. With all the problems associated with pulling casing through settled barite, it is understandable that the operator would try to avoid the deepest layers with the highest density of solid settlements. The depth of cut is a thorough consideration of how deep the kick-off point have to be, not to collide with other wells and to leave room for future slot recovery while simultaneously providing formation strength for a permanent barrier. On another side, the operator must consider the risk assessments and economic considerations with pulling a deep casing through settled barite that may be time-consuming. However, all these cuts had reports of high amounts of settled barite on casings during pulling operations and high amounts of settled barite over the shakers on the subsequent clean-out run. This shows that the three-layered model is conservative and that there exists settled barite high up in the heavy mud column. Most likely. this barite is unconsolidated but still exerts high friction on the casing and formation, effectively holding more pressure than what should be expected of a pure hydrostatic column.

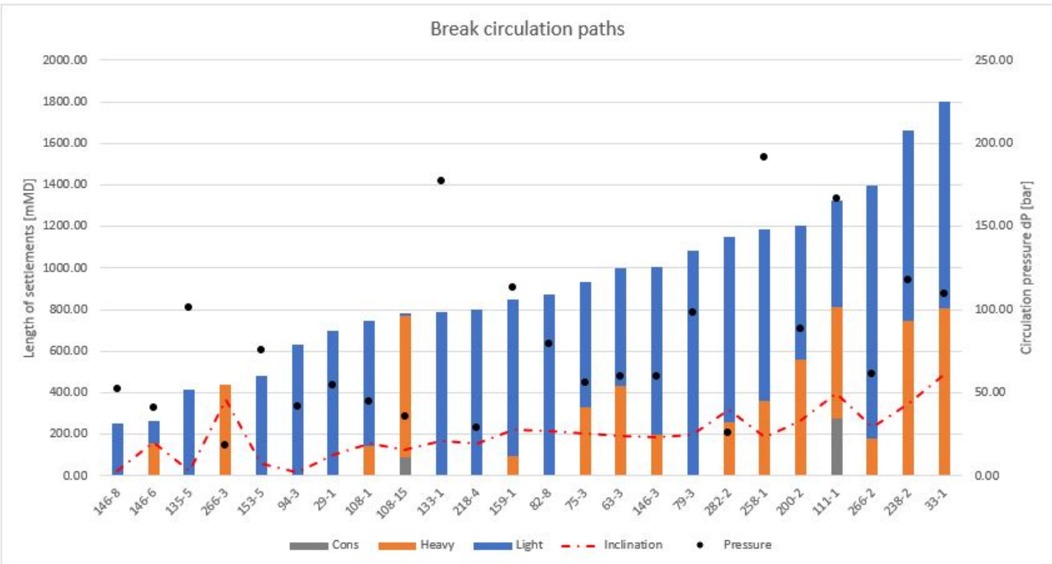


Figure 5.3: Circulation paths showing length of circulation with segmentation of different densities. Black points are the circulation pressure.

Fig. 5.4 presents the differential pressure points for all break-circulations plotted versus the length of settlements. It is important to note that this is a differential pressure, meaning it is the pressure above the hydrostatic pressure in the column of settled solids. This pressure represents the settlements' internal friction and the friction between the

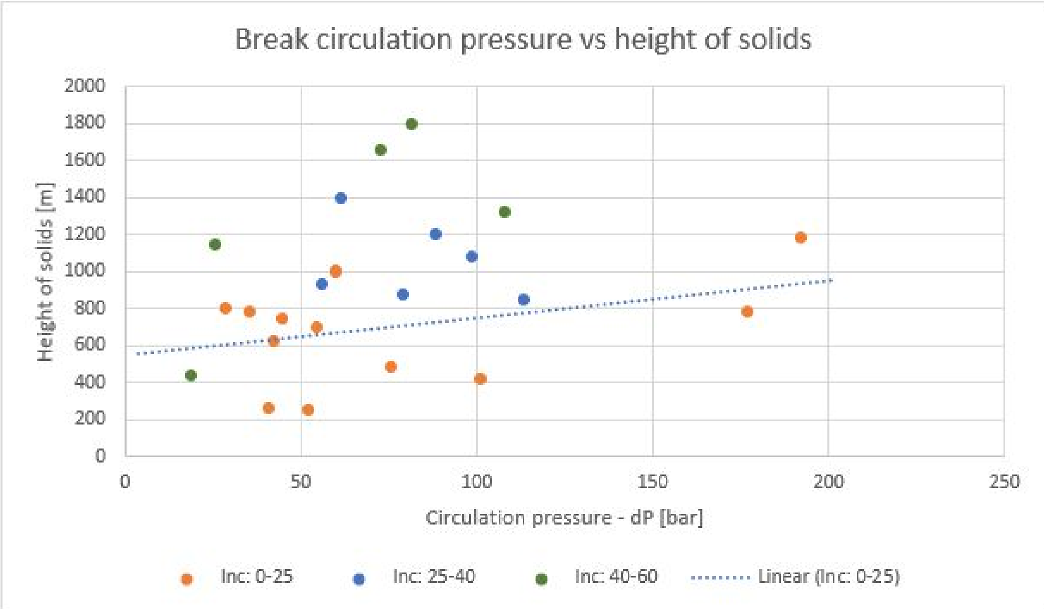


Figure 5.4: Data points for circulation pressures vs height of settlements using the three layered model where the light fluid density is that of the carrier fluid, mid layer density is 1.15 s.g and the lower layer density is 3.0 s.g.

settled solids and the annulus walls. The plot is divided into segments of inclination and one can see a trend indicating that higher angles of inclinations requires a lower pressure to circulate a longer path of settled solids. Unfortunately, there are too few points to get any decent correlation between pressure and length of settlements. A weak trend indicates that longer circulation paths require higher circulation pressure as was expected, but the R^2 value of 0.2 does not give a usable correlation.

5.1.3 Usability of the plug

Fig. 5.5 and Fig. 5.6 presents the circulation path and pressure calculations of the differential pressure above hydrostatic applied to the failed circulations. As mentioned above, the pressure points for failed circulation does not give any information of the maximum pressure the barite plug may withstand, so it can not be used for correlation. However, it shows what pressure it can withstand. Again, this pressure represent the friction forces in the solid settlements after hydrostatic pressure from the solids' column and weight are subtracted. In section 2.4 the requirements for a well barrier are listed. One of these requirements is that the barrier must withstand the maximum anticipated differential pressure it may become exposed to. This implies that the differential pressure is based on a

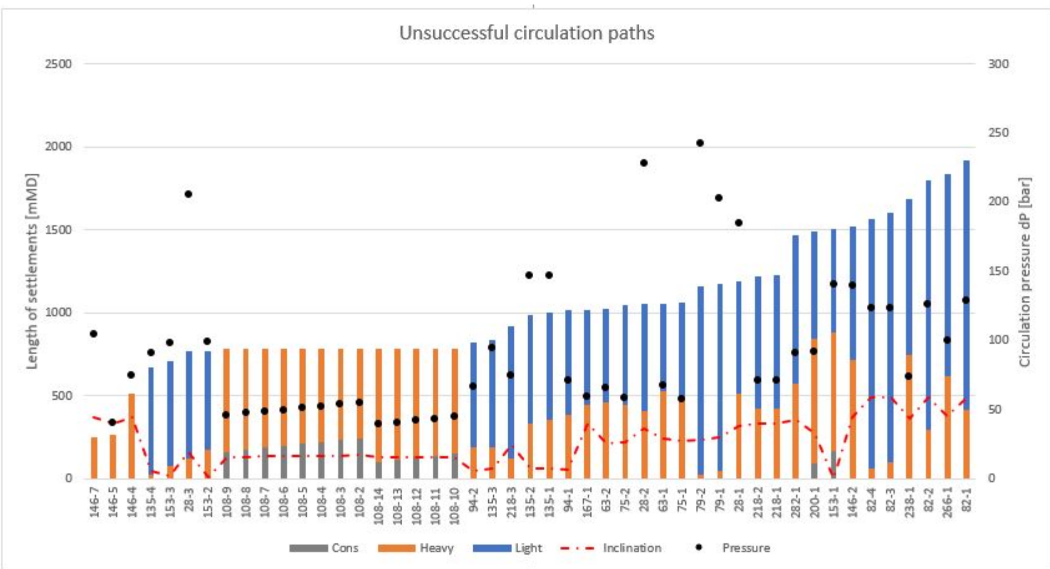


Figure 5.5: Circulation paths or length of circulation with segmentation of different densities.

worst anticipated reservoir pressure due to natural re-pressurization to initial virgin level, and lowest anticipated fluid density for the abandonment period.

For the reservoir investigated in this thesis a future reservoir pressure of 350 bar is expected with a formation fluid of 0.75 s.g. With the given predictions this would produce a maximum pressure under the plug equal to $P_{res} - g \cdot \rho_{res} \cdot dH_{res-plug}(mTVD)$. By adding the settled column's hydrostatic weight, the total pressure exposed to the plug and the total pressure resistance of the plug would be given. Fig. 5.7 shows the pressure points of the total pressure resistance of the settled barite plugs related to the worst anticipated reservoir pressure. Five of the wellbores had annulus settlements that could withstand a re-pressurized formation's differential pressure. It is important to note that for several of the wellbores, the cut was made high up in the settled column, and thus the pressure resistance could possibly be higher than what the failed circulation data presents. The same is true for the maximum circulation pressure applied in the attempt. Higher pressures could possibly be applied while still having a failed circulation meaning that the plug would hold the pressure. The data points only show a potential, but not the maximum pressure resistance.

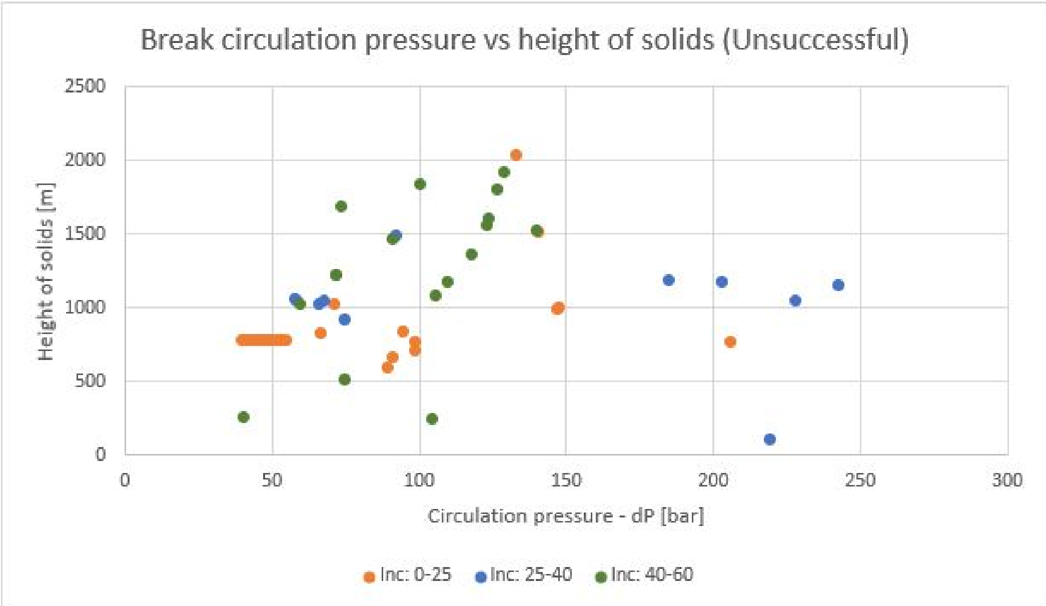


Figure 5.6: Data points for failed circulation pressures vs height of settlements using the three layered model where the light fluid density is that of the carrier fluid, mid layer density is 1.15 s.g and the lower layer density is 3.0 s.g.

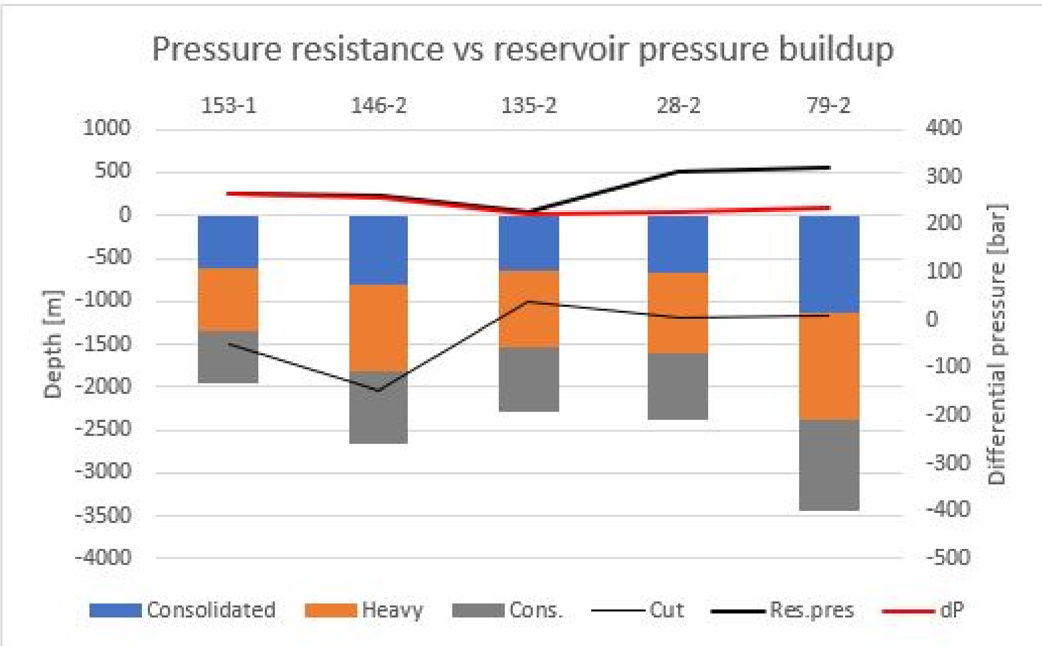


Figure 5.7: Pressure resistance of the settled barite plug versus reservoir pressure build-up.

5.1.4 Angle of inclination

Angle of inclination and whether this affects the sealability of the barite plug was one of the research questions asked in the introduction of this thesis. As stated above, using the pressure data for the unsuccessful circulations does not make sense because the potential pressure resistance of the plugs in question could be much higher than the pressures applied. Therefore, successful break-circulation attempts were used when analysing the effect of inclination. Initially, the pressure per unit length of plug was plotted versus inclination as visualized i Fig. 5.8. A decreasing pressure trend can be seen as inclination increases.

In an attempt to normalise the data points, the ratio between total circulation pressure and annulus hydrostatic pressure was used as a variable. This variable (y) describes the frictional pressure above hydrostatic per unit length and was plotted versus inclination (Fig. 5.9). Both graphs show a decrease in resistance as the inclination increases, but there are too few data points to make any meaningful correlation. The data set had an R^2 value of 0.55 which is not conclusive. However, the trend seen in the graph supports the theory of settling in slanted tubes, where barite beds are formed with an overlaying clear layer that disrupts the compaction process. This could potentially create layers of weaker compaction, enabling flow paths with reduced pressure resistance of the plug. Dye et al. [1999] concluded in their study that dynamic barite sag increased as hole angle increased from 45-60◦, results gathered from the data set shows reduced pressure resistance at a somewhat lower angle of 30-35 degrees.

5.2 Placeability and positioning

A barite plug is created through natural segregation from the drilling mud used during installation and settles in the annular gap between the two casings or casing and formation. It is generally not placed with intent but is the by-product of the casing installation procedure. Barite settlements in the annulus constitute a considerable challenge in P&A operations, especially in removing casing to enable a rock-to-rock cross-sectional barrier. Due to compaction and packing, barite settlements exert high friction to the casing walls, generating excessive over-pull and may require several cut and pull runs of short casing stumps. Tripping in and out of the hole to extract these casing stumps compose a substantial part of the total P&A time expenditure. Subsequent clean-out runs intended to

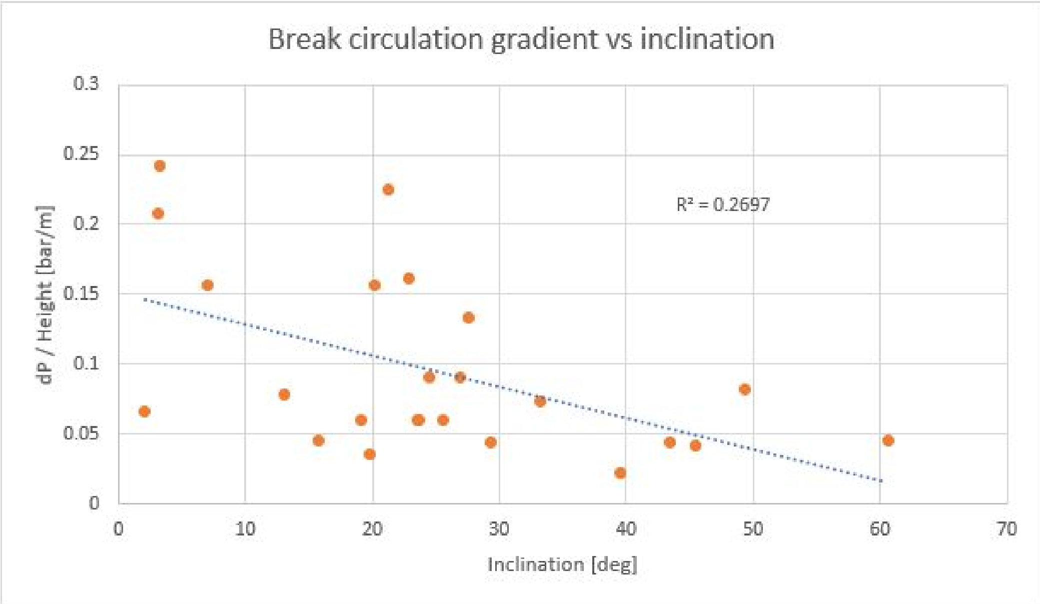


Figure 5.8: Friction pressure per unit length plotted versus inclination for successful break-circulation attempts

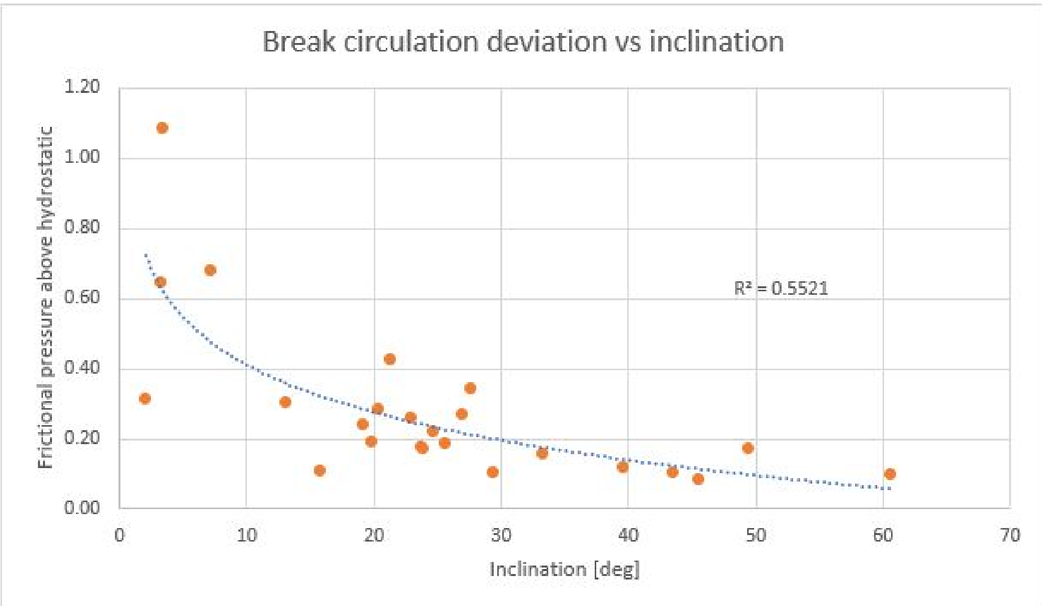


Figure 5.9: Normalised pressure per unit length plotted versus inclination for successful break circulation attempts

remove the settled barite often results in plugging of shakers and surface lines (Fig. 5.13) adding to the total time and uncertainty in the operations. The barite is already in place behind the casing and resting on a solid foundation. If it could be utilized as a benefit instead of an obstacle in P&A operations, several tripping runs could possibly be avoided and the potential saving is immense. The plug's placement and position would still need to be verified before it can be considered a barrier element. Like other well barrier elements, a plug of settled barite needs formation strength to withstand the pressure build up the plug could be exposed to in the future. Therefore, the plug needs to be located as deep as the formation fracture pressure dictates and have a length and composition to withstand the maximum differential pressure it may be exposed to over time. If the plug is placed in a suitable formation, it has sufficient length, composition and is located in a part of the well without too high inclination it could be utilized as a barrier. This would save time in reduced cut and pull runs or the time and uncertainties with long section milling.

5.3 Identification and verification

One of the challenges in P&A and specifically in cut and pull operations has been the verification of behind casing material. There has been a knowledge gap in the industry, making it difficult to differentiate formation creep, TOC, settled barite, and other fluids in the annular gap behind the casing. Recent experimental work as the one described by Govil et al. [2020, 2021] have displayed techniques that can identify the difference between cement, formation, barite, liquid and gas, and greatly improving the identification of these materials. In their paper, [Govil et al., 2021] present a viable solution to verify the presence of settled barite. The cross-plotting technique of computed pulse-echo acoustic impedance (AIAV) vs flexural attenuation (AIFAV) is a powerful method to identify the nature of the material in the annular space. Comparison of field data with logs obtained in controlled reference cells show that it is possible to distinguish between gas/liquid, settled barite, light and conventional cement, and various types of formation in field logs [Govil et al., 2021].

In case study 4: Well X4 [Govil et al., 2021] shows a well where the 12 1/4-in hole section was drilled from the 13 3/8-in casing shoe at 5.421-ft MD in November 2001. Special about this well is the existence of a packer between the two casings guaranteeing that only barite settlements can be present behind the casing in this section. The logging objective

Figure 5.10: Plugged pipe with settled barite due to circulating settled barite out of a well (Equinor 2020)

was to quantify annulus cement barriers prior to P&A of the main wellbore for a sidetrack operation [Govil et al., 2021], but the logging result clearly show that barite sag is observed above the packer in the concentric string. The external casing packer, just within the casing shoe, offers a distinct fingerprint cross-plot of settled barite, which can be used to distinguish barite settlement from formation creep or light cement in deeper intervals [Govil et al., 2021]. On the flexural attenuation map, the lower settlements' compaction can be easily seen, and using this method can enable operators to evaluate settled barite usable as WBE.

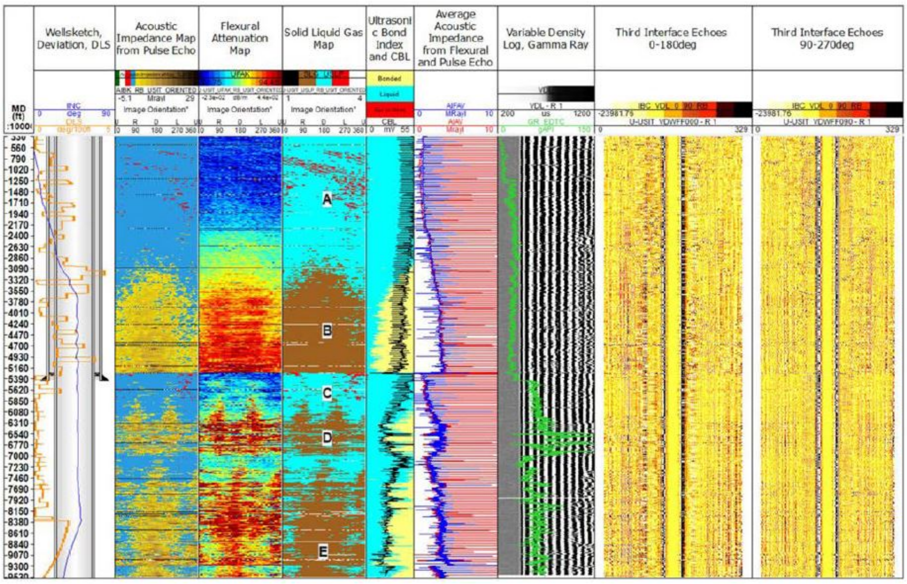


Figure 5.11: Case study Log plot across the logged interval highlighting typical signature of materials present behind casing. (From Govil et al.(2021))

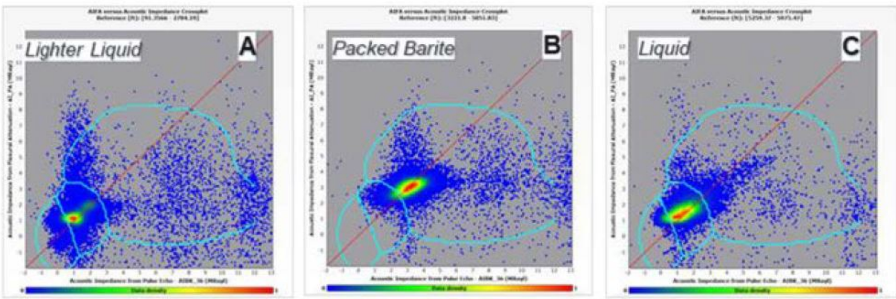


Figure 5.12: Acoustic impedances (flexural vs pulse echo) crossplots, indicating presence of material behind the casing. Plot A: liquid, Plot B: barite, Plot C: Liquid. (From Govil et al.(2021))

NORSOK-D010 states that when using cement as a permanent barrier element it shall be verified by logging. With a tested and qualified means of logging settled barite, this requirement could also be extended to apply for a settled barite plug. In the P&A campaign the casing will most likely be logged for identifications of potential wear, ovality, good cement or formation creep. Incorporating settled barite in the same logging run would not greatly increase rig time. It could be beneficial to investigate the quality of settled barite to be used as WBE or as an extension to the casing cement. By accurately determining the composition and placement of the packed barite, the operator would ensure an additional option when deciding what barriers to use. This would be specially beneficial in difficult P&A operations where conventional methods are unusable. While this study's result is not conclusive in the pressure resistance of settled barite, a more thorough study combined with the cross-plotting technique of [Govil et al., 2021] merit consideration.

5.4 Sealing and self-healing

The particle distribution of barite is similar to that seen in unconsolidated sand slurries. The bulk will be made up of a matrix of larger particles with the void filled with smaller particles. The void between the smaller particles will be filled with even smaller particles continuing down to the micro particles in the lower range of particle distribution, hence producing a bed of maximum packing. The settled barite permeability would be reduced by particles larger and smaller than d_p (d_{50} 25μm of API barite) and would thus be defined by micron-sized particles. The composition of the plug will not be a homogeneous collection of barite due to other solids' presence in the mud. The larger particles will typically be the largest barite particles in the distribution or micro cuttings from the drilling operation, while the smaller particles will be bentonite settlements or the smallest barite particles. The compaction regime at the bottom of the settlement consists of grains that support each other mechanically and the fluid in the compaction regime is squeezed out upwards as the bed compacts [Zamora, 2009]. Over time and with the right down hole conditions, the particles can bind to each other such as seen in solids due to surface chemistry and electrostatic bonds creating a consolidated barite plug. Even with maximum packing the bed would contain micro porosity, but because the bulk matrix is defined by micron-sized particles the permeability through the plug would be in the order of centimetres per year.

Higher up in the barite column or for columns not consolidated, a transition zone exists where the barite can be compared to a Bingham plastic unconsolidated sand slurry. Such slurries can also be utilized as a plugging material when they contain a high solid concentration and particle distribution ranging from 0.1-100μm which is similar to that of a standard API barite. This unconsolidated barite will have a high density and create a hydrostatic head on the underlying consolidated barite and help with pressure isolation.

Barite does not generally set as a solid after settlement and does not shrink. Therefore, it can not fracture even when shear forces exceed its yield strength. If exposed to shear forces the material would flow and reducing the shesr forces below its yield strength effectively reshaping to its original form. This is a purely mechanical process and the transition between these two states is repeatedly reversible, giving the material a self healing property. This self-healing eliminates any leakage through channels and micro annuli. Barite is a thermodynamically and chemically inert material and is thus unaffected by down-hole fluids such as CO_2, H_2S or hydrocarbons. It remains stable and impermeable permanently provided a stable foundation, maximum packing and compaction.

5.5 Barrier element

A common uncertainty and apprehension often voiced by the oil and gas industry when discussing the subject of settled barite as a barrier element is not the permeability of the plug. It is rather the ability to adhere to the casing and formation wall or that previous experiments have shown the plug to not be diffusion tight against gases. Without adhesive forces holding the plug in place, subsurface pressure forces could move the plug upward in the annulus conclusively moving the barrier out of place and function. If the plug is moved upward there would no longer be a solid foundation beneath the plug allowing it to flow and create channels. Even though the result of the data gathering showed high adhesive forces between the barite and the annuli walls, an extra impediment should be in place to prevent movement of the plug. This adheres to the recommendations provided by NOROK-D010 [2013]. NORSOK-D010 does not state what material a WBE should consist of, but a new EAC must be made by the user of the WBE. When an uncommon WBE is used, a risk analysis shall be performed and risk reducing measures applied. A risk-reducing measurement could be to lock the barite plug in place with a top cement plug.

If using settled barite as a barrier element, the recommended solution would be to section mill a small window or pull casing down to packed barite similarly with the current procedure. A mechanical plug should be placed inside the casing below TOC and a standard cement barrier plug is placed above the mechanical plug. At the top of the packed barite, the cement plug is extended to encompass the bore hole's full hole diameter, effectively locking the barite plug in place without any room for movement. Due to the impermeable matrix within the settled barite and the inability to move, the plug is diffusion tight whilst still having the ability to flow if exposed to high shear forces. Where the casing cement shrinkage can create micro annuli and channels, the barite will self-heal, effectively blocking off any leak paths through the barite plug. According to NOROK-D010 [2013], a well barrier element in itself may or may not prevent flow, but in combination with other WBE's forms a well barrier. By itself, the settled barite would not be defined as a barrier envelope, but in combination with a cement plug sealing it in place, it can prevent fluids from flowing unintentionally from one formation into another formation or to the external environment.

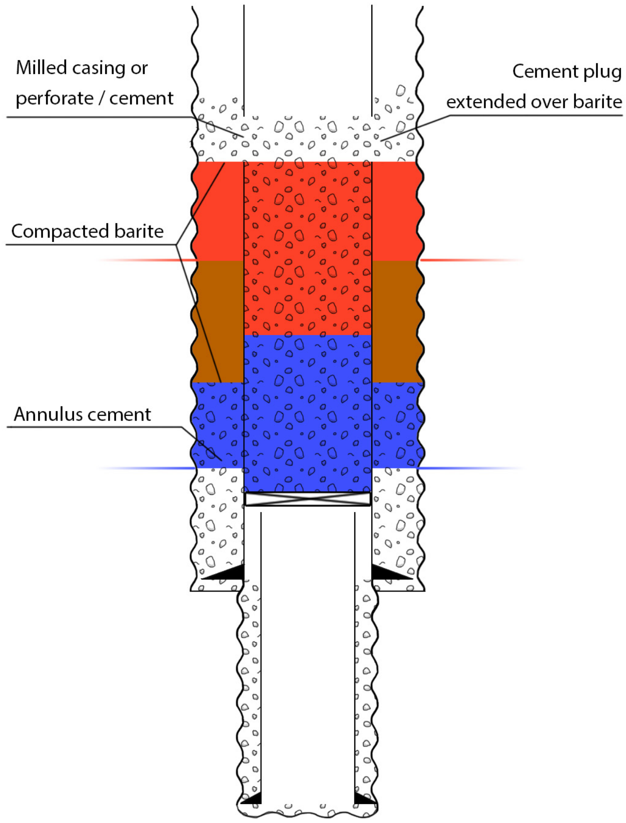


Figure 5.13: Example of how a settled barite WBE could be utilized.

Settled barite is currently not viewed as a qualified barrier material, even though a barite plug in the annulus often will withstand considerable pressure differentials, as seen in casing recovery operations [Govil et al., 2021]. The data gathering and analysis done during this thesis verify that a barite plug can withstand considerable pressure differential when such a plug's conditions are present. [NOROK-D010, 2013, S.9.3.1, p.81] states that non-cement barrier materials are usable as a barrier element if the operator makes a new EAC table. The operator is the only responsible body for ensuring the well is secured and simply following governmental recommendations or best practice does not waive this responsibility. When operating companies on the NCS are known to have their own requirements, higher than that stated in NOROK-D010 [2013] to be certain they are compliant with the standard, it is understandable they would be wary of new and untested techniques and innovations. However, responsible well-integrity management is not only a requirement but it can give companies willing and able to implement new technology a competitive advantage in the industry.

The settled barite has shown to be effectively sealing the wellbore. It has a verification method by logging that shows location and height. It is durable due to being thermodynamic and chemically inert. These are important factors in P&A for any well barrier element and the fact that it is already in place and could be used as a benefit instead of a challenge advocates its utility. NOROK-D010 [2013] states that the composition of well barrier elements shall be known. In addition, the narrow range of inclinations where a barite plugg can be utilized would not envision widespread adaptation in the imminent future. Nonetheless, a barrier element consisting of settled barite could be utilized in emergency plugging operations. Challenging wells where other plug and abandonment operations have been exhausted due to buckled tubing or other mechanical damages to the well could benefit from the possibility of utilizing a barite plug as part of a barrier element. Wells where only one barrier is required, such as normally pressured formations with no hydrocarbon and no potential to flow to surface, could also be a good candidate for settled barite barriers.

5.6 Uncertainties

One of the uncertainties of this study is due to all the un-logged wellbores. Even though the TOC calculations correspond to logged wellbores, there is an uncertainty that they are erroneous. Especially wellbores with over-gauged holes and wellbores where losses were observed during cementing may contain large deviations between calculated values and real TOC. When it comes to the three-layered model there may also be discrepancies between calculations and TOS, again due to the lack of good locks of the annulus materials. The calculations correlates well with reports of settled solids on the casing, pulling force and returns during clean-out runs. Still, the composition, density and homogeneity of the settled solids are just assumptions. Laboratory studies of the settling regime with field-ready drilling mud, intended to analyse the density gradient through the settlements, could improve the model for future study.

None of the cut and pull operations used in this study were done and recorded with a future study in mind. The cut and pulls were performed according to standard operating procedures, and thus the different circulation paths gathered is the only base of information available. While it would be of great interest to have circulation paths extending through a gradually shorter interval of settlements or pressures high enough to break circulation, this is not realistically possible. Even with a systematic screening of wellbores according to strict acceptance criteria, there may still be wells in the final data set that are not representative for a through plug circulation without tight spots and other obstacles.

6 | Conclusion

Analysis done of 77 field circulations through settled barite plugs have documented that the settled barite adheres to steel and formation. 4 of the 22 wells investigated showed adhesive friction between settled barite and the annulus walls, strong enough to overpower a re-pressurized reservoir pressure. The remaining circulation attempts demonstrate a significantly higher pressure resistance than what could be explained by the hydrostatic column of settled barite and mud solids alone. Due to the limitations of how the data was produced through cut and pull operations, no relationship between pressure resistance and length of settlements was obtained.

Barite is thermodynamically stable and chemically inert and thus is unaffected by downhole fluids such as CO_2, H_2S and hydrocarbons. Additionally, a barite plug is non-shrinking and the uncertainties related to flow channels and micro-annuli, which are typically associated with other plugging materials, are not a factor. Barite does not set like cement and if exposed to mechanical loads, the material will flow and reduce the shear forces below the yield strength, effectively reshaping to its original form. This is a purely mechanical process and can be repeated over and over, effectively allowing the plug to self-heal.

Settled barite has shown to be impermeable to both gas and liquids when the compaction regime is defined by maximum packing and the inclination of the wellbore is less than 35 degrees. It has such a low permeability that the migration through the plug is in the order of centimetres per year and volumetric rate is negligible. Resting on a solid foundation located in a section with formation integrity and being comprised of a matrix defined by maximum packing verified by logging, settled barite possesses the properties needed to be considered a barrier material.

7 | The way forward

Further laboratory studies is recommended to improve the models and understanding of how settled barite can be used as a barrier element. By using barite solutions closer in property to drilling fluids, one would produce more accurate settling regimes that closer represents the settled barite found in the field. Using such fluids would replicate the real physical phenomena with maximum packing as seen in the field, and could thus be used for pressure versus depth experiments. Using solutions with different amounts of other solids, such as bentonite, to see what composition has the highest adhesive force and are able to form acceptable barriers. It would be interesting to investigate a setup with several different length plugs, and see if there is a relationship between length and pressure resistance. Improving the three layered model with accurate fluid density values, or producing a model with more layers based on experimental studies would give a more correct analysis of future field pressure data.

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A Standards and guidelines for well integrity

This list includes standards and other documents which address well control and well integrity. Please note that the list may not be exhaustive and that there exists more documents covering the same areas.

Well control standards

- API RP 59 Well Control Operations
- API RP 5C7 Coiled Tubing Operations in Oil and Gas Well Services
- API RP 92U Underbalanced Drilling Operations
- EI Model code of safe practice Part 17 Volume 2: Well control during the drilling and testing of high pressure offshore wells
- EI Model code of safe practice Part 17 Volume 3: High pressure and high temperature well completions and interventions
- IADC Deepwater Well Control guidelines
- Norwegian Oil & Gas 135 Classification and Categorization of Well Control Incidents

Well integrity standards

- API RP 65-2 Isolating Potential Flow Zones During Well Construction
- API RP 90 Annular Casing Pressure Management for Offshore Wells
- API RP 90-2 Annular Casing Pressure Management for Onshore Wells
- API RP 96 Deepwater well design and construction
- ISO 16530-1 Well integrity - Part 1: Lifecycle governance manual
- NORSOK D-010 Well integrity in drilling and well operations
- Norwegian Oil & Gas 117 Well Integrity
- OGUK OP095 Well Life Cycle Integrity Guidelines

Well control Equipment

- API 17F Subsea production control systems
- API 19V Subsurface barrier valves and related equipment
- API 64 Diverter Systems Equipment and Operations
- API 6AV1 Specification for Validation of Wellhead Surface Safety Valves and Underwater Safety Valves for Offshore Service

- API RP 14B Design, Installation, Operation, Test, and Redress of Subsurface Safety Valve Systems
- API RP 16ST - Coiled Tubing Well Control Equipment
- API RP 17W Subsea Capping Stacks
- API RP14C Analysis, Design, Installation, and Testing of Safety Systems for Offshore Production Facilities
- API Spec 11D1 Packers and bridge plugs
- API Spec 14A Specification for Subsurface safety valve equipment
- API Spec 16C Choke and Kill Equipment
- API Spec 16D Control systems for drilling well control equipment and diverter equipment
- API Spec 16RCD Rotating Control Devices
- API Spec 7-1 Specification for Rotary Drill Stem Elements
- API Spec 7NRV Drill String non-return valves
- API Specification 16A Specification forr Drill through equipment
- API Std 16AR Standard for Repair and Remanufacture of Drill-through Equipment
- API Std 53 Blow Out Prevention equipment systems for drilling wells
- API STD 6AV2 Installation, Maintenance, and Repair of Surface Safety Valves and Underwater Safety Valves Offshore
- DNVGL-RP-142 2015-04 Well Head Fatigue Analisys
- ISO 10417 - Subsurface safety valve systems - Design, installation, operation and redress
- ISO 10423/API Spec 6A Specification for Wellhead and Christmas tree equipment
- ISO 10432 - Downhole equipment - Subsurface safety valve equipment
- ISO 13354 Shallow gas diverter equipment
- ISO 13533 - Drilling and production equipment – Drillthrough equipment
- ISO 13628-06 – Design and operation of subsea production systems – Part 6: Subsea production control systems
- ISO 13628-4/API Spec 17D Design and Operation of Subsea Production Systems-Subsea Wellhead and Tree Equipment
- ISO 14310 - Downhole equipment - Packers and bridge plugs
- OGUK OP092 BOP Systems for Offshore Wells

Equipment and system general

- API 17TR8 High-Pressure High-Temperature (HPHT) Design Guidelines
- API 19AC Specification for Completion Accessories, first edition (Sept 2016)
- API 19TT Well Test Tools
- API RP 100-1 Hydraulic Fracturing - Well Integrity and Fracture
- API RP 100-2 Managing Environmental Aspects Associated with Exploration and Production Operations Including Hydraulic Fracturing
- API RP 16Q* Design and operation of marine drilling riser equipment

- API RP 17A Design and operation of subsea production systems
- API RP 17H ROV interfaces on subsea production systems
- API RP 49 Drilling and Well Servicing Operations Involving Hydrogen Sulfide
- API Spec 16F Marine drilling riser equipment
- API Spec 5CRA/ISO 13680 Corrosion-resistant Alloy Seamless Tubes for Use as Casing, Tubing, and Coupling Stock
- API Spec 5CT Casing and Tubing
- API Spec 7K Drilling and Well Servicing Equipment
- API Std 7CW Casing Wear Tests
- DNV-OS-E101 Drilling Plant
- IEC 61511 Safety instrumented systems for the process industry sector
- ISO 11961/API Spec 5DP Drill pipe
- ISO 13624 - Drilling and production equipment – Part 1: Design and operation of marine drilling riser equipment
- ISO 13628-1 - Design and operation of subsea production systems – Part 1: General requirements and recommendations
- ISO 13628-7/API RP 17G Completion/-workover riser systems
- NORSOK D-001 Drilling facilities
- NORSOK D-002 System requirements well intervention equipment
- NORSOK D-007 Well testing system
- OGUK OP064 Relief Well Planning
- OGUK OP071 Guidelines for the suspension and abandonment of wells including guidelines on qualification of materials for the suspension and abandonment of wells

Cementing

- API RP 10B-2 – Recommended Practice for Testing Well Cements
- API RP 10B-3 Testing of deepwater well cement formulations
- API RP 10B-4 Preparation and testing of foamed cement slurries at atmospheric pressure
- API RP 10F Performance testing of cementing float equipment
- API RP 65-1 Cementing Shallow Water Flow Zones in Deepwater Wells
- API Spec 10A Cements and materials for well cementing
- ISO 10426-1 – Cements and materials for well cementing – Part 1: Specification
- ISO 10426-2 Cements and materials for well cementing – Part 2: Testing of well cements
- ISO 10426-3 Cements and materials for well cementing – Part 3: Testing of deepwater well cement formulations
- ISO 10426-4 Cements and materials for well cementing – Part 4: Preparation and testing of foamed cement slurries at atmospheric pressure
- ISO 10426-5/API RP 10B-5 – Determination of shrinkage and expansion of well cement formulations at atmospheric pressure

- ISO 10426-6/API RP 10B-6 Methods of determining the static gel strength of cement formulations
- ISO 10427-3 - Equipment for well cementing – Part 3: Performance testing of cementing float equipment

Competence

- IOGP 476 Recommendations for enhancements to well control training, examination and certification
- ISO 17969 Guidelines on competency management for well operations personnel
- Norwegian oil and gas guideline 024: Recommended guidelines for competence requirements for drilling and well personnel
- OGUK OP065 Competency for Wells Personnel