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Abstract

Plug and Abandonment (P&A) has become a major focus in the petroleum industry and especially in Norway due to the maturity of the fields. Therefore, an extensive number of wells to be abandoned just show how big the challenge will be and how much focus the regulatory authorities should include into this issue.

From an operational point of view, P&A is the last phase of the life cycle of a well and hence no return of capital from it is actually expected. Furthermore, the driver for operators relies under a strict regulatory framework and the responsibility for the abandoned well long after the wellbore has been plugged and the surface equipment removed.

Under such uneconomical conditions, this thesis intends to investigate new technology trends that provide an effective P&A operation. Therefore, first the regulatory framework is deeply studied for better understanding of the Norwegian structure and requirements for P&A. An example case of a Conventional Platform P&A is provided with the intention of identifying the operational procedure and conventional tools. Finally, the new technology trends are introduced, analyzed and compared from a technical/operational point of view.

By understanding the similarities, key features, limitations and differences between the new technology and criteria it is possible to create an analysis case for the same well presented in the example case. This analysis intends to find the maximum and minimum operational steps that can result by using these new technologies thereafter validating their benefit over a conventional P&A operation.

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Nomenclature

NCS = Norwegian Continental Shelf.

NPD = Norwegian Petroleum Department.

P&A = Plug and Abandonment.

NORSOK = Norsk Sokkels Konkurranseposisjon = Competitive Standing of the Norwegian Offshore Sector.

A.D. = After Death.

Texas RRC = Texas Railroad Commission.

PAF = Plug and Abandonment Forum.

US = United States.

PSA = Petroleum Safety Authority.

HSE = Health, Security and Environment.

API = American Petroleum Institute.

AGA = American Gas Association

ISO = International Organization for Standardization.

OTC = Offshore Technology Conference

HC = Hydrocarbons.

SPE = Society of Petroleum Engineers.

UKOOA = UK Offshore Operators Association

UK = United Kingdom.

WBSs = Well Barrier Schematics.

WBS = Well Barrier Schematic.

RBP = Retrievable Bridge Plugs.

H_2S = Hydrogen Sulfide.

CO_2 = Carbon Dioxide.

WBE = Well Barrier Element.

e.g. = exempli gratia (Latin: For Example)

CBL = Cement Bond Log.

VDL = Variable Density Log.

SBT = Segment Bond Tool.

USIT = Ultrasonic Imaging Tool.

HPHT = High Pressure High Temperature.

GOR = Gas Oil Relationship.

IBP = Inflatable Barrier Plug.

BOP = Blow Out Prevention

XMT = Christmas tree.

SCSSV = Surface Control Subsurface Valve.

MODU = Mobile Offshore Drilling Unit.

rDHSV = Retrievable Downhole Safety Valve.

PBR = Polished Bore Receptacle.

WOC = Wait On Cement.

CCL = Casing Collar Log.

GR = Gamma Ray.

BPV = Back Pressure Valve.

TOC = Top of Cement.

RPM = Revolutions per minute.

Psi = Pound per square inch.

min = minutes.

ID = Internal Diameter.

lb. = pounds.

in = inches.

POOH = Pull out of hole.

PBP = Permanent Bridge Plug.

ECD = Equivalent Circulating densities.

BHA = Bottom hole Assembly

ppg = Pounds per gallon.

BHT = Bottom Hole Temperature.

MRayl = 10^6 Rayl

Rayl = Unit for acoustic impedance [kg/(s*m^2)]

UWRS = Universal Wellhead Retrieving System

PDMs = positive displacement mud motors

NCA = Norse Cutting & Abandonment

IMCT = Internal Multi-String Cutting Tool

MPa = Mega Pascal.

PWC = Perforate, Wash and Cement.

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I. Introduction

1.1 Background

With the discovery of Ekofisk in 1969, Norway started with its own chapter in the petroleum and gas industry and thereafter by developing what is now known as the Norwegian Continental Shelf (NCS) the country became a worldwide icon due to production and export of petroleum. In this sense, according to the latest version of FACTS from Norwegian Petroleum Department (NPD) [1], the country was ranked in 2011 regarding to exportation as the seventh largest in oil and second largest in gas and with respect to production as the fourteenth largest in oil and sixth largest in gas.

For almost 40 years Norway's petroleum industry has mainly focused on new technologies for field development. This though, does not mean that the country is not still pursuing novel developments due to remarkable new discoveries. However, as expected and as also reported by NPD, the production from several of the major fields is now declining and many of their wells are entering into a "mature" or "brown zone" where no more economic hydrocarbons can be recovered. In other words, the fact of maturity leads to the very last phase of the life cycle of a well better known as Plug and Abandonment (P&A), where much attention is now being focused.

A conventional life cycle of a well starts with *Seismic Surveys and Geological Interpretation* for determining the possibility of hydrocarbon existence, once defined the hypothetical presence, a *Drilling Phase* is required (either exploration or development drilling) to confirm indeed hydrocarbon potential. After the well has been drilled, a *Completion Phase* is required to prepare the well by means of the best tubular combination to allow reservoir fluids to come out to surface in a controlled and safe way and provide a long lasting *Production Phase.* After some years, a *Well Intervention Phase* will arise in order to improve recoveries and fix minor problems that might occur due to production and finally when production is no longer available a *Plug and Abandonment (P&A) Phase* will be initiated to leave the well sealed with minimal risk to the environment.

A general and precise definition of P&A has not been stated by any of the regulatory institutions. Nonetheless, an interesting understanding of the criteria and combination of words has been presented by Jon Olav Nessa; *Collective operation associated with sealing off the wellbore through the setting of effective abandonment barriers across the wellbore cross section* [2].

In a regulation framework, as NORSOK [3], a P&A operation is classified according to the time frame of the abandonment. Hence, a Temporary Abandonment is proposed when the intention of re-entering the well is still desirable and on the other hand a Permanent Abandonment is designed with the purpose of an eternal perspective.

This thesis intends to investigate the new technology trends that claim giving an effective P&A operation. For the purpose, regulations should be firstly understood as the major driver for the whole P&A process. Thereafter, by explaining how a P&A operation could be possible be performed intend to give an operational insight on where tools, operations, equipment and plugging materials could be possibly improved. Finally, analyzing and comparing the key technical/operational features from new technology provide the knowledge for deciding when it is feasible to use one technology over the other.

1.2 Motivation

As explained before, P&A has become a major concern in the petroleum industry and especially in Norway due to the maturity of the fields. In that sense, a rough estimation of wells to be abandoned was presented as an approximate number of 2000 wells before the year 2040 [4]. This number is an indication of just show how big the challenge will be with respect to P&A and how much focus the regulatory authorities are including in this issue.

However, the challenge of P&A does not only rely on the number of wells to be abandoned. It also depends on searching for economical and optimal operations that fulfill a highly government regulated environmental policy. Hence, oil companies are interested in looking for novel strategies, technologies and materials which provide the desired benefits for both the Operating Company and the Government.

Consequently, many service companies have applied resources to research and fulfill the requests of these operating companies. Such is the case that special departments for P&A have been introduced into their structure and/or new companies specially focused on P&A have been created.

Therefore, based on the notable increase of P&A operations in Norway and motivated by the issue of providing a clear and easy understanding of the well abandonment process in the country. This thesis intends to study from a technical/operational view the new technology trends for effective P&A.

1.3 Scope of study

This thesis centers its attention in Norway and the NCS as possible scenario of P&A operations. Therefore, intends to present P&A and the governing Norwegian regulations and standards used for guidance/initiative to follow. However, it is not limited to use other similar regulations to strength the given concepts.

This project intends to give an insight on how P&A operations could possibly be outlined. Therefore, intends to summarize all the information that should be gathered to start planning a P&A program and for better understanding includes an example case of a detailed procedure for Platform P&A.

A brief theoretical section to distinguish between Platform and Subsea P&A will be included. However, rig specifications and evaluations will not be considered due to the complexity and extension inside the thesis direction.

The focus of study relies directly on the well technology to perform P&A. Therefore, first conventional tools, operations, equipment and plugging materials are explained. Subsequently, the new technology trends to perform improved P&A are introduced from a technical/operational perspective. Here, special issues from each technology proposal will be identified to later on perform a comparative analysis.

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II. P&A Fundamentals.

2.1 Definition of Plug and Abandonment.

As mentioned before, one simple and illustrative approach of the P&A activity was proposed by Jon Olav Nessa in his Master Thesis [2].

The Norwegian Standards for the Petroleum Industry NORSOK D010 - Well Integrity in Drilling and Well operations [3], provide definitions of P&A by defining terms like *Plugging, Temporary Abandonment and Permanent Abandonment*. These are given by:

- ***Plugging:*** Operation of securing a well by installing required well barriers.
- ***Temporary Abandonment:*** Well status where the well is abandoned and/or the well control equipment is removed. This is done with the further intention of resuming operations within a specified time frame (from days up to several years).
- ***Permanent abandonment:*** Well status where the well or part of the well is plugged and abandoned permanently with the intention of never being used or re-entered again.

2.2 Historical background of P&A.

It is not well defined whom, when and where exactly the first well abandonment operation was performed. As a matter of fact, it is known that it holds the same uncertainty as the history of drilling. Some versions believe that it could start as early as A.D. 347 in China or in A.D. 600 in Japan or France or in the Northeast of Baku. The truth is that no matter how many different versions exist the result will remain the same “gaping holes in the ground”.

A true milestone for the drilling industry and probably the world’s most widely recognized drilling milestone occurred in 1859. In that year, the first documented or purposely planned Oil and Gas drilling began in Pennsylvania «United States» with little or no idea of reservoir well productivity. Hence, the perception of treating a well after a production phase or knowledge/consequence of the possible impact was out of scope due to the imminent absence of a regulatory framework.

In 1890, almost 30 years later, the same state of Pennsylvania came out with the bright idea of regulating well plugging activities. The idea arose under the strategy of prolonging production by protecting the pay zones from water flooding. However, little or no bibliography can actually be found to support the statement [5].

Nonetheless, the increase of dry holes to be abandoned became a well-known challenge for other states. Subsequently, the interest of establishing an institute to set standards associated with plugging activities became a priority. Hence, in 1919 the state of Texas authorized to the Texas Railroad Commission (Texas RRC) to regulate well plugging activities in the same state and consequently became the first documented institution in the world.

P&A history has developed according to the understanding of the regulatory framework. In that sense, some of the most significant points that Texas RRC had stated can be mentioned in order of occurrence as in Table 2.1.

It is remarkable that these early regulations presented in Table 2.1, were mostly focused on protecting the oil and gas resources rather than the environment until 1970. In that year, the environment protection became a bigger driver in the regulation of the oil and gas industry as it is actually now.

Table 2.1 – Historical development of P&A according to a regulatory framework [5].

Year	Statement	Aim
1919	Dry or abandoned wells should be plugged in such a way as to confine oil, gas, and water in the strata in which they are found and prevent them from escaping into other strata. Shall be the duty of the supervisor and his deputies to supervise the plugging of all wells.	Give a general objective of P&A operations and assign the responsible persons in charge of the operations and control

1934	Plugging operations should be started within 20 days on all dry and abandoned wells or when production operations ceased. Cement is required to be circulated through tubing or drill pipe across these producing formations. Nonproducing formations, where no high-pressure gas sands or commercial water sands were encountered, could be plugged with mud-laden fluid.	Set a time limit for reference. Protect the producing formations from water flooding and suggest the first plugging material for well abandonment.
1957	In a dry hole, the short string of surface casing must be cemented in its entirety, and the deepest fresh water zone must be protected by a cement plug covering this water zone to at least 50 feet above and below the zone.	Change the focus to environment by protecting fresh water sands. Include references about plug lengths.
1974	Plugging operations on each dry or inactive well shall be commenced within a period of one year after drilling or operations cease and shall proceed with due diligence until completed. Plugging operations on delinquent inactive wells shall be commenced immediately unless the well is restored to active operation. For good cause, a reasonable extension of time in which to start the plugging operations may be granted pursuant to the following procedures.	Specific plugging requirements to protect usable quality water from pollution and to isolate each productive horizon.

2.3 Norway as major Potential for P&A Activities.

It was not until 1962 that Phillips Petroleum became interested in exploring the North Sea due to a recent discovery in the Netherlands. However, the first drilling operation started in the summer of 1966 with a negative or "dry" result and Norway had to wait until 1969 to discover Ekofisk and start with the country's oil adventure.

Production from Ekofisk field started on 15 June 1971, and in the following years a number of major discoveries like Statfjord, Gullfaks, Oseberg, Snorre, Troll, etc. were made and developed into what is now known as Norwegian Continental Shelf (NCS). These major fields have contributed significantly to the economic growth in Norway.

Through 40 years of operations, as reported by the Norwegian Ministry of Petroleum and Energy [6], only around 40 percent of the total expected resources on the NCS have been produced. The production plateau level was reached in 1995 with about 3 million barrels per day. However, in 2009 the oil production had decreased to 2.4 million barrels per day, and it is expected to shrink further in the years to come.

A good illustration of this oil production statistics numbers were presented in *The Shelf in 2012* by NPD [7]. Here, Fig. 2.1 shows these statistics and pinpoints that the decrease of production started in 2002 and of course the desire of the government is to keep a constant production at least for some years.

This notorious decrease of production undoubtedly raised several comments with respect to the topic and the most common one is the fact of maturity of the fields according to time (better known as "Brown Field period").

Fig. 2.2 illustrates an individual evaluation of production of each Giant field. Here, an interesting quote is also provided by author (Euan Mearns) [8]: "*Production from 7 giant fields is the power behind Norwegian oil production. These fields have performed beyond expectation, and now it is time for them to die*"

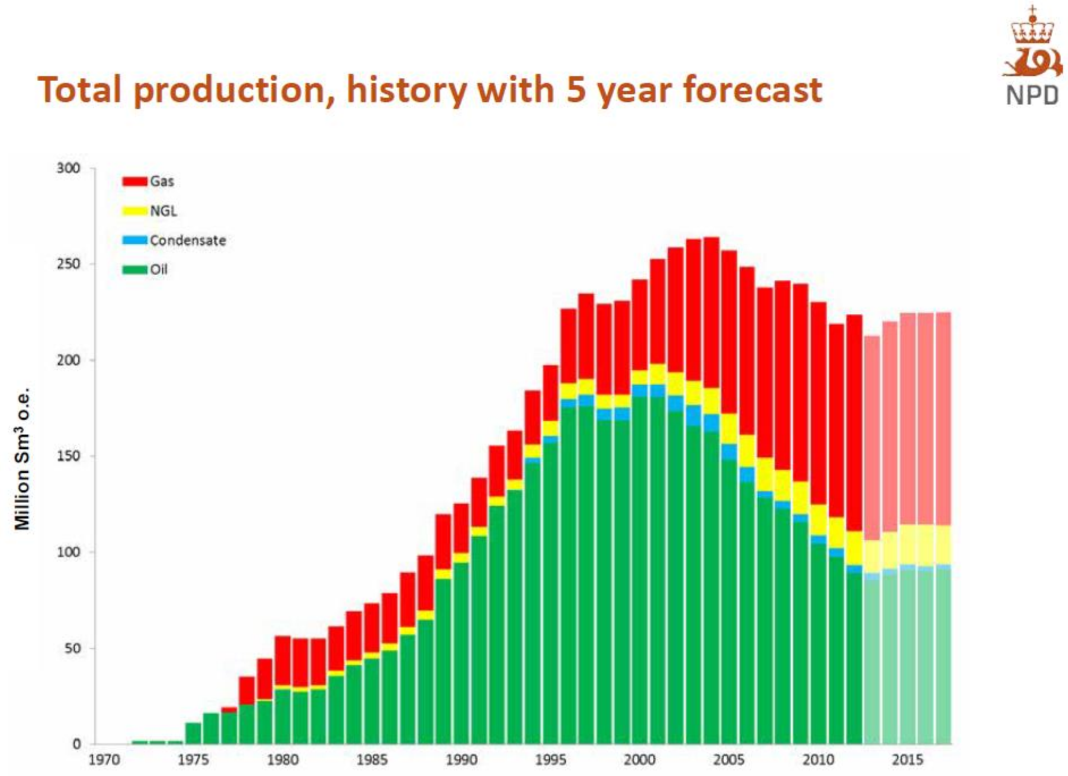

Fig. 2.1 - Production Histogram and Forecast in the NCS taken from NPD [7].

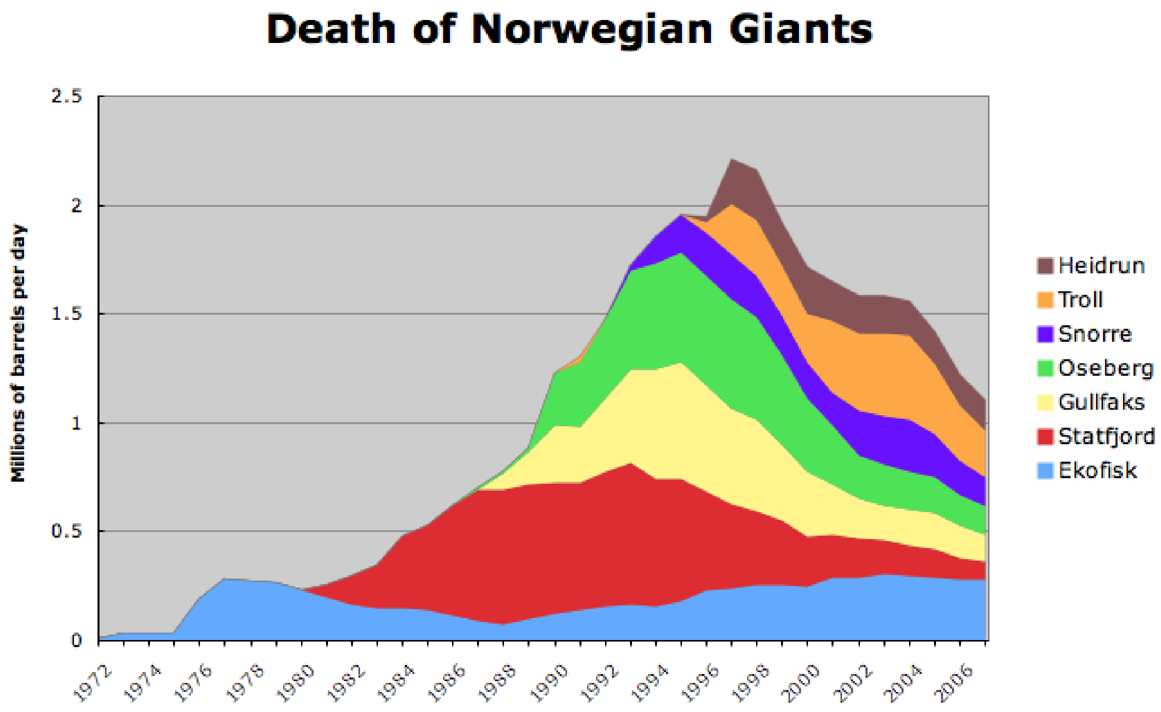

Fig. 2.2 - Production Histogram per individual Giant field provided [8].

The Brown Field category defines a field in a state of declining production or reaching the end of their productive lives, which is related to very last phase of the life cycle of a well presented already as Plug and Abandonment (P&A).

In Norway, P&A phase is getting more and more attention and such is the case that a special forum has been created under the name "Plug and Abandonment Forum" (PAF). The PAF has the goal of presenting challenges and solutions to diverse P&A situations between operators and service companies.

In the PAF conference arranged in June of 2012 [4], a rough estimate of 2000 wells to be abandoned until 2040 was mentioned by Martin Straume (PAF Chairman). He also announces a valuable question to the audience *"Are we ready?"* leaving an open discussion on the future challenges that Norway will have with respect to P&A.

III. Regulatory Framework of P&A.

Sect. 2.2 has already stated some arguments on how P&A is mainly dominated by the understanding of the regulatory framework. It can also be inferred that each state in case of US (in those days) or other relevant countries may have different rules and perspectives of how well abandonment should be performed. Nonetheless, all the guidelines essentially share the same environmental core and aim.

3.1 Norwegian State Organization of the petroleum activities.

Before entering into technical details of how P&A should be performed according to a regulatory framework, it is convenient to present a brief summary of the Norwegian state organization for the petroleum activities. This information will provide a better understanding from where and who the so mentioned regulations depend and are being controlled in the country.

The Norwegian State organization for the petroleum sector is organized as illustrated in Fig. 3.1.

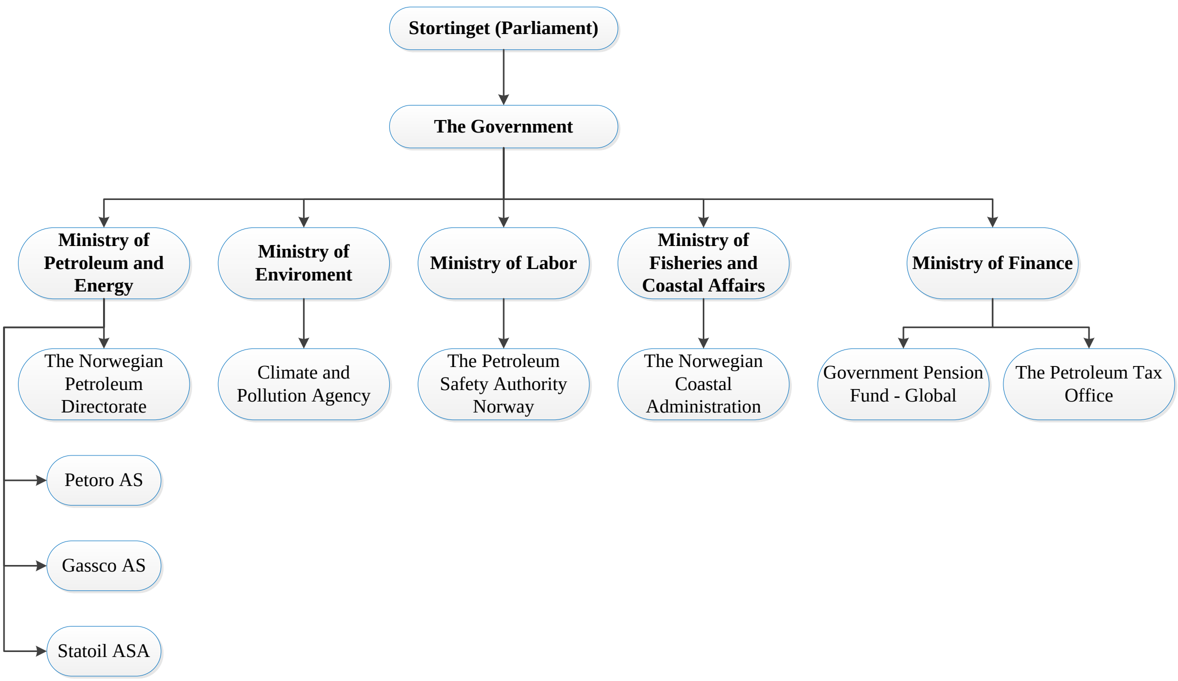

Fig. 3.1. Norwegian State organization of the petroleum sector [1].

The top level is constituted by The Norwegian parliament, which establishes the framework for the petroleum activities and supervises the Government and the public administration. The Government holds the second level and performs as an executive authority over petroleum policy. The third level is depicted by the Ministries, which in essence each has different responsibilities that ensure that the petroleum activities are carried out in accordance with the guidelines given by the two previous ones. The following levels are constituted by subordinate directorates and agencies.

Facts 2013 [1] describes in short concepts the responsibilities of each Ministry. These are given by:

- ***The Ministry of Petroleum and Energy.*** Responsible for resource management and for the sector as a whole.
- ***The Ministry of the Environment.*** Responsible for the external environment.
- ***The Ministry of Labor.*** Responsible for health, the working environment and safety.
- ***The Ministry of Fisheries and Coastal Affairs.*** Responsible for oil spill contingency measures.
- ***The Ministry of Finance.*** Responsible for state revenues.

Even with the previous description of each Ministry responsibility, it is still difficult to relate which entity is the one in charge of controlling P&A operations. Hence, it is still necessary to develop the next level. By using again Facts 2013 [1] the details are shown in Table 3.1.

Table 3.1 – Fourth level of the Norwegian State organization of the petroleum sector [1].

The Ministry of Petroleum and Energy	**The Norwegian Petroleum Directorate** The Norwegian Petroleum Directorate (NPD) reports to the Ministry of Petroleum and Energy. The NPD plays a key role in petroleum resource management, and is an advisory body for the Ministry of Petroleum and Energy. The NPD exercises authority in connection with exploration for and production of petroleum deposits on the Norwegian continental shelf, including statuary powers and to make decisions based on the rules and regulations governing the petroleum activities.

The Ministry of the Environment.	**The Climate and Pollution Agency** The responsibilities of the Norwegian Pollution Control Authority include enforcing the Pollution Control Act. Another key task is to provide the Ministry of the Environment with advice, guidelines and technical documentation.
The Ministry of Labor.	**The Petroleum Safety Authority Norway** The Petroleum Safety Authority Norway (PSA) is responsible for technical and operational safety, including emergency preparedness and the working environment in the petroleum sector.
The Ministry of Fisheries and Coastal Affairs.	**The Norwegian Coastal Administration** The Coastal Administration is responsible for national oil spill contingency measures.
The Ministry of Finance.	**The Government Pension Fund – Global** The Ministry of Finance is responsible for managing the Government Pension Fund - Global. Responsibility for operational administration has been delegated to Norges Bank. **The Petroleum Tax Office** The Petroleum Tax Office is part of the Norwegian Tax Administration, which is subordinate to the Ministry of Finance. The main function of the Petroleum Tax Office is to ensure correct assessment and collection of the taxes and fees that have been determined by the political authorities.

By understanding specific statements from Table 3.1 like: *safety*, *contingency measures* and *technical and operational safety*, and cross-checking with the definition of P&A provided in Sect. 2.1, now it is easy to state that the *Ministry of Labor* with the specific assistance of the *Petroleum Safety Authority (PSA)* are the entities in charge of regulating and controlling P&A operations.

3.2 Petroleum Safety Authority (PSA).

PSA has been independently working in Norway since 1st of October of 2004. Table 3.1 has already presented in essence the Key Role of PSA. However, another more precise description can be found on the electronic website of the institution [9]:

"*The Petroleum Safety Authority Norway shall stipulate premises and follow up to ensure that the players in the petroleum activities maintain high standards of health, environment, safety and emergency preparedness, and thereby also contribute to creating the greatest possible value for society*".

Likewise, the same electronic website [9] shows the exact duties that The government assigned to PSA. These are given by:

- *Through its own audits and in cooperation with other regulatory authorities in the HSE area, the PSA will ensure that the petroleum activity and activities relating to it are supervised in a unified manner.*
- *The PSA will also provide information and advice to the players in the industry, establish appropriate collaborative relationships with other HSE regulators nationally and internationally, and contribute actively to a transfer of knowledge from the HSE area to society in general.*
- *The PSA will provide input to the supervising ministry on issues being dealt with by that ministry, and support the ministry on issues at request.*

The PSA is organized into four big subdivisions; *Supervision, Professional Competence, Internal Support and Development, and Legal and Regulatory Affairs.* These four give origin to the actual icon of the organization as it is illustrated in Fig. 3.2.

In order to remain under the technical scope of this thesis, the subdivisions of *Supervision, Internal support and development, and Legal and Regulatory Affairs* will be left aside due to their minor relevance.

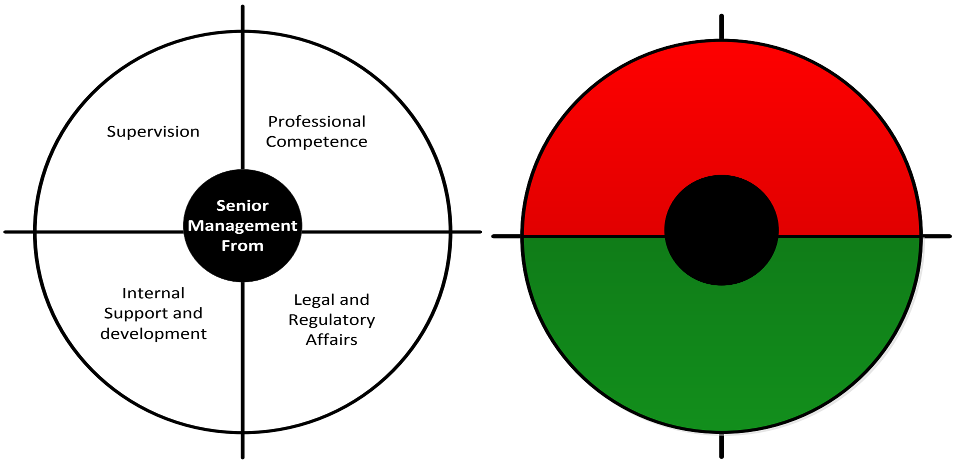

Fig. 3.2. Petroleum Safety Authority Subdivision and Icon [9].

However, the *Professional Competence subdivision* according to PSA [9] is divided into six disciplines*; Drilling and well technology, Process integrity, Structural integrity, Logistics and emergency preparedness, Occupational health and safety and HSE management.* Thereafter, the specific discipline of *Drilling and Well technology* comprises criteria for regulating P&A activities in the country.

3.3 Legal framework hierarchy for the Norwegian Petroleum Industry.

The implementation of the legal framework for the petroleum industry in Norway is based on the dispositions of the Constitution. According to the hierarchy, shown in Fig. 3.3, the following are Acts, Regulations, Guidelines and Standards in order of importance.

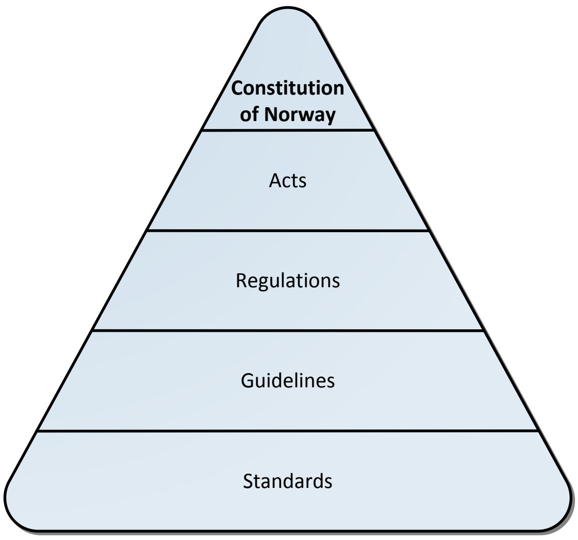

Fig. 3.3. Legal Framework hierarchy for the Norwegian Petroleum Industry.

- **The constitution of Norway.** Set of fundamental principles or established precedents according to which the state or other organization is governed.
- **Acts.** The Petroleum Act (Act of 29 November 1996 No 72 relating to petroleum activities) contains the general legal basis for the Norwegian petroleum activities.
- **Regulations.** Centralizes offshore and onshore regulations regarding Health, Safety and Environment (HSE) and includes the new working environment regulations. Regulations are stated under the area of authority of the PSA.
- **Guidelines.** Recommended practices that shows how to achieve successfully a goal. Normally, guidelines and regulations work combined in order to provide the best possible result.
- **Standards.** Tools/criteria/concepts that in certain way help to fulfill the functional requirements in the regulations.

3.4 Technical handling of the Norwegian Regulatory framework for P&A.

Sect. 3.2 has already introduced the role of the PSA in P&A activities and Sect. 3.3 has presented how the legal hierarchy for the petroleum industry in Norway is constituted. Therefore, now it is possible to specifically quote in technical terms how P&A is regulated in the country according to PSA [10].

3.4.1 Regulations.

Technical regulations for P&A can be found inside the *Activities Regulations* and the *Facilities Regulations [10]*.

Section 88 – Securing Wells from the *Activities Regulations [10]* states the importance of securing a well for well integrity purposes (related to *Section 48* in the facilities regulation). It sets a well integrity criterion for subsea-completed wells and temporary abandonment wells and it presents the correct procedure regarding abandonment of radioactive sources. These can be quoted as follows:

- *All wells shall be secured before they are abandoned so that well integrity is safeguarded during the time they are abandoned.*
- *For subsea-completed wells, well integrity shall be monitored if the plan is to abandon the wells for more than twelve months.*
- *It shall be possible to check well integrity in the event of reconnection on temporarily abandoned wells.*
- *Abandonment of radioactive sources in the well shall not be planned. If the radioactive source cannot be removed, it shall be abandoned in a prudent manner.*

The *Facilities Regulations [10],* especially *CHAPTER VIII – DRILLING AND WELL SYSTEM,* provides which is indeed the most relevant criteria for P&A purposes in *Section 48 – Well barriers.* These are given as follows and will be deeply explained in Chapter IV due to its relevance for this thesis.

- *Well barriers shall be designed such that well integrity is ensured and the barrier functions are safeguarded during the well's lifetime.*
- *Well barriers shall be designed such that unintended well influx and outflow to the external environment is prevented, and such that they do not hinder well activities.*
- *When a well is temporarily or permanently abandoned, the barriers shall be designed such that they take into account well integrity for the longest period of time the well is expected to be abandoned.*
- *When plugging wells, it shall be possible to cut the casings without harming the surroundings.*
- *The well barriers shall be designed such that their performance can be verified*

3.4.2 Guidelines.

The guideline gives more details on how a “paragraph” in the regulation should be achieved. It provides more details either by referring to other parts of the regulations or by referring to a more specific standard.

Table 3.2 – Systematic example of a Guideline for P&A (*Re Section 48 – Well Barriers*).

Guideline Re Section 48 – Well Barriers	**Aim**	**Regulation**	**Standard**	**Chapters**
	Health, working environment and safety	- Section 5. Of the Management Regulations - Section 8. Of Facility regulations	NORSOK D-010	4.2.1, 4.2.3, 5.6, 9 and 15
	Independence among Barriers	- Section 4. Of the Management Regulations		
	Dimensioning of binding agents, plugs and seals	- Section 11. Of Facility regulations		

For P&A purposes, a practical and systematic example on how the guideline works can be provided from the *Guideline Section 48 of the Facilities Regulations* as presented in Table 3.2. Here three major aims can be recognized and for the purpose a set of specific sections inside the regulatory framework are suggested. Likewise, a specific Standard is recommended with the possible useful chapters.

This example refers to NORSOK D-010 [3] as the required Standard for Health, working environment and safety. However, other guidelines may also refer to other Standards like NORSOK D-001, NORSOK D-002, DNV OS-E101, etc.

3.4.3 Standards.

The Standards as described in Sect. 3.3 are the very last and most useful tools/criteria/concepts for developing an action to a desired level of quality. For example, in America it is very common to use the American Petroleum Institute (API) or the American Gas Association (AGA) Standards to regulate certain procedures/activities in the American oil industry.

A more general standardization is provided by the International Organization for Standardization (ISO), which is the institution in charge of promoting worldwide proprietary, industrial, and commercial standards for any kind of commercial activity.

In Norway the governing Standard for the petroleum industry is known as NORSOK and the most relevant requirements for P&A activities (See Table 3.2) rely under NORSOK D-010 - Well Integrity in Drilling and Well operations [3].

3.4.3.1 NORSOK and What does it stand for?

NORSOK comes from the Norwegian *Norsk Sokkels Konkurranseposisjon* which in English means the *Competitive Standing of the Norwegian Offshore Sector.*

According to OTC 8182 - NORSOK Standards [11], NORSOK was established in the summer of 1993 after an initiative from the Norwegian Minister of Industry and Energy, Mr. Finn Kristensen. The idea came out due to the rising cost of offshore development and reduction in oil prices which led to the necessity of replacing the individual company specifications with new industry standards.

Before 1993, Norway used mainly standards originated in the US. Even though, many changes were proposed due to different conditions in the Norwegian petroleum industry, the lack of predictability, prolonged delivery time, rising cost and especially the lack of a good and suitable standard led the Norwegian industry to create and replace the company/project specifications by a specific standard that could reduce the capital and operational cost without compromising safety issues.

The main principles for the NORSOK standards are established as follows [11]:

- *Define an acceptable level of safety.*
- *Make extensive references to international standards.*
- *Specify functional requirements where possible.*

- *Include variation control (E.g. Different revisions to the Standard like NORSOK D-010 Rev 1, NORSOK D-010 Rev 2, etc.) to secure defined interface and exchangeability.*
- *Describe "good enough" requirements.*
- *Be short.*

3.4.3.2 NORSOK D-010 - Well Integrity in Drilling and Well operations.

The scope of NORSOK D-010 [3] is to provide a standard that mainly focus on well integrity by defining the minimum functional and performance oriented requirements and guidelines for well design, planning and execution of well operations in Norway.

This thesis will use the actual/official version which was released on August of 2004 under a third revision.

Currently, a fourth revision is being prepared by the correspondent institution and this will include, between many other changes, a well-defined Abandonment Section. The new revision will put special attention on the following issues [12]:

- *Re-defined suspension, temporary abandonment with/without monitoring.*
- *Only one well barrier required for over-pressured impermeable formation with no HC.*
- *Depth position of well barrier elements.*
- *Use of examples to illustrate placement of plugs/ casing cement (permanent P&A).*
- *Decision support for when to perform section milling vs. perforate, wash and cement.*

3.4.3.3 NORSOK and the surrounding Standards in the North Sea.

The paper SPE 100771 - Permanent Plug and Abandonment Solution for the North Sea [13] already summarizes the similarities in lines and aims between three different regulatory frameworks, (UKOOA) UK Offshore Operators Association - Guidelines for Suspension and Abandonment [21]; (NORSOK D-010) Well Integrity in Drilling and Well operations [3] and The Netherlands sector in Dutch mining authority guidelines. These are given by:

- *Preventing leakages to surface.*
- *Preventing hydrocarbon movement between different strata.*
- *Preventing contamination of aquifers.*
- *Preventing pressure breakdown of shallow formations.*

Differences between the three of them and some other considerations are also presented in SPE 100771 [13]. However, in order to respect the scope of this thesis, those will not be mentioned and therefore left to the reader’s consideration.

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IV. Well Barriers Requirements and Design premises.

4.1 Well Barrier Intention and design.

Plugging activities, as defined in Sect. 2.1, are related to the proper use of well barriers. According to NORSOK D-010 [3], a Well Barrier prevents fluids or gases to flow unintentionally from the formation, into another formation or to surface by using a closed envelope of one or several dependent Well Barrier Elements.

Consequently, a Well Barrier Element is defined as an object that alone cannot prevent flow from one side to the other side of itself. An interesting understanding has been provided by the psychologist James Reason with a project called *Swiss Cheese Model* in 1990 [14].

Reasons model can be widely applied for all kind of situations where many layers are considered against a hazard. Hence, as it is stated *"in an ideal world each defensive layer should be more than enough to counteract a hazard"*. However, in reality it is better to consider that each layer might have a weakness and could be better represented as a Swiss cheese with many holes. Fig. 4.1 illustrates the Swiss Cheese Model.

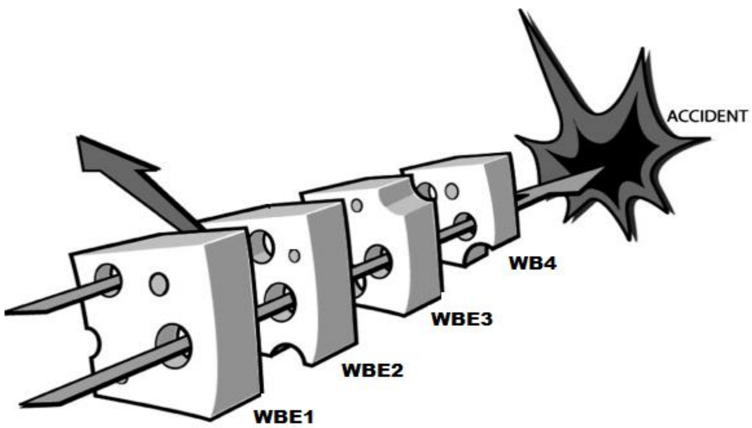


Fig. 4.1. Swiss Cheese Model for P&A activities.

General well barrier requirements are presented according to the *Facilities Regulations – Section 48* [10]. The purpose of this section is to describe the criteria for designing well barriers with respect to purpose, function and duration.

4.2 Function and Type of Well Barriers.

NORSOK D-010 [3] covers all well barrier and functions that they have in different abandonment scenarios. For the purpose, the Standard distinguishes between a Primary and a Secondary well barrier. Likewise, it considers the possibility of having multiple reservoirs sections. Table 4.1 shows a replica from the table presented in the Standard.

Table 4.1 – Functions and Type of Well Barriers [3].

Name	Function	Purpose
Primary well barrier	First well barrier against flow of formation fluids to surface, or to secure a last open hole.	To isolate a potential source of inflow from surface.
Secondary well barrier, reservoir.	Back-up the primary well	Same purpose as the primary well barrier, and applies where the potential source of inflow is also a reservoir (w/ flow potential and/or hydrocarbons)
Well barrier between reservoirs.	To isolate reservoir from each other.	To reduce potential for flow between reservoirs.
Open hole well barrier.	To isolate an open hole from surface, which is exposed whilst plugging the well.	"Fail Safe" well barrier, where a potential source of flow is exposed after e.g. a casing cut.
Secondary well barrier, temporary abandonment.	Second, independent well barrier in connection with drilling and well activities.	To ensure safe re-connection to a temporary abandoned well, and applies consequently only where well activities has not been concluded.

NORSOK D-010 [3], also clarifies that a secondary well barrier can never be a primary well barrier for the same reservoir. However, it may act as primary well barrier for a shallower formation, if the well barrier is designed to meet the requirements of both formations.

For better understanding of Table 4.1, the reader is encouraged to take a random example from one of the many Well Barrier Schematics (WBSs) proposed by the Standard and also presented inside the Appendix A and go to Sect. 5.1.2 for a detailed explanation.

4.3 Positioning of Well Barriers and Materials.

With respect to position of well barriers and materials, NORSOK D-010 [3] is very practical and punctual stating the following:

- *Well barriers should be installed as close to the potential source of inflow as possible, covering all possible leak paths.*
- *The primary and secondary well barriers shall be positioned at a depth where the estimated formation fracture pressure at the base of the plug is in excess of the potential internal pressure.*
- *The materials used in well barriers shall withstand the load/environmental conditions it may be exposed to for the time the well will be abandoned.*

4.4 Types of Abandonment

According to NORSOK D-010 [3], abandonment operations could be either temporary or permanent. The definitions for each one of them are shown in Sect. 2.1. However, the intention of the present section is to enhance them with respect to well barriers.

4.4.1 Temporary Abandonment.

Since the intention of a temporary abandonment is to re-enter the well, NORSOK-D10 [3] seeks for a safe manner to perform the activity. In that sense, the Standard states that the integrity of the materials used for the abandonment should be designed for two time periods of the actual desired abandonment.

Likewise, the Standard accepts the use of mechanical well barriers subject to type, planned abandonment period and subsurface environment.

Actually, many service companies provide mechanical well barriers for temporary abandonment. Within the industry some of them are commonly known as Retrievable Bridge Plugs (RBP). Fig. 4.2 shows different RBP which of course may differ depending on the service company and the technology used.

HEX RBP from Interwell [15] **RBP Generic Model from Baker Hughes[16]** **Versa-Set® RBP from Halliburton [17]**

Fig. 4.2. Retrievable Bridge Plugs from different Service Companies.

A RBP is only one variety of mechanical well barriers many others could exist or could still be developed by the corresponding services companies.

NORSOK D-010 [3] also suggests considering the degradation of the casing body in time, external protection of seabed equipment against possible loads due to fishing activities and constant monitoring of pressures between the tubing and annulus better known as “A annulus”.

4.4.2 Permanent Abandonment.

Permanent abandonment, as mentioned in NORSOK D-010 [3], directly infers to an eternal perspective condition. Therefore, the Standard focuses a lot on describing the design criteria and requirements for establishing a permanent well barrier.

The Standard states that a permanent well barrier shall extend the full cross section of the well, including all annuli and seal both vertically and horizontally as illustrated in Fig. 4.3.

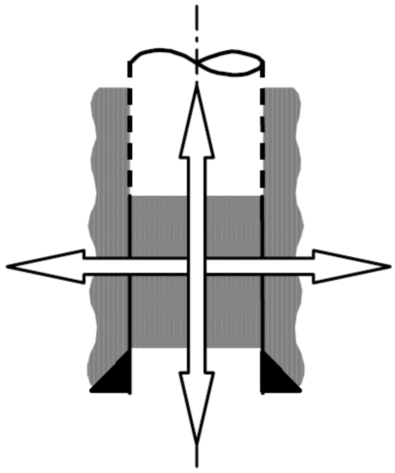


Fig. 4.3. Permanent Well barrier design criteria.

Likewise, the Standard sets the following properties as the desired ones for a permanent well barrier:

- *Impermeable*
- *Long term integrity.*
- *Non shrinking.*
- *Ductile – (non brittle) – able to withstand mechanical loads/impact.*
- *Resistance to different chemicals/ substances (H_2S, CO_2 and hydrocarbons).*
- *Wetting, to ensure bonding to steel.*

Steel tubular is not accepted as a barrier element unless it is supported by a plugging material that is placed on the inside and outside. The plugging material must fulfill/have the properties described above.

A very valuable quote for future sections, also extracted from NORSOK-D010 [3], is the pressure integrity of casing cement, which is considered as a vertical seal but not as a horizontal seal as illustrated in Fig. 4.4. Therefore, casing cement will not qualify as well barrier element across the wall.

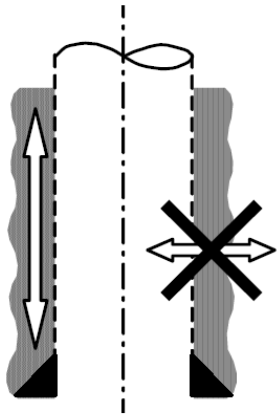


Fig. 4.4. Casing cement as a well barrier element.

Other criteria for open hole cement plugs, cement in liner lap and handling of control cables and lines are also presented inside the Standard. These are given by:

- *Open hole cement plugs can be used as well barrier between reservoirs.*
- *Cement in the liner lap, shall not be regarded as permanent WBE.*
- *Control cables and lines shall be removed from areas where permanent well barriers are installed.*
- *Removal of downhole equipment is not required as long as the integrity of the well barriers is achieved*.

4.4.2.1 Full Well Abandonment vs Section Abandonment (Slot Recovery).

Full well abandonment is undertaken when no future economic production or utility of a wellbore can be determined. Section abandonment is undertaken to extend a wells usable life when portions of the producing interval(s) have been depleted and/or watered out.

Actually, the decision to either fully abandon the well or only abandon a section of the well is based on an economic evaluation and reservoir study performed by the operator company. Hence, the company will be the one in charge to decide the future of the declining well.

Full abandonment or section abandonment should meet the same requirements presented in Sect. 4.2 and Sect. 4.3. In other words, a primary and a secondary barrier should still be considered and the positioning and material should meet the requirements stated in NORSOK – D010 [3].

However, the difference is that Slot Recovery consists of plugging and abandoning the lower completion, better known as the section below the production packer. Thereafter, a sidetrack should be performed and resume with drilling operations until reaching the desired target depth.

Full abandonment, as expected and according to NORSOK-010 [3], states first the necessity of setting an open hole well barrier to avoid possible shallow fluids to result into surface (See Table 4.1). Thereafter, it also states the necessity of removing the seabed equipment in order to accomplish the environmental intention of the Standard. For that purpose, the wellhead and casings should be cut at a minimum depth of 5m below the seabed. The use of explosives to cut the casing is acceptable only if the corresponding measures are taken into consideration regarding the environment.

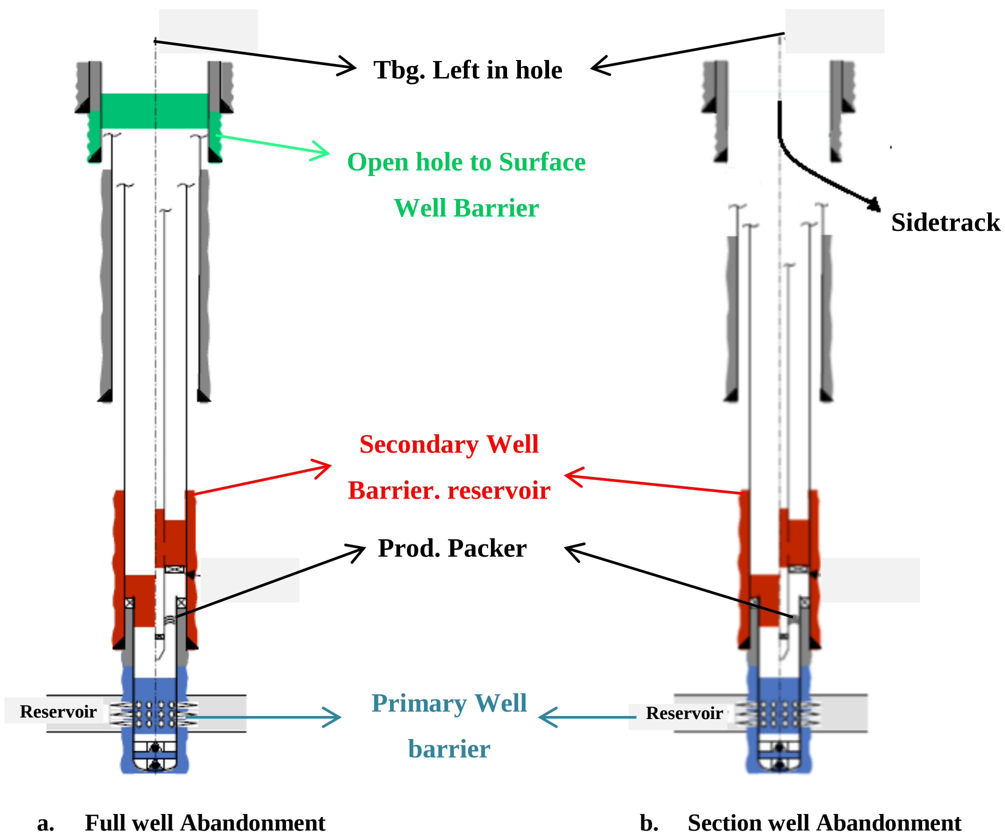


Fig. 4.5. Comparison between Full Well Abandonment and Section Abandonment.

Fig. 4.5 shows a WBSs comparison between a full well abandonment and a section well abandonment. In the figure, the scenario of a "*Perforated well*" proposed by NORSOK – D010 [3] is taken into consideration. Fig. 4.5a is similar to the figure presented in the Appendix A.4. Hence, better details that could be referenced over there. However, Fig. 4.5b is a sketch made of the same well under a Slot recovery scenario.

As illustrated in Fig. 4.5, the main difference between the two scenarios is that a surface barrier and the wellhead cutting/removal are needed in addition for a permanent P&A. It is remarkable to note that no matter the abandonment scenario, any of the presented in the Appendix A, only the top part of the well will be affected for Slot recovery purposes.

V. Outline of a P&A Operation.

It is important to understand that there are no specific outlines for P&A operations. Each company or set of companies (owner/s of a well) might have different procedures or perceptions of P&A, especially since it is unavoidable cost that actually represents no return of investment, except for the special case known as slot recovery.

Likewise, it is relevant to consider the country where the operation will be performed, the respective regulatory framework and the location of the well (offshore/onshore). In that context, it may of course be differences in requirements for abandoning a well in the Gulf of Mexico, the North Sea, the Middle East or other countries where P&A operations are required.

The present section will mention the criteria from where to start planning a P&A operation. Subsequently, it will describe a set of possible scenarios, the difference between platform and subsea P&A and finally summarize on how P&A could be possible be performed in an example case.

5.1 Planning P&A operations

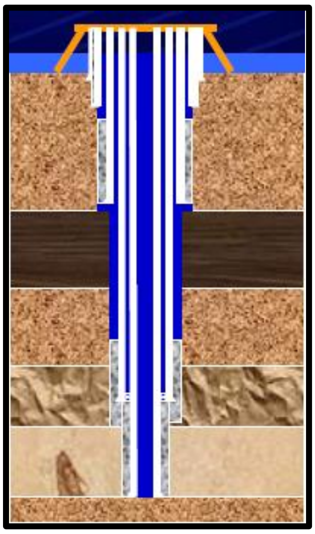
In general, planning P&A operations should be a much simpler process than planning drilling or well intervention operations. Somehow, the data acquisition criterion might be similar to an intervention operation since both of them are facing the same initial conditions (an already drilled and produced well). However, the intention and final results are of course different.

5.1.1 Start up Well Information.

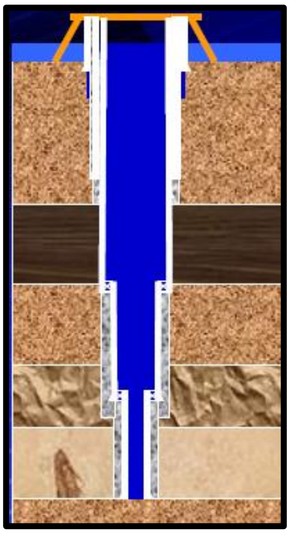
NORSOK -010 [3], suggests the typical information that should be gathered before planning P&A operations. These are given as follows:

- ***Well configuration.***

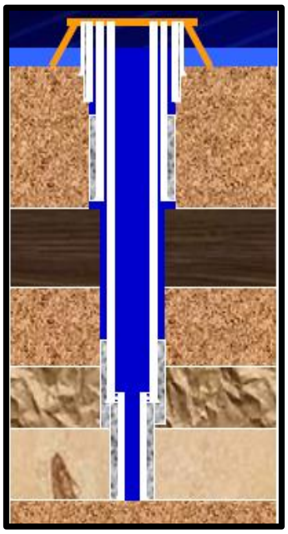
  - Depths and specification of permeable formations.
  - Casing strings. (e.g Fig.5.1 for casing configuration evolution at Ekofisk).
  - Primary cement behind casing status. See Fig. 5.2 (later explained).
  - Well bores, side-tracks, etc.



First wells constructed with 4 casings strings



3 string design: 9 9/8" Production casing and 2 reservoir liners.



***Latest design: Two casing Strings 13 3/8" x 9 7/8" and production casing/liner.**

Fig. 5.1. Casing String Evolution according to Øyvind Lunde [18].

- ***Stratigraphic sequence.***

This shows the reservoir(s) and provides information about their current and future production potential. Also depicts where reservoir fluids and pressures (initial, current and in an eternal perspective) are included. See Fig. 5.3 (later explained).

- ***Primary cementing operations in the well.***

If a plug is to be placed in a casing or liner, it is necessary to verify a proper sealing element on the outside of the tubular. This has to be verified by old or new logs.

Fig. 5.2 illustrates an Acoustic Cement Log, which is considered as one of the most conventional methods to evaluate cement quality behind the casing.

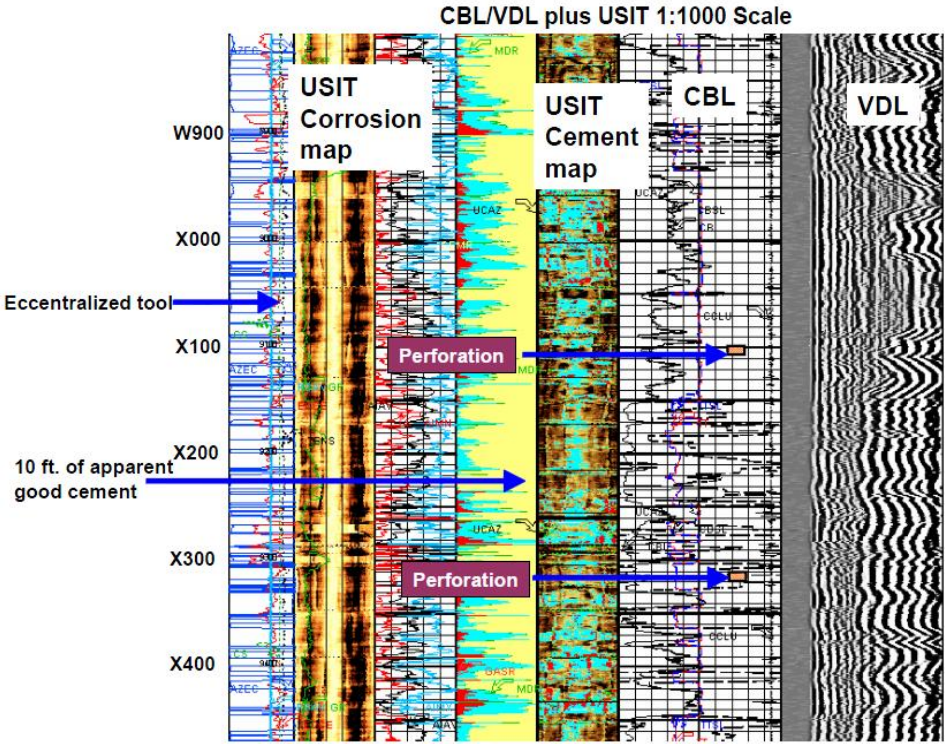


Fig. 5.2. USIT-CBL-VDL Log for evaluation cement behind the casing [19].

Two classes of acoustic logging tools exist:

- Sonic: Cement Bond Log (CBL) / Variable Density Log (VDL) or Segment Bond Tool (SBT)
- Ultrasonic: Ultrasonic imaging tool (USIT)

USIT logs provide a high-resolution, 360° scan of the condition of the casing-to-cement bond, while CBL/VDL gives an average volumetric assessment of the cement in the casing-to-formation annular space. SBT is a combination of CBL/VDL and pad sonic devices that provides a low-resolution map of the cement condition behind casing [19].

- ***Estimated formation fracture gradient.***

Fig. 5.3 illustrates a stratigraphic sequence and estimated pore and fracture pressure gradients from a well in the NCS. The fracture gradient will provide the maximum pressure at which the well barriers should be designed and tested.

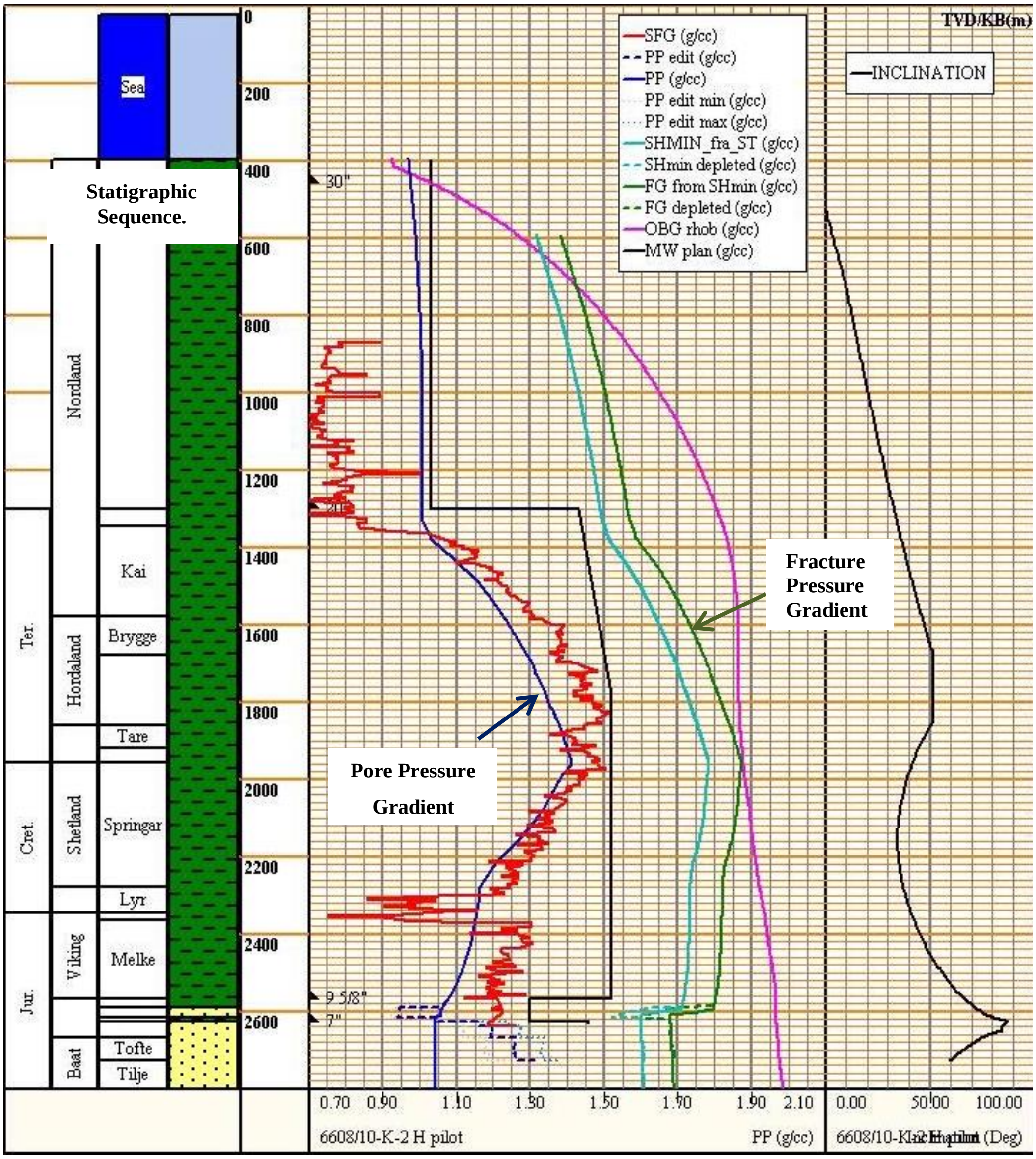


Fig. 5.3. Stratigraphic sequence, estimated pore and fracture pressure gradients [20]

- ***Specific well conditions.***

NORSOK D-010 [3], only provides some specific well conditions that should be considered like scale build up, casing wear, collapsed casing, fill. However, UKOOA is more specific and also includes issues like irretrievable radioactive sources, multilateral wells, high angle and horizontal wells, liner laps, control lines, electro submersible pump cables, gauge cables, HPHT wells, H_2S wells, CO_2 wells, gas wells and high GOR wells, Annular fluids, shallow permeable zones [21].

5.1.2 Phases and Typical design scenarios of P&A.

5.1.2.1 Phases of P&A.

It is not clearly stated in NORSOK-D010 [3], how to process or consider all the gathered information from Sect. 5.1.1. Different is the case when considering UKOOA [21] that suggests a valuable *Input Data Sheet*, which intends to give a better perception of all future work to be performed.

After the actual well to be abandoned has been analyzed, the already presented Chapter IV gives the design premises as intended by NORSOK-D010 [3]. It is inferred, however not stated in the Norwegian Standard, three clearly defined phases for designing a P&A program. This is different when considering the UK Standard. UKOOA [21] precisely states three well defined phases according to the work to be performed. These are given by:

- **Phase 1 – Reservoir Abandonment.**

Primary and secondary permanent barriers set to isolate all reservoir producing or injecting zones. The tubing may be left in place, partly or fully retrieved. The phase is complete when the reservoir is fully isolated from the wellbore [21].

- **Phase 2 – Intermediate Abandonment.**

Includes: isolating liners, milling and retrieving casing, and setting barriers intermediate barriers to isolate potential hydrocarbon or water-bearing permeable zones. Near surface cement may also be installed. The tubing may be partly retrieved, if not already performed in Phase 1. Complete when no further plugging is required [21].

- **Phase 3 – Wellhead and Conductor Removal.**

Includes: retrieval of wellhead, conductor, shallow cuts of casing string and cement filling of craters. Complete when no further operations are required for the well [21].

By looking at the comparison presented in Fig. 4.5 and combining with the new phase classification, now it is easy to conclude that Slot recovery neglects the operations performed in Phase 3.

5.1.2.2 Typical Scenarios of P&A.

NORSOK D-010 [3], suggests six typical example wells to show how the barrier configuration should be performed. Two of them correspond to temporary abandonment and four to permanent abandonment.

All of them are illustrated as WBSs in Appendix A and four of them will be briefly explained for better understanding. For the purpose, the two temporary abandonment scenarios and the permanent abandonment in Open hole and Multibore with slotted liners or sand screens scenario will be described.

The permanent abandonment in a perforated well scenario will not be covered and the scenario of permanent abandonment with Slotted liner in multiple reservoirs will be explained in detail in the example case presented in Sect. 5.3.

- **Temporary abandonment – Non-perforated well.**

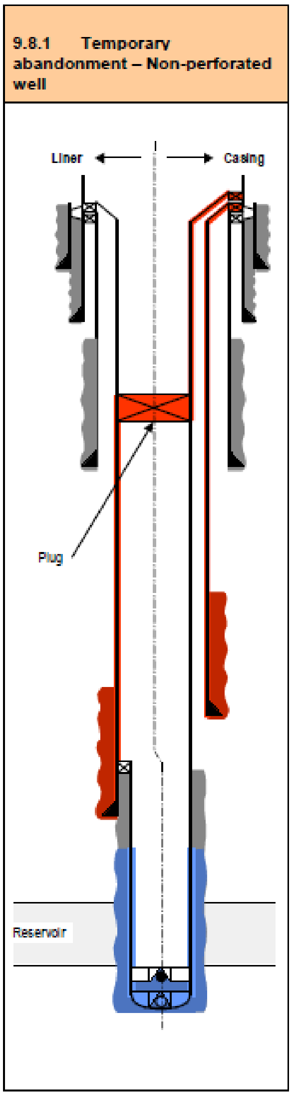
There might be many reasons for leaving a non-perforated well under temporary abandonment. Some examples could be enlisted as follows:

- ❖ Wellbore left due to geological uncertainties in exploration or development phase.
- ❖ Pilot hole in multilateral development well.
- ❖ Bad weather conditions, etc.

There are differences between an exploration and development well, since normally an exploration well experiences several geological uncertainties. Nonetheless, it could be also the case of a tricky development well with geological anomalies not previously foreseen.

Fig. 5.4 illustrates a non-perforated well under temporary abandonment conditions. The well scenario considers two possible casing configurations divided by a vertical semi-hyphen/dotted line. At the left side, a combination of one production casing string and one liner string and at the right side one complete casing string to surface.

The establishment of well barriers is as suggested in the right hand table of Fig. 5.4. From these figure, it is important to note that the shoe track is considered as first well barrier element. Likewise, that the cement behind the casing or liner should be verified and approved by means of an acoustic log. Finally, a shallow plug should be considered as a secondary well barrier and this could be either from approved plugging material (like cement) or a mechanical created device.



Well barrier elements	See Table	Comments
Primary well barrier, last open hole		
1. Cement plug	24	Shoe track.
2. Casing (liner) cement	22	
3. Casing (reservoir liner)	2	Un-perforated w/2 each float valves.
or		
1. Cement plug	24	Shoe track.
2. Casing cement	22	
3. Reservoir casing	2	Un-perforated w/2 each float valves.
Secondary well barrier, temporary abandonment		
1. Casing	2	
2. Casing cement	22	
3. Cement plug or mechanical plug	24 28	Shallow plug.
or		
1. Casing cement	22	
2. Casing	2	Intermediate
3. Wellhead	5	
4. Casing	2	Production casing.
5. Cement plug or mechanical plug	24 28	Shallow plug.

Note
None

Fig. 5.4. WBS Temporary Abandonment – Non-perforated well [3].

In case of choosing a mechanical well barrier device, it could be a RBP similar to the ones presented in Fig. 4.2 or a new technological development like the inflatable packer shown in Fig. 5.5. These can be retrieved after accomplishing their primary intention.

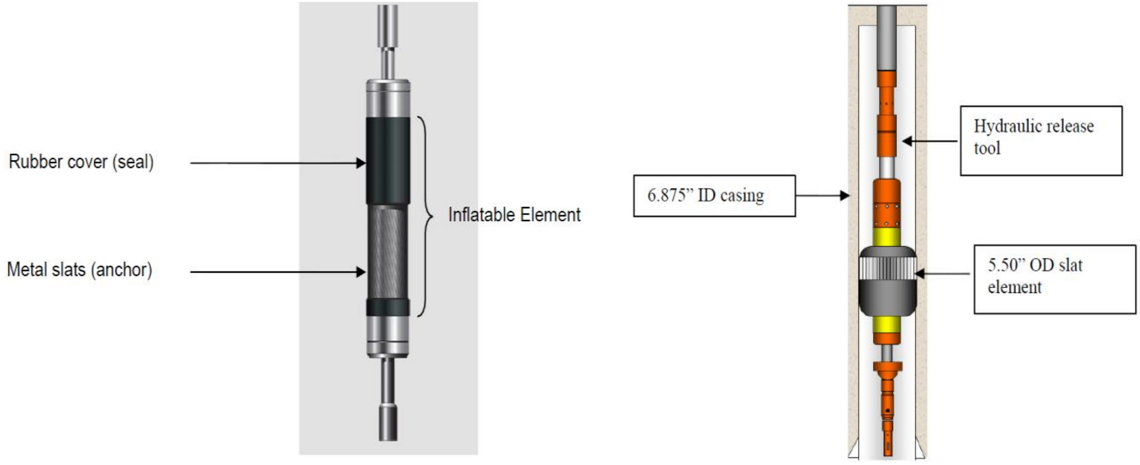


Fig. 5.5. Alternative Mechanical Well Barrier - Inflatable Barrier Plug (IBP) [22].

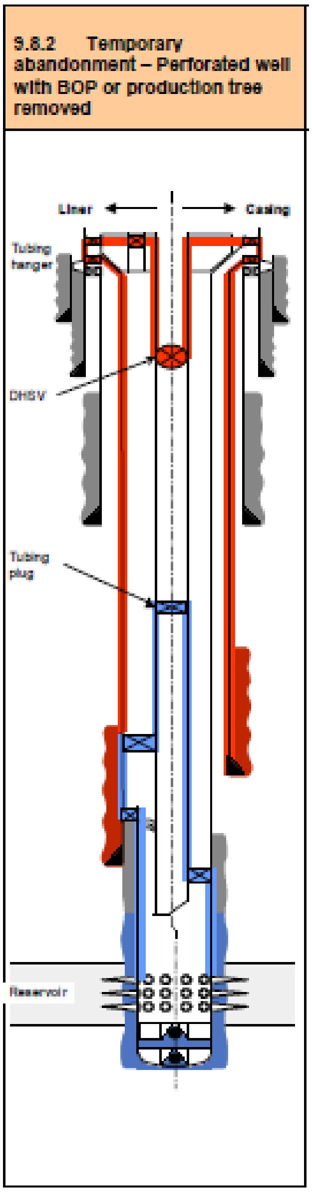
- **Temporary abandonment – Perforated Well with BOP or production tree removed.**

Another example scenario of a temporary well abandonment is illustrated as in Fig. 5.6. This scenario considers perforations at the reservoir section and represents the case when the well has been completed.

The WBS shows the barriers required, in this case if BOP or XMT is removed. Some of the many possible reasons are enlisted as follows:

- ❖ Maintenance of the BOP or production tree.
- ❖ Changing between a drilling/intervention phase and production phase or vice versa.
- ❖ Change of vessels between an intervention and a drilling operation, etc.

The well scenario, as illustrated in Fig. 5.6, presents the same casing configuration as in the previous temporary abandonment scenario. Thus, the vertical semi-hyphen/dotted line shows on the left side a Production/Liner casing combination and on the right side a complete casing string to surface.



Well barrier elements	See Table	Comments
Primary well barrier		
1. Casing (liner) cement	22	
2. Casing (liner)	2	Liner above perforations.
3. Liner top packer	43	
4. Casing	2	Below production packer.
5. Production packer	7	50 m below TOC in casing annulus.
6. Completion string	25	
7. Deep set tubing plug	6	
or,		
1. Casing cement	22	
2. Casing	2	Above perforations.
3. Production packer	7	
4. Completion string	25	
5. Deep set tubing plug	6	
Secondary well barrier, reservoir		
1. Casing cement	22	Above production packer.
2. Casing	2	Common WBE, between liner top packer and production packer.
3. Wellhead	5	
4. Tubing hanger	10	
5. Tubing hanger plug	11	For SSWs.
6. Completion string	25	Down to SCSSV.
7. SCSSV	8	
or,		
1. Casing cement	22	Intermediate casing.
2. Casing	2	Intermediate casing.
3. Wellhead	5	
4. Tubing hanger	10	
5. Tubing hanger plug	11	For SSWs.
6. Completion string	25	Down to SCSSV.
7. SCSSV	8	

Note
None

Fig. 5.6. WBS Temporary Abandonment – Perforated well with BOP or production removed [3].

Different from Fig. 5.5, Fig. 5.6 considers a completion string inside the well for both casing configuration scenarios and their respective production packers. On the left side of the figure the production packer is located in the production casing. On the right side it could be located anywhere since there is only one casing string.

The establishment of well barriers is again as suggested in the right hand table of Fig. 5.6. Regardless of the casing configuration, a deep tubing plug should be located to close primary well barrier envelope. This again could be achieved by a RBP or any mechanical plug alternative. Likewise, as part of the completion string, the Surface Control Subsurface Valve (SCSSV) closes the secondary well barrier envelope.

- **Permanent abandonment – Open Hole.**

Fig. 5.7 illustrates a permanent abandonment - Open Hole scenario. Here, indistinct from the previous two temporary scenarios, the same casing configuration is given and separated by the semi-hyphen/dotted line. However, this scenario considers an open hole section below the respective casing shoe.

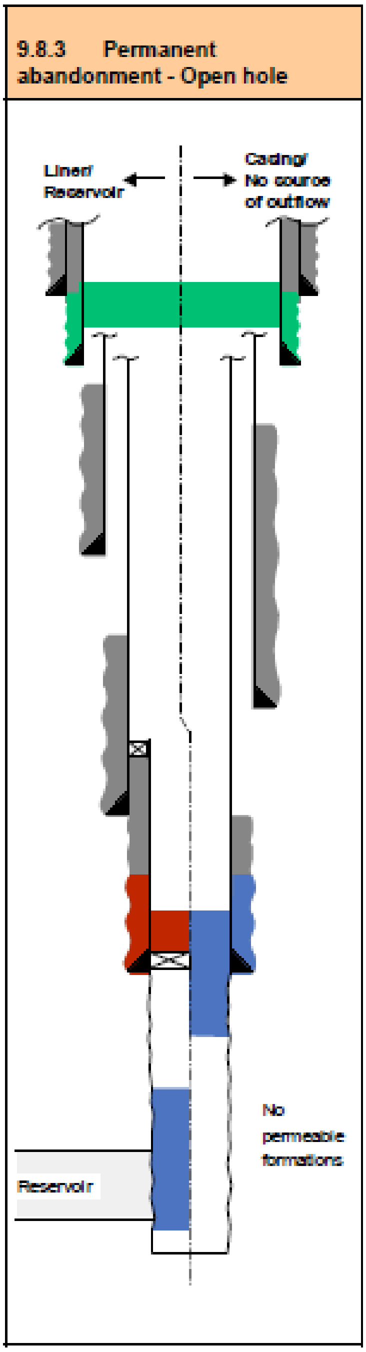
As shown in the Fig. 5.7, at the left side of the semi-hyphen/dotted line below the liner casing shoe a reservoir section is considered in the open hole. Meanwhile, at the right side no permeable formations are considered below the production casing shoe.

In Fig. 5.7, it easy to identify the three phases mentioned in Sect. 5.1.2.1, especially when considering the left side of the semi-hyphen/dotted line. Different is the case on the right side, which since there is no existence of source of inflow only a primary and an open hole to surface well barriers are needed for the P&A design.

- **Permanent abandonment – Multibore with slotted liner or sand screens.**

Fig. 5.8 shows a relative modern well profile and a multibore well completion using sand screen or slotted liner for production control. Here, it is possible to notice two reservoir sections.

Fig 5.8, illustrates again the three phases mentioned in Sec. 5.1.2.1 regardless the complexity of well profile and completion. However, the idea of explaining this scenario is due to the inclusion of the barrier between the reservoirs criteria.



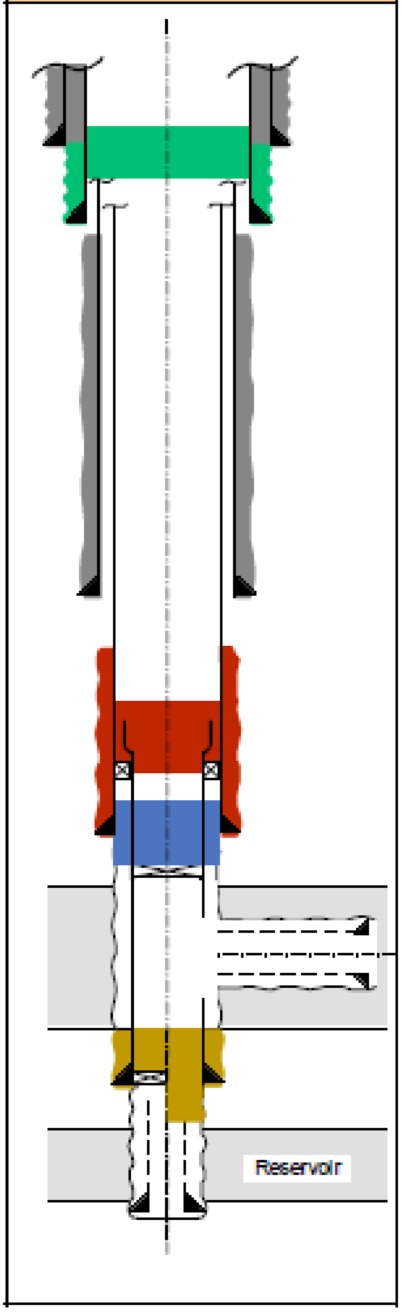
Well barrier elements	See Table	Comments
Primary well barrier		
1. Cement plug	24	Open hole.
or, ("primary well barrier, last open hole"):		
1. Casing cement	22	
2. Cement plug	24	Transition plug across casing shoe.
Secondary well barrier, reservoir		
1. Casing cement	22	
2. Cement plug	24	Cased hole cement plug installed on top of a mechanical plug.
Open hole to surface well barrier		
1. Cement plug	24	Cased hole cement plug.
2. Casing cement	22	Surface casing.

Notes
a. Verification of primary well barrier in the "liner case" to be carried out as detailed in Table 22.
b. The well barrier in deepest casing shoe can for both cases be designed either way, if casing/liner cement is verified and O.K.
c. The secondary well barrier shall as a minimum be positioned at a depth where the estimated formation fracture pressure exceeds the contained pressure below the well barrier.

Fig. 5.7. WBS Permanent Abandonment – Open hole [3].

The well barrier between reservoirs, as written in the *"Notes"* on the lower right side of Fig. 5.8, states that it could act as a primary well barrier for the deep reservoir, and that the primary well barrier for the shallow reservoir may be considered as the secondary well barrier for deep reservoir. The last is true if this is designed to take the differential pressures for both formations.

9.8.5 Permanent abandonment - Multibore with slotted liners or sand screens



Well barrier elements	See Table	Comments
Barrier between reservoirs		
1. Casing cement	22	
2. Cement plug	24	Cased hole.
or,		
2. Cement plug	24	Transition plug across casing shoe.
Primary well barrier		
1. Cement plug	24	Across wellbore and casing shoe.
Secondary well barrier, reservoir		
1. Casing cement	22	
2. Cement plug	24	Casing plug across liner top.
Open Holes to surface wellbarrier		
1. Cement plug	24	Cased hole cement plug.
2. Casing cement	22	Surface casing.

Notes
1. The "well barrier between reservoirs" may act as the primary well barrier for the "deep" reservoir, and "primary well barrier" may be the secondary well barrier for "deep" reservoir, if the latter is designed to take the differential pressures for both formations.
2. Secondary well barrier shall not be set higher than the formation integrity at this depth, considering that the design criteria may be initial reservoir pressure, as applicable in each case.

Fig. 5.8. WBS Permanent Abandonment – Multibore with Slotted Liner or Sand Screen. [3]

Likewise, the second note states that the secondary well barrier shall not be set higher than the formation integrity at this depth, considering that the design criteria may be initial reservoir pressure, as applicable in each case.

5.2 Platform vs Subsea P&A.

All the theory presented so far focuses directly on well abandonment. However, Norwegian regulations or Standards do not distinguish between Platform and Subsea P&A on the NCS. Therefore, this section will intend to present some characteristics considering both of them and try to give a better understanding of the work scope that should be performed.

Nonetheless, in order to respect the scope of the present thesis, this will be briefly described and explained by graphical figures.

5.2.1 Field development decision gap.

The already adopted decision on how to drill and produce an offshore field will have direct impact on future P&A operations.

An example could be adopted from a very recent and still planned field development like the Ivar Aasen field. This field, located in the northern part of the Norwegian North Sea, shares licenses between Det Norske (operator), Statoil and Bayerngas Norge.

Fig. 5.9. Ivar Aasen Field development location [24].

The field development comprises of three discoveries named Ivar Aasen (PL 001B), West Cable (PL 242) and Hanz (PL 028B) [23]. The location of the three of them is illustrated in Fig. 5.9.

For the field development, the wells on Aasen and West Cable will be drilled from a fixed platform, while the wells on Hanz will be drilled from a template that is connected to the platform as shown in Fig. 5.10.

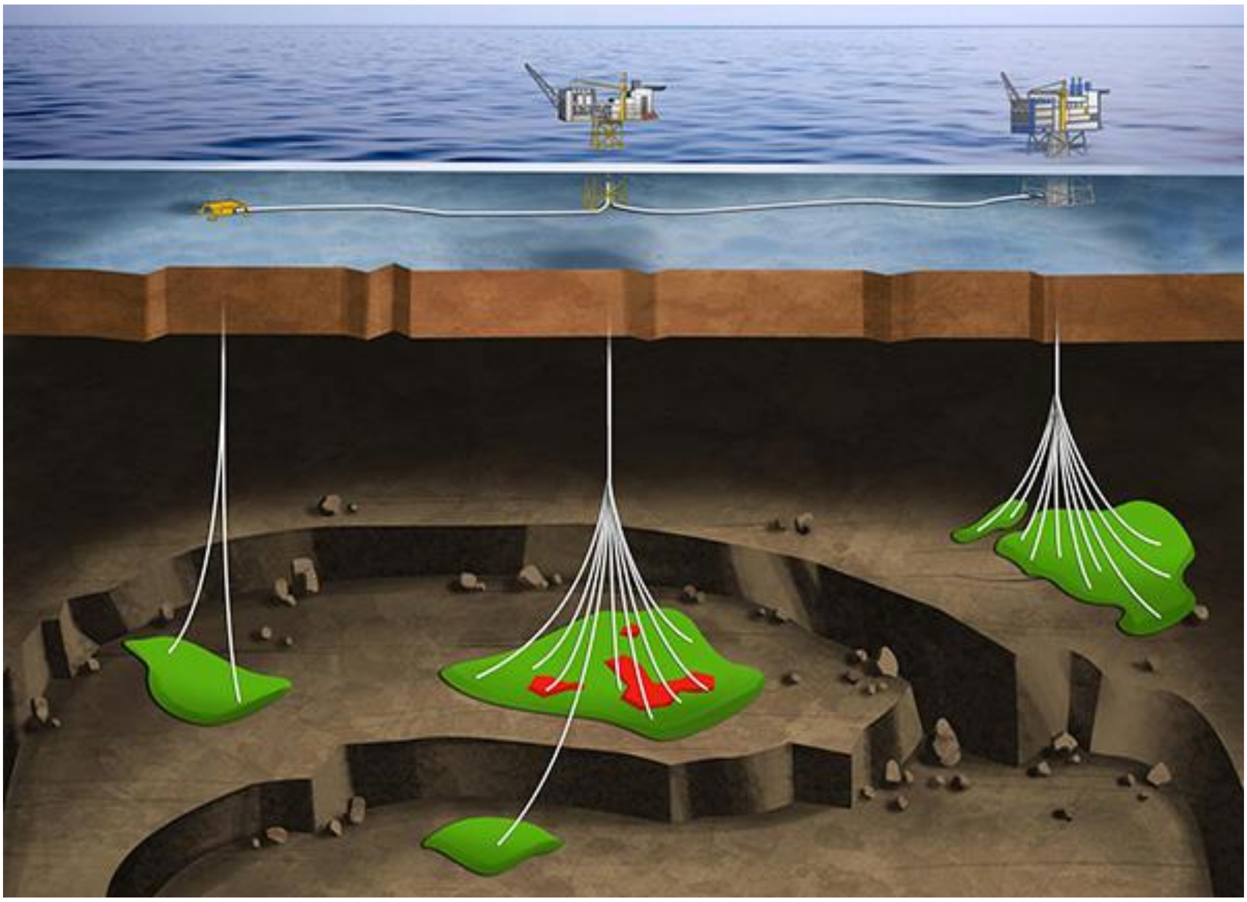
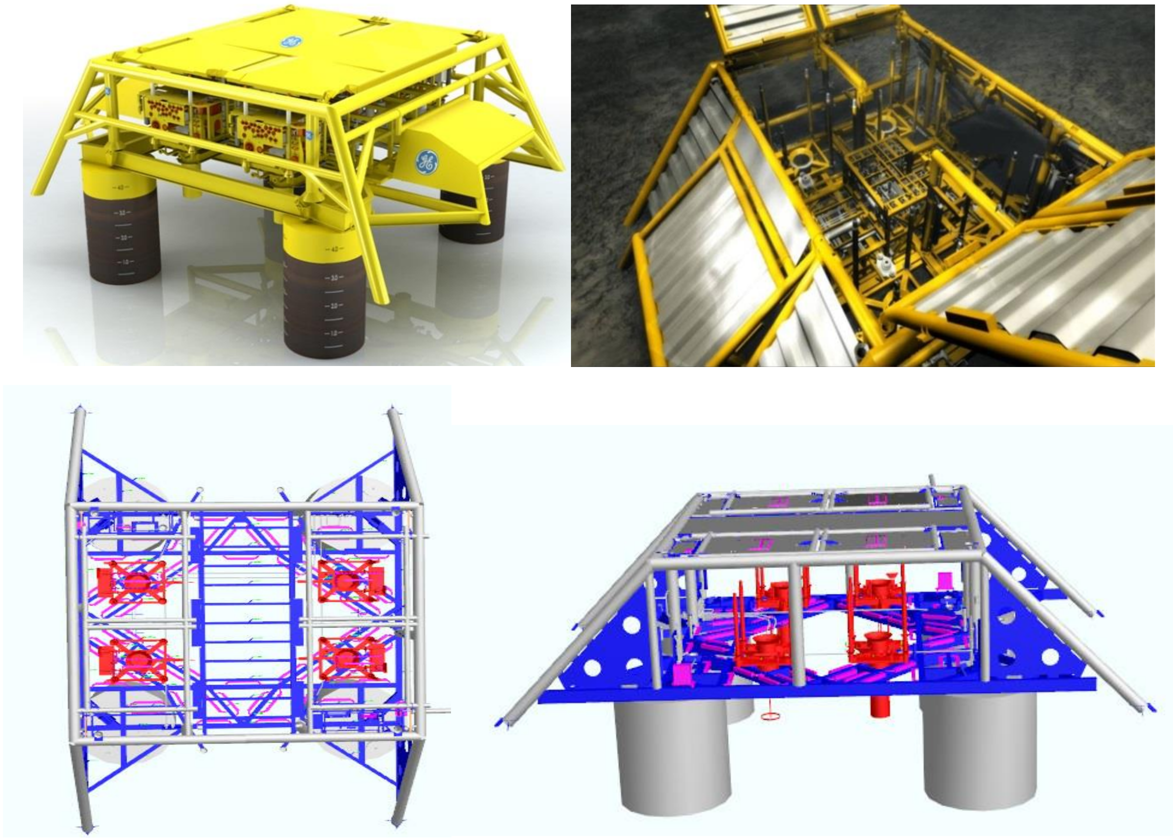
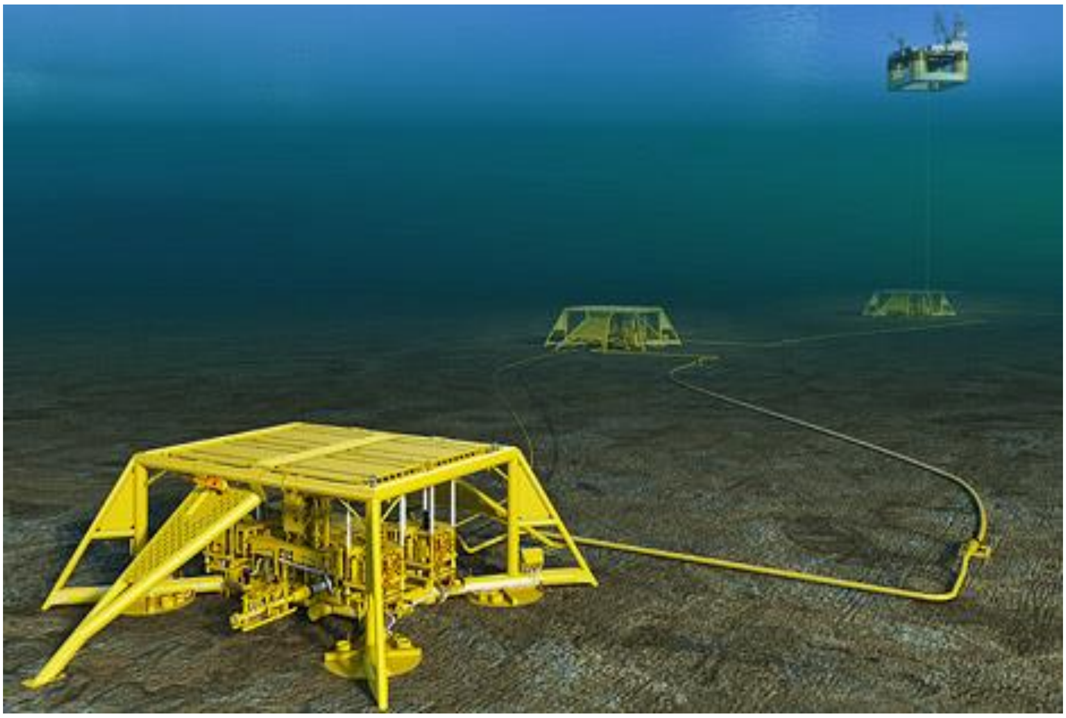


Fig. 5.10. Subsea and Platform Ivar Aasen Field development [23].

In this case, the drilling decision of using a pre-drilled subsea template (shown in Fig. 5.11) or using the platform well slot (shown in Fig. 5.12) already sets the requirements for the future P&A operations as it will be later explained.



a. Subsea Templates



b. Mobile Offshore Drilling Unit (MODU)

Fig. 5.11. Subsea Template and MODU Drilling [25].

a. Conductor Guides

b. Platform Well Slots

Fig. 5.12. Conductor Guides and Platform Slots [26].

5.2.2 Platform P&A.

One illustrative example of Platform P&A is presented in SPE 92165 - Abandonment of the NW Hutton Platform wells [27]. Here, the abandonment strategy adopted by the operator was divided in two phases:

- P&A Phase 1: Full abandonment of the Reservoir.
- P&A Phase 2: Well abandonment.

If relating these P&A phases with the ones presented in Sect. 5.1.2.1, P&A Phase 1 will correspond to Phase 1 and Phase 2 and P&A Phase 2 will be related to Phase 3.

For this particular case, P&A Phase 1 was performed in the same manner for both the Platform or Subsea drilled wells. However, the operations performed in P&A Phase 2 are the ones that sets the difference between both of them.

As mentioned in the SPE 92165 [27], the platform wells were drilled with a conventional 5 1/2” production tubing, 9 5/8” production casing, 13 3/8” intermediate casing, 18 5/8” surface casing and 26” conductor casing.

The abandonment of the wells was divided into two campaigns. The first one in 1993, where 13 wells were subject to P&A Phase 1 abandoned including retrieval of production tubing and production casing. The second campaign was performed between May 2002 and April 2003. Here, the remaining 27 wells went through P&A Phase 1 abandonment but here all tubulars were left in place.

Hence, the first task for P&A Phase 2 was to recover the tubulars left in place for the 27 wells. The details are mentioned in SPE 92165 [27] and will be left to the reader’s consideration.

The second task for P&A Phase 2 was to perform operations as the ones described in Phase 3 of Sect. 5.1.2.1. According to the reference paper [27], the cut for retrieving the wellhead and following casings was made 10ft below seabed as established by the UKOOA regulation [21].

In case of a Norwegian Field, like the Ivar Aasen example, this cut should be done at 5m below sea bed as required by NORSOK D-010 [3]. The wellhead and following casings retrieval details are also well explained in the SPE 92165 [27]. However, they will not be mentioned due to minor relevance for the present project.

5.2.3 Subsea P&A.

The wells that were drilled by using the subsea template containing a 5 1/2" production tubing, 9 5/8” casing below the template and 10 3/4" tieback as production casing, 13 3/8” casing/tieback and 20” conductor/tieback [27].

The issues related to performing the second task of P&A Phase 2 were slightly different from the ones presented for the Platform P&A. According to the reference SPE paper [27], the template wellheads were pinned into the template and would require an overpull in excess of one million pounds to shear out. In any event the wellheads were 1” diameter larger than the conductor guides.

The solution that came out was cutting the tieback string 20ft above the seabed in order to maintain access to the wells. Subsequently, the template was removed and after that the cutting and retrieval operation continued as stated by Phase 3.

One should note that the NW Hutton Field had a combination of subsea template drilled wells and platform drilled wells under the same platform jacket. The case will be different for the Ivar Aasen Field, where the Subsea Template for the Hanz field will be at some distance from the Ivar Aasen production platform. Hence, when performing the abandonment of the Hanz field the template again might challenge the operation only if the well design is the same as the considered by the NW Hutton Field.

The template challenge is only one of the many issues that can be different between Platform and Subsea P&A. Another example could be the type of rig that can be used in Subsea P&A.

Fig. 5.13 illustrates different rigs for accessing subsea wells. SPE 148859 – Abandonment of offshore exploration wells using a Vessel Deployed System for cutting and Retrieval of Wellheads [29], shows the actual intention of transferring activities normally performed by a Category “C” rig into a Category “A” vessel. Nevertheless, this will not be explained due to the extension of the topic and in order to follow the scope of the present project.

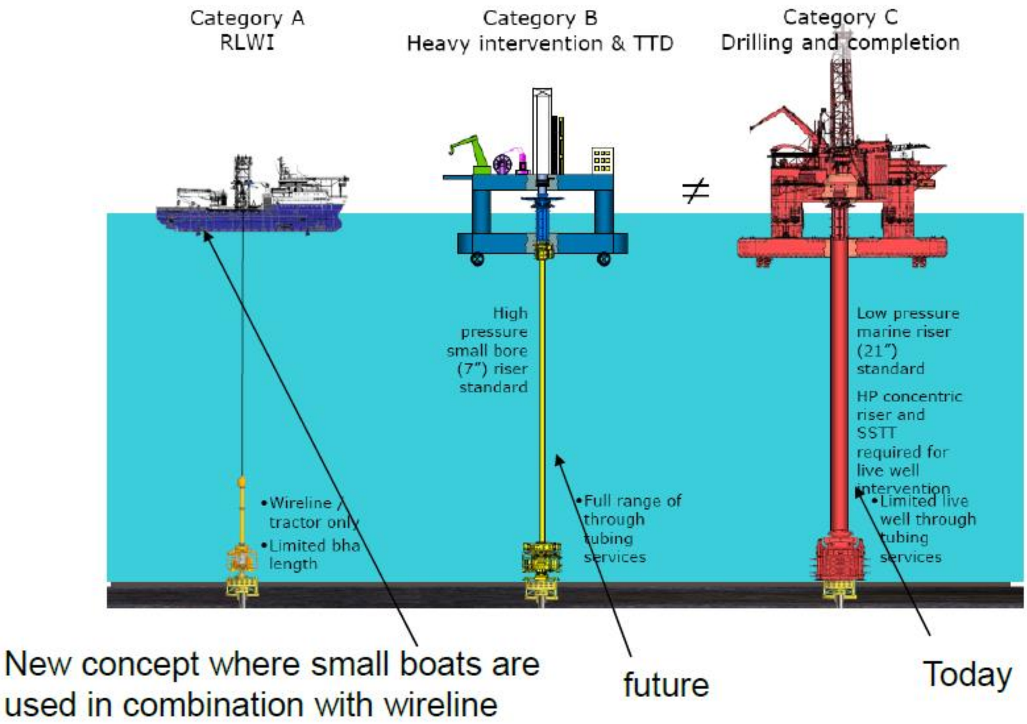


Fig. 5.13. Rig Types for accessing Subsea Wells [28]

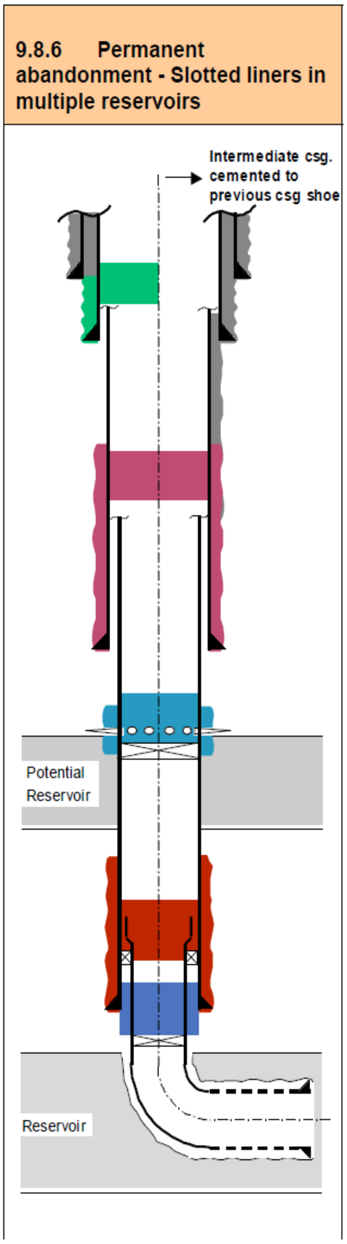
5.3 Example Case: Detailed procedure for a Conventional Platform P&A.

This section intends to present an example of a conventional set of operations for a Platform P&A. For the purpose, one of the typical scenarios suggested in NORSOK – D010 [3] will be taken into consideration.

Since four of the six scenarios were already presented in Sect. 5.1.2, one of the two remaining ones will be considered. Hence, by choosing the NORSOK scenario *Permanent abandonment – Slotted liners in multiple reservoirs*, the well will be as illustrated in Fig. 5.14 and better detailed in Appendix A.6.

Fig. 5.14 shows how the well will look after the corresponding P&A operations. However, the initial scenario is as illustrated in Fig. 5.15. Here, the casing configuration is similar to the one described in SPE 92165 [27] and the scenario is similar to the left side of the vertical semi-hyphen/dotted line shown in Fig. 5.14. In other words, the 13 3/8” intermediate casing is not cemented up to the previous 18 5/8” casing shoe.

For this scenario, the logging run for evaluating cement behind the 7" Liner will be neglected since it is not feasible to pump cement through the slotted liner. A logging run could be justified if the intention is to evaluate the bond between the formation and casing. However, for simplicity and since formation was conventionally not accepted as well barrier until recently (See Sect. 6.2.3.3) a section milling operation will be predefined for that liner.



Well barrier elements	See Table	Comments
Primary well barrier, deep reservoir		
1. Cement plug	24	Through liner and across casing shoe/Open hole transition.
Secondary well barrier		
1. Casing cement	22	
2. Cement plug	24	Across liner top.
Primary well barrier, shallow reservoir		
1. Cement plug	22	Squeezed into perforated casing annulus above potential reservoir.
Secondary well barrier, shallow reservoir		
1. Casing cement	22	
2. Cement plug	24	
Open holes to surface well barrier		
3) Cement plug	24	Cased hole.
4) Casing cement	22	Surface casing.

Notes
1. Secondary well barrier shall not be set higher than the formation integrity at this depth, considering that the design criteria may be initial reservoir pressure, which may develop over time.
2. The case on the right hand side indicates that the intermediate casing string is cemented into surface casing, i.e. with no open annulus to surface. Hence, no open holes to surface well barrier is required.

Fig. 5.14. Permanent Abandonment - Slotted liners in multiple reservoirs. [3]

The abandonment sequence can be summarized in 24 steps. These are given as follows and are illustrated from Fig 5.16 to Fig. 5.25.

Step 1. Rig Mobilization.

For this particular example case, a Platform Rig has already been chosen. However, in case of a subsea well other vessels or combination of vessels could be chosen according to the work-scope of the abandoned well (See Fig. 5.13).

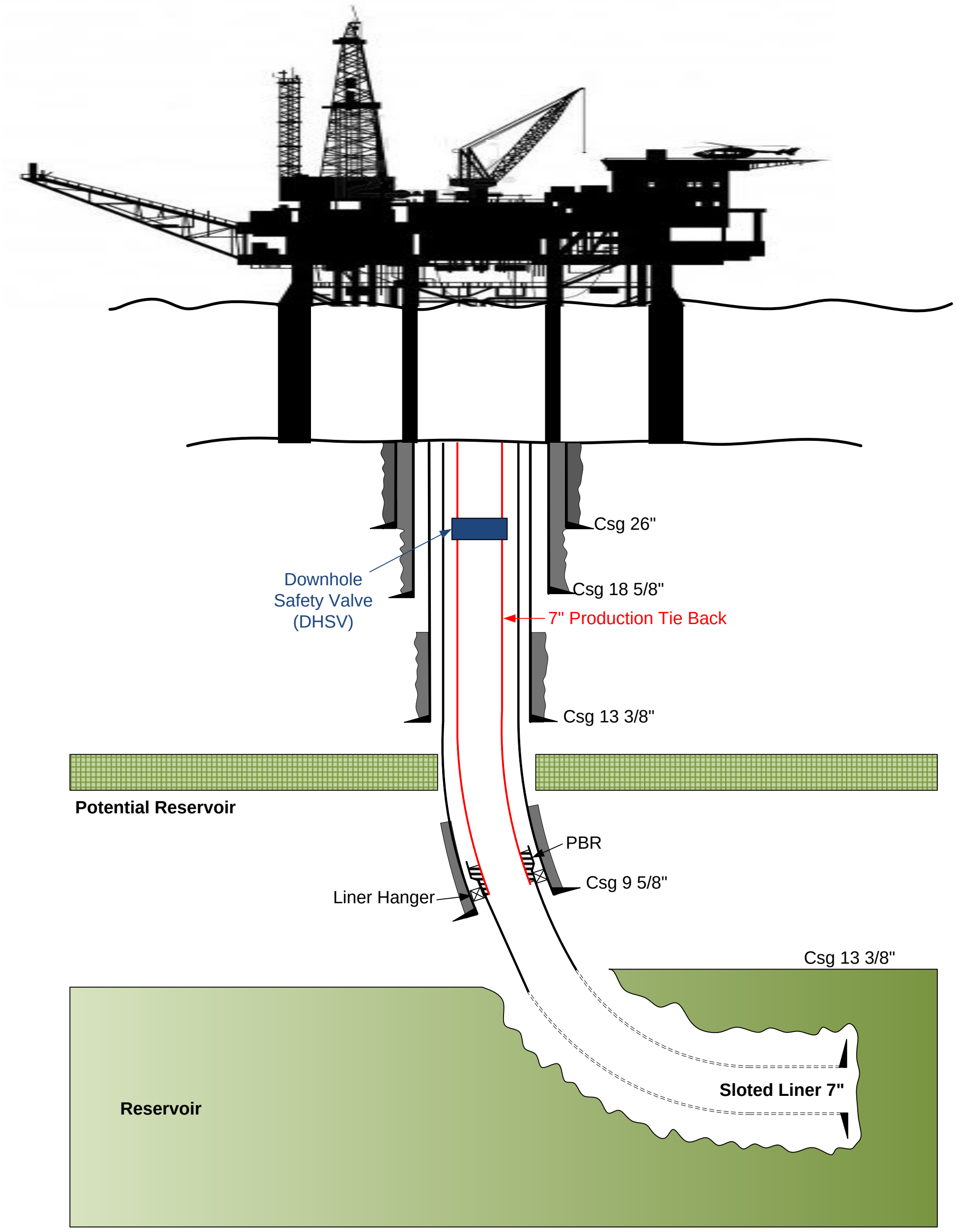


Fig. 5.15. Example Case: Well Schematics - Step 1.

Step 2. Deploy a Retrievable Downhole Safety Valve (rDHSV).

A rDHSV could be deployed with either Slickline or Wireline and set at a certain distance from the 7” Liner Hanger. Normally, a rDHSV is set in a nipple profile though it could also be set inside the full body part (not in front of the slots) of the 7” Slotted Liner. In this example, it will be set at some meters below the previous production casing shoe or for better understanding where the full body area is guaranteed.

Step 3. Killing the Well.

Low pressures and flow rates are expected which is normally the reason when an operator company decides to abandon a well. However, this does not exactly mean the exemption of hazards with respect to safety and the environment. Therefore, before abandoning the well a killing procedure should be performed in order to reestablish an overbalance or controlled condition.

This example will consider one of the most typical well killing procedures, which is normally known as *Bullheading*. For the purpose, brine is pumped through the 7” tie back production tubing by using the cementing unit pumps for accuracy in pumping rate and pressure.

The usage of the rDHSV will avoid any possible reaction from the reservoir against the Bullheading fluid and will be useful until the hydrostatic column is re-gained. At this point, it is expected that all the produced fluid inside the tubing is forced back into the corresponding formation and the hydrostatic pressure is higher than the formation pressure.

Step 4. Retrieve the retrievable Downhole Safety Valve (rDHSV).

Since the hydrostatic column is in place to act as primary well barrier, the 7” production tieback and the existing DHSV can act as secondary well barriers. Therefore, the rDHSV is no longer required and could be retrieved.

This fishing and retrieval procedure is normally performed with a Slick line unit due to simplicity and cost effectiveness.

Step 5. Set a Mechanical Plug in the 7” Slotted Liner.

By following the WBS illustrated in Fig. 5.14, a mechanical plug should be set inside the 7” Slotted Liner at some meters below the previous production casing shoe. Again, the criteria for setting the plug should be the same as the one described in Step 2 or for simplicity it could be set in the exact same depth where the rDHSV was previously set.

In this example, the mechanical plug will perform as cement retainer, which is logical due the slots and the impossibility of balancing a viscous plug as foundation for the plugging material.

A mechanical plug could be deployed either with Wireline or by using tubing. It should be remarked that if the deployment is performed with tubing, it will take a longer time due to connections.

Step 6. Replacing XMT with BOP.

Since the well barriers are still considered as in Step 4, it is possible to remove the XMT and replace for a BOP. The intention of including the BOP is due to former tripping operations and the presence of a potential upper reservoir.

Step 7. Lift up, circulate and wash behind the 7” Production Tieback.

The Bullheading operation performed in Step 3 left brine inside the 7” production tieback and slotted liner. However, now the attention moves to the fluid behind the 7” production tubing. In a conventional completion operation, completion fluid is left on this annular space and normally this fluid is a combination between fresh water and other additives which intend to prevent corrosion and water degradation.

Therefore, in order to equalize the fluids between the tubing/casing annulus a lift up operation is proposed followed by a brine circulation for washing.

Since the 7” production tieback is latched to the PBR, it should be easy to lift the string just by using the pulling capacity from the derrick. In a very positive scenario, an internal fishing tool could be deployed and latched to the tubing hanger. Thereafter, an overpull on the tubing should unlatch the string from the PBR and give the desired condition for circulating.

A non-desired event could arise if the bond between the tubing and PBR is strong enough that it hinders unlatching by the overpull. Then, some other operations should be performed to create this tubing/casing connection (U-tube connection) and at the same time the unlatching condition for future retrieval.

If the negative scenario is produced, for simplicity it is easier to sever the tubing at the required depth by deploying Wireline with chemical cutters or explosive jets [30]. Subsequently, again an internal fishing tool could be used to latch the tubing hanger and lift the tubing string for a couple of meters to create the required space for circulating.

Step 8. Retrieving the 7” Production Tieback.

The previous step has already presented the unlatching or cutting condition of the 7” production tieback. Likewise, the tubing was also fished and lifted hence the present step only includes the disconnection or breaking of the tubing joints for future storage or disposal.

Step 9. Evaluate 9 5/8” production casing cement quality.

Sect. 5.1.1 already introduces the Acoustic Cement Log as one of the most conventional methods to evaluate cement quality.

In case of bad cement bonding corrective operations should be considered as the one described in Step 10.

Step 10. Section Milling of the 7” Slotted Liner and/or 9 5/8” Production Casing.

By following the WBS illustrated in Fig. 5.14 and in order to fulfill the cross section integrity as the one illustrated in Fig. 4.3, is necessary to perform a conventional section milling above the mechanical plug set in Step 5. Normally, this section milling will start at some meters below the liner hanger yet still inside the previous production casing shoe.

Section milling could also be applied in case of bad cement of the 9 5/8” casing as a corrective operation.

Step 11. Setting the primary well barrier for the deep reservoir.

Since a full cross sectional window has already been created in the 7” Slotted Liner according to Step 10, the primary well barrier for the deep reservoir can now be established.

For this example, a single tubing assembly is deployed. Subsequently, the primary well barrier is established by balancing a cement plug just above the mechanical plug and until covering the complete 7” milled window.

According to NORSOK – D010 [3], the existence of this plug should be verified by tagging the top of it and should be tested with a positive or negative pressure test to ensure pressure integrity (See Table 24 from NORSOK – D010 [3]). Therefore, a wait on cement time (WOC) should be considered and also all the corresponding pressure integrity tests.

In this case and for all the remaining plugs considered as well barriers in this example, cement is considered as the conventional plugging material.

Step 12. Setting the secondary well barrier for the deep reservoir.

Before setting the secondary well barrier, optimal conditions are expected for the 9 5/8” casing either by good cement or by the one made with the corrective section milling operation.

For this example, considering that either Step 9 or Step 10 has already been performed, the tubing assembly deployed in Step 11 still remains in the wellbore. In that case, the assembly should be lifted until the top of the liner hanger and thereafter proceed with balancing a cement plug at that location. In other words, establishing the secondary well barrier.

Again after WOC, the plug should be tagged and pressure integrity tested.

Step 13. Set a Mechanical Plug in 9 5/8" Casing.

According to the WBS shown in Fig. 5.14, a mechanical plug should be set inside the 9 5/8" casing at some meters below of what it is considered the top of the upper reservoir.

This mechanical plug, similar to one explained in Step 5, will act as cement retainer and could be deployed by using the same techniques.

Step 14. Perforate above the potential upper reservoir.

Even if the upper reservoir has not even been perforated and produced, it is still necessary to consider it as a potential hazard and as a source of flow. Therefore, according to NORSOK – D010 [3] a primary and secondary well barriers should be established.

By using a conventional assembly composed by a Canon, Casing Collar Log (CCL), and Gamma Ray (GR) and if deploying with Wireline, a fast and very precise perforation could be achieved just at the top of the potential reservoir. This perforation is made in order to establish a connection between the inner and outer annular space of the 9 5/8" casing.

CCL provides a reading of the exact position of the casing couples. Explained in technical words, sections where the magnetic tool detects a higher concentration of metal as is normal in the case of couples.

Meanwhile, GR provides a correlation tool between the previous open hole GR log and the actual cased hole GR log. Actually, both should show almost the same peaks.

Step 15. Setting the primary well barrier for the shallow reservoir.

With the already punched perforations and the cement retainer at location, now it is possible to establish the shallow primary well barrier and fulfill the cross section integrity required by NORSOK – D010 [3]. (See Fig. 4.13)

In this example, a conventional single tubing assembly is deployed including a case hole squeeze packer [31]. The primary cement plug for the shallow reservoir is balanced above the cement retainer and different from the previous cement plugs presented in Step 11 and Step 12, the case hole squeeze packer is set and a squeezing operation should be considered in order to induce cement to pass through the perforations.

Normally, the squeeze operation is performed immediately after balancing the cement plug just by increasing pressure above the plug. One should note that the squeezing pressure, in any case, should not be higher than the fracture pressure in order to avoid an undesired formation fracture. Once again, in order to validate the plug it should be tagged and pressure tested.

Step 16. Nipple down C-Section.

The normal sequence of events to nipple down the C-section is as the following:

- Install a shallow Back Pressure Valve (BPV) at some meters from the top of the well.
- Nipple Down the BOP
- Nipple Down the C-section
- Nipple Up the BOP
- Retrieve the shallow BPV.

Step 17. Cut and retrieve the 9 5/8” production casing.

Since the shallow reservoir has already been isolated, now it is possible to cut and retrieve a section of the 9 5/8” casing string.

For this example, the cut will be made at some meters below the relative Top of Cement (TOC) of the 13 3/8” intermediate casing. Normally, this cut is performed at least 100 meters below the previous TOC such that a consistent plug can be placed with plugging material inside the 13 3/8” casing.

For the purpose, a single milling tool could be used and the retrieval operation will be made by using a spear set close to the casing hanger. Actually, since the 9 5/8” casing is not cemented to surface, pulling the casing should not represent a major concern to the operation.

Step 18. Evaluate 13 3/8” intermediate casing cement quality.

In order to set the secondary well barrier of the shallow reservoir, first it is necessary to evaluate the cement quality behind the casing. The operational procedure and tools are as the ones suggested in Step 9 and if necessary corrective measures should be considered as in Step 10.

To keep it simple and since an example of corrective measure was already explained in Step 10, good cement behind the casing will be assumed.

Step 19. Setting the secondary well barrier for the shallow reservoir.

A single tubing assembly is deployed and the secondary well barrier is established by balancing a cement plug. Here, the plug should be set above the cut performed in Step 17 and at a desired depth where good cement behind the casing has been defined as in Step 18.

The WBS illustrated in Fig. 5.14 does not show a mechanical plug as cement retainer for this well barrier. Hence, it could be inferred that a viscous plug was balanced before the cement as foundation base.

Step 20. Nipple down B-Section.

The sequence of events to Nipple down the B-section is similar to one presented in Step 16.

Step 21. Cut and retrieve the 13 3/8" intermediate casing.

For this example, the cut will be made some meters above the casing shoe of the 18 5/8" surface casing. The cutting and retrieving procedure will be similar to the one suggested in Step 17.

Step 22. Evaluate 18 5/8" surface casing cement quality.

This is the same procedure as the one presented in Step 9 and Step 18.

Step 23. Setting the Open hole to surface well barrier.

In this step the last well barrier is established. Here, the operational procedure and criteria is similar to the one presented in Step 19.

Step 24. Cut and retrieve the 18 5/8" surface casing and 26" conductor casing.

Initially the wellhead and the corresponding 18 5/8" and 26" casings should be cut 5 meters below the seabed and retrieved to surface in compliance with NORSOK-D010 [3].

Conventionally, cut and retrieval are performed in two different separate operations similar to the ones presented in Step 17 and 21.

If relating the 24 Steps presented in the Example Case with the phases in Sect. 5.1.2.1. The following could be summarized:

- **Phase 1 – Reservoir Abandonment.**

  Steps 2 to 12 shown in Fig. 5.16 to Fig. 5.18.

- **Phase 2 – Intermediate Abandonment.**

  Steps 13 to 23 shown in Fig. 5.19 to Fig. 5.24.

- **Phase 3 – Wellhead and Conductor Removal.**

  Step 24 shown in Fig. 5.25.

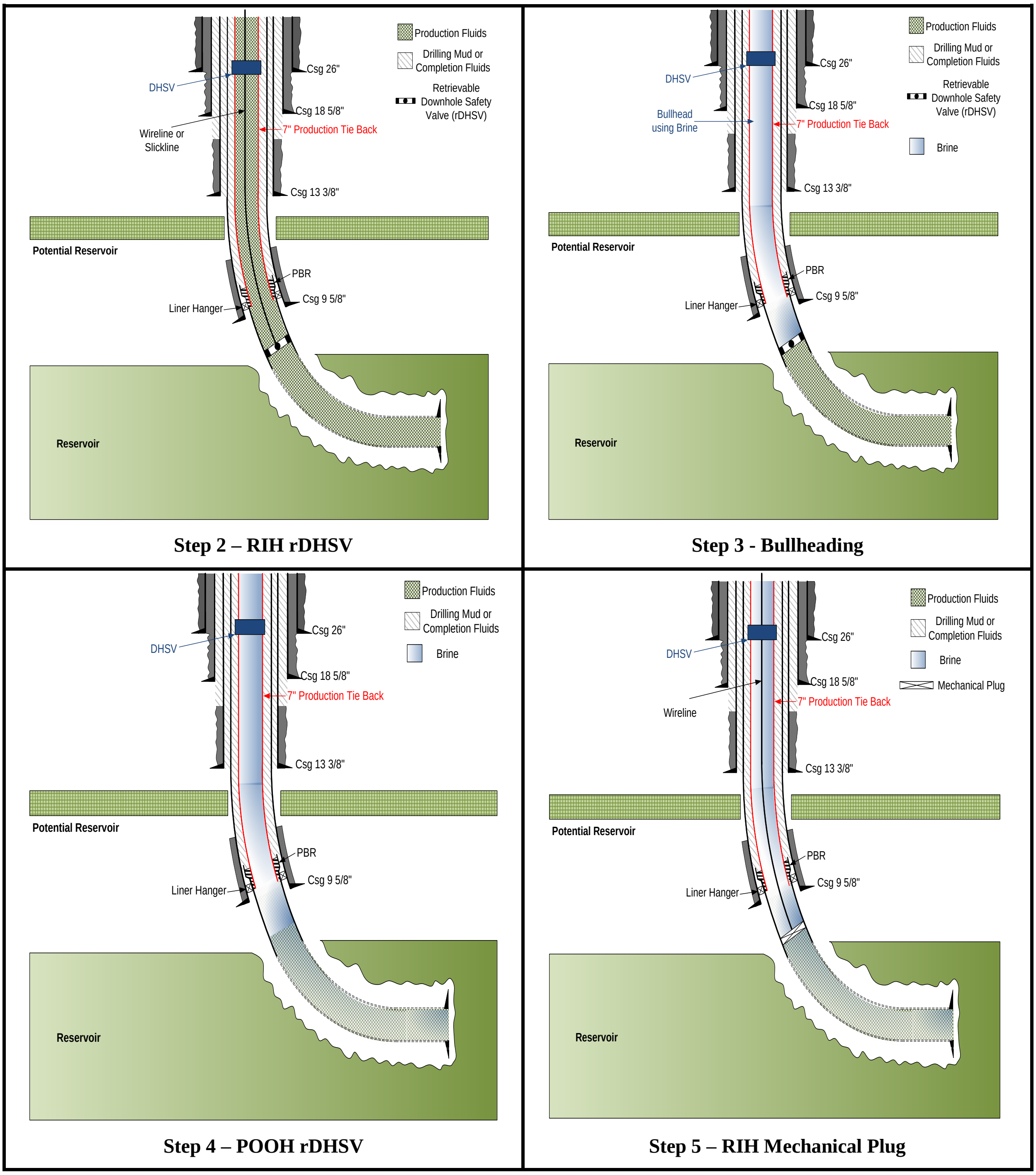
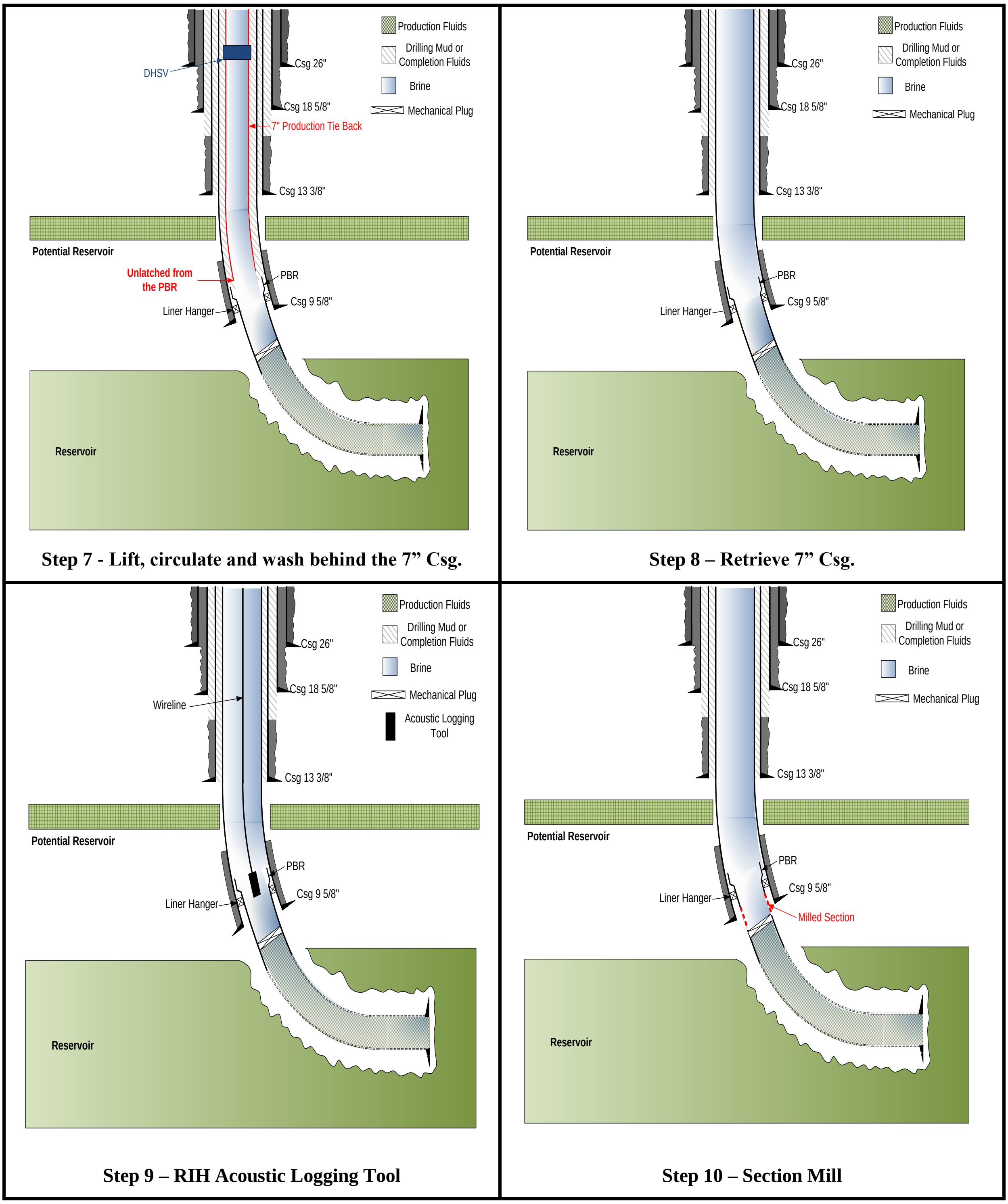


Fig. 5.16. Example Case: Permanent Abandonment Steps 2 to 5.



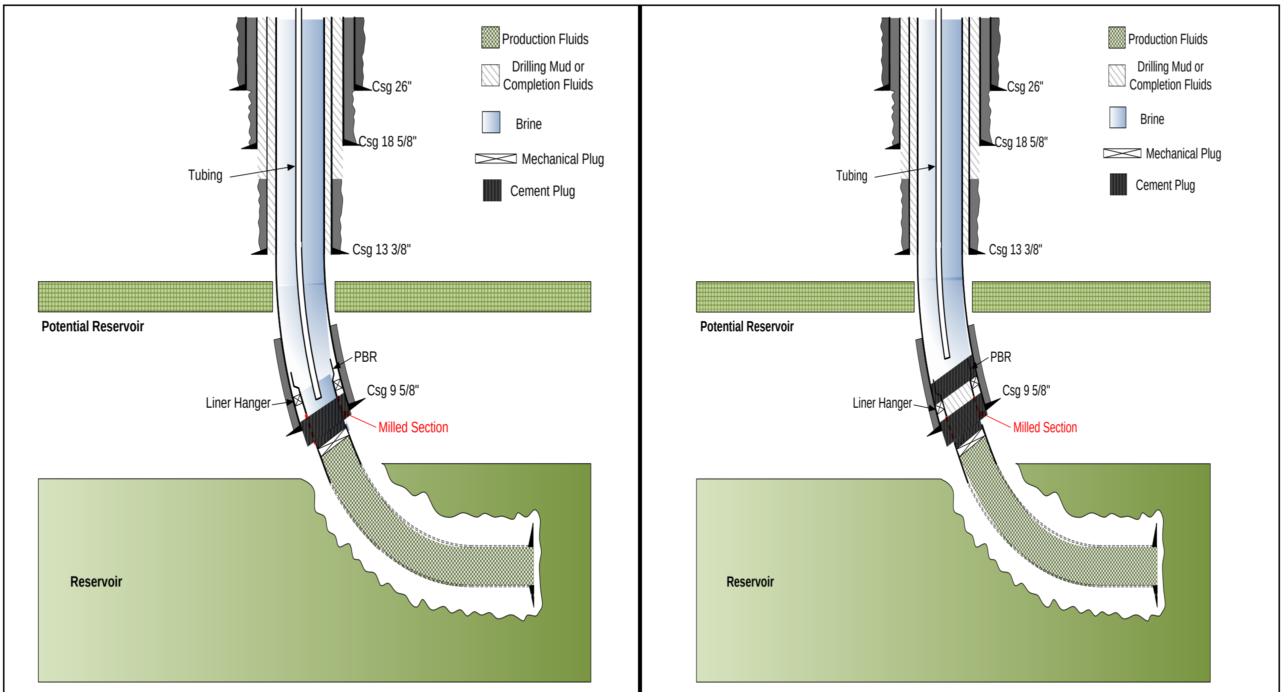
Step 7 - Lift, circulate and wash behind the 7" Csg.

Step 8 – Retrieve 7" Csg.

Step 9 – RIH Acoustic Logging Tool

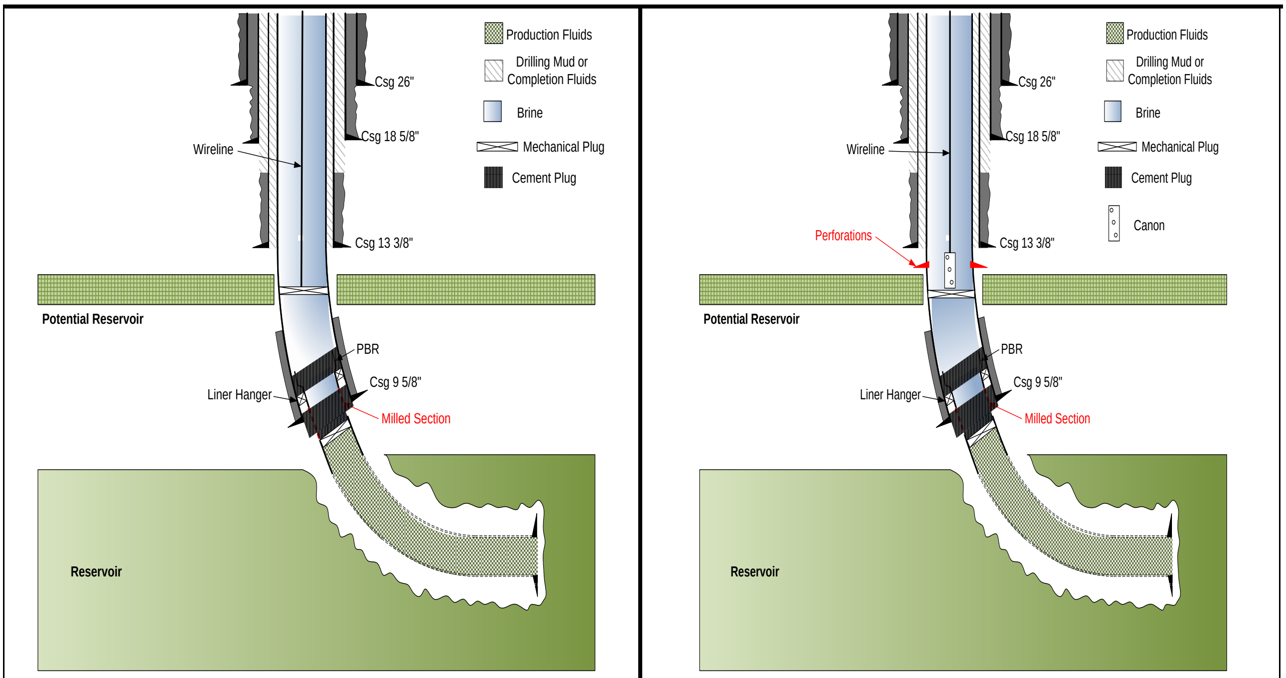
Step 10 – Section Mill

Fig. 5.17. Example Case: Permanent Abandonment Steps 7 to 10.



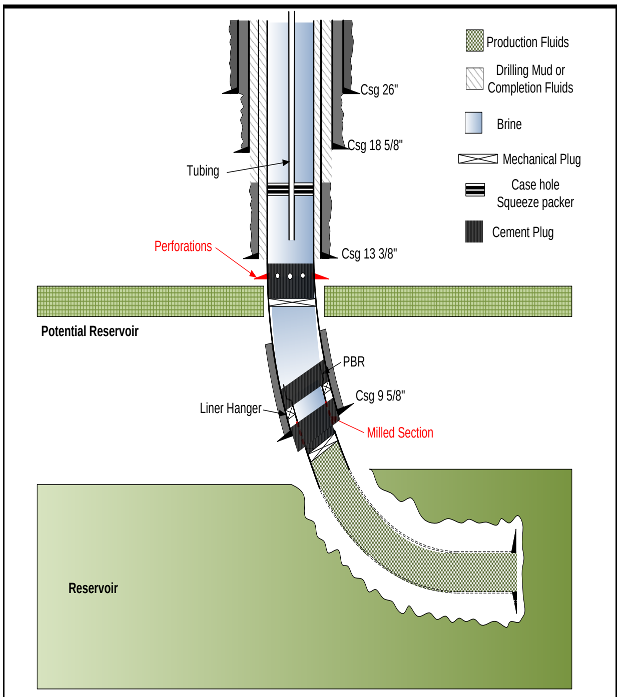
Step 11 - Setting the primary well barrier **Step 12 - Setting the secondary well barrier**

Fig. 5.18. Example Case: Permanent Abandonment Steps 11 and 12.



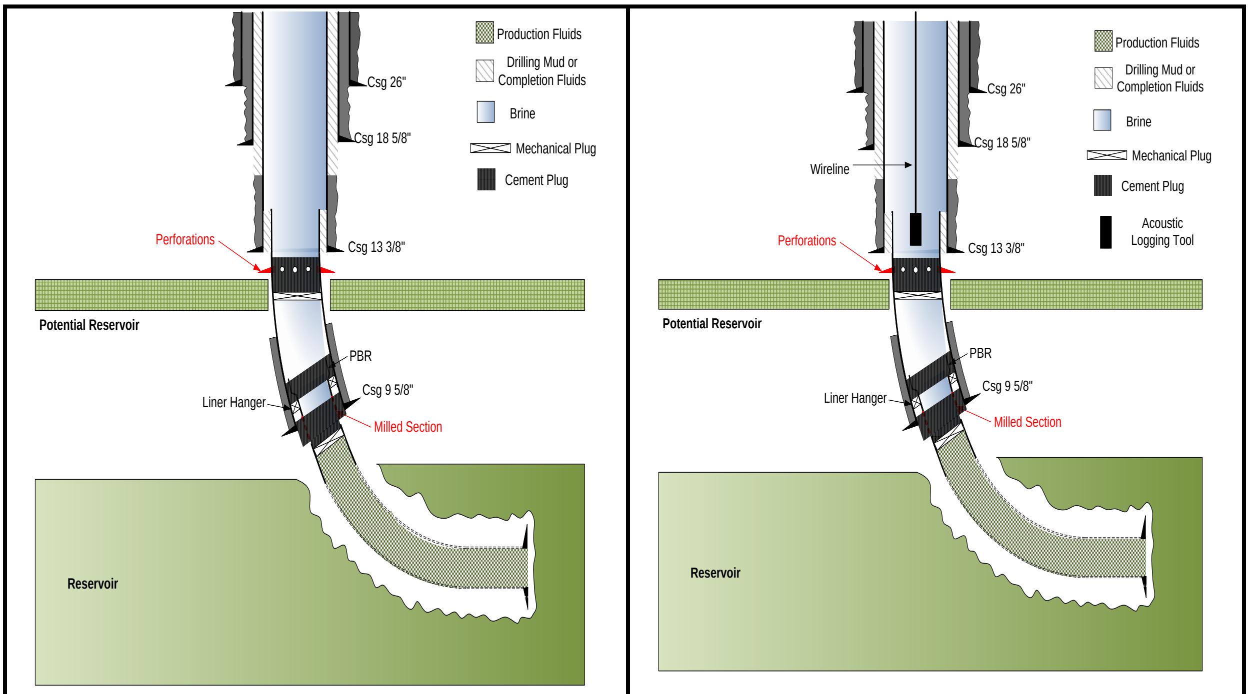
Step 13 – RIH Mechanical Plug **Step 14 – RIH Perforation Gun**

Fig. 5.19. Example Case: Permanent Abandonment Steps 13 and 14.



Step 15 - Setting the primary well barrier

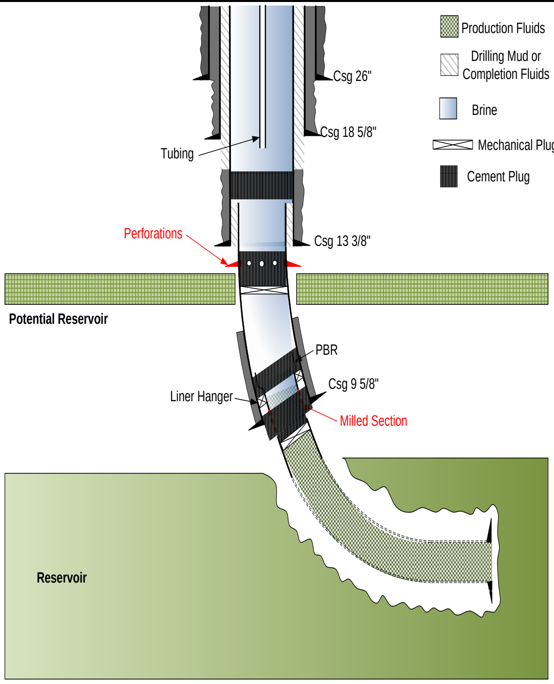
Fig. 5.20. Example Case: Permanent Abandonment Step 15.



Step 17 – Cut and pull the 9 5/8" Csg.

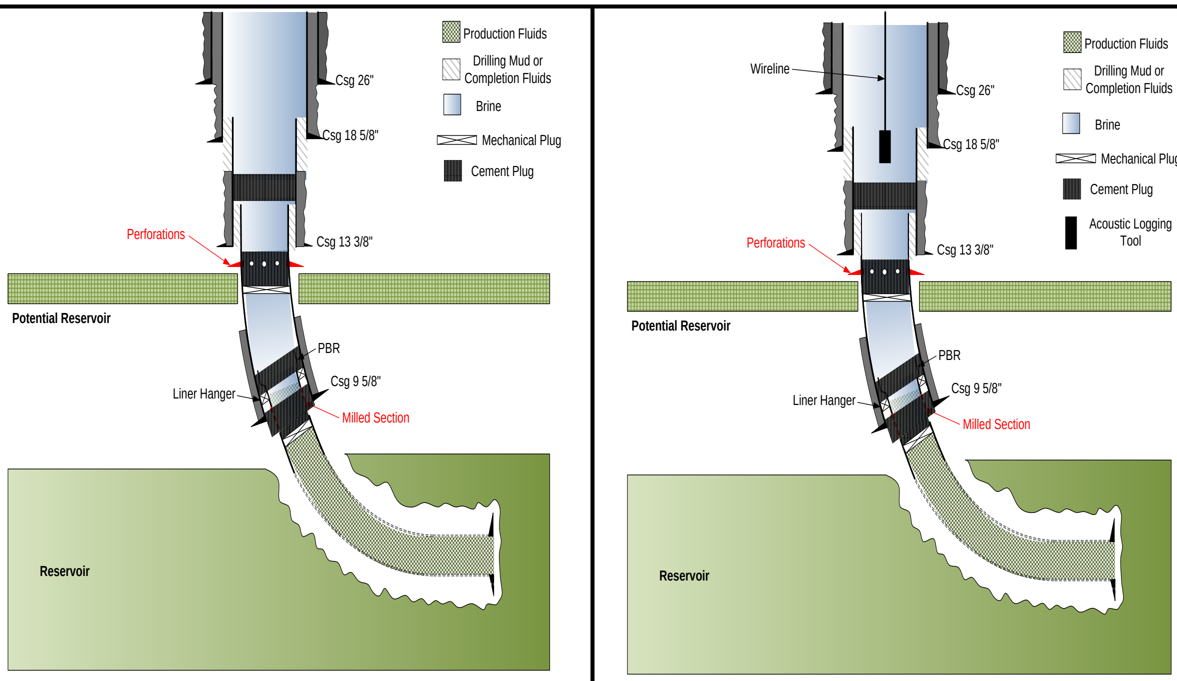
Step 18 – RIH Acoustic Logging Tool

Fig. 5.21. Example Case: Permanent Abandonment Step 17 and 18.



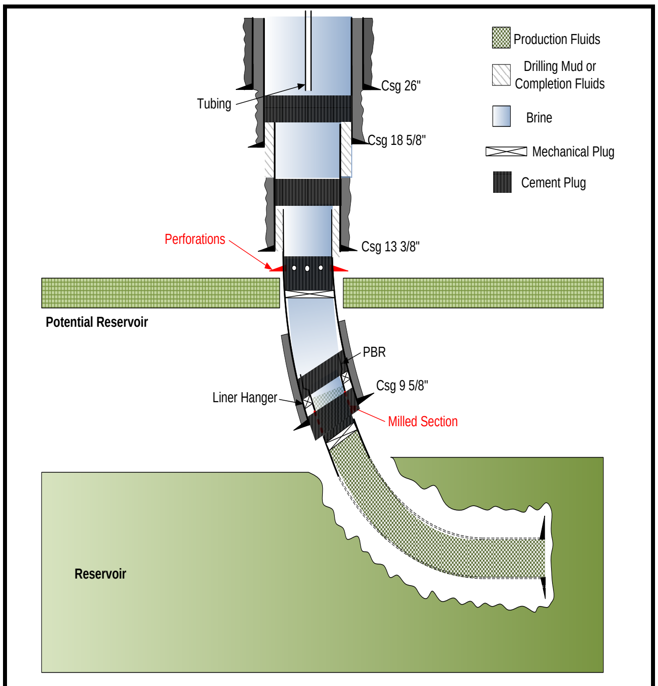
Step 19 - Setting the secondary well barrier

Fig. 5.22. Example Case: Permanent Abandonment Step 19.



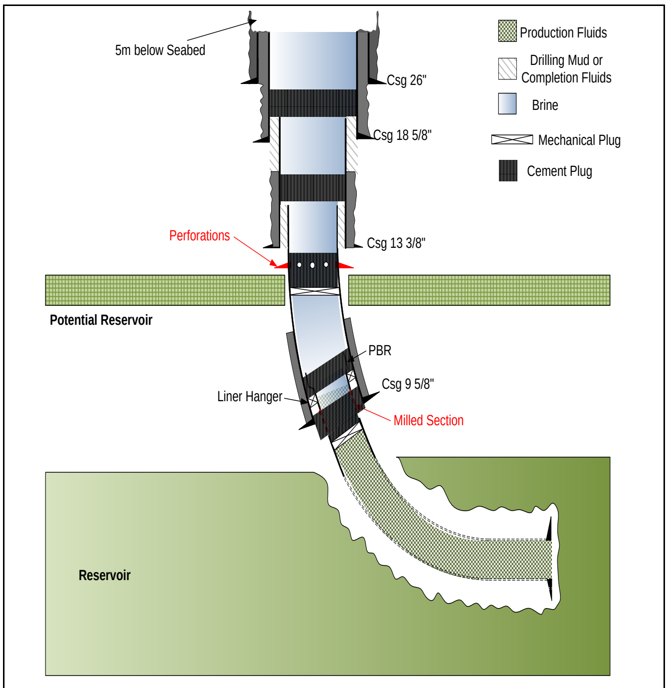
Step 21 - Cut and pull the 13 3/8" Csg. **Step 22 – RIH Acoustic Logging Tool.**

Fig. 5.23. Example Case: Permanent Abandonment Step 21 and 22.



Step 23 - Set Open hole to surface well barrier.

Fig. 5.24. Example Case: Permanent Abandonment Step 23.



Step 24 – Multistring Cutting and Wellhead Retrieval

Fig. 5.25. Example Case: Permanent Abandonment Step 24.

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VI. Technology and Plugging materials for P&A.

6.1 Traditional Technology

The example case presented in Sect. 5.3 gives an idea of the traditional technology required to perform P&A. Hence, the intention of this section is to give a brief introduction to the most common tools and operations to perform P&A.

It can be observed from the three phases presented in the example case that common activities like section milling and/or Perforate/Wash/Cement/squeeze (Conventional PWC), single/multiple casing cut-and-pull and the use of cement as plugging material were repeated in each one of them.

6.1.1 Section Milling.

A Milling operation is defined as an action to grind up or pulverize a desired object. Milling is a wide branch that can be used in several applications like junk mill, dress the top of a fish to be caught by another fishing tool, ream out collapsed casing, ream tubulars with scale, remove a section of a casing or to remove cement plugs [32].

It is important to understand that the milling tool semblance will differ from the application and the technology from the service provider. However, it is clear that a milling tool used for dressing the top of a fish will be different in design from one used in removing a section of a casing and so on.

Fig. 6.1 illustrates some different tools to perform milling operations provided by the service company Weatherford [32]. Here, it is shown that for section milling lateral blades are required dressed with different sets of cutters.

To denote is that a section milling operation, according to NORSOK – D010 [3], should comprise of at least 165 feet of casing removal before the cement plug is set against the open formation.

Fig. 6.1. Milling tools appearance [32].

A traditional section milling tool has the particularity that one or more blades are rotatable extendable outward from the tool body. These blades are pushed outwards to achieve a full milling sweep by pumping fluids (hydraulic push). Fig. 6.2 shows the appearance of a single blade or also known as "knife" and the same inside the milling tool body.

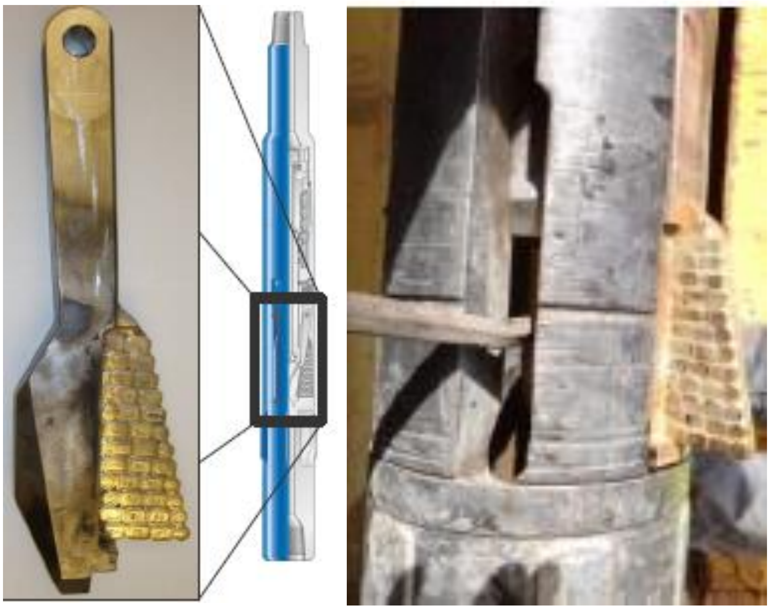


Fig. 6.2. Section Milling Tool [33].

Weatherfords guideline for effective milling [32], suggest a typical procedure for section milling. This is given by 8 steps and could be reproduced as follows:

1. Make up the tool string, and run in the hole to the depth of the intended cutout.
2. Rotate at 60 to 80 RPM for the cut.
3. Start the pumps, and build the pump strokes (gallons or liters per minute) required to give the minimum pressure drop across the piston nozzle of the tool, depending on its size. After the cut-out, the pressure drops 200 to 500psi, depending on the tool size.
4. After the cut-out, rotate 10 to 15min to clean out.
5. Apply weight and increase the rotational speed to 150 to 350 RPM. The most efficient milling weight is usually 2000 to 9000lb.
6. After the section milling the knives are worn out, circulate until the hole is clean.
7. Stop the circulation, and rotate for 5 to 10min for the correct knife closure.
8. Pull the tool in the shoe, and trip out conventionally.

To remark is that a traditional section milling, regardless the number of blades will always be in a progressive way (from top to bottom) [33]. By milling downwardly, the weight of the drill string will be applied as downward force to the mill and this will cause the desired progress through the tubing being milled.

6.1.2 Cut and Pull.

According to SPE 67747 – Using Multi-function Fishing Tool String to improve efficiency and economics of Deepwater Plug and Abandonment [44], three or more drill pipe trips are conventionally required to remove each intermediate casing string.

In this context, the first trip retrieves the casing hanger seal from the wellhead. Thereafter, the casing is cut on a second trip; this is normally done in a similar way as in the first part of the section milling. In other words, the same milling tool is used and the same transversal cut of the casing body is performed. However, in this case it is not required to perform a top to bottom milling as it is the case of section milling.

The third trip is required to remove the casing and casing hanger from the well. Traditionally, this operation is done with an internal catching tool or better known as “Spear”. Again, the market for spears is wide and the technology varies according to the service company. However, all of them share the same application “*Back-off operation”.*

An internal catch tool must be able to penetrate the internal diameter of the casing to engage the fish, transmit torque, and easy to release.

Again Weatherford [34], as an example of service provider, proposes a single and universal tool for internal catching purposes. This tool has the name of *“H-E Universal Rotating and Releasing Spear”* and the most important component, the one that engages the fish with the internal diameter is called “*Grapple Spear”*.

A sequence of operations to use the spear is also suggested by the service company and can be reproduced as follows [34]:

1. Run the spear in the catch position, penetrating the ID of the string.
2. Apply an upward pull of 30000 to 40000 lb overpull to the grapple in the fish.
3. Reduce weight to a minimum of 3000 lb overpull.
4. Apply right- or left- hand torque to back off and retrieve the fish.

6.1.3 Balancing a cement plug [31].

Balancing a cement plug means that the hydrostatic pressure in the annulus and in the workstring are equal upon placement. This is done to prevent U-tubing after cement placement and helps to prevent contamination.

Normally, cement is displaced in the annulus under a balance point with the amount of cement that is inside of the pipe. This allows cement to fall while the pipe is being pulled, filling up the space that was occupied by the pipe. It also allows the pipe to be pulled without bringing fluids out onto the rig floor.

When balancing a plug, the hydrostatic pressures in the pipe and in the annulus must be equal. To achieve this, the fluids used to displace the cement must be the same fluids that are ahead of the cement, but in the reverse order. The heights of each of the fluids in the pipe and the annulus must be equal. Fig. 6.3 illustrates a wellbore diagram for a desired plug and the distribution of fluids at the end of displacement.

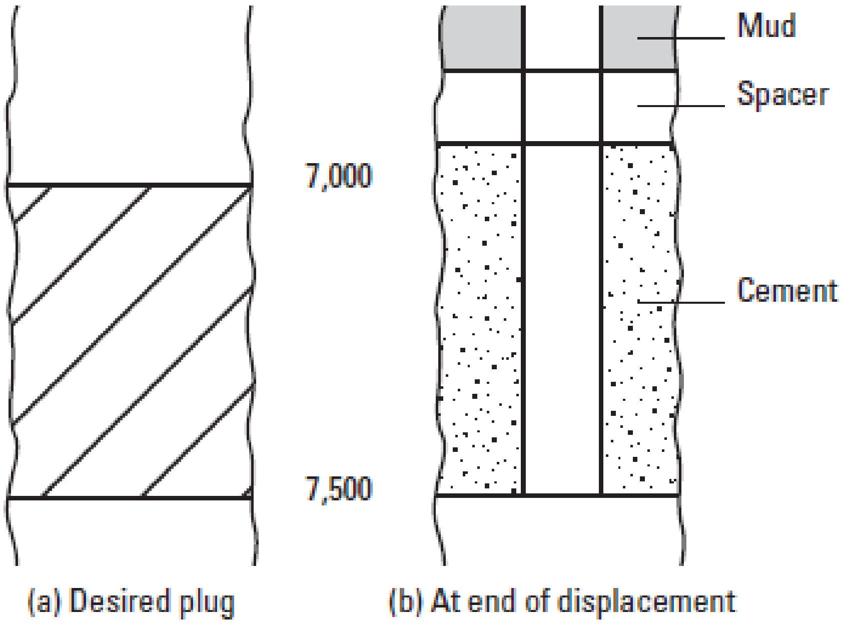


Fig. 6.3. Wellbore diagram for balancing a cement plug [31].

To ensure that the top of the plug is placed at the desired location, sufficient cement is normally pumped so that the top is above from its desired location. In some cases the excess of cement may be reversed out so that the top of the cement plug is at the desired location. However, for P&A purposes it can be assumed that reversing cement is not normally performed since precision is not required but this should be hard enough to handle a tag in operation in order to be validated.

6.1.4 Multistring casing cutting [35] and wellhead removal.

In a traditional way, multistring casing cutting and wellhead removal is performed in two different runs since both of them require different tools and operations.

In order to perform a multistring cut, the service company Schlumberger proposes two general versions of Multistring Casing Cutter tool [35]. These can be explained as follows:

- **Hydraulic pipe cutter**

The hydraulic pipe cutter (Fig. 6.4) has three heavy-duty cutter arms dressed with crushed carbide. It is capable of completing a cutout in most weights and grades of casing, conductor pipe, and marine risers. It is available between 3in – 72in and the cutters can complete operations for concentric, eccentric, cemented, and non-cemented pipe strings.

The hydraulic pipe cutter uses a proprietary knife return system to ensure that the knives are secured in a retracted position while running in hole, eliminating the need to banding or wedging. This feature also assists with knife retraction once pumping has stopped.

To eliminate the risk of pulling the tool before the string has been completely severed, pressure indications are provided at surface. The knife return system ensures retraction and retention regardless of wellbore inclination.

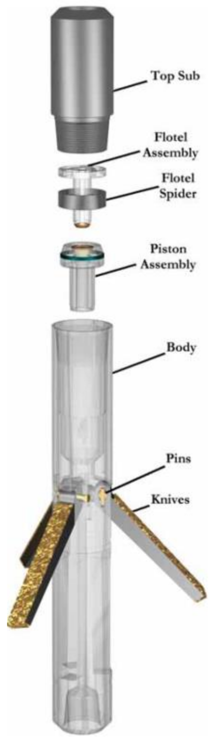


Fig. 6.4. Expanded view of Hydraulically Casing Cutter [36].

- **Mechanical casing cutter**

The mechanical casing cutter is designed to quickly convert and alternate between cutting diameters. Available for casings from 4 ½ in to 13 3/8 in, the tool comprises of a friction assembly to assist setting the tool in the pipe, a slip assembly to anchor the tool, a retractable cutting assembly and an automatic nut that permits repeated resetting and disengaging of the tool without returning to surface.

On the other hand, a second run should be performed in order to retrieve the Wellhead from its position. Hence, this is again traditionally performed by using a heavy duty spear as presented in Sect. 6.1.2.

6.2 New Technology

Due to high expenses and prolonged abandonment operations, operators and regulators are continuously looking to change the traditional way of performing P&A operations. Hence, service companies are striving to stay ahead of these challenges and to develop tools and techniques to facilitate them.

The intention of this section is to present some of the most interesting and innovative technologies suggested by the services companies.

6.2.1 Section milling improvements and alternatives.

A relevant study on how improved technologies and smaller improvements can affect in the performance of section milling has been presented in SPE 140277 – New Technologies to Enhance Performance of section Milling Operations that reduce Rig Time for P&A Campaign in Norway [37]. Here, the authors propose a new cutter technology to increase resistance to wear and also the implementation of downhole optimization sub to gather and send information in real time.

Despite of the good field results discussed in SPE 140277 [37], some challenges are not fully resolved by the improved cutter technology. This is for instance *swarf handling* and *swarf settlements* inside the well. Hence, two outstanding new technologies are proposed to upward section mill and left the swarf/debris residuals on the bottom.

On the other hand, one effective alternative to section milling is presented in SPE 148640 – Novel Approach to more effective Plug and Abandonment Cementing Techniques [38]. Here, the authors suggest a new method that creates a permanent abandonment plug through the use of a system that perforates uncemented casing, washes the annular space and mechanically places the cement across the wellbore in a single run.

6.2.1.1 New Cutter Technology.

A technical explanation on why cutters should be considered as a sensitive variable is provided in the patent US 6679328 – Reverse section milling method and Apparatus [39]. Here, it is detailed that during downward milling, the application of force to the mill by weight creates a wobble in the milling work string, which has a tendency to fracture the cutting inserts on the section mill blades. This causes the mill to wear out sooner, resulting in the removal of less pipe footage before replacement of the mill is required.

Actually, this explanation suits perfectly and is in line with the initial breakdown of time spent on section milling of the 9 5/8" casing on the well Whiskey – 04 (W-04) operated by ConocoPhillips in Norway. For the purpose Fig. 6.5 illustrates the individual time used on specific activities to set the barriers.

Fig. 6.5 shows that the most difficult and time consuming operation was section milling. Hence, the explanation provided in SPE 140277 [37] indicates that the operation took a total number of five trips « pull out of hole (POOH) and run in hole (RIH) ». From these five trips, three of them were due to 100% wear of the knives and the two remaining ones due to mechanical issues from the tool and the well.

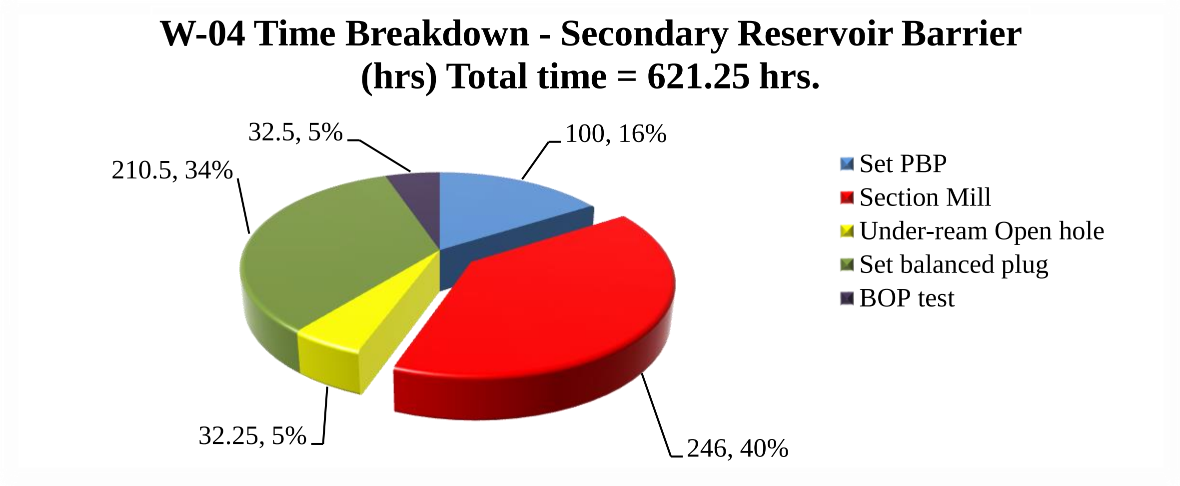


Fig. 6.5. W-04 Well barrier Time breakdown [37].

For the second campaign of the Whiskey P&A, ConocoPhillips intended to reduce the time spent on section milling by suggesting a reduction of trips. Therefore, it was clear for the service company that the challenge was related to the knives and/or cutter technology.

Baker Hughes [37], proposes a new cutter technology for section milling. Here, the service company describes the evolution of the most common types of cutting structures. For simplicity and better understanding, this evolution could be summarized as in Table 6.1.

Table 6.1 – Cutting structure evolution [37].

No.	Cutter Material	Manufacture	Application	Benefits
1	Tungsten Carbide	Randomly Crushed.	All types of downhole milling and cutting.	• Tight control of manufacturing process assures uniformity and quality. • Highest quality cutting carbide can be used for enhanced performance. • Rod form for easy application.
2	Powder Carbide.	Pressing carbide powder into a mold for specific buttons shape.	Ideal for milling special alloy metals.	• Higher penetration rates. • Smaller cuttings. • Extended mill life. • Aggressive cutting structure for cutting alloys.

3	Powder Carbide.	Pressing carbide powder into a mold for specific identical pointed aggressive shape.	Ideal for dressing, cutting and milling tools to exact OD's and ID's.	• Sharp cutting edges and points are looking down no matter how the insert is positioned. • Increased surface area for improved bonding to base metal. • Dual concave ends for optimum exposure of cutting points. • Rod form for easy application.
4	Improved Mixture of materials.	Pressing carbide powder into a mold for specific longer cutting edge.	Long lasting cutting structure (Section Mill)	• Long lasting material. • Less susceptible to single point loading. • Chip breaker incorporated to each insert that reduces the length of cuttings.

The newest type of cutter, No. 4 from Table 6.1, it is actually the new cutter technology proposed by the service company. This cutter receives the name of 'P' cutter and could be found under the service company brand MetalMuncher® [40]. The cutter is applied to the cutting surface of a blade and for better understanding, Fig. 6.6a and Fig. 6.6b illustrates a section milling blade dressed with two different cutters and Fig. 6.6c shows the modeled semblance of the 'P' cutter.

a. Section Blade with traditional cutters

b. Section Blade with 'P' cutters

c. 'P' cutter modeled semblance.

Fig. 6.6. New cutter Technology – 'P' cutter [37].

According to SPE 140277 [37], the application of this new cutter technology on the milling blades showed remarkable results on the second campaign of the Whiskey P&A. Hence, the challenge proposed to the service company was successfully accomplished by reducing the number trips to two and in the best of the cases to one.

6.2.1.2 Downhole optimization sub.

Sect. 6.1.1 suggested an 8 step operational procedure to perform section milling [32]. Inside these steps, milling parameters are suggested in order to have an effective operation. However, how to be sure that the working depth is actually being influenced by the surface parameters?

Therefore, with the intention of covering this issue Baker Hughes proposed a downhole optimization sub for acquiring downhole parameters like weight on tool, torque, RPM, bending moment, vibrations, pressure and temperature via mud pulse telemetry. Thereafter, considering a real time scenario, use these parameters to compare and analyze with the applied surface data.

According to SPE 140277 [37], in the second campaign of the Whiskey P&A the downhole optimization sub was implemented in compliance with the new cutter technology (‘P’ cutters). The sub was placed directly above the section mill, placing the sensors at approximately 15ft above the milling blades for accuracy on the readings.

Due to the downhole optimization sub the following parameters were analyzed:

- 30-50% of the applied surface torque reached to the working depth.
- Whirl, lateral and axial vibrations were seen to be steady and low.
- High level of Stick Slip (Normal in section milling).
- Increment and decrement of bending moment that could affect in over-torque or damage of connections or BHA components.

6.2.1.3 Upward Section milling.

Similar to drilling, it is a well know practice to remove cuttings (swarf) when section milling is in progress. This is normally done to avoid forming a ball of swarf around the mill and reduce its effectiveness. In that sense, special milling fluids should be considered in compliance with proper fluid flow rates to circulate the swarf out of the hole.

According to SPE 148640 [38], the design of these milling fluids with respect to weight and viscosity must ensure that the open hole is stable and swarf is transported to surface. Hence, special issues may arise due to high Equivalent Circulating densities (ECD) and the possibility of exceeding the fracture gradient and fracturing the formation.

Poor cleaning of the hole can lead to problems related to becoming stuck. It can also affect the functionality of the BOP due to swarf settlements. On the other hand, swarf handling at surface could also be HSE issue.

This section intends to present two possible variations of upward section milling tools that were found in the literature. The first one proposed by the patent US 6679328 [39] named *"Reverse Section Mill*" and the second one proposed by the service company WestGroup [41] named *"SwarfPak"*.

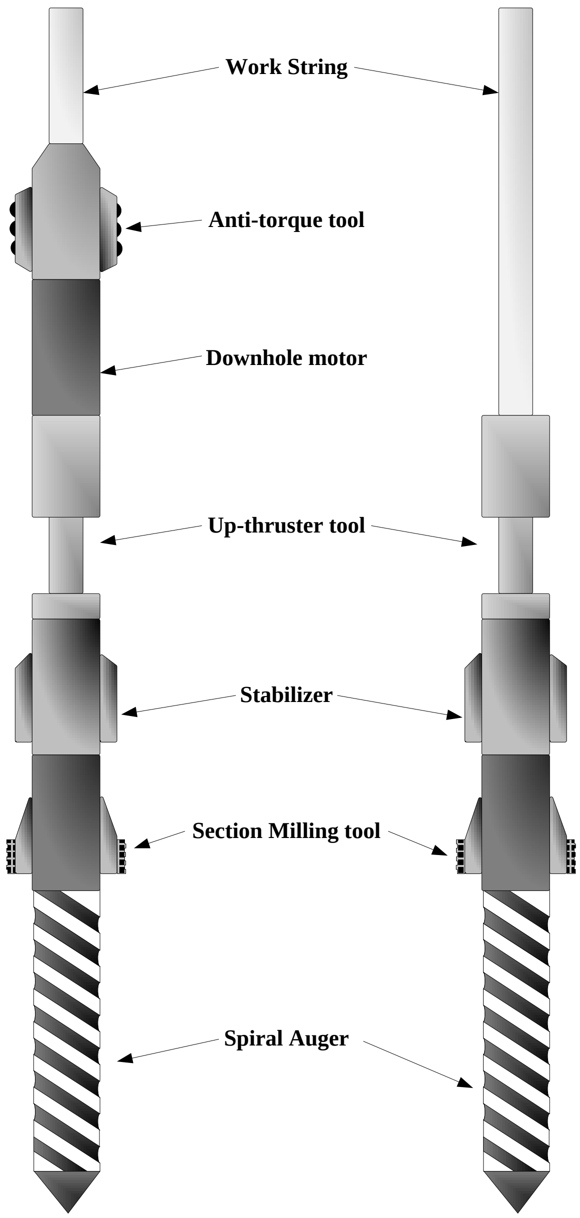
6.2.1.3.1 Reverse Section Milling.

The patent US 6679328 [39], proposes a section milling tool that is capable of milling upwardly by using tension instead of weight, which is normally the case of downward section milling. Some of the benefits of using this technology could be enlisted as follows:

- Swarf can be left downhole.
- No need or partial need for special milling muds.
- No need or partial need for surface swarf handling equipment.
- Relative constant force on the cutting blades due to the tension applied force and regulated pump pressure.
- Better centralization and less wobbling due to the use of centralizers.

- Heavy tubulars (Drill Collars, Heavy weights drill pipe, etc) are not needed.
- Smaller pipes can be used.
- Increased safety – no swarf in BOP.

Fig. 6.7 illustrates the upward section milling tool and required components proposed by the patent US 6679328 [39]. Here, the patent mentions that the tool can be used either with a mud motor or just with a single rotating work string. Hence, Fig. 6.7a and Fig. 6.7b illustrate both assemblies and their respective components.



a. Upward milling tool with Downhole motor **b. Upward milling tool with workstring**

Fig. 6.7. Upward milling Assemblies [39].

A brief description of the tool components and working methodology can be described as follows:

- *Anti-torque tool.*

This component, also called *torque anchor*, prevents the drill string from being affected by the torque generated from the mud motor. Often, without the torque anchor, the drill string would torque up and reduce in length (shrink) as the motor stalls, causing the milling tool blades quickly degrade.

The torque anchor is engaged with the borehole wall or casing with a hydraulic outward direction gripping member. These griping members are designed with contours such as teeth, ridges, or ribs that engage to the borehole or casing wall and prevent rotational movement. However, the members can also be configured to allow movement in longitudinal direction or only in the uphole direction by using one or more rolling wheels as illustrated in Fig. 6.7a.

- *Up-thruster*

The purpose of the up-thruster tool or lift cylinder is to supply constant upward load on the section mill. If the downhole motor is considered in the assembly (Fig. 6.7a) without the up-thruster, the tension load imparted by the rig would be too erratic.

The up-thruster is a hydraulic cylinder pressurized by mud flow which is pumped through the inside of the assembly. The milling tool, as it will be explained later, has on the bottom a restriction nozzle for backpressure (See Fig. 6.8c). This backpressure, in essence is used to active the mechanism upwardly.

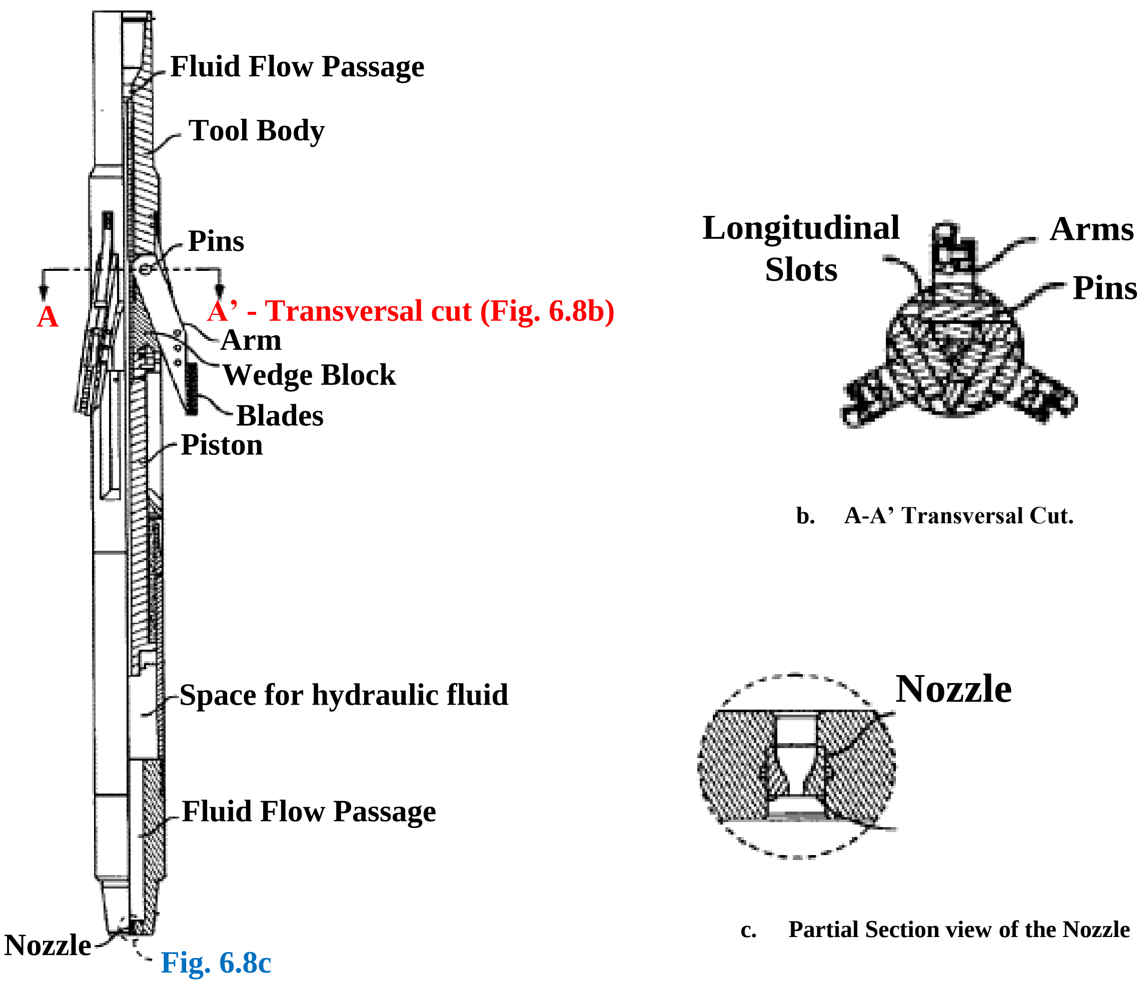
The tool is initially RIH in a fully extended position granted by a shear pin. Once in position, milling fluid is pumped and the backpressure is high enough to shear the shear pin. Thereafter, the inner piston and mandrels moves upwardly toward the work string.

❖ *Stabilizer.*

The assembly includes an expandable stabilizer to stabilize the mill. Basically, the stabilizer is identical to the section mill (later explained), except that the arms are dressed with hard facing material with a size equal to the casing inner diameter.

❖ *Section milling tool.*

Fig. 6.8 illustrates the section milling tool proposed in the patent US 6679328 [39]. Here, the arms are held in open position by an upward moving wedge block that support the arms and prevents them from collapsing under heavy loading.



b. A-A' Transversal Cut.

c. Partial Section view of the Nozzle

a. Hydraulic actuated section milling tool.

Fig. 6.8. Upward Section milling tool [39].

The section mill has pivotable arms mounted in longitudinal slots in a tool body as shown in the transversal cut of Fig. 6.8b. Also, a piston below the arms is slidably disposed to move the wedge block upwardly against the lower ends and inner sides of the pivotable arms.

The application of fluid pressure to the space below the piston exerts an upward hydraulic force, moving the piston and wedge block upwardly against the arms. The piston can have a fluid inlet port through which the drilling flows to reach the space below the piston.

In order to retract the tool arms and blades, a ball can be pumped with drilling fluid until it reaches the inlet port. Thereafter, pressure is applied to force the ball against the piston and driving it downwardly.

A nozzle can be mounted in the lower end of the tool body as illustrated in Fig. 6.8a and better detailed in Fig. 6.8c. This nozzle can be sized to create the desired backpressure, necessary for also operating the up-thruster tool.

The section mill arms can be fitted with a casing cutter type blade as the ones presented in Fig. 6.6a and Fig. 6.6b. Likewise, the arm can be fitted with the square type blade typically found on a pilot mill, to provide an extend length milling of casing.

- *Spiral Auger.*

Is a short drill collar dressed with aggressive left hand spiral ribs. The ribs tend to force or auger the cuttings to the bottom of the well, moving them away from the cutter blades and preventing the cutting from balling up around the mill.

6.2.1.3.2 SwarfPak.

As mentioned, WestGroup [41] proposes an alternative tool for upward section milling. This tool has the name of “SwarfPak” and its working methodology comprises of applying reverse flow principles (like in Gravel Pack). Hence, as it is claimed by the service company, by using this technology swarf can be easily left downhole.

Fig. 6.9 illustrates a sketch of the upward section milling tool and required components proposed by the West Group [41]. Here, the company explains the working procedure of the tool, which can be detailed as follows:

Fig. 6.9. West Group Upward Section milling assembly– "SwarfPak" [41].

❖ The SwarfPak assembly is RIH until the required working depth.
❖ The slips are upwardly retracted. (Does not specify how this step is done)
❖ Circulation starts as conventionally through the working string until it reaches the milling tool. Here, the flow is divided into different fluid flow paths (same number of arms considered in the milling tool) as illustrated in Fig. 6.10.

The lower ends of the fluid flow paths are open to the annulus between the milling tool and casing. When the fluid reaches and passes this point, it has a direct impact on the working section between the arms and the casing.

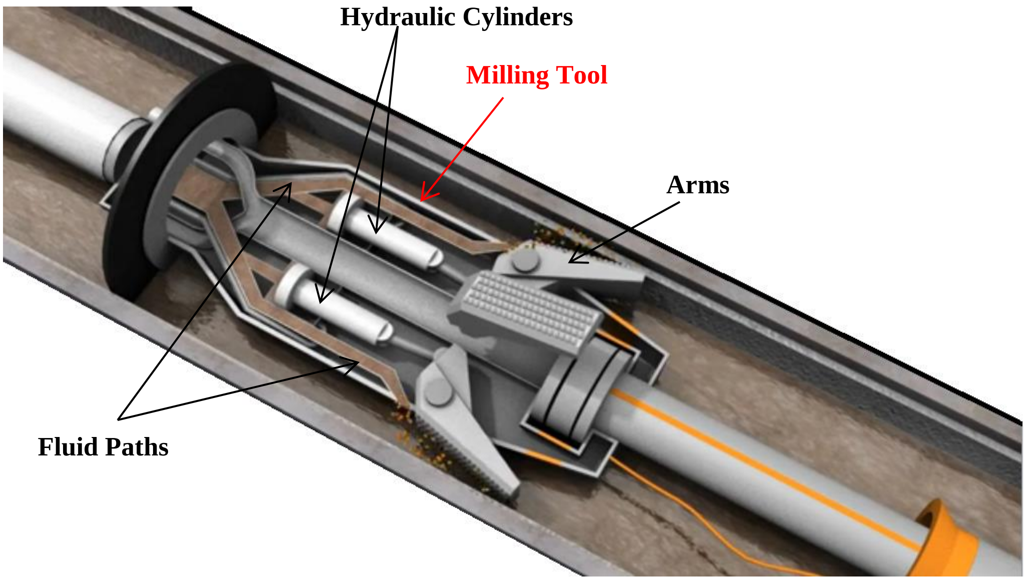
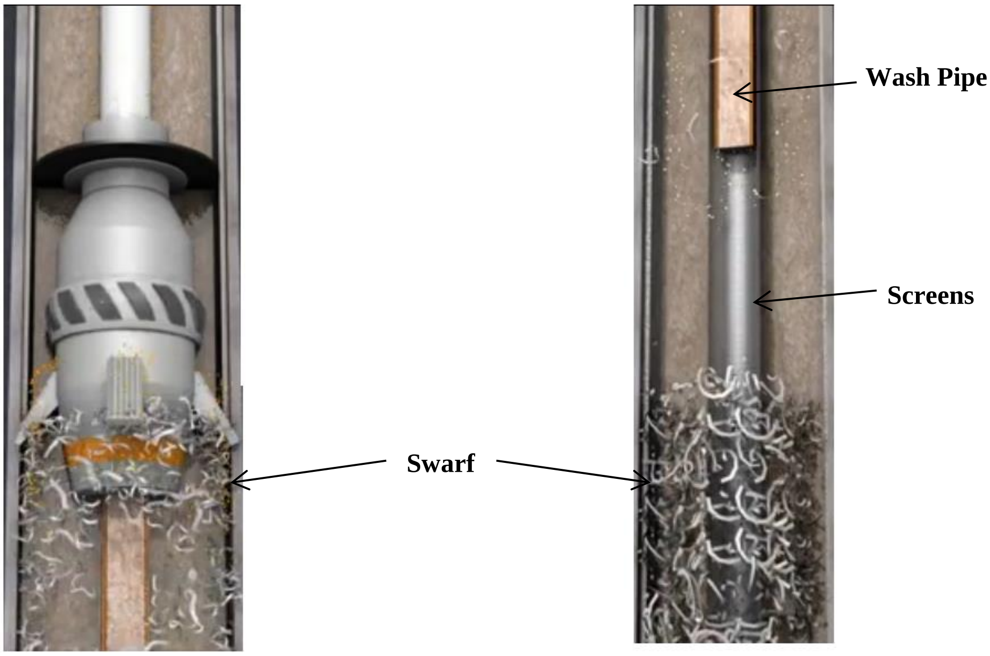


Fig. 6.10. Fluid Paths inside the "SwarfPak" milling tool [41].

❖ Hydraulic cylinders located at the middle of the milling tool are fed by another fluid flow path (derived from the main one). These cylinders give the hydraulic push to the arms to open and remain in that position during the milling operation.
❖ Like in Gravel Pack a Wash Pipe (shown in Fig. 6.11b) is already set inside the screen. This Wash Pipe diverts the annular flow, resulting from the fluid paths, through its inner diameter and creates a fluid return to surface.
❖ After a complete fluid cycle has been performed, upward section milling can start.

Fig. 6.11 illustrates how the upward milling process is expected to be by using the "SwarfPak" assembly. Here, Fig. 6.11a shows the milling tool working on a casing section and Fig. 6.11b illustrates the swarf settlement/packing around the screens and the actual upward motion of the Wash Pipe.



a. Upward Section Milling **b. Swarf settlement/packing**

Fig. 6.11. Upward milling process by using the "SwarfPak" tool [41].

According to PAF 2012 [4] this technology has not yet been proved and will be field tested on the first quarter of 2013.

6.2.1.4 HydraWash^{TM} system.

An innovative alternative for Section milling and Conventional PWC has been proposed by the service company HydraWell Intervention [42]. This novel approach, as it is called in SPE 148640 [38], is capable of leaving a full cross section integrity plug (illustrated in Fig. 4.3), without the necessity of creating a window on a section of the casing.

Some of the benefits of this system could be enlisted as follows [42]:

- One trip plugging system.

- No milling required.
- Allows full flow when tripping in and out.
- Simple design and operation.
- Base for plugging material.
- Available for all casing sizes.
- Swarf handling, transport and disposal are eliminated.

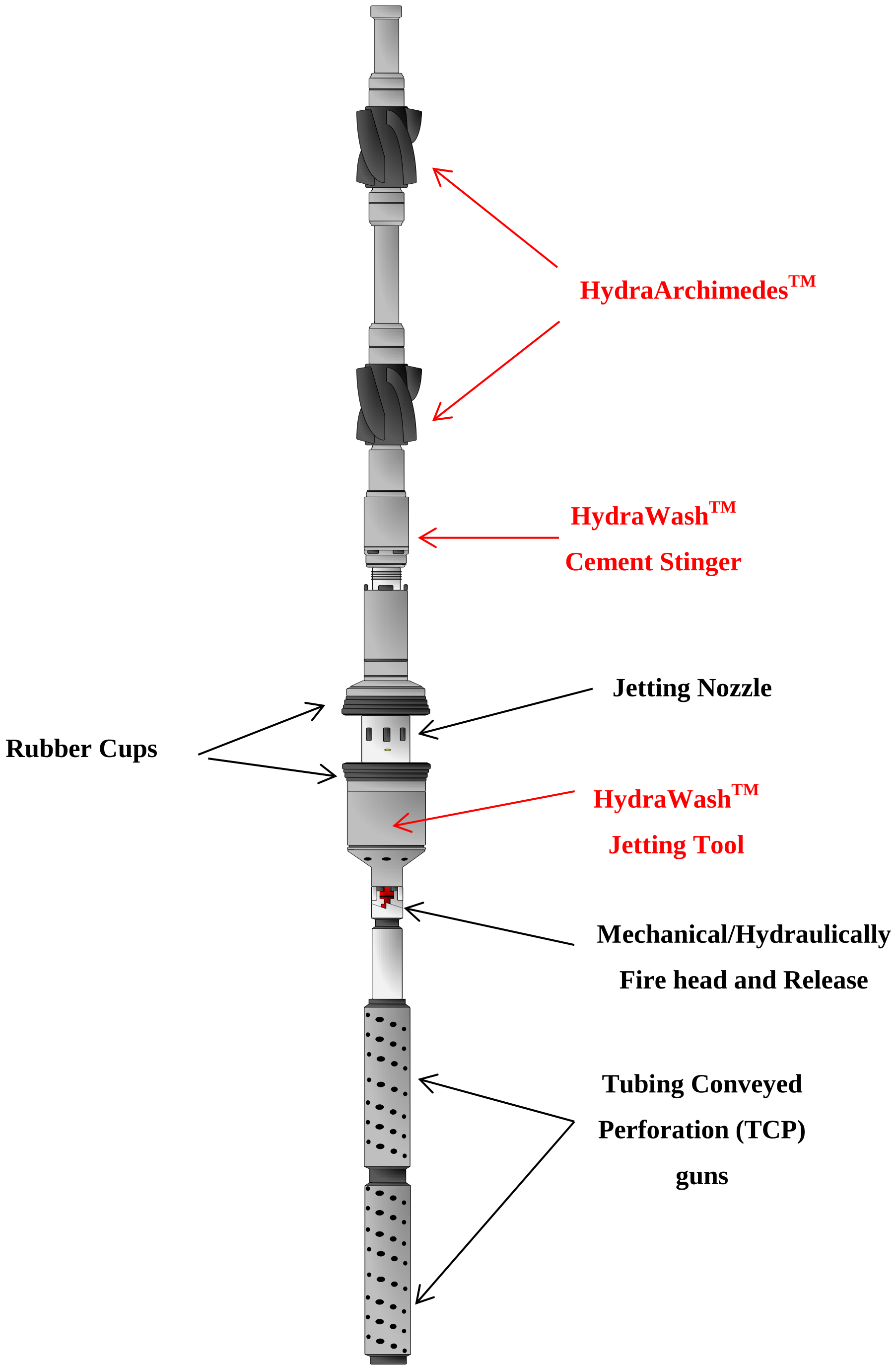


Fig. 6.12. HydraWash™ System tool [42].

According to the HydraWell website [42], a combination of innovative tools provided by the same service company plus a Tubing Conveyed Perforation (TCP) gun, creates a system named “HydraWash™”. Fig. 6.12 illustrates a sketch of the “HydraWash™” system as presented in the multimedia video of the service company [42] and the presentation of the company in the University of Stavanger [43]. The video also explains the working procedure of the tool, which can be summarized as follows:

❖ *The HydraWash™ assembly is RIH until the required working depth.*

One can note that during RIH, the two opposed rubber cups from HydraWash™ jetting tool represent a challenge due to its size compared to the inner casing diameter. Therefore, the design of this tool contains internal bypass channels to divert the fluid without affecting the tool motion.

❖ *The perforating guns are fired and automatically dropped/left in the well.*

Normally, this is done by applying hydraulic pressure over the fire head or by percussion obtained by dropping a steel bar or ball.

According to SPE 148640 [38], the perforation gun should have a length of approximately 200ft, especially if a 165ft plug is desired. This length is the same as the one considered for section milling and suggested by NORSOK – D010 [3].

Other details from the gun are also specified in SPE 148640 [38], for simplicity these details can be summarized in Table 6.2 and remarking “*the limited entry perforating back pressure”* as the biggest issue for later operations.

Furthermore, the *limited entry perforating back pressure,* as explained in the Well Completion Design Book [44], is a technique that relies purely on the perforation pressure drop to achieve an even injection profile when washing behind the perforations. Hence, this technique intends to treat all the intervals simultaneously while washing.

For the purpose, it states that back-pressure through the perforations (Δp_{pf}) is dependent on the perforation diameter, the density of the fluid and a perforation discharge coefficient. Hence, it could be represented as in the following equation:

$$\Delta p_{pf} = \frac{0.2369\rho}{{D_p}^4 C^2}\left(\frac{q}{n}\right)^2$$

Where,

ρ = Fluid density [ppg].

D_p = Perforation diameter [in]

C = Discharge Coefficient (between 0.45 and 0.95)

q = Flow rate [bpm]

n = Number of perforations per interval.

Table 6.2 – Perforation Requirements and Design [38].

<table>
<tr><th>Gun Specification</th><th>Detail</th></tr>
<tr><td>Charge Density:</td><td>12 Shoot per foot (SPF)</td></tr>
<tr><td>Charge Phasing:</td><td>135/45 Degrees.</td></tr>
<tr><td>Gun Segment length:</td><td>7ft (e.g. 7ft x 24 Segments = 168ft)</td></tr>
<tr><td>Perforation Diameter:</td><td>Varies with respect to position in the gun segment and function:
<table>
<tr><th>Position</th><th>Function</th></tr>
<tr><td>Top</td><td>Large diameter due to easier initiation of washing behind the casing.</td></tr>
<tr><td>Middle</td><td>Sized according to the limited entry perforating backpressure.</td></tr>
<tr><td>Bottom</td><td>Large diameter due to easier displacement of mud by cement spacer and displacement.</td></tr>
</table>
</td></tr>
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According to SPE 148640 [38], the middle gun perforation diameters should be designed to create 55 to 75 psi back pressure across the 12 SPF open perforation.

After the detonation has been performed, 200ft gun will be automatically released. Therefore, it is essential to ensure that there is enough space below the perforations (rat hole) capable of receiving this residual gun.

- *A ball is dropped to stop circulation through the HydraWash^{TM} Jetting tool and initiate the washing process behind the casing.*

Fig. 6.13 illustrates the moment when the ball is placed in HydraWash^{TM} Jetting tool and the washing process is initiated. Here, it should be noted that the washing process will initiate from top to bottom. Fluid, provided by the jetting nozzles located between both rubber cups will flow through and behind the perforations and resume over the top of the HydraWash^{TM} Jetting tool.

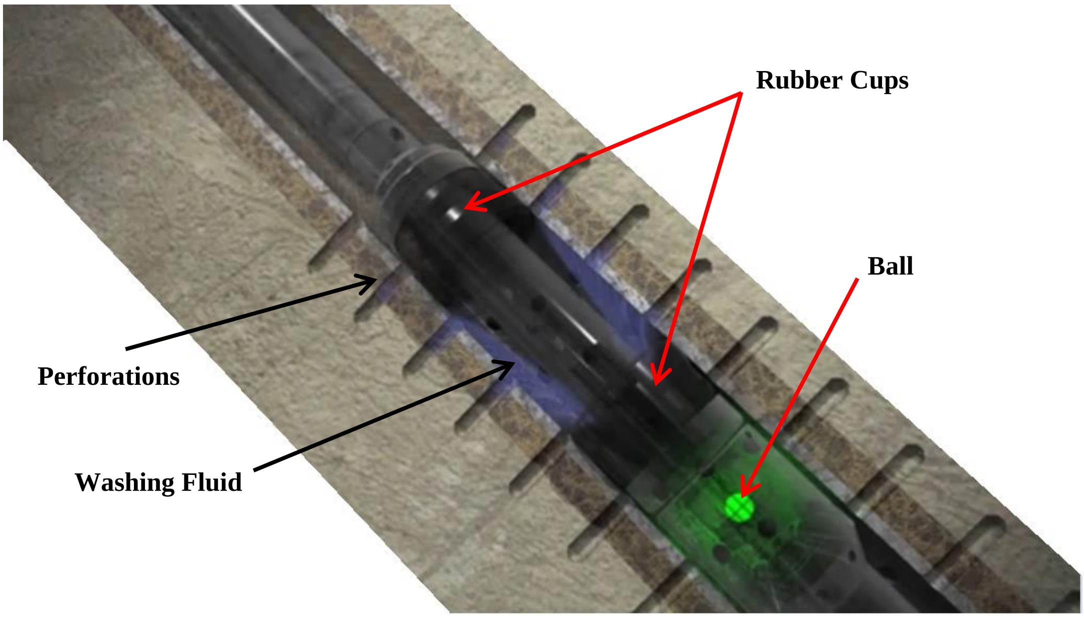


Fig. 6.13. HydraWash^{TM} Jetting tool – Washing behind the casing [42].

According to SPE 148640 [38], the space between the rubber cups is 12 inches. This means that 12 inches of casing are being continuously washed or that a maximum of 12 perforations are being covered at any time.

The washing operation ends when the annular space between the casing and the formation is assumed to be clean. This means that the shakers are showing minimal (if not

100% absence) traces of debris, old mud, barite, old cuttings and cement. Thereafter, spacer fluid should be pumped into the perforated area.

As it is explained in SPE 148640 [38], it is highly relevant to design the wash and spacer fluids carefully. These fluids are normally dependent of the compatibility between each other and the formation behind the casing. Therefore, if reactive clay is found at the plugging intervals (as it was the case of SPE 148640 [38]) water based KCl polymer could be a suitable option. However, if a different formation is present then perhaps another fluid could be considered.

- ❖ *The tool is RIH below the perforations and a second ball is dropped to disconnect the HydraWash™ Jetting tool from the HydraWash™ Cement stinger.*

At this point the HydraWash™ Jetting tool is left below the perforations to act as a base for the cement plug or as presented before as a cement retainer.

In this case again, cement should be carefully designed to fulfill the operational needs. This mostly refers to gas migration and fluid loss during cementing. However, many other particularities may also arise depending on the specific case of the abandonment well.

- ❖ *Cement is pumped through the HydraWash™ Cement stinger. The HydraArchimedes™ tool is used to aid in the cementing operation. It rotates and this helps on squeezing cement through the perforations.*

The cementing technique is similar to the one presented in Sect. 6.1.3. However, the inclusion of the HydraArchimedes™ tool is to ensure a full cross sectional plug like the one illustrated in Fig. 4.3.

According to HydraWell website [42], the HydraWash™ system has already been used for installing 55 plugs. However, for the 20 plugs mentioned in SPE 148640 [38], all of them show outstanding results and it is also stated that 124 rig days have been saved by using this system.

6.2.2 Cut and Pull in a single trip.

As explained in Sect. 6.1.2 casing removal involves severing a section of the casing string and pulling the free end to the surface. The paper SPE 67747 [45] already mentions that many advances in "cut-and-pull" technology and trials have been achieved during the past decade. However, still multiple trips were required due to the difficult task of cutting each intermediate casing string.

This section intends to present two technology proposals to perform cut-and-pull operations in a single trip.

6.2.2.1 Single Multistring cut and pull in a single trip.

6.2.2.1.1 Hercules Multi-String cutter, Marine Swivel/Seal Extractor, Hydraulic Casing Spear.

SPE 67747 [45] provides an explanation of a discrete set of tools that combined compose a system capable of performing a cut in the casing, latching the fish and retrieve it to surface in single operation. These tools provided by the service company Baker Hughes receive the name of *Hercules Multi-string Casing cutter*, *Marine Swivel/Seal extractor (Subsea P&A) and Hydraulic casing Spear.*

To denote is that SPE 67747 [45] is focused on Subsea P&A. Hence, the Marine Swivel/Seal extractor tool is only useful for subsea applications since it intends to latch the seals from the subsea wellhead.

Some of the benefits of using this technology could be enlisted as follows [45]:

- One trip cutting/pulling system.
- Possible to combine sets of blades of different lengths, or one set of long blades.
- The blades are hydraulically pivotable.
- Spear tool in the BHA.
- Multiple strings can be cut and removed from the hole.

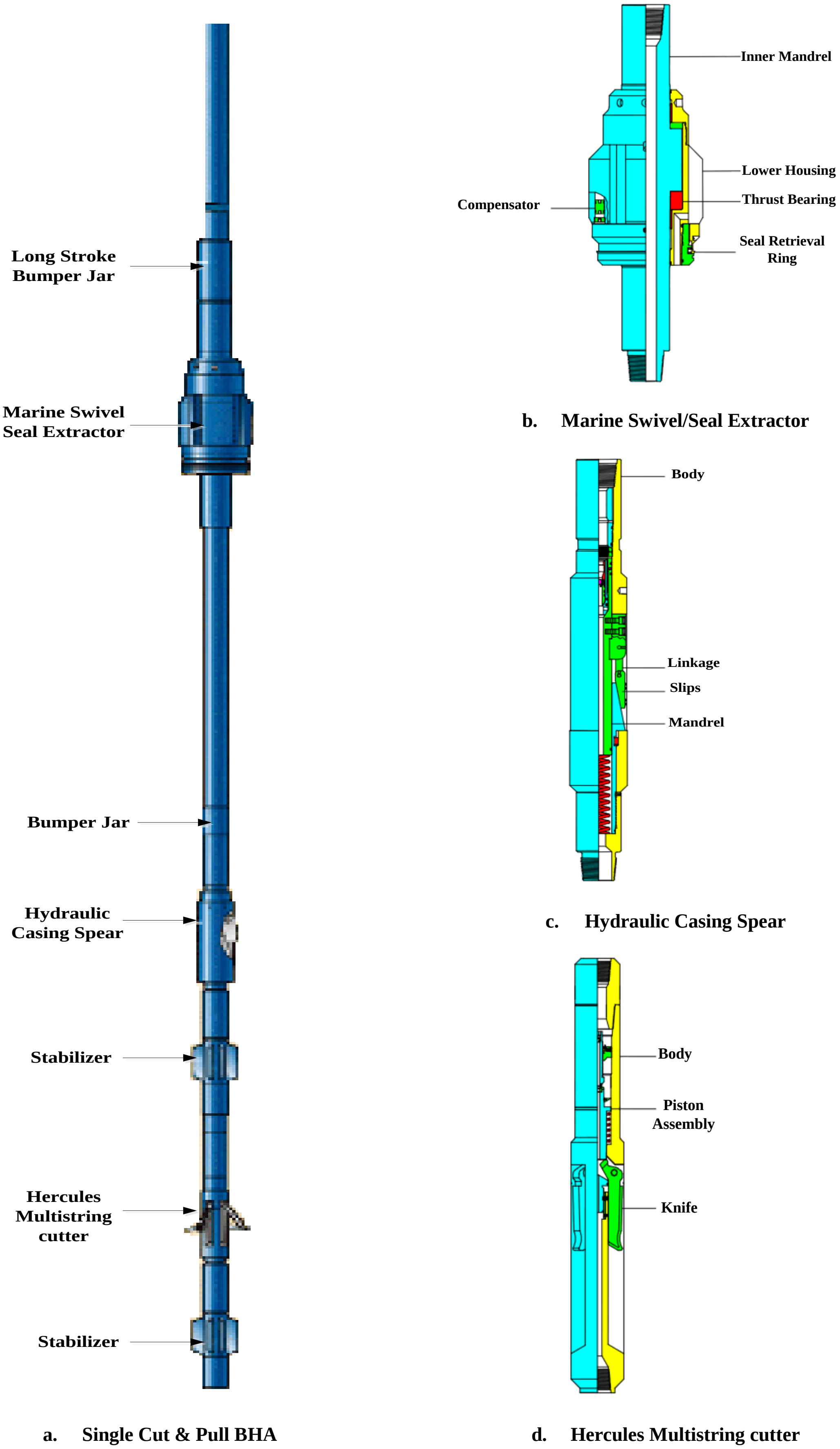


Fig. 6.14. Bottom Hole Assembly for single cut and pull operations [45].

Fig. 6.14 shows the specific BHA configuration to perform a single multistring cut and pull operations as proposed by the paper SPE 67747 [45]. Here, Fig. 6.14a shows the position of the tools in the assembly and Fig. 6.14b, Fig. 6.14c, Fig. 6.14d illustrates the details of the key components of the system.

A brief description of the tool components and working methodology can be described as follows:

❖ *Hercules Multi-string Casing cutter.*

The Hercules Multi-string cutter is an improvement to the conventional design that has been in service for decades. Here, the knives and cutter structure work with the similar "hydraulic push" concept as presented in Sect. 6.2.1. However, as claimed by SPE 67747 [45] the implementation of *"tattle-tail"* feature and an *"adjustable internal stop"*, provide a surface indication of the fully extension of the knives and a control of the maximum knife cutting.

As presented in Sect 6.2.1.1, this tool also relies on the adequate use of the cutter technology. Therefore, the newest type of cutter (No. 4 from Table 6.1) are used with the exception that here in a cylindrical shape and also belonging to the brand MetalMuncher® [40].

The cutter arms are fitted with a special large OD sleeve to provide maximum stabilization when cutting large diameter strings. The design of the sleeve is well explained in the patent US 6125929 – Casing Cutter Blade Support [46]. However, in general terms, it is easy to understand that when knifes are in contact with the inner diameter of the string, torque is transferred only at the top of the blade and the rest of the length is unsupported and capable of bending or breaking. This sleeve intends to reduce the excessive bending stress or shear stress on the blade due to its unsupported condition while performing the cut.

❖ *Marine Swivel/Seal extractor.*

As claimed by SPE 67747 [45], this tool allows pinpoint accuracy in locating the casing cut and provides a stationary position during the cutting process. This tool, designed to pull the seals from the wellhead (Subsea P&A), it is equipped with a seal-pulling adapter according to the wellhead manufacturer's specification. Hence, its design allows the casing string to be cut with the hanger seals locked in to the wellhead, preventing the hanger from moving after the cut is made. With the seal unlocked and retracted, the hanger can be pulled and recovered in the same trip.

❖ *Hydraulic casing Spear.*

The hydraulic spear eliminates the need for right- or left- hand rotation to set or release the tool. A high load spring maintains the slips fully retracted until engagement of casing is required.

The hydraulic spear is activated by a higher flow rate than the one required to perform the cut. However, it is still necessary to ensure that this flow will not activate the spear unexpectedly. Hence, according to SPE 67747 [45], this is accomplished by applying a metering sleeve after the cut has been performed.

Therefore, once the cut is completed the workstring is elevated, releasing and pulling the hanger seals from the wellhead. The hydraulic spear is positioned just below the casing hanger and the metering sleeve is dropped down the workstring and to be seated in the hydraulic spear.

When the metering sleeve is set, fluid circulation at a predetermined rate sets the spear. At this point the casing is securely engaged, the workstring is elevated and the casing is pulled free to the rig floor. If desired, after the casing is securely held by slips at rig floor, the spear can be released from its latching point by dropping a ball and pressuring the work string.

According to SPE 67747 [45], operators in West Africa and in the Gulf of Mexico have already tried the system but not for cutting intermediate casing. In other words, it is not a proven technology for intermediate casing cut. However, the system was field tested for multistring casing cutting and wellhead retrieval as it will be explained in Sect. 6.2.4.1 but with a little variation of the Marine Swivel/Seal Extractor tool.

6.2.2.1.2 Shortcut Deepwater P&A System.

OTC 23906 [47] provides an alternative tool designed to latch and retrieve the seal assembly, sever a single string of casing, engage it for removal and retrieve the wellhead seal assembly in one operation. This system of tools provided by the service company Schlumberger has the name of *Shortcut Deepwater P&A system.*

Similar to SPE 67747 [45], OTC 23906 [47] is also focused on Subsea P&A. Hence, some of the benefits of using this technology could be enlisted as follows [48]:

- Maximizes reliability of cutting operations with system components designed to work together.
- Saves rig time by retrieving wellhead seal assembly or wear bushing, and casing in one trip.
- Cuts faster because casing is held in tension.
- Requires a single trip for multiple cuts.
- Increases safety of surface handling by engaging the cut casing segment from the top.
- Minimizes possible drillstring failure because the drillstring is not rotated in open water.

Fig. 6.15 shows the specific BHA configuration to perform a multistring casing cut and pull operations as proposed by the paper OTC 23906 [47] and better detailed in "*Service Sheet*" provided by the company website [48]. Here, it is also possible to find a brief description of the working methodology required to use the system, which can be described as follows:

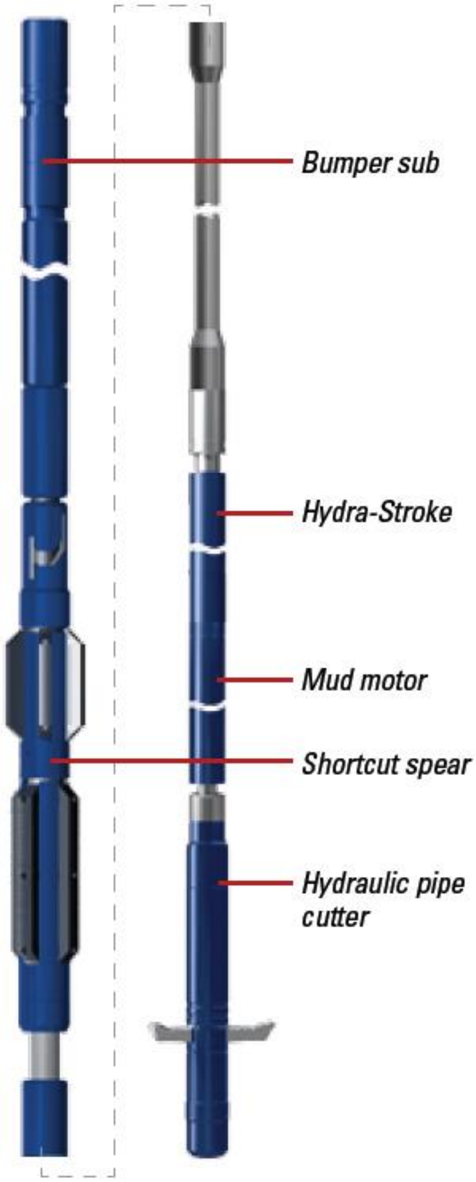


Fig. 6.15. Deepwater P&A system [48].

- Engage the wellhead seal assembly with the retrieval tool and strip it up into the riser.
- Position the casing cutter at the predetermined depth.
- Engage the spear and place the casing in tension.
- Start the pump, slowly increase the flow rate to run the motor, and sever the pipe with the hydraulic casing cutter (See 6.1.4 for better understanding of the Hydraulic pipe cutter).
- Slack off to string weight, disengage the spear, and POOH until the spear is just below the wellhead.

- ❖ Reengage the spear and POOH with the casing.
- ❖ Lay out the seal assembly and retrieval tool to surface.
- ❖ POOH until the casing hanger is landed out on the rotary table.
- ❖ Disengage the spear and rack back in the derrick.
- ❖ Lay down the casing.

According to OTC 23906 [47], the system has been successfully operated in the Gulf of Mexico and has played a key role in minimizing the well abandonment cost.

6.2.2.2 Multi-Cycle multiple cut and pull in a single trip.

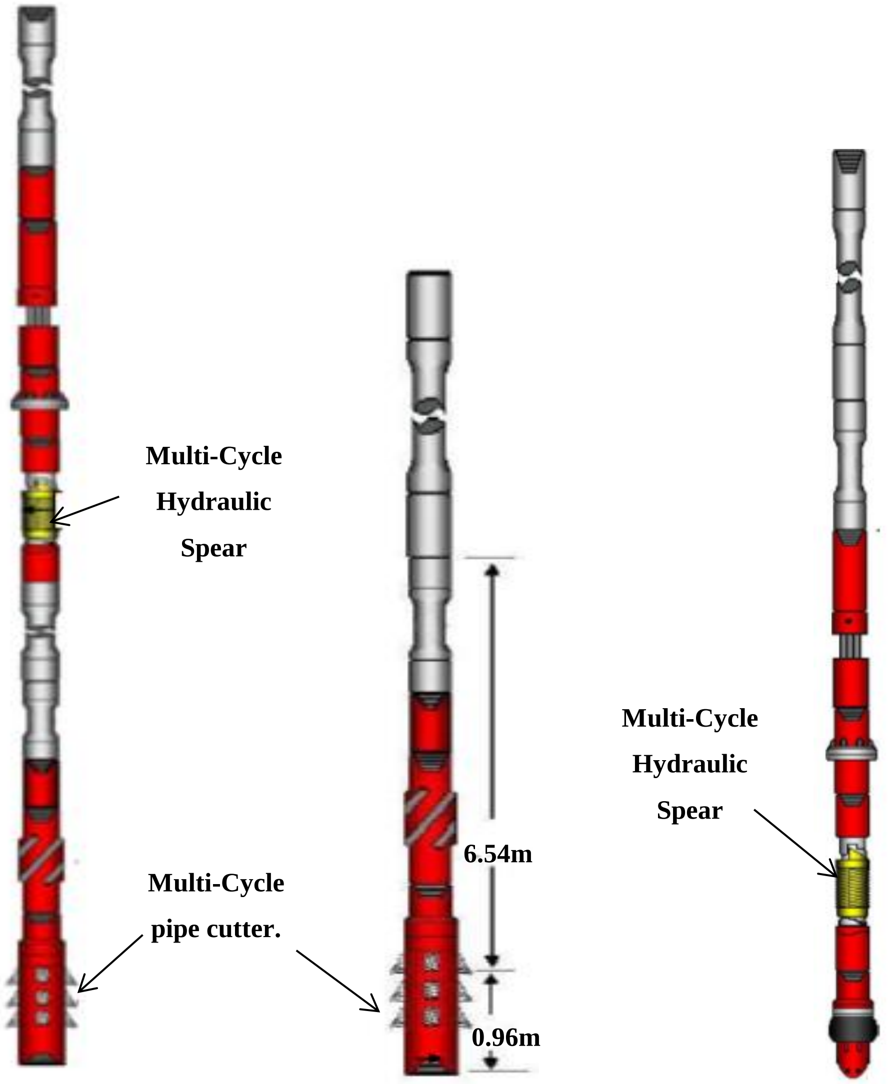
In certain situations, difficulties may arise during the retrieving/pulling operation. In such cases, a cutting device needs to be reinserted in the wellbore and a second cut should be performed in a different location.

SPE 145494 – Increasing Reliability of cutting/pulling casing in a single trip [49] mentions that the typical reasons for an inefficient pulling operation are due to firm cement, barite settling from the drilling fluid in the annulus, or both. However, it is also possible to include “well geometry changes” as a relevant issue, since P&A is normally performed in mature wells where geology might play an unpredictable positive or negative role (e.g. hole enlargement or downsizing).

This section intends to present an innovative tool to minimize the number of trips required during casing removal suggested in the paper SPE 145494 [49] and better detailed in the patent US 2012/0186817 – Multi-Cycle pipe cutter and related methods [50]. Therefore, some of the benefits of using this technology could be enlisted as follows:

- One trip cutting/pulling system.
- Severing a casing at one or more locations.
- Only one set of cutters will be deployed during cutting.
- Selectively activate each set of cutter remotely.
- Pressure drop surface indicator to confirm cut completion.
- Spear/packer tool in the BHA.

Fig. 6.16 shows three specific BHA configurations proposed by the SPE 145494 [49] to perform multiple cut and pull operations. Here, Fig. 6.16b and Fig. 6.16c illustrate the tools required to perform separated operations like the ones explained in Sect. 6.1.2 and Fig. 6.16a illustrates the combined assembly for a single operation.



a. Cut & Pull BHA **b. Cut only BHA** **c. Pull only BHA.**

Fig. 6.16. Bottom Hole Assemblies for multiple cut and pull operations [49].

The particularity of the assemblies shown in Fig. 6.16a and Fig. 6.16b is the inclusion the Multi-cycle pipe cutter. For better understanding of the tool, Fig. 6.17 illustrates its mechanism as presented in the patent US 2012/0186817 [50], followed by a brief description of the tool components and working methodology:

❖ *Cutting Structure (Knife Sets).*

The multi-cycle downhole cutting tool includes one or more cutter knife sets. Each cutter knife set may include one or more individual pivotable cutter knives arranged circumferentially around the tool body and configured to selectively engage by the motion of a pressure activated piston assembly. Fig. 6.17 shows three sets of knifes hinged with a pin for pivotability.

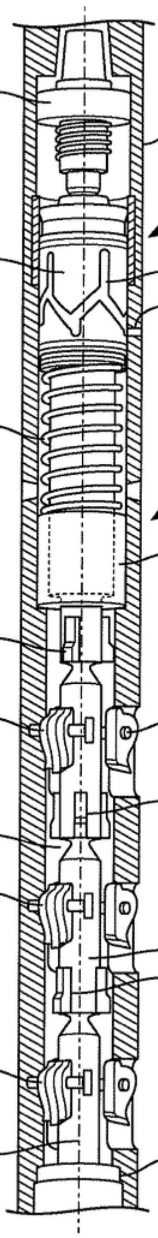


Fig. 6.17. Cross Section view of Multi-Cycle pipe cutter [50].

- *Pressure activated piston assembly.*

The piston assembly is composed of a piston head and a mandrel with blade lobes. It is capable of being hydraulically activated and configured to move longitudinally within the tool body in response to the applied fluid pressure. Hence, the axial movement of the blade lobes engages with each knife sets during the translation of the piston providing the selectivity property to the tool.

- *Pressure drop Indicator.*

A pressure drop indicator is configured to confirm completion of each casing cut by indicating a pressure drop when the casing is severed by the cutter knives. For the purpose, a stationary stinger is located at the top of the piston with an axial length equal to the axial stroke (required to complete the cut) of the piston assembly.

Initially, the stinger stays in the bore creating restricted flow area and thereby requiring higher activation pressure. When the cut is complete, the piston assembly moves downward equal to the stroke, thereby clearing the stinger from the bore and removing the flow restriction resulting in drop of the activation pressure.

- *Indexing Mechanism.*

The indexing mechanism is configured to dictate the selective engagement between the blade lobes and cutter knife sets. As shown in Fig. 6.17, it includes a circumferential indexing track in which a fixed travel pin is configured to engage. Thus, the engagement of the travel pin with the indexing track in combination with fluctuations in fluid pressure, results in a predetermined longitudinal and angular motion of the piston assembly.

Fig. 6.18 illustrates a detail of the indexing track. Here, it is possible to recognize two main track sections. A *longitudinal track section* which intends to align the blade activating lobes with one of the cutter sets and an *angular track sections* to manipulate the piston assembly (rotate and translate longitudinally within the tool body). In addition, a third auxiliary track is proposed for timing purposes due to no alignment of blade activating lobes/cutter knife.

For example, if the pin is positioned at the top of the longitudinal track "1" means that the activating lobe #1 and cutter knife set #1 are aligned, hence the cutter knife is extended. However, if the pin is traveling through the angular track sections means that activating lobe #1 and cutter knife set #1 are misaligned, resulting in a retracted position of the cutters. The transition slots, located at the bottom side of the angular track sections, are configured to direct the one-way rotational movement of the piston assembly.

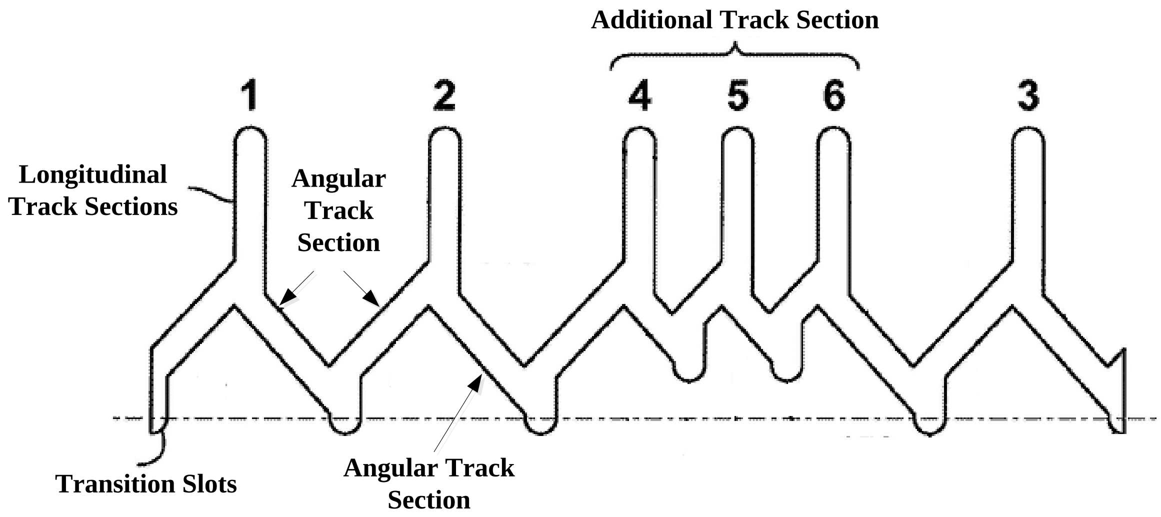


Fig. 6.18. Indexing Track detail [46].

Since the Multi-Cycle pipe cutter is a hydraulic tool, the methods for activating the cutters are related to changes in fluid pressure. Therefore, if pressure is increased, the piston assembly moves downwardly resulting in a rotation of the travel pin through the angular track section. Thereafter, pressure should be decreased to allow alignment of the blade and cutters.

After the cut has been performed a pulling operation should be applied. According to SPE 145494 [49], the first Multi-Cycle hydraulic spear was developed and included in the assembly shown in Fig. 6.16a. This hydraulic spear, applies the same concept as the one presented in Sect. 6.2.2.1.1. Hence, it is also activated by a higher flow rate than that required to active the Multi-Cycle pipe cutter. However, the difference relies on the auxiliary tracks or "blank tracks" which ensures the correct cut-pull-cut-pull sequencing.

The tool has been field tested in Norway by cutting and pulling a 9 5/8 in, 53.5 lbs/ft grade C-95 in two trips. The objective was to evaluate the Multi-Cycle Pipe Cutting tool and to validate the selective multiple cut mechanism. For the test, three cuts were made in the casing at depths of 1575m, 1579m and 1582m using the 8 ½ in tool. Once all cuts were completed, each casing segment was retrieved to surface in separate trips successfully.

6.2.3 Alternative Plugging Materials.

Sect. 4.4.2 mentions the desired properties for a permanent well barrier according to NORSOK - D010 [3]. Here, the Standard does not exactly mention “cement” as the desired plugging material. However, all the typical scenarios and further description of permanent well barriers (inside the Standard) indirectly suggest cement as the most common and traditional plugging material.

In order to open a discussion, cement effectiveness is questioned when extreme/unexpected cases are raised like cracking due to changes in temperature and pressure, subsidence/compaction, fault/earth quake, vibration, etc. The intention of this section is to briefly present some of the new releases with respect to plugging materials.

6.2.3.1 SANDABAND®.

According to the company website [51], SANDABAND ® is an acronym that stands for “SAND for ABANDdonment”. Here, it is mentioned that SANDABAND® is a unique non-consolidating well plugging material that combines individual high-strength quartz particles with Bingham-plastic properties. This means that the material is capable of behaving as a rigid body at low stresses but flows as a viscous fluid at high stress.

The presentation of the company in the PAF of 2011 [4], mentions that the sand slurry is composed of 15% of fluid (Water, Brine) and 85% of solids. Hence, a density of 17.9 ppg is reached and also the title of “Non segregating” fluid.

SANDABAND® properties could be enlisted as follows [4]:

- Long term integrity
- Bonds to steel
- Removable
- Ductile
- Non shrinking
- Chemically inert
- Gas-tight
- Pumpable
- Environmentally safe
- No health hazards
- Verifiable
- HPHT resistant
- No reservoir damage
- Non-erosional.

According to SPE 133446 – Permanent Abandonment of a North Sea Well using Unconsolidated Well Plugging material [52], SandAband® is a field tested plugging material applied in the exploration well "Jetta" operated by Det Norske Oljeselskap in the North Sea.

Furthermore, SPE 133446 [52] also mentions that the operation was accomplished in a safe and successful manner and even considering time saving associated with the elimination of the WOC time in addition of neglecting the need of running a cement stinger.

6.2.3.2 ThermaSet®.

ThermaSet® is an alternative plugging material proposed by the service company WellCem AS [53]. ThermaSet® is a low viscosity resin system which exceeds the compressive and tensile strengths traditionally found in cement systems. In this sense, the specifications offered by the service company could be enlisted as follows:

- A non-reactive polymer – particle free liquid
- Specific gravity can be adjusted from 0.7 - 2.5 SG
- Viscosity range 10 –2000 CP
- Operating temperature range from -9 ºC to 150 ºC BHT, resistant to 320 ºC in cured conditions.
- Curing/setting times can be accurately regulated from a few minutes to several hours.

As cement, ThermaSet® is a fluid when pumped and thereafter become solid at a predesigned temperature. Some other benefits proposed by the service company could be enlisted as follows [53]:

- Superior mechanical properties (that are long lasting)
- Fast setting time (can be adjusted as required)
- Effectively reduces permeability
- Easy to prepare and handle on location
- Good bonding to steel
- Compatible with most fluids and cements
- Extremely tolerable to contamination
- Withstands thermal expansion of the casing without cracking.

According to presentation of the company in the PAF of 2012 [4], ThermaSet® has been used to solve a barrier problem in a collapse tubing and ruptured production casing in a well of the NCS. Here, a ThermaSet® plug was pumped through the collapsed tubing, the desired volume was squeezed into the reservoir through perforations and the top of the plug was kept above the collapsed points. Thereafter, the plug was tagged at the desired depth and pressure tested with 2500 psi in compliance with the requirements of NORSOK – D010 [3].

6.2.3.3 Shale formation as annular barrier.

Sect. 6.2.2 already mentioned "well geometry changes" as a negative issue for cut and pull operations. However, this section intends to present well geometry changes as a positive issue, specially referring to shale as annular well barrier.

For the purpose, according to SPE 119321 – Identification and Qualification of Shale Annular Barriers Using Wireline Logs During Plug and Abandonment Operations [54], traditional sonic and a variation of the ultrasonic logging presented in Sect. 5.1.1 named *"Ultrasonic azimuthal bond logging*" provides the information of the material immediately behind the casing.

An Ultrasonic azimuthal bond logging tool uses a high-frequency pulse-echo technique to scan the casing with an azimuthal resolution of 10 or 5 degrees providing 36 or 72 measurements at each depth. The data is processed to yield the casing thickness, internal radius, and inner wall smoothness as well as an azimuthal image of the acoustic impedance of the material behind the casing. If the acoustic impedance is larger than 2.6 MRayl then a good bonded material is expected.

Therefore, if the log shows the following observations [54]:

- Good bond log response far above the top of the theoretical cement.
- Good quality bond correlates with shale rich intervals.
- Large and sometime frequent changes in bond log response at the same depth as geological changes.
- Above the casing shoe of an outer casing string the log response changes from good quality bond to free pipe as the formation can no longer impinge onto the inner casing string.

It is possible to say that the formation has been displaced towards the outside of the casing in a uniform manner and over a sufficient interval. Thereafter, it is necessary to prove that physical properties like rock strength and low permeability are good enough to declare the formation as an annular barrier to reservoir fluids.

A more technical description or requirements on how to declare shale as annular barrier could be enlisted as follows [54]:

- The barrier must be shale demonstrated through electrical logs or cutting description logs made during or after drilling.
- The strength of the shale must be sufficient to withstand the maximum expected pressure that could be applied to it (Calculating the worst case scenario).
- The displacement mechanism of the shale must be suitable to preserve the well barrier properties.
- The barrier must extend and seal over the full circumference of the casing and over a suitable interval along the well.

According to SPE 119321 [54], these new procedures to qualify shale as an annular well barrier element were already accepted by PSA. Therefore, over 40 P&A operations have used this method with a success rate of 90%.

6.2.4 Multistring Casing cutting and Wellhead Removal in a single operation.

This section shares the same objective as Sect. 6.2.2 since it intends to present the technology used to perform cut and pull operations in a single trip. However, the difference relies on the position of the cut and the multiple casing strings to be severed (Phase 3). Thereafter, consider the removal of the wellhead (Subsea P&A) or surface/conductor casing (Platform P&A).

Two possible alternatives were found in the literature. The first one proposed in the paper SPE 67747 [45] named *Hercules Multistring cutter/Universal Wellhead Retrieving System (UWRS)* and the second one proposed in the paper SPE 148859 – Abandonment of offshore exploration wells using a vessel deployed system for cutting and retrieval of Wellheads [55] named *"Abrasive water jet cutting and Wellhead retrieval"*.

6.2.4.1 Hercules Multistring cutter/UWRS.

The UWRS is a combination of a latching tool and the Marine Swivel presented in Sect. 6.2.2.1.1. Hence, it is also a technology proposal for Subsea P&A. The *UWRS* is run above the *Hercules Multistring cutter* to secure the wellhead during the cutting process and recover the wellhead once it is severed from the cemented conductor strings.

The BHA assembly to perform this operation is almost similar to the one presented in Fig. 6.14a, but in this set up the inclusion of the hydraulic spear is neglected since the UWRS already performs this operation. Fig. 6.19 illustrates the appearance and parts of the UWRS for better understanding of the working mechanism.

The working mechanism, as explained in SPE 67747 [45] mentions that a shoulder beneath the wellhead polished bore is engaged in tension with a collet system. A J-slot in the top of the UWRS controls the setting and releasing of the collet from the wellhead.

Therefore, the UWRS is run with the J-slot latching the collet in the release position. Once the tool is shouldered on the top of the wellhead, one quarter turn rotation to the left allows the inner mandrel to release from the run-in position and to be raised, locking the collect into the wellhead.

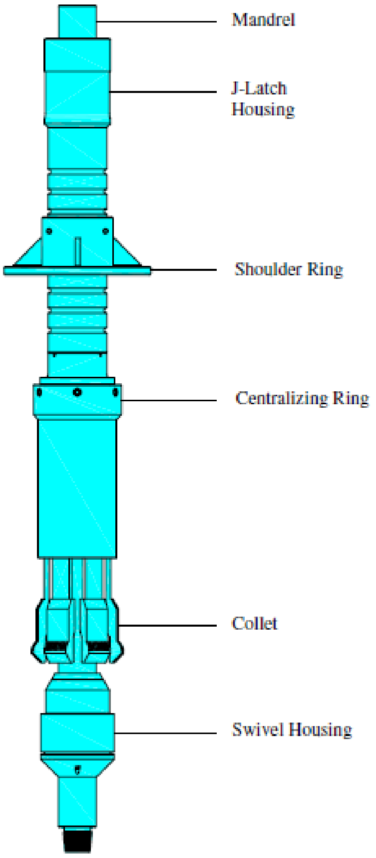


Fig. 6.19. Universal Wellhead Retrieving System (UWRS) [45].

If the workstring is needed to be recovered prior to the complete severing of the wellhead, slacking off on the drillstring disengages the collet. When the inner mandrel is lowered it will automatically re-engage the J-slot to maintain the collet in the released position.

UWRS is rated for an overpull up to 300000 pounds during rotation to cut the pipe and 1240000 pounds to recover the wellhead (static condition).

As mentioned in Sect. 6.2.2.1.1, the combination of UWRS and Hercules Multi-string Casing cutter has already been field tested meeting their design goals of improved operational efficiency and high reliability.

The comparative case explained in Sect. 5.2 (extracted from SPE 92165 [27]), claims that the "World's first multiple mechanical cutting" was performed in NW Hutton Platform wells in UK. Here, the tool used a positive displacement mud motors (PDMs) to power the multistring casing cutters, somehow similar in concept to the *Deepwater P&A system* described in Sect. 6.2.2.1.2. However, other details from the tool are not provided, hence it is not possible to say that the actual system or an early version of it was used in this particular.

6.2.4.2 Abrasive water jet cutting and wellhead picker.

Norse Cutting & Abandonment (NCA) is an example of service company providing and innovative alternative to the conventional mechanical cutting by using abrasive water jet instead of cutters and a wellhead picker. According to the *"Service Sheet"* provided by company [56], Abrasive Water Cutting is commercially offered as Internal Multi-String Cutting Tool (IMCT).

Some of the benefits claimed by the service company of using this technology could be enlisted as follows [56]:

- Capable of cutting and recovering of wellhead in one deployment.
- Capable of cutting 5 layers of casing (7 – 36in) in one run.
- Can be operated from a vessel and does not require drillpipe or workstring.
- Produces a clean and even cut for easier and safer recovery and handling of conductor – ideal for installation of conductor whipstocks.
- Eliminates hazardous handling of drillpipe and use of explosive charges.
- System is not affected by compressive forces.
- Capable of cutting conductors with or without annuli cement, concentric or eccentric.
- Superior cutting speed.
- Stand alone, rigless surface package is available.

- Computer based control and monitoring system.
- Could be applied for Subsea or Platform P&A.

According to SPE 148859 [55], if IMCT is desired to be used for Subsea P&A the cutting tool assembly is composed by a purpose built wellhead connector and a stinger with the cutting nozzle at the lower end. However, in order to operate the assembly a system using high pressure water jetting pumps, abrasive mixer and an umbilical is required.

The working mechanism, as explained in SPE 148859 [55] mentions that the wellhead connector locks onto the outer profile of the wellhead, and the stinger is spaced out to achieve the correct cutting depth. The principle for abrasive water jet technology is to pressurize water up to between 60MPa and 120Mpa, add abrasive particles (e.g. sand) and pump this slurry through a nozzle creating a kinetic energy capable of cutting the different layers of casing. Thereafter, since the wellhead is already locked up any kind of hoisting mechanism (crane, rig, etc.) could lift up the remaining pieces.

According to SPE 148859 [55], abrasive water jet for well severance started in early 2001, test cuts were performed in 2002 in Norway (Ekofisk), and the first commercial conductor cuts were done on the Frigg Platform in 2003. By the time of the publication of the article, 400 conductors are claimed to be cut by the service company.

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VII. Discussion and Analysis of the new technology trends for P&A.

This section intends to objectively discuss and technically compare the similarities, key features, limitations and differences between all the remarkable technologies proposed in Sect. 6.2.

7.1 Technical comparison of new technologies.

7.1.1 Downward Section Milling vs Upward section Milling.

Appendix B.2 (blue semi-hyphen line) shows a comparative chart between downward section milling and upward section milling. Here it is shown that one of the biggest differences between both of them is the ***working mechanism*.** Therefore, upward section milling considers *tension on the mill* given by the rig and downward section milling considers *weight on mill* given by heavy tools.

A second difference relies on the ***special fluid*** to be considered for the operation. Here, for upward section milling this feature is *optional* or *not required*. Meanwhile, for downward section milling, it is one of the *major issues* for a successful progress of the operation.

A third sensitivity is the ***Swarf Handling*** (equipment). This again will depend on the fluid circulation requirements of the well. Therefore, for upward section milling special apparatus are *optional* or *not required* and for downward section milling it is *definitely required* due to the continuous circulation situation.

Furthermore, if carefully analyzing the ***key technical equipment*** for each technology, it is possible to mention that upward section milling relies either on the *Up-thruster tool* or *the screens/reverse flow mill* and downward section milling is highly dependent of the *cutter technology*.

To denote is that milling with tension is not yet a proven technology. Hence, the reliability of both proposed tools are still an open issue against the well-known downward section milling mechanism.

Also, some features were mentioned as “optional” due to the particularities of the Reverse Section milling mechanism with respect to flow. Consequently, if this mechanism is used some circulation might be required due to the absence of a flow path that may lead fluid to impact directly on the working section. Different is the case of the SwarfPak milling tool that includes these flow paths and uses a reverse flow mechanism to divert the annular flow through the inside.

Finally, one should be aware that both technologies require a heavy duty either Platform or Subsea rig to accomplish their milling purpose.

7.1.2 Section Milling vs HydraWash™ system.

Appendix B.2 (red semi-hyphen line) shows a comparative chart between section milling and HydraWash™. Here, the gap is much wider since both of them perform different operations to accomplish the same objective. Hence, it is fundamental to understand that section milling creates a full cross sectional window in the casing meanwhile Conventional PWC and/or HydraWash™ system only perforates the casing. Therefore, another chart should be used to distinguish when to use the different technologies.

Appendix B.1 shows a decision chart on when each technology could be applied by understanding their limitations. Here, the chart has similar initial points as the ones presented in the new revised version of NORSOK-D010 [12]. However, the one proposed in this thesis is a modified version that intends to compare the applicability of section milling, conventional PWC and the HydraWash™ system.

For better and easier understanding of the chart presented in Appendix B.1, the following pinpoints could be used:

- *Perform an initial logging run.*

An initial logging run should be primarily performed. It could be done with an “Acoustic logging tool” or the newest version “Ultrasonic Azimuthal logging tool” combined with a caliper for an inner casing size measure.

- *Verify sufficient cement/formation to act as a barrier.*

Both technologies could be applied after verifying that there is no sufficient cement/formation length to act as a barrier.

- *Verify sufficient length with bond to act as foundation.*

If the log shows that there is sufficient length with bond to act as foundation, then a mechanical plug could be set in the bounded area and operations can resume as for section milling or conventional PWC. However, if there is no sufficient length with bond other borehole particularities should be taken into consideration.

- *Verify restrictions or minor downsizing in the casing.*

If the caliper log shows restrictions or minor downsizing in the casing, then HydraWash™ is highly challenged due to the size of rubber cups in the HydraWash™ Jetting Tool. If the operator decides to run the HydraWash™ system relying on the flexibility of the rubber cups, there might be some risk related with not reaching the desired perforation depth. Therefore, in order to avoid that risk, it is easier to run and install a mechanical plug as close as possible to the source of inflow and resume with section milling or conventional PWC.

If the caliper log shows high downsizing, casing collapse u other inner diameter relative problems, then corrective operations should be performed. However, these corrective operations are not covered in this thesis due to its extension.

- *Verify a length larger than 200ft below the perforations to act as rat hole for the residual perforation guns.*

Assuming that restrictions or minor downsizing in the well are not an issue, then it should confirmed that a length higher than 200ft below the perforations is capable of receiving the residual guns. If this length is available, then the HydraWash^{TM} system is the best technology choice to create the well barrier in a single trip. However, if this length is not available conventional PWC could also be performed but not as a single trip due to the retrieval of the perforating guns to surface.

Furthermore, if carefully analyzing both technology proposals, it is possible to be aware of the notable reduction in time and operational steps by using HydraWash^{TM}. On the other hand, conventional PWC and section milling could share the same amount of steps (blue semi-hyphen line from Appendix B.1) but of course perforating is a much less time consuming operation than section milling.

In general PWC, either conventional or HydraWash^{TM}, does not require a heavy duty rig to accomplish its purpose since heavy work is not being performed. Different is the case of section milling as it was detailed explained in Sect. 7.1.1.

7.1.3 Single Multistring cut vs Multi-Cycle multiple cut and pull in a single trip.

Appendix B.3 shows a comparative chart between technologies capable of cutting and pulling in single trip. Here, the blue semi-hyphen line encloses a technical comparison between two systems capable of performing a similar multistring cut and pull in a single trip. Likewise, the red semi-hyphen line intends to compare the particularities between the already mention single multistring cut and pull and the multi-cycle multiple cut and pull.

Therefore, if the technologies enclosed in the blue semi-hyphen are first analyzed, the following similarities can be pinpointed:

- Both are system proposals for Subsea P&A.
- Both propose tools to mechanically latch the seals from the wellhead.
- Both can be used to cut deeply (far from seabed) a multiple set casing strings.
- Both include one knife set of cutters to perform the cut.

- Both propose surface indicators to mitigate different downhole situations.
- Both use the “hydraulic push” concept to manipulate the knifes.
- Both propose a pulling mechanism to retrieve the severed casing.

Similarly, differences between these two technologies could be enlisted as follows:

- The ***cutter technology*** for the Hercules Multistring Casing cutter is much more advanced than the one used in Hydraulic Casing cutter. Hence, Hercules Multistring Casing cutter uses the latest cutting technology (No. 4 in table 6.1) and Hydraulic Casing cutter uses a conventional one like No. in table 6.1.
- Only Hercules Multistring Casing cutter includes a ***special cutter controller*** comprised by an *adjustable internal stop* to control the maximum knife cutting.
- The ***surface indicators*** in the Hercules Multistring Casing cutter include a *Tattle Tail* feature that indicates the full extension of knifes. Meanwhile, the Hydraulic Casing cutter relies on a *differential pressure* reading to confirm the casing cut.
- The ***key technical equipment*** for Hercules Multistring Casing cutter is a *special large OD sleeve* capable of providing maximum stabilization, rest and support on the cutter arms. On the other hand, the Hydraulic Casing cutter proposes a *Knife return system* capable of ensuring the correct return of arms to the tool body.
- The ***main pulling tool*** for the Hercules Multistring cutter/Marine Swivel/Hydraulic spear system is indeed the “Hydraulic Spear” that accomplishes its function by using a *Metering Sleeve*. Opposite is the case of the “Shortcut Spear” that is a mechanical heavy duty Spear.
- The Hercules Multistring cutter/Marine Swivel/Hydraulic spear system uses the rotation of the workstring to perform the casing cut. Meanwhile, the Shortcut Deepwater P&A system include a PDM to perform the cut.

Correspondingly, if the technologies enclosed in the red semi-hyphen are now analyzed, similarities can also be found. These are given by:

- All can be used to cut deeply (far from seabed) the intermediate casing.
- All propose surface indicators against different downhole situations.
- All use hydraulic force to manipulate the knifes.

- All propose a pulling mechanism to retrieve the severed casing.

In that sense, differences between these technologies could be enlisted as follows:

- The Single Multistring cut and pull systems only allow *one cut per run*. This means that if the cutters are worn the tool should be retrieved and a new set of fresh cutters should be deployed to resume the activities or cut in a new desired depth. Meanwhile, opposite to that ***knife particularity***, the Multi-Cycle multiple cut and pull system allows *one or more cuts in a single run*.
- The ***surface indicators*** for the three technologies apply different principles and concepts to control a desired variable (two of them previously explained). Hence, the Multi-Cycle multiple cut and pull system uses a *Stationary Stinger* to confirm the casing cut. To denote, is that the surface indicators for the Shortcut Deepwater P&A system and the Multi-Cycle multiple cut and pull system share the same purpose.
- The ***key technical equipment*** for three technologies is different (two of them previously explained). Therefore, the Multi-Cycle multiple cut and pull system rely on an *Indexing Mechanism* capable of dictating the selectivity of the different knife sets.
- The ***main pulling tool*** for the Multi-Cycle multiple cut and pull system is similar to the Hercules Multistring cutter/Marine Swivel/Hydraulic spear system. However, the Multi-Cycle multiple cut and pull system applies the *"Auxiliary Track of the Indexing Mechanism"* to allow a correct cut-pull-cut-pull sequencing.
- The Multi-Cycle multiple cut and pull system uses the rotation of the workstring to perform the casing cut, which is similar to the Hercules Multistring cutter/Marine Swivel/Hydraulic spear system and different from the Shortcut Deepwater P&A system that includes a downhole motor.

The three technologies compared in this section require a heavy duty rig to accomplish their purpose. Likewise, special attention should be put to the Single Multistring cut and pull systems since both are commercially proposed for deep cuts in Subsea P&A. Furthermore, it should be also remarked that Hercules Multistring cutter/Marine Swivel/Hydraulic spear system has not been field tested yet.

7.1.4 SANDABAND® vs ThermaSet® vs Shale as well Barrier.

Comparing these three new plugging materials from an objective perspective is simple, since the three of them intend to conform or be part of a well barrier capable of withstand the load/environmental conditions for the time the well will be abandoned.

However, from a technological point of view the comparison task becomes more challenging due to the necessity of advanced experimental trials (not included in this thesis). This section intends to present a comparison of these three innovative plugging materials from an *operational point of view*.

In that sense, it is easy to understand that the operational steps will be considerable reduced if shale is declared as annular barrier. This reduction is due to the lack of necessity of creating a window (section milling) or perforating the casing (PWC).

On the other hand, if the bond between the casing and the formation is not good enough to act as a barrier, then operations like section milling or perforating the casing are required. Hence, plugging materials like SANDABAND® or ThermaSet® are subsequently needed to create the desired well barrier.

Furthermore, again from an operational perspective, SANDABAND® represents a better option since there is no need for waiting on the plug to harder. However, this plug cannot be tagged due to its physical properties and according to NORSOK – D010 [3] (Table 24) it is a requirement that the plug should be tagged.

7.1.5 Hercules Multistring cutter/UWRS vs Abrasive water jet cut and Wellhead retrieval.

Appendix B.4 shows a comparative chart between both technologies capable of performing multistring cutting and pulling in single trip (Phase 3 from Sect. 5.1.2.1). Here, it should be noted that Hercules Multistring cutter/UWRS could be better referenced as mechanical multistring cut and pull.

Therefore, if both technologies are analyzed, the following similarities can be pinpointed:

- Both propose tools to mechanically latch the wellhead.
- Both can be used to cut shallow (close to seabed) a multiple set of casing strings
- Both propose a pulling mechanism to retrieve the severed casings and wellhead.

Similarly, differences between these two technologies could be enlisted as follows:

- The ***cutting mechanism*** is different for both technologies. Hence, the Mechanical multistring cut and pull system uses the *Hercules Multistring Casing cutter* (explained before) meanwhile the Abrasive water jet cut and Wellhead retrieval system uses a device named *Internal Multistring cutting tool (IMCT).*
- The IMCT uses *kinetic energy* as ***working mechanism*** to perform the desired cut. Meanwhile, Hercules Multistring Casing cutter uses *hydraulic force* to activate one set of knifes.
- The ***key technical equipment*** for the Mechanical multistring cut and pull system is the combination between the *Special large OD Sleeve* on cutters in the Hercules Multistring Casing cutter and *Collet/J-slot latching system* in the UWRS. Meanwhile, for the Abrasive water jet cut and Wellhead retrieval system, it is the *Pumping capacity* that provides the jetting force required to perform the cut.

In general, both systems are commercially offered for Subsea P&A. However, Abrasive water jet cut and Wellhead retrieval could also be applied for Platform P&A. It should also be noted that the Mechanical multistring cut and pull system require a heavy duty rig to accomplish its purpose. Opposite is the case of Abrasive water jet cut and Wellhead retrieval that only requires a vessel.

7.2 Analysis Case: Applying new technologies in Platform P&A.

The example case presented in Sect. 5.3 already explained a detailed procedure on how a Platform P&A could possibly be performed. For the purpose, the typical scenario *of Permanent abandonment – Slotted liners in multiple reservoirs* was taken into consideration.

Subsequently, Sect. 6.2 and Sect. 7.1 presented and discussed new technologies to perform P&A. Therefore, the intention of this analytical case is to present how the number of operational steps is changed when taking into use the benefits of the new technologies and materials.

For simplicity, this analysis does not intend to show a detailed procedure as the one presented in Sect. 5.3. Hence, this will mostly pinpoint the steps that could be reduced or affected by applying these new technology trends.

Table 7.1 – Summary of Well Barriers used in the Example Case.

	Type of barrier	**Log Evaluation**	**Well barrier Method**	**Steps comprised**
	Open Hole to surface Well Barrier (Barrier 5)	Good Cement bond with 18 5/8” Casing.	Conventional internal cement Plug	Step 23
Shallow Reservoir	Secondary Well Barrier (Barrier 4)	Good Cement bond with 13 3/8” Casing	Conventional internal cement Plug	Step 19
	Primary Well Barrier (Barrier 3)	Sufficient length with bond to act as foundation.	Perforate 9 5/8”, wash and Squeeze Cement (conventional PWC).	Step 13 (MP) Step 14 Step 15
Deep Reservoir	Secondary Well Barrier (Barrier 2)	Good Cement Bond with 9 5/8” Casing.	Conventional internal cement Plug	Step 12
	Primary Well Barrier (Barrier 1)	Not Performed*	Section Mill 7” Liner and later Conventional cement Plug	Step 5 (MP) Step 10 Step 11

In that sense, Table 7.1 shows a summary of the well barriers used in the example case. Here, the table shows the assumed results obtained from a logging runs (Step 9, Step 18 and Step 22), the well barrier establishing method and the steps comprised to set the barrier. This table could also be cross-linked with the decision chart presented in Appendix B.1 for better understanding.

As shown in Table 7.1 and precisely pointed in the Decision Chart of Appendix B.1, the results obtained from a logging run actually dictate the complexity of the future well barrier method to be applied.

Appendix B.5 shows 243 possible combinations found to P&A the example well. This number just shows how wide and different P&A could actually be. Here, row 7 of the twenty four step division illustrates the actual combination used in the example case and summarized in Table 7.1.

For better understanding, Table 7.2 shows three generic possible scenarios. Here, it could be recognized a *super optimistic scenario* where the cement/shale bond between the casing and the formation is not good enough but special well conditions allow the use of the HydraWash™ system (1 trip system). Then, a *super middle scenario* where the cement/shale bond is in optimal conditions but a Mechanical Plug (MP) is still required as cement retainer (2 trip system). Finally, a *super pessimistic scenario* where all heavy duty or multiple trip operations should be performed. The word "super" is only used to generalize the hypothetical scenario since actually multiple situations/combinations could be configured as shown in Appendix B.5.

Table 7.2 – Super combinations for Well Barrier scenarios.

		Super Optimistic	**Super Middle**	**Super Pessimistic**
	Type of barrier	**Well barrier Method**	**Well barrier Method**	**Well barrier Method**
	Barrier 5	HydraWash™	Good Bond	PWC/Section Milling
Shallow Reservoir	Barrier4	HydraWash™	Good Bond	PWC/Section Milling
	Barrier 3	HydraWash™	Good Bond	PWC/Section Milling
Deep Reservoir	Barrier 2	HydraWash™	Good Bond	PWC/Section Milling
	Barrier 1	HydraWash™	Good Bond	PWC/Section Milling

By analyzing Table 7.2, the Super Optimistic scenario results in 20 operational steps to abandon the well. On the other hand, the Super Middle scenario requires 22 Steps and finally the Super Pessimistic involves 27 operational steps to accomplish P&A. Fig. 7.1 illustrates the statistics of all the possible well barrier configurations and the number operational steps required to abandon the well.

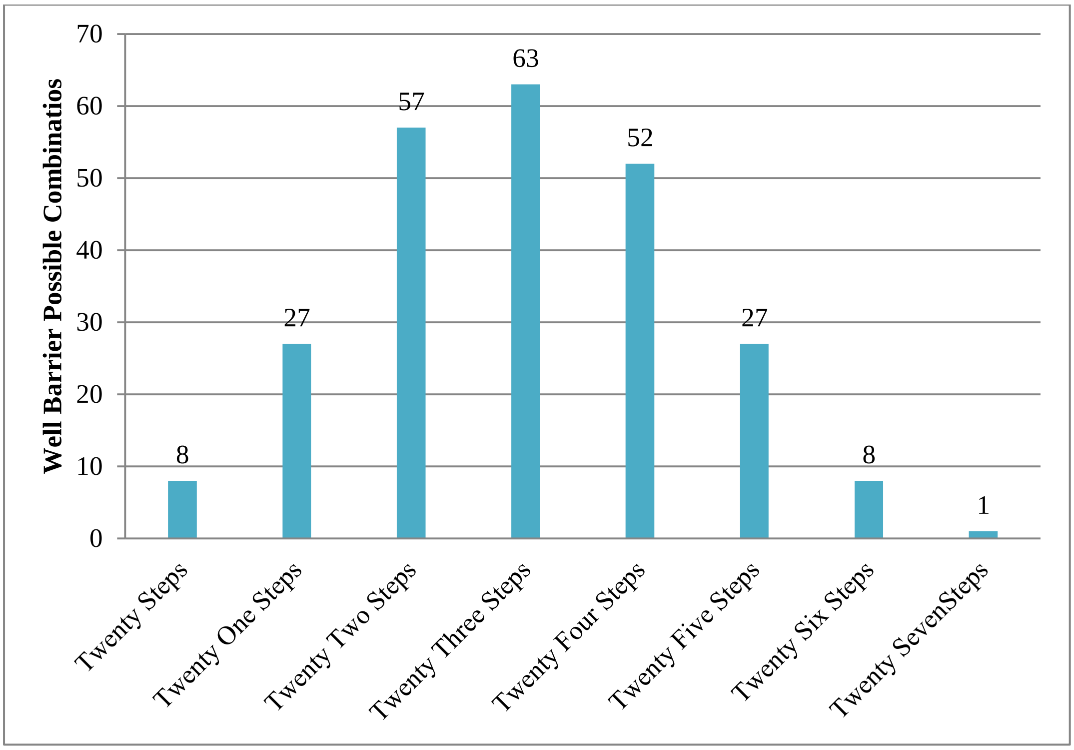

Fig. 7.1. Statistics of the Well barrier possible configurations for the Example Case.

From an operational point of view, the implementation of the HydraWash™ system in both primary barriers is actually the main factor that reduces the operational steps. However, from an economical point of view the Super Middle scenario might be much more convenient since both mechanical plugs could be deployed with wireline and continued with conventional cementing operations.

Another factor could be the plugging material used to create the well barriers. As explained in Sect. 7.1.4, SANDABAND® is the best option since no time is needed to wait on the plug to harder.

Similar is the case of cut and pull operations, in the example case these activities were performed separately from each other due to its complexity (Steps 17, 21 and 24). However, by implementing the Multi-Cycle Multiple cut and pull system (only technology not directly specified for Subsea P&A) both activities could be combined in a single cost effective trip.

Finally, if the Abrasive water jet cut and Wellhead retrieval system is used to perform the last phase of the well abandonment, costs could be representatively reduced since this technology is simpler and does not require the use of a rig.

VIII. Conclusion and Recommendation

The research and work in this thesis has detailed several interesting tools that have a positive impact on cost, duration, method, etc. of P&A operations. Furthermore the use of decision and comparison charts illustrate the key futures of each technology with respect to working mechanism and several other minor features. This chapter intends to cover the conclusions and recommendations based on the previous chapters of this thesis.

8.1 Conclusions.

- The Norwegian oil industry has already more than 40 years of existence. Therefore, many of their old fields are already declared to be in a brown field period and a considerable amount of those wells require P&A operations.
- Full permanent well abandonment operations represent an unavoidable cost with no return of capital. Therefore, the driver for operators to perform an impeccable job relies under a strict governmental regulatory framework.
- By understanding the details on how P&A is regulated in Norway and studying the corresponding Standard it is possible to understand the work scope that is required for a P&A operation.
- NORSOK D-010 [3] is a full structured Standard but does not distinguish between full permanent well abandonment and section abandonment (Slot Recovery). Therefore, this thesis includes a specific section that establishes the difference between both of them. Similar is the case of Subsea P&A and Platform P&A, which in essence dictates the future requirements of P&A.
- By providing an example case of a conventional Platform P&A it is possible to distinguish the required operations and the use of the traditional technology. Thereafter, it is possible to introduce new technology trends to replace the traditional one.
- Time consuming operations and multiple trips were the major drivers to propose new technology releases for P&A.
- Under a new technology perspective, it was found that the results obtained from a logging run dictate the complexity of the well abandonment operations. This means

that the results from a logging run affects directly on the well barrier method to be applied.

- According to the regulatory framework a well barrier comprises of a full cross sectional plug. Therefore, in order to accomplish this requirement, tools like Downward Section Milling Tool, Upward Section Milling Tool or perforation guns should be used on the casing.
- Downward Section Milling works by applying weight on the mill and relying on the cutter technology.
- Upward Section Milling works by applying tension on the mill and avoids surface swarf handling and related problems. However, it is not a proven technology yet.
- Conventional PWC and HydraWash™ is an effective alternative for section milling but special well conditions should be taken into considerations. HydraWash™ is a one single trip system meanwhile Conventional PWC first Perforates in one trip and then Wash/Cement/Squeeze in separate trip.
- The two single multistring cut and pull alternatives are almost similar in performance and criteria. However, the Shortcut Deepwater P&A system use a PDM and it is a proven technology.
- The Multi-cycle multiple cut and pull system is capable of performing multiple cuts in the same casing string. Normally, multiple cuts are required due to inefficient pulling operation. The tool includes an indexing mechanism for cutter(s)/pull system selectivity.
- SANDABAND® is a promising alternative for plugging material due to its physical properties. However, NORSOK D-010 [3] should be modified due to the tagging requirement.
- Abrasive water jet cut and Wellhead is a superior system over a mechanical multistring cut and pull system due to operational time, simplicity and working mechanism.
- Deciding when to use one technology over the other it is actually the main concern that affects the number of operational steps. In that sense, 243 possible configurations were found to possible abandon the well for the example case. Here, 8 configurations allow a 20 steps operational procedure, 27 configurations allow a 21 steps operational procedure, 57 configurations allow a 22 steps operational procedure, 62 configurations allow a 23 steps operational procedure, 52 configurations allow a 24 steps operational

procedure, 27 configurations allow a 25 steps operational procedure, 8 configurations allow a 26 steps operational procedure and finally 1 configuration allow a 27 steps operational procedure.

- By implementing new technology and criteria operations could be highly reduced in time steps. However, understanding the similarities, key features, limitations and differences between all them is an extensive job that requires a high level of understanding of each technology. This could be better referenced in Appendix B.1 to Appendix B.4.

8.2 Recommendations for further studies.

- Slot Recovery is an economical alternative to access untapped reserves and develop mature fields. Therefore, studying the determination of the amount of residual oil saturation and combined with well technology is an excellent field for future studies.
- This thesis could be complemented by studying the required technology or corrective measures in case of major hole downsizing, casing collapse and other wellbore related problems.
- Performing an experimental study to compare cement, SANDABAND®, ThermaSet® and shale as plugging materials could also be a beneficial further study.

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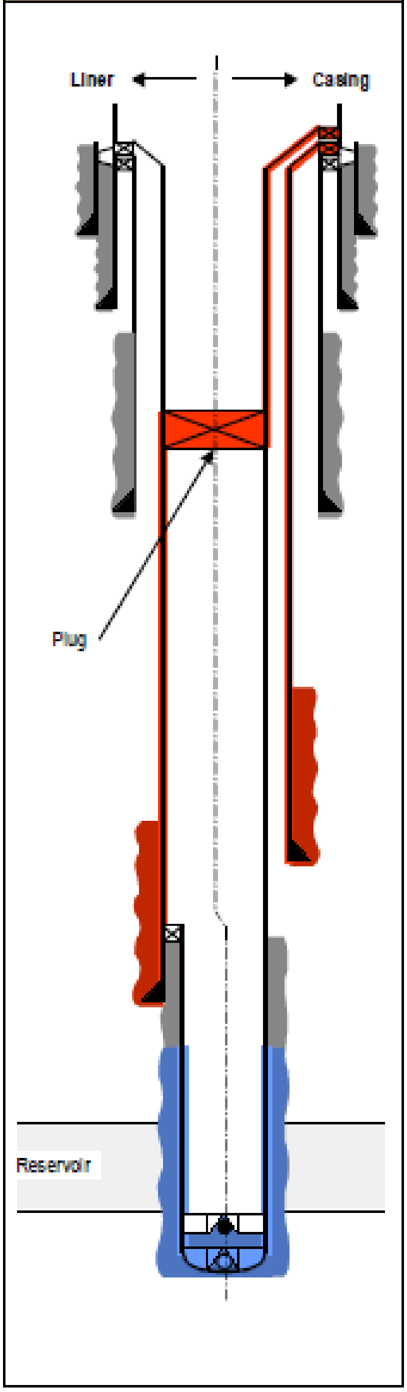
Appendices

Appendix A – Well Barrier Schematics

A.1 Temporary Abandonment – Non Perforated Well [3].

9.8.1 Temporary abandonment – Non-perforated well

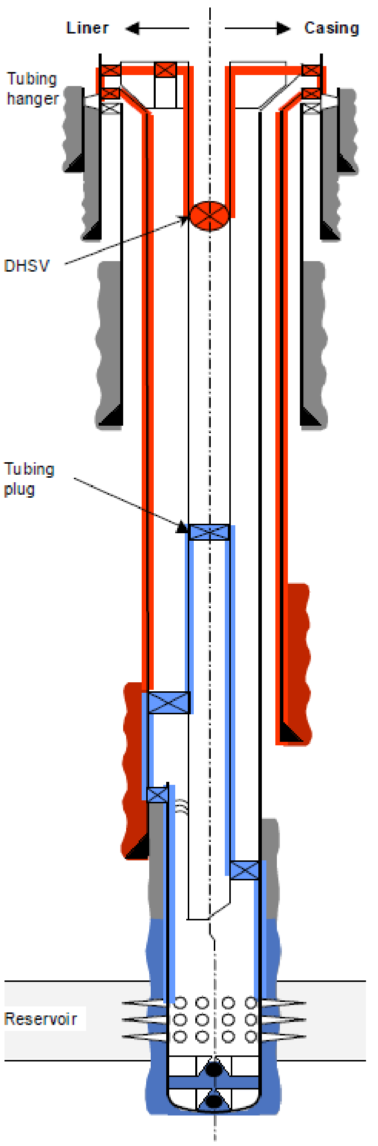


Well barrier elements	See Table	Comments
Primary well barrier, last open hole		
1. Cement plug	24	Shoe track.
2. Casing (liner) cement	22	
3. Casing (reservoir liner)	2	Un-perforated w/2 each float valves.
or		
1. Cement plug	24	Shoe track.
2. Casing cement	22	
3. Reservoir casing	2	Un-perforated w/2 each float valves.
Secondary well barrier, temporary abandonment		
1. Casing	2	
2. Casing cement	22	
3. Cement plug or mechanical plug	24 28	Shallow plug.
or		
1. Casing cement	22	
2. Casing	2	Intermediate
3. Wellhead	5	
4. Casing	2	Production casing.
5. Cement plug or mechanical plug	24 28	Shallow plug.

Note
None

A.2 Temporary Abandonment – Perforated Well with BOP or production tree removed [3].

9.8.2 Temporary abandonment – Perforated well with BOP or production tree removed

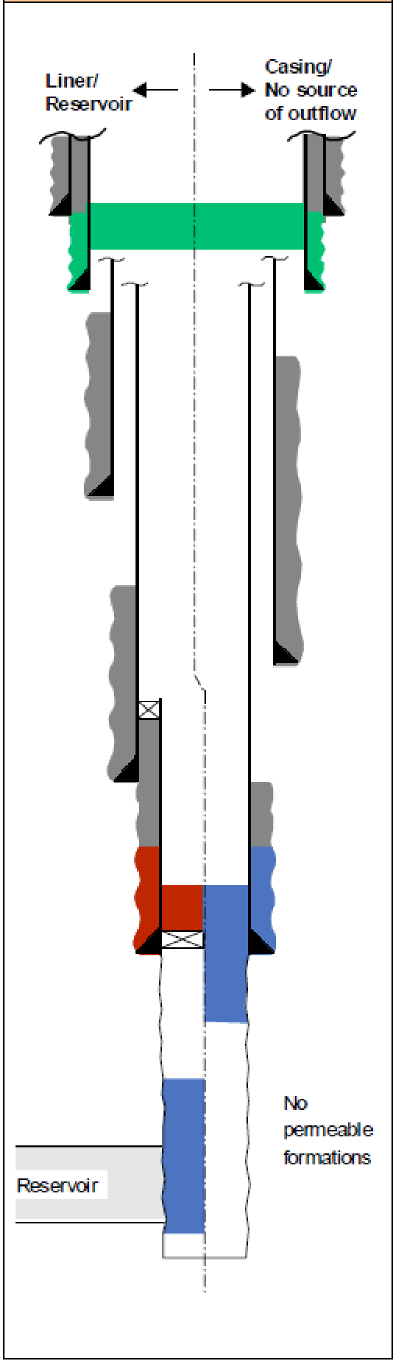


Well barrier elements	See Table	Comments
Primary well barrier		
1. Casing (liner) cement	22	
2. Casing (liner)	2	Liner above perforations.
3. Liner top packer	43	
4. Casing	2	Below production packer.
5. Production packer	7	50 m below TOC in casing annulus.
6. Completion string	25	
7. Deep set tubing plug	6	
or,		
1. Casing cement	22	
2. Casing	2	Above perforations.
3. Production packer	7	
4. Completion string	25	
5. Deep set tubing plug	6	
Secondary well barrier, reservoir		
1. Casing cement	22	Above production packer.
2. Casing	2	Common WBE, between liner top packer and production packer.
3. Wellhead	5	
4. Tubing hanger	10	
5. Tubing hanger plug	11	For SSWs.
6. Completion string	25	Down to SCSSV.
7. SCSSV	8	
or,		
1. Casing cement	22	Intermediate casing.
2. Casing	2	Intermediate casing.
3. Wellhead	5	
4. Tubing hanger	10	
5. Tubing hanger plug	11	For SSWs.
6. Completion string	25	Down to SCSSV.
7. SCSSV	8	

Note
None

A.3 Permanent Abandonment – Open hole [3].

9.8.3 Permanent abandonment - Open hole



Well barrier elements	See Table	Comments
Primary well barrier		
1. Cement plug	24	Open hole.
or, (“**primary well barrier, last open hole**”):		
1. Casing cement	22	
2. Cement plug	24	Transition plug across casing shoe.
Secondary well barrier, reservoir		
1. Casing cement	22	
2. Cement plug	24	Cased hole cement plug installed on top of a mechanical plug.
Open hole to surface well barrier		
1. Cement plug	24	Cased hole cement plug.
2. Casing cement	22	Surface casing.

Notes

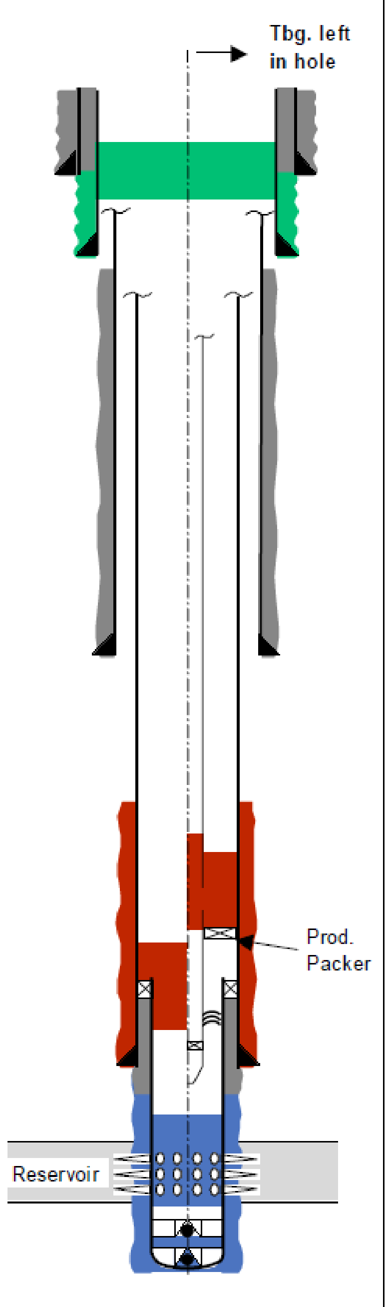
a. Verification of primary well barrier in the “liner case” to be carried out as detailed in Table 22.

b. The well barrier in deepest casing shoe can for both cases be designed either way, if casing/liner cement is verified and O.K.

c. The secondary well barrier shall as a minimum be positioned at a depth where the estimated formation fracture pressure exceeds the contained pressure below the well barrier.

A.4 Permanent Abandonment – Perforated Well [3].

9.8.4 Permanent abandonment - Perforated well

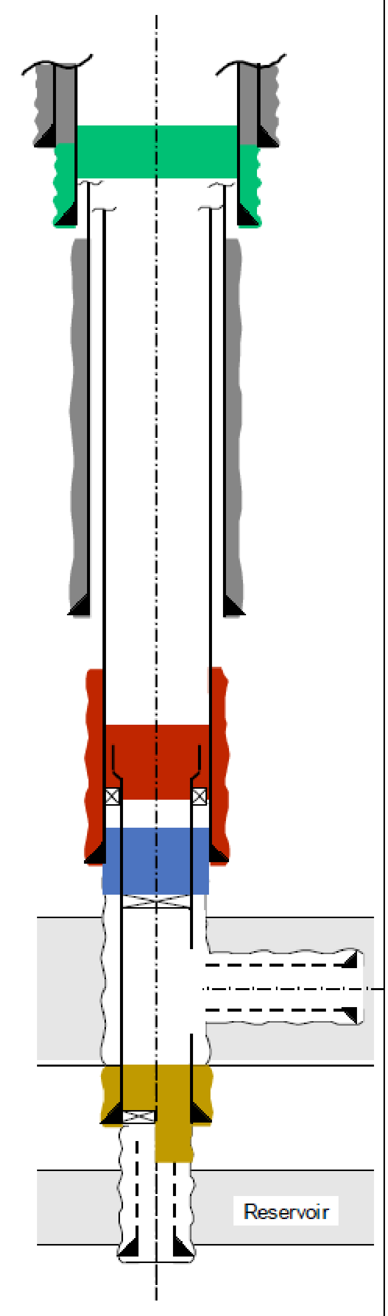


Well barrier elements	See Table	Comments
Primary well barrier		
1. Liner cement	22	
2. Cement plug	24	Across and above perforations.
Secondary well barrier, reservoir		
1. Casing cement	22	
2. Cement plug	24	Across liner top.
or, for tubing left in hole case:		
1. Casing cement	22	
2. Cement plug	24	Inside and outside of tubing.
Open holes to surface well barrier		
1. Cement plug	24	
2. Casing cement	22	Surface casing.

Notes
1. Cement plugs inside casing shall be set in areas with verified cement in casing annulus.
2. The secondary well barrier shall as a minimum be positioned at a depth where the estimated formation fracture pressure exceeds the contained pressure below the well barrier.

A.5 Permanent Abandonment –Multibore with slotted liners or sand screens [3].

9.8.5 Permanent abandonment - Multibore with slotted liners or sand screens



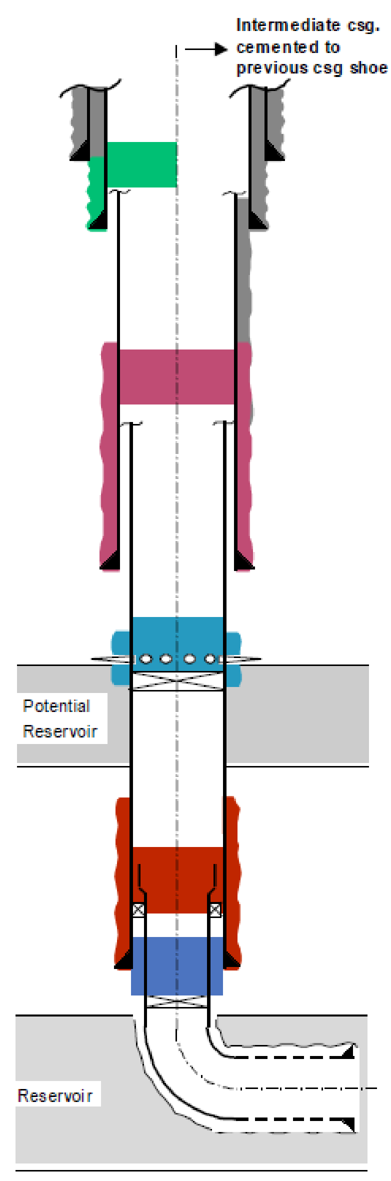
Well barrier elements	See Table	Comments
Barrier between reservoirs		
1. Casing cement	22	
2. Cement plug	24	Cased hole.
or,		
2. Cement plug	24	Transition plug across casing shoe.
Primary well barrier		
1. Cement plug	24	Across wellbore and casing shoe.
Secondary well barrier, reservoir		
1. Casing cement	22	
2. Cement plug	24	Casing plug across liner top.
Open Holes to surface wellbarrier		
1. Cement plug	24	Cased hole cement plug.
2. Casing cement	22	Surface casing.

Notes

1. The "well barrier between reservoirs" may act as the primary well barrier for the "deep" reservoir, and "primary well barrier" may be the secondary well barrier for "deep" reservoir, if the latter is designed to take the differential pressures for both formations.
2. Secondary well barrier shall not be set higher than the formation integrity at this depth, considering that the design criteria may be initial reservoir pressure, as applicable in each case.

A.6 Permanent Abandonment – Slotted liners in multiple reservoirs [3].

9.8.6 Permanent abandonment - Slotted liners in multiple reservoirs



Well barrier elements	See Table	Comments
Primary well barrier, deep reservoir		
1. Cement plug	24	Through liner and across casing shoe/Open hole transition.
Secondary well barrier		
1. Casing cement	22	
2. Cement plug	24	Across liner top.
Primary well barrier, shallow reservoir		
1. Cement plug	22	Squeezed into perforated casing annulus above potential reservoir.
Secondary well barrier, shallow reservoir		
1. Casing cement	22	
2. Cement plug	24	
Open holes to surface well barrier		
3) Cement plug	24	Cased hole.
4) Casing cement	22	Surface casing.

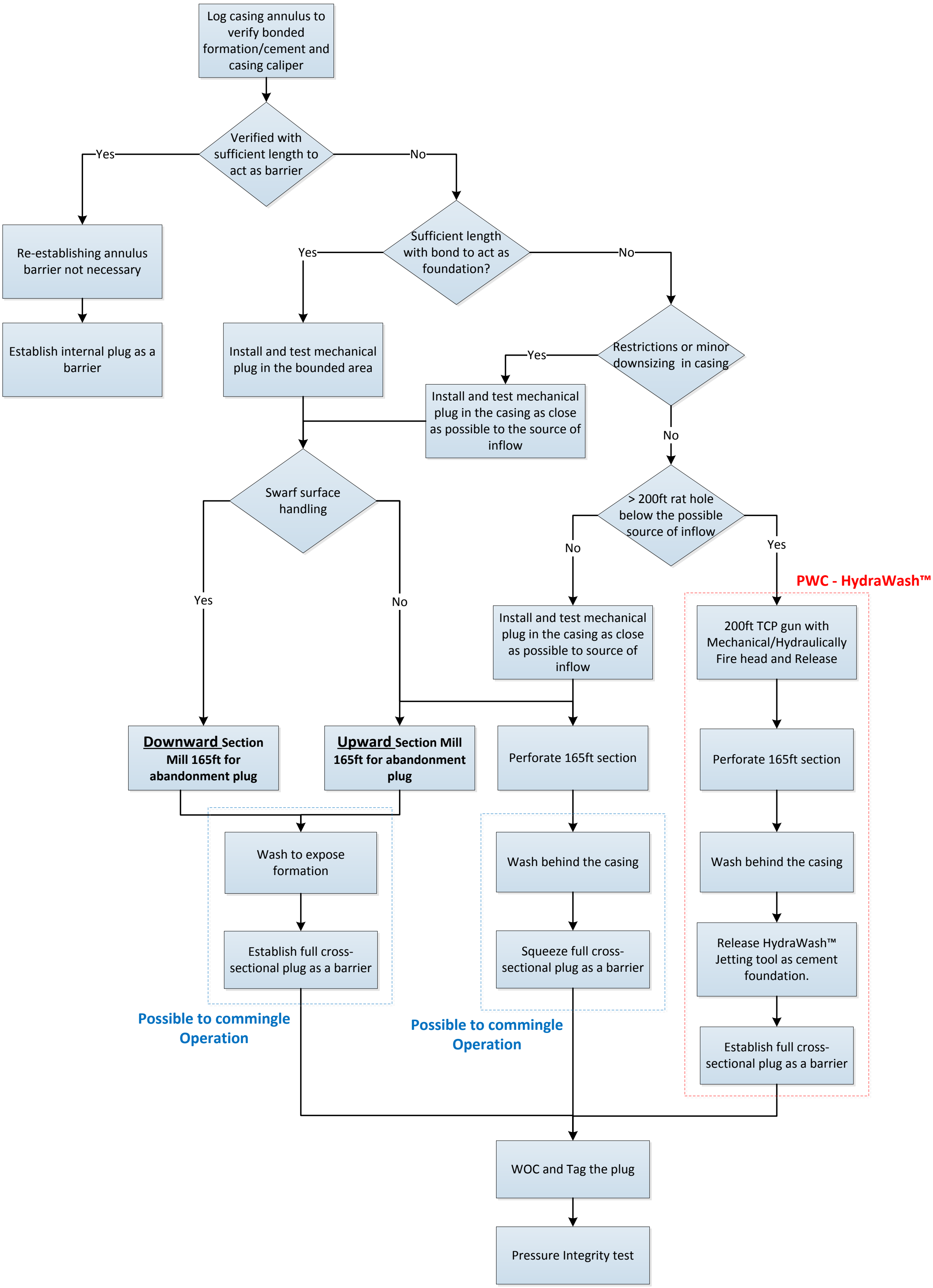
Notes

1. Secondary well barrier shall not be set higher than the formation integrity at this depth, considering that the design criteria may be initial reservoir pressure, which may develop over time.
2. The case on the right hand side indicates that the intermediate casing string is cemented into surface casing, i.e. with no open annulus to surface. Hence, no open holes to surface well barrier is required.

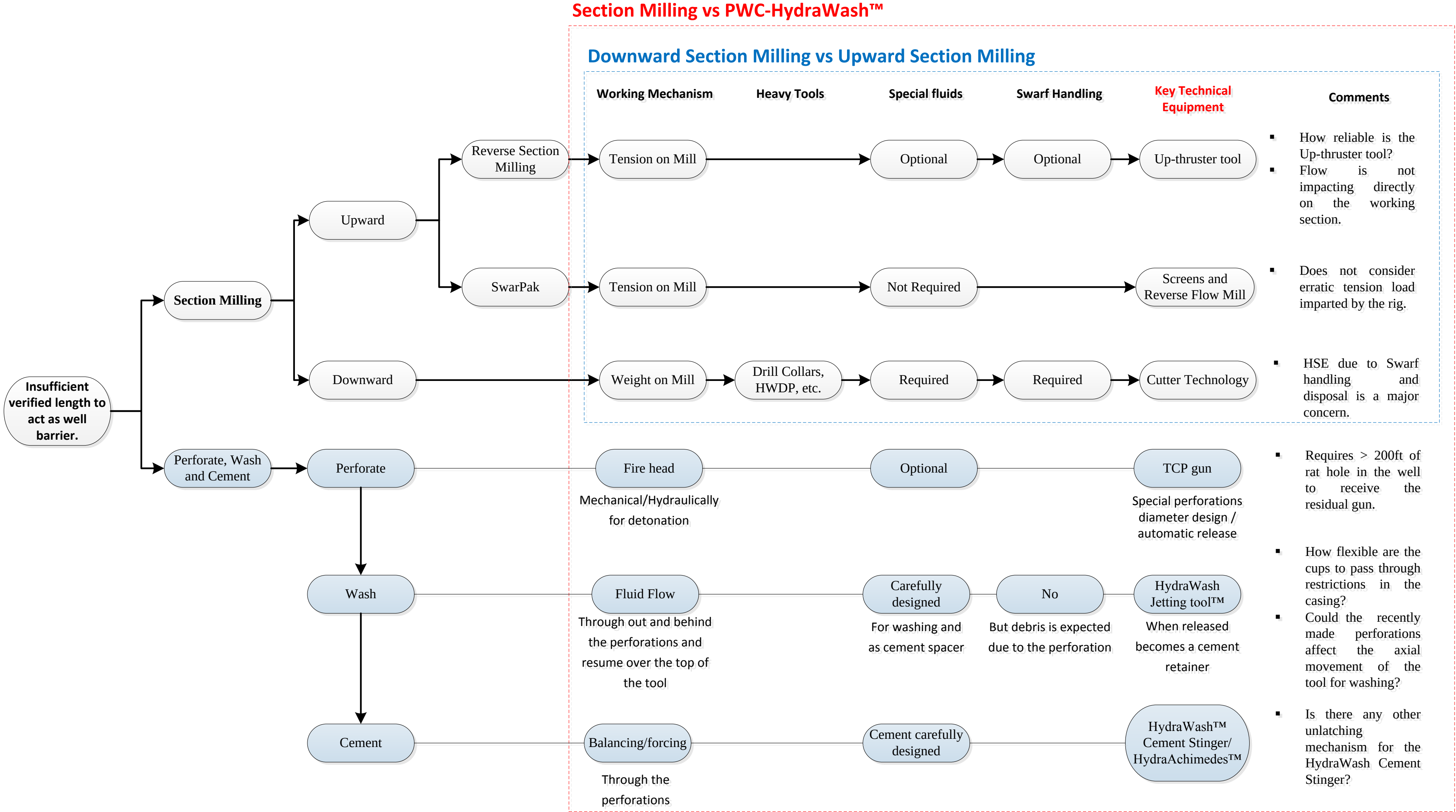
Appendix B – Discussion and Analysis comparison charts.

B.1 Decision chart to establish a well barrier.

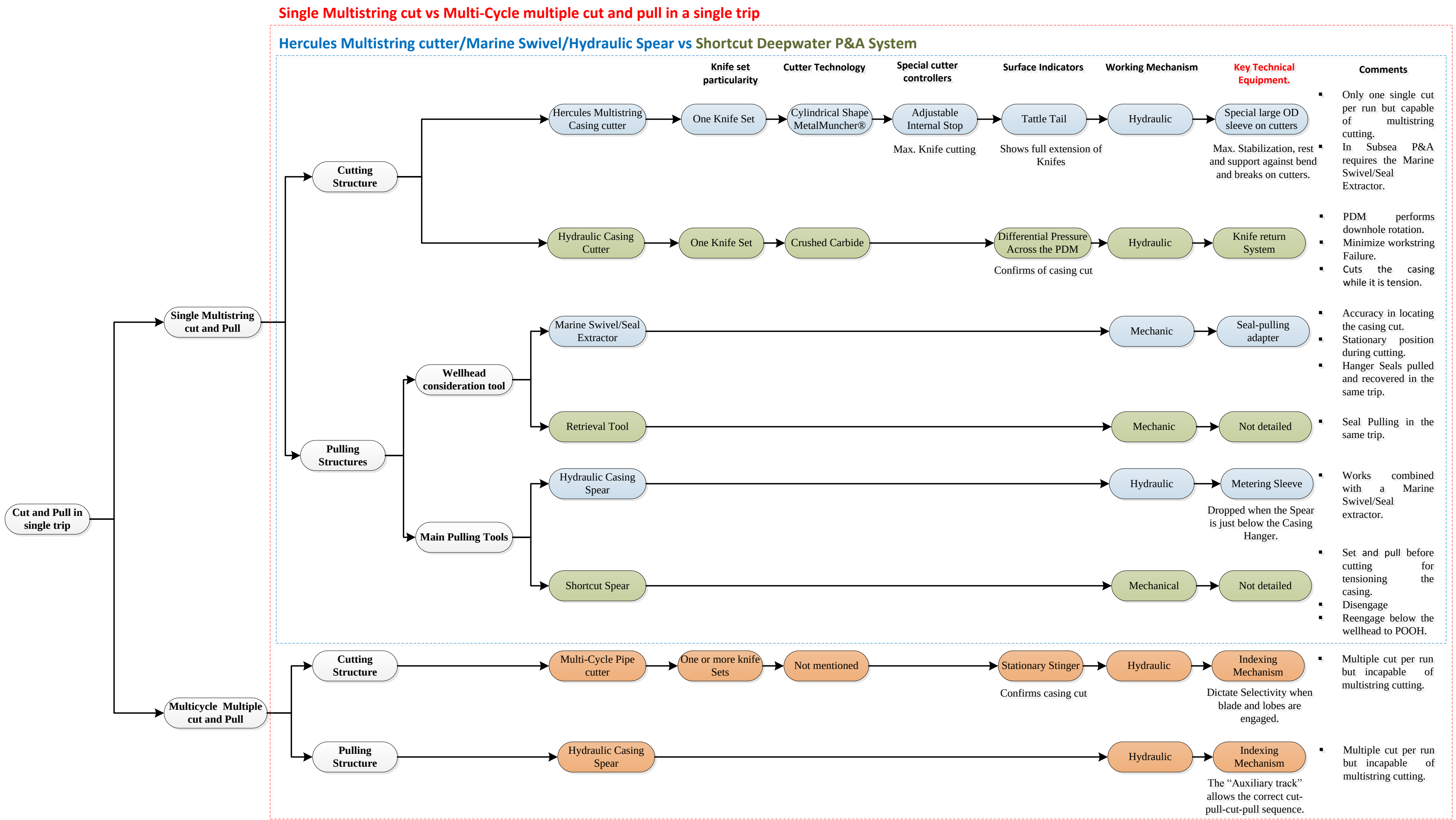
Chart Based on the fourth revision of NORSOK – D010 [12]



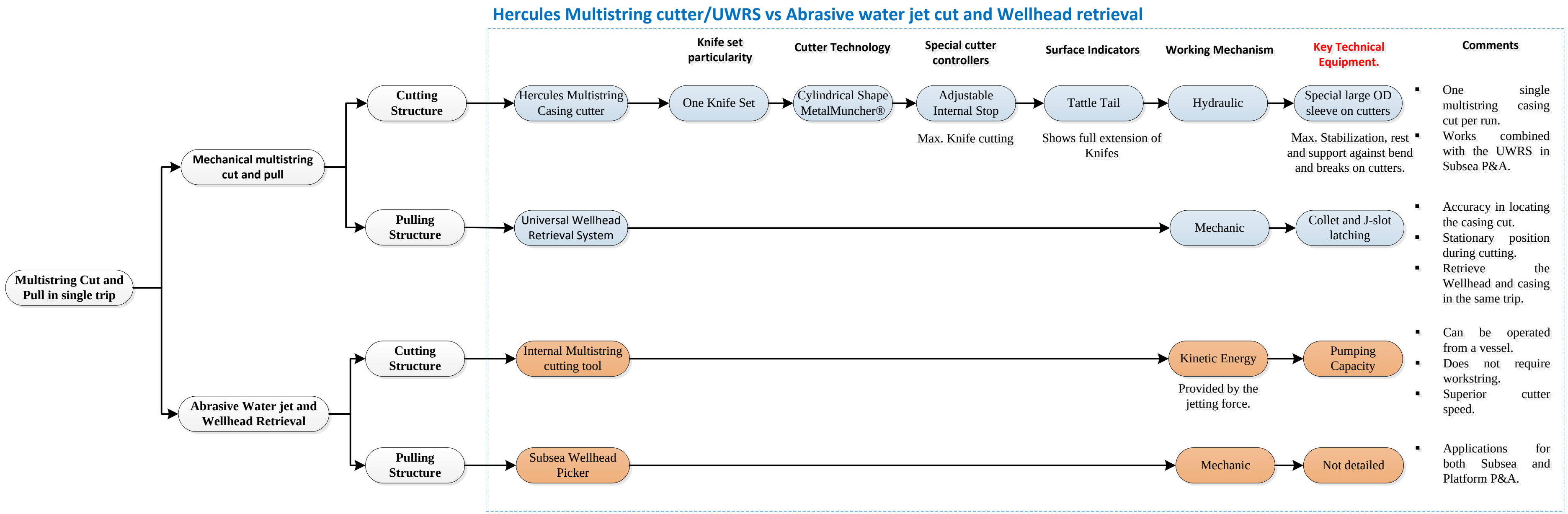
B.2 Section Milling vs PWC-HydraWash™ Chart.



B.3 Single Multistring cut vs Multi-Cycle multiple cut and pull in a single trip.



B.4 Universal Wellhead Retrieving System vs Abrasive water jet cut and Wellhead Retrieval.



B.5 Well barrier possible configurations.

Twenty (20) Step Configurations												
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**				
Barrier 5	HydraWash™	Good Bond	HydraWash™	Good Bond	HydraWash™	Good Bond	HydraWash™	Good Bond				
Barrier 4	HydraWash™	Good Bond	Good Bond	HydraWash™	HydraWash™	Good Bond	Good Bond	HydraWash™				
Barrier 3	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™				
Barrier 2	HydraWash™	Good Bond	Good Bond	Good Bond	Good Bond	HydraWash™	HydraWash™	HydraWash™				
Barrier 1	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™				
Twenty One (21) Step Configurations												
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
Barrier 5	Good Bond	HydraWash™	Good Bond	HydraWash™	Good Bond	HydraWash™	PWC/SM	Good Bond	HydraWash™	PWC/SM	Good Bond	HydraWash™
Barrier 4	Good Bond	Good Bond	HydraWash™	HydraWash™	Good Bond	Good Bond	Good Bond	HydraWash™	HydraWash™	HydraWash™	PWC/SM	PWC/SM
Barrier 3	Good Bond	Good Bond	Good Bond	Good Bond	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™
Barrier 2	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond
Barrier 1	HydraWash™	HydraWash™	HydraWash™	HydraWash™	Good Bond	Good Bond	HydraWash™	Good Bond	Good Bond	HydraWash™	HydraWash™	HydraWash™
	13	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
Barrier 5	Good Bond	HydraWash™	Good Bond	Good Bond	HydraWash™	Good Bond	HydraWash™	PWC/SM	Good Bond	HydraWash™	Good Bond	HydraWash™
Barrier 4	Good Bond	Good Bond	HydraWash™	Good Bond	Good Bond	HydraWash™	HydraWash™	HydraWash™	PWC/SM	PWC/SM	Good Bond	Good Bond
Barrier 3	Good Bond	Good Bond	Good Bond	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™
Barrier 2	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	PWC/SM	PWC/SM
Barrier 1	HydraWash™	HydraWash™	HydraWash™	Good Bond	Good Bond	Good Bond	Good Bond	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™
	25	**26**	**27**									
Barrier 5	Good Bond	HydraWash™	PWC/SM									
Barrier 4	HydraWash™	HydraWash™	Good Bond									
Barrier 3	HydraWash™	HydraWash™	HydraWash™									
Barrier 2	PWC/SM	PWC/SM	HydraWash™									
Barrier 1	HydraWash™	HydraWash™	HydraWash™									

Twenty two (22) Step Configurations												
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
Barrier 5	Good Bond	HydraWash™	PWC/SM	Good Bond	HydraWash™	PWC/SM	Good Bond	Good Bond	HydraWash™	HydraWash™	PWC/SM	Good Bond
Barrier 4	Good Bond	Good Bond	Good Bond	HydraWash™	HydraWash™	HydraWash™	PWC/SM	PWC/SM	PWC/SM	Good Bond	Good Bond	HydraWash™
Barrier 3	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	HydraWash™	HydraWash™	HydraWash™
Barrier 2	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond
Barrier 1	Good Bond	Good Bond	HydraWash™	Good Bond	Good Bond	HydraWash™	Good Bond	HydraWash™	HydraWash™	PWC/SM	Good Bond	PWC/SM
	13	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
Barrier 5	HydraWash™	PWC/SM	Good Bond	HydraWash™	PWC/SM	Good Bond	HydraWash™	Good Bond	HydraWash™	Good Bond	HydraWash™	PWC/SM
Barrier 4	HydraWash™	HydraWash™	PWC/SM	PWC/SM	PWC/SM	Good Bond	Good Bond	HydraWash™	HydraWash™	Good Bond	Good Bond	Good Bond
Barrier 3	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	PWC/SM	PWC/SM	PWC/SM	PWC/SM	Good Bond	Good Bond	Good Bond
Barrier 2	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	HydraWash™	HydraWash™	HydraWash™
Barrier 1	PWC/SM	Good Bond	Good Bond	Good Bond	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	Good Bond	Good Bond	HydraWash™
	25	**26**	**27**	**28**	**29**	**30**	**31**	**32**	**33**	**34**	**35**	**36**
Barrier 5	Good Bond	HydraWash™	PWC/SM	Good Bond	HydraWash™	HydraWash™	Good Bond	HydraWash™	PWC/SM	Good Bond	HydraWash™	PWC/SM
Barrier 4	HydraWash™	HydraWash™	HydraWash™	PWC/SM	PWC/SM	HydraWash™	Good Bond	Good Bond	Good Bond	HydraWash™	HydraWash™	HydraWash™
Barrier 3	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™
Barrier 2	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™
Barrier 1	Good Bond	HydraWash™	HydraWash™	HydraWash™	HydraWash™	Good Bond	PWC/SM	PWC/SM	Good Bond	PWC/SM	PWC/SM	Good Bond
	37	**38**	**39**	**40**	**41**	**42**	**43**	**44**	**45**	**46**	**47**	**48**
Barrier 5	Good Bond	HydraWash™	PWC/SM	Good Bond	HydraWash™	HydraWash™	Good Bond	HydraWash™	Good Bond	HydraWash™	Good Bond	Good Bond
Barrier 4	PWC/SM	PWC/SM	PWC/SM	Good Bond	Good Bond	HydraWash™	Good Bond	Good Bond	HydraWash™	HydraWash™	HydraWash™	Good Bond
Barrier 3	HydraWash™	HydraWash™	HydraWash™	PWC/SM	PWC/SM	PWC/SM	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	HydraWash™
Barrier 2	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM
Barrier 1	Good Bond	Good Bond	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	Good Bond	Good Bond
	49	**50**	**51**	**52**	**53**	**54**	**55**	**56**	**57**			
Barrier 5	HydraWash™	PWC/SM	Good Bond	HydraWash™	PWC/SM	Good Bond	HydraWash™	Good Bond	Good Bond			
Barrier 4	Good Bond	Good Bond	HydraWash™	HydraWash™	HydraWash™	PWC/SM	PWC/SM	HydraWash™	Good Bond			
Barrier 3	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	PWC/SM	HydraWash™			
Barrier 2	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM	HydraWash™	Good Bond			
Barrier 1	Good Bond	HydraWash™	Good Bond	Good Bond	HydraWash™	HydraWash™	HydraWash™	HydraWash™	PWC/SM			

Twenty three (23) Step Configurations												
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
Barrier 5	Good Bond	HydraWash™	PWC/SM	Good Bond	HydraWash™	PWC/SM	HydraWash™	PWC/SM	PWC/SM	PWC/SM	Good Bond	HydraWash™
Barrier 4	Good Bond	Good Bond	Good Bond	HydraWash™	HydraWash™	HydraWash™	PWC/SM	PWC/SM	Good Bond	HydraWash™	PWC/SM	PWC/SM
Barrier 3	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	HydraWash™	HydraWash™	HydraWash™	HydraWash™
Barrier 2	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond
Barrier 1	PWC/SM	PWC/SM	Good Bond	PWC/SM	PWC/SM	Good Bond	Good Bond	HydraWash™	PWC/SM	PWC/SM	PWC/SM	PWC/SM

	13	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
Barrier 5	PWC/SM	Good Bond	HydraWash™	PWC/SM	Good Bond	HydraWash™	PWC/SM	Good Bond	HydraWash™	Good Bond	HydraWash™	PWC/SM
Barrier 4	PWC/SM	Good Bond	Good Bond	Good Bond	HydraWash™	HydraWash™	HydraWash™	PWC/SM	PWC/SM	Good Bond	Good Bond	Good Bond
Barrier 3	HydraWash™	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM	Good Bond	Good Bond	Good Bond
Barrier 2	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	HydraWash™	HydraWash™	HydraWash™
Barrier 1	Good Bond	Good Bond	Good Bond	HydraWash™	Good Bond	Good Bond	HydraWash™	HydraWash™	HydraWash™	PWC/SM	PWC/SM	Good Bond
	25	**26**	**27**	**28**	**29**	**30**	**31**	**32**	**33**	**34**	**35**	**36**
Barrier 5	Good Bond	HydraWash™	PWC/SM	Good Bond	HydraWash™	PWC/SM	PWC/SM	PWC/SM	Good Bond	HydraWash™	PWC/SM	Good Bond
Barrier 4	HydraWash™	HydraWash™	HydraWash™	PWC/SM	PWC/SM	PWC/SM	Good Bond	HydraWash™	PWC/SM	PWC/SM	PWC/SM	Good Bond
Barrier 3	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	PWC/SM
Barrier 2	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™
Barrier 1	PWC/SM	PWC/SM	Good Bond	Good Bond	Good Bond	HydraWash™	PWC/SM	PWC/SM	PWC/SM	PWC/SM	Good Bond	Good Bond
	37	**38**	**39**	**40**	**41**	**42**	**43**	**44**	**45**	**46**	**47**	**48**
Barrier 5	HydraWash™	PWC/SM	Good Bond	HydraWash™	PWC/SM	Good Bond	HydraWash™	Good Bond	HydraWash™	PWC/SM	HydraWash™	PWC/SM
Barrier 4	Good Bond	Good Bond	HydraWash™	HydraWash™	HydraWash™	PWC/SM	PWC/SM	Good Bond	Good Bond	Good Bond	HydraWash™	HydraWash™
Barrier 3	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond
Barrier 2	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM
Barrier 1	Good Bond	HydraWash™	Good Bond	Good Bond	HydraWash™	HydraWash™	HydraWash™	Good Bond	Good Bond	HydraWash™	Good Bond	HydraWash™
	49	**50**	**51**	**52**	**53**	**54**	**55**	**56**	**57**	**58**	**59**	**60**
Barrier 5	Good Bond	HydraWash™	Good Bond	HydraWash™	PWC/SM	Good Bond	HydraWash™	PWC/SM	Good Bond	HydraWash™	PWC/SM	Good Bond
Barrier 4	PWC/SM	PWC/SM	Good Bond	Good Bond	Good Bond	HydraWash™	HydraWash™	HydraWash™	PWC/SM	PWC/SM	PWC/SM	Good Bond
Barrier 3	Good Bond	Good Bond	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	PWC/SM
Barrier 2	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM
Barrier 1	HydraWash™	HydraWash™	PWC/SM	PWC/SM	Good Bond	PWC/SM	PWC/SM	Good Bond	Good Bond	Good Bond	HydraWash™	HydraWash™
	61	**62**	**63**									
Barrier 5	HydraWash™	Good Bond	HydraWash™									
Barrier 4	Good Bond	HydraWash™	HydraWash™									
Barrier 3	PWC/SM	PWC/SM	PWC/SM									
Barrier 2	PWC/SM	PWC/SM	PWC/SM									
Barrier 1	HydraWash™	HydraWash™	HydraWash™									
Twenty four (24) Step Configurations												
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
Barrier 5	PWC/SM	PWC/SM	Good Bond	HydraWash™	PWC/SM	PWC/SM	Good Bond	HydraWash™	PWC/SM	Good Bond	HydraWash™	PWC/SM
Barrier 4	Good Bond	HydraWash™	PWC/SM	PWC/SM	PWC/SM	PWC/SM	Good Bond	Good Bond	Good Bond	HydraWash™	HydraWash™	HydraWash™
Barrier 3	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	HydraWash™	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM
Barrier 2	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond
Barrier 1	PWC/SM	PWC/SM	PWC/SM	PWC/SM	Good Bond	PWC/SM	PWC/SM	PWC/SM	Good Bond	PWC/SM	PWC/SM	Good Bond

	13	14	15	16	17	18	19	20	21	22	23	24
Barrier 5	Good Bond	HydraWash™	PWC/SM	PWC/SM	PWC/SM	PWC/SM	Good Bond	HydraWash™	PWC/SM	Good Bond	HydraWash™	PWC/SM
Barrier 4	PWC/SM	PWC/SM	PWC/SM	Good Bond	PWC/SM	HydraWash™	PWC/SM	PWC/SM	PWC/SM	Good Bond	Good Bond	Good Bond
Barrier 3	PWC/SM	PWC/SM	PWC/SM	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	HydraWash™	PWC/SM	PWC/SM	PWC/SM
Barrier 2	Good Bond	Good Bond	Good Bond	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™
Barrier 1	Good Bond	Good Bond	HydraWash™	PWC/SM	Good Bond	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM	Good Bond
	25	**26**	**27**	**28**	**29**	**30**	**31**	**32**	**33**	**34**	**35**	**36**
Barrier 5	Good Bond	HydraWash™	PWC/SM	Good Bond	HydraWash™	PWC/SM	PWC/SM	Good Bond	HydraWash™	Good Bond	HydraWash™	PWC/SM
Barrier 4	HydraWash™	HydraWash™	PWC/SM	PWC/SM	PWC/SM	HydraWash™	Good Bond	Good Bond	Good Bond	HydraWash™	HydraWash™	HydraWash™
Barrier 3	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond
Barrier 2	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM
Barrier 1	PWC/SM	PWC/SM	HydraWash™	Good Bond	Good Bond	Good Bond	Good Bond	PWC/SM	PWC/SM	PWC/SM	PWC/SM	Good Bond
	37	**38**	**39**	**40**	**41**	**42**	**43**	**44**	**45**	**46**	**47**	**48**
Barrier 5	Good Bond	HydraWash™	PWC/SM	PWC/SM	PWC/SM	Good Bond	HydraWash™	Good Bond	PWC/SM	HydraWash™	PWC/SM	Good Bond
Barrier 4	PWC/SM	PWC/SM	PWC/SM	Good Bond	HydraWash™	PWC/SM	PWC/SM	Good Bond	PWC/SM	Good Bond	Good Bond	HydraWash™
Barrier 3	Good Bond	Good Bond	Good Bond	HydraWash™	HydraWash™	HydraWash™	HydraWash™	PWC/SM	HydraWash™	PWC/SM	PWC/SM	PWC/SM
Barrier 2	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM
Barrier 1	Good Bond	Good Bond	HydraWash™	PWC/SM	PWC/SM	PWC/SM	PWC/SM	Good Bond	Good Bond	Good Bond	HydraWash™	Good Bond
	49	**50**	**51**	**52**								
Barrier 5	HydraWash™	PWC/SM	Good Bond	HydraWash™								
Barrier 4	HydraWash™	HydraWash™	PWC/SM	PWC/SM								
Barrier 3	PWC/SM	PWC/SM	PWC/SM	PWC/SM								
Barrier 2	PWC/SM	PWC/SM	PWC/SM	PWC/SM								
Barrier 1	Good Bond	HydraWash™	HydraWash™	HydraWash™								
						Twenty Five (25) Step Configurations						
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
Barrier 5	PWC/SM	PWC/SM	PWC/SM	Good Bond	HydraWash™	PWC/SM	PWC/SM	PWC/SM	PWC/SM	Good Bond	HydraWash™	PWC/SM
Barrier 4	PWC/SM	Good Bond	HydraWash™	PWC/SM	PWC/SM	PWC/SM	PWC/SM	Good Bond	HydraWash™	PWC/SM	PWC/SM	PWC/SM
Barrier 3	Good Bond	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM	Good Bond	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM
Barrier 2	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™	HydraWash™
Barrier 1	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM	Good Bond	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM	Good Bond
	13	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
Barrier 5	PWC/SM	PWC/SM	Good Bond	HydraWash™	PWC/SM	PWC/SM	Good Bond	HydraWash™	Good Bond	PWC/SM	HydraWash™	PWC/SM
Barrier 4	Good Bond	HydraWash™	PWC/SM	PWC/SM	PWC/SM	PWC/SM	Good Bond	Good Bond	HydraWash™	Good Bond	HydraWash™	HydraWash™
Barrier 3	Good Bond	Good Bond	Good Bond	Good Bond	Good Bond	HydraWash™	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM
Barrier 2	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM
Barrier 1	PWC/SM	PWC/SM	PWC/SM	PWC/SM	Good Bond	PWC/SM	PWC/SM	PWC/SM	PWC/SM	Good Bond	PWC/SM	Good Bond

	25	26	27									
Barrier 5	Good Bond	HydraWash™	PWC/SM									
Barrier 4	PWC/SM	PWC/SM	PWC/SM									
Barrier 3	PWC/SM	PWC/SM	PWC/SM									
Barrier 2	PWC/SM	PWC/SM	PWC/SM									
Barrier 1	Good Bond	Good Bond	HydraWash™									
Twenty Six (26) Step Configurations												
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**				
Barrier 5	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM	Good Bond	HydraWash™				
Barrier 4	PWC/SM	PWC/SM	PWC/SM	PWC/SM	Good Bond	HydraWash™	PWC/SM	PWC/SM				
Barrier 3	PWC/SM	PWC/SM	Good Bond	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM				
Barrier 2	Good Bond	HydraWash™	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM	PWC/SM				
Barrier 1	PWC/SM	PWC/SM	PWC/SM	Good Bond	PWC/SM	PWC/SM	PWC/SM	PWC/SM				
Twenty Seven (27) Step Configurations												
	1											
Barrier 5	PWC/SM											
Barrier 4	PWC/SM											
Barrier 3	PWC/SM											
Barrier 2	PWC/SM											
Barrier 1	PWC/SM											