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A Comprehensive Completion Method Selection Based on Probability and Impact Matrix for Iris Production HPHT Well

by

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ABSTRACT

HPHT well completion require special attention to well design. The conservatism of well completion is constantly put to the test by introducing and qualifying new equipment meant to enhance well performance, minimize HS&E risks, and provide a cost-effective design. Multiple operators on the Norwegian Continental Shelf has completed high-pressure, high-temperature wells with different completions and results. OMV (Norge) AS is set to look into a field development for PL 644 Hades/Iris field, and operational experience become highly valuable for their well completion strategy.

Completing a well requires the need to select the most ideal method. The reservoir completion needs to be designed to provide the most optimal exposure and flow of hydrocarbons. Providing an open hole completion introduce specific risks and considerations, so will a perforated liner. Completion fluids, perforation explosives, completion limitations and operational readiness for HPHT field is among many factors to influence the selection. The need for reservoir isolation contributes to additional considerations and risks, which again will influence the method selection with respect to well integrity. Tubing selection, packer design and load cases will dictate the upper completion method selection. This thesis shall provide a general method assessment of important completion components from reservoir to wellhead, where risks encountered from previous field developments is included.

By using real well information obtained from 6506/11-11S Iris Appraisal, a new production well shall be studied and completed. The method selection process will be carried out by a risk assessment matrix. Basing the likelihood and consequence of the identified risks, the risk level can be determined. This qualitative methodology is common in the industry and provide a straightforward overview of the mapped risks.

Based on the results from the risk register presented in this thesis, a method selection of lower, middle, and upper completion will be presented. Full completion proposals will be investigated and integrated, covering advantages and disadvantages, before concluding on a final proposal.

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ABBREVIATIONS

BOP	Blowout Preventer
CO_2	Carbon Dioxide
CT	Coiled Tubing
CRA	Corrosion-Resistant-Alloys
C&P	Cased & Perforated
DIV	Downhole Isolation Valve
DP	Drillpipe
DST	Drill Stem Test
DUB	Dynamic Underbalance
ECD	Equivalent Circulating Density
GBR	Glass Barrier Plug
HMX	High Molecular Weight RDX
HNS	Hexanitrostilbene
HPHT	High Pressure High Temperature
HS&E	Health, Safety & Environment
HXMT	Horizontal Christmas Tree
H_2S	Hydrogen Sulphide
ID	Inner Diameter
ILCBA	Integrated Lower Completion Barrier Assembly
ISO	International Organization of Standardization
MC	Middle Completion
MD	Measured Depth
NACE	National Association of Corrosion Engineers
NCS	Norwegian Continental Shelf
OB	Overbalance
OBM	Oil-Based Mud
OD	Outer Diameter
OH	Open Hole

PBR	Polished Bore Receptacle
PI	Productivity Index
RKB	Rotary Kelly Bushing
PYX	Picrylaminodinitropyridin
RDX	Research Department Composition X
RS-OBCF	Reduced Solid-Oil Based Completion Fluid
SAS	Stand Alone Screens
SCSSV	Surface Controlled Subsurface Safety Valve
SF	Safety Factor
SIWHP	Shut-In Wellhead Pressure
TCP	Tubing-Conveyed Perforation
TD	Target Depth
TH	Tubing Hanger
TVD	True Vertical Depth
T&C	Time & Cost
VXMT	Vertical Christmas Tree
WCP	Wireline-Conveyed Perforation
WL	Wireline
WOBJ	Well Objective
WPRST	Wells Project Risk Screening Tool
WSRA	Well-specific Risk Assessment
XMT	Christmas Tree

NOMENCLATURE

D	Non-Darcy coefficient	
h	Net thickness	[ft]
h_p	Height of completed interval	[ft]
k	Permeability	[mD]
k_g	Gas permeability	[mD]
$\bar{p}_r$	Average reservoir pressure	[psi]
p_w	Wellbore flowing pressure	[psi]
q	Flow rate	[Mscf/D]
q_g	Gas flow rate	[Mscf/D]
r_e	Effective drainage area	[ft]
r_w	Wellbore radius	[ft]
S	Skin	
$\acute{S}$	Total skin	
T	Reservoir temperature	[R]
z	Compressibility factor	
β	Turbulence coefficient	
μ	Viscosity	[c]
μ_g	Gas viscosity	[cP]
γ_g	Gas gravity	[g]

CHAPTER 1

1 INTRODUCTION

The objective of the thesis is to examine a method selection for a fictive Iris Production high-pressure high-temperature (HPHT) well based on a "*Probability and Impact Risk Matrix*". The selection of completion method involves a case with available data from OMV (Norge) AS, basing the location and general reservoir data on the previously drilled appraisal well, 6506/11-11S Iris Appraisal on the OMV operated license PL 644 / PL 644B / PL 644C. The study will look to create a new fictive production well with the intention to learn and adapt to a HPHT well completion perspective. A lower, middle, and upper completion proposal shall be implemented. The thesis covers the following chapters:

- Chapter 1: Introduction
- Chapter 2: Introduction to HPHT Well Completion
- Chapter 3: PL644 / PL644B / PL644C Hades/Iris Field
- Chapter 4: Method Assessment
- Chapter 5: Probability and Impact Matrix
- Chapter 6: Method Selection
- Chapter 7: Conclusion and Recommendations for Future Work

1.1 BACKGROUND

OMV (Norge) AS is set to look into a potential field development at PL644 / PL644B / PL644C Hades/Iris field. Well results from 6506/11-11S Iris Appraisal gave promising reservoir conditions with good permeability and depositional data for Iris, a deep HPHT reservoir (4100 m True Vertical Depth (TVD)). With 6506/11-12S Hades Appraisal spudding summer of 2020, the shallowest reservoir, Hades, will be fully explored to evaluate the geological composition and production potential. The field development process initiates once necessary data is collected and is currently in the early planning phase.

1.2 SCOPE OF STUDY

As an up and coming engineer, well completion in HPHT environment distribute a great perspective for future and more advanced field developments. For that purpose, a new well based on of 6506/11-11S Iris Appraisal reservoir properties and target will be conducted in this thesis. Together with guidance from the OMV (Norge) AS well engineering team, combined with previous experience of HPHT field developments on the Norwegian Continental Shelf (NCS), a method selection of a fictive Iris Production well shall be presented.

First, an introduction to well completion will be submitted. General principles of well completion considerations and requirements shall be investigated. Following the introduction, in chapter 3, PL 644 / PL644B / PL644C Hades/Iris field is introduced to the reader.

A variety of completion methods will be studied, where chapter 4 is presenting a general assessment of the proposed methods. The analysis includes a general description of the method, advantages and disadvantages and the installation procedure. For HPHT purposes, operational readiness, and previous experience by operators in comparable HPHT fields on the NCS shall be analyzed, with the intention to investigate operational risks.

The methodology for determining which completion method to select for Iris Production well shall be based on a qualitative risk assessment. A "*Probability and Impact Risk Matrix*" will be discussed in chapter 5, containing the use of risk level in order to establish differences in regard to Health, Safety & Environment (HS&E), Time & Cost (T&C), and well objectives (WOBJ) among methods.

Once the risk assessment is provided, the method selection will be introduced in chapter 6, with the objective to present a full completion based on the mitigated operational risks investigated in the method assessment. The risk assessment shall provide an overview and grading of the methods and deliver a proposed design. After the method selection is complete, the thesis will present the conclusion with proposed method in chapter 7, before finalizing with a discussion of considerations for future work.

CHAPTER 2

2 INTRODUCTION TO HPHT WELL COMPLETION

2.1 WHAT IS WELL COMPLETION?

Well completion is the set of equipment and tubulars creating the conduit for produced hydrocarbons from the reservoir to the surface facilities. When the well has been successfully drilled to target depth, the well needs to be converted to a safe, reliable, and efficient flow-system. The completion needs to consider necessary well barriers to ensure safe production over the estimated life span, the right level of complexity and method to suit the optimal hydrocarbon flow performance, and the justification of material and equipment selection for specific well conditions. The well completion design depends on well objective - a well can be completed as a producer or injector. Depending on what conditions encountered, well completion must be implemented to suit and adapt for the challenges and risks involved

2.2 ROLE OF A COMPLETION ENGINEER

Well completion has a broad scope in petroleum engineering. In some companies, completion engineering is a part of an engineering discipline sub-group, including reservoir engineering, petrophysics and well operations. A completion engineer needs to understand the interface between reservoir and facilities. Having insight and understanding with the service sector is therefore a vital part. The service sector is often responsible of supplying the drilling rig with necessary equipment, consumables, and rental equipment. Examples of this can be completion equipment, wireline, fluids (brine, mud) and personnel (Bellarby, 2009).

The completion engineer designs the completion, coordinates equipment and services, and oversees the completion installation. It is vital for the completion engineer to maintain a solid connection with the involving parts. Having operational experience is of great benefit. Depending on the project size, several completion engineers may work together, dividing scope of work (Bellarby, 2009).

2.3 DESIGNING A HPHT WELL

When designing a well, data gathering is essential, as the completion is based on available data. Data can be raw (measured reservoir temperature and pressure) or predicted (production profiles).

The design of a well is associated with uncertainties. The more uncertainties, the harder it is to complete a well and obtain the planned production rates. Obtaining more data from a field will reduce the uncertainties when planning the completion design. For lower completion, the design is dependent on locating and reducing the risks based on field knowledge and previous experience with respect to the reservoir section. Formation type, permeability, hydrocarbon column and structural composition of the rock is of many aspects vital for selecting the design. Reservoir isolation (middle completion) design is heavily time dependent, with the focus on how to come up with more cost-effective solutions. For the upper completion, the production profiles, casing sizes and material selection will be among many factors to influence the design, making completions vary from well to well.

Completion is highly affecting the total economical state of a field development. Completion costs may represent a major part of the total capital costs of a field, but in return effect the revenues and operational costs. Important for well design is knowing how economics is influenced by production rates, how the production rates increase, stabilize, and decrease. A subsea well need to consider costs related to delayed production, high workover costs and potential enormous rental costs, which forces upfront reliability in the completion design process (Bellarby, 2009). Completion design is as drilling, intervention and plugging highly affected by the NORSOK-Standard, especially for HPHT wells.

2.3.1 NORSOK Standard D-010: Well Completion

Completions need to maintain safety throughout the lifespan of the well. Providing sufficient well barriers are required to deliver a safe conduit for the reservoir fluids without damaging personnel or environment. When designing a well, NORSK-standard provide recommendations and requirements for well completion. According to NORSOK (2004) standard D-010,

> "*The completion activity typically starts after having drilled the well to total depth and starting with cleaning of the well and installation of completion equipment. The activity concludes with the suspension of the tubing hanger in the subsea wellhead or upon completion of the installation of the surface production tree*" (p. 46).

NORSOK (2004) standard D-010 continues to state:

- "*Wells that are producing or are capable of producing hydrocarbons, shall have a mechanical annular seal between the completion string and the casing/liner, i.e. production packer" (*p. 46).
- *A SCSSV shall be installed if the completion string for all hydrocarbon wells and wells with sufficient reservoir pressure to lift fluids to seabed level"* (p. 46).

(NORSOK, 2004)

The completion starts as the reservoir section is drilled and hole cleaning is commenced. To secure sufficient barriers, NORSOK D-010 states the requirement of annular seal and downhole isolation. Continuing defining well completion requirements, NORSOK D-010 states:

- *"All components of the completion string including connections (i.e. tubing, packers, polished bore receptacle, nipples, mandrels ASCSSV, valve bodies, SCSSV, plugs, etc.) shall be subjected to load case verification"* (p. 47).

In order to identify the weaknesses of the design, load cases shall be implemented. NORSOK D-010 is stating the need for design factors to be established. A safety factor (SF) greater than 1 (one) should ensure that the tubular remain intact. The safety factor definition is:

$$SF = \frac{Rating}{Load}$$

In order to keep the safety factor above 1 (one), the equipment rating must be higher than the actual load subjected. To reduce the uncertainty, a greater safety factor can be considered. Company specific safety factors is usual, although many companies follow the NORSOK completion design factors with small adjustments. According to *"Casing Design"* document provided by OMV (Norge) AS, the general design factors is used:

- Burst: 1.1
- Collapse: 1.1
- Tension: 1.5
- Biaxial/Triaxial: 1.25

(OMV, 2017)

which is corresponding to NORSK minimum requirements for loads and ratings.

For HPHT wells, NORSOK (2004) continues to state the following:

"*Specification and qualification criteria for equipment and fluids to be used or installed in HPHT well shall be established, with particular emphasis on*

- *"Dimensional stability of the well as a function of temperature and pressure"* (p. 50).
- *"Sealing capability of metal to metal seals as a function of well bore fluids, pressure and temperature"* (p. 50).
- *"Stability of explosive and chemical perforating charges as function of temperature/pressure exposure time"* (p. 50).

For HPHT wells, the equipment and fluids require a set qualification and specification to be operated in such environment. This is done by providing the equipment and tubular specific testing in harsh environment. "International Organization of Standardization" (ISO) provide international standards and combined with National Association of Corrosion Engineers (NACE), equipment can pass minimum ratings for use in HPHT environments. Examples of documents suitable for HPHT equipment qualification, is:

- NACE MR 0175 / ISO 15156: "*Materials for use in H_2S-containing environments in oil and gas production"*
- NACE 51318-11509: "*Assessment of materials compatibility with high density Brines for completion fluid of HPHT wells"*
- ISO 14310: "*Petroleum and natural gas industries – Downhole equipment – Packers and bridge plugs"*

Both NORSOK standard D-010 and NACE/ISO is important when designing an HPHT well. The implementation of these standards and requirements will be brought in as considerations in the thesis.

2.4 COMPLETION TYPES

Wells can be established for many purposes. Wells can be a *producer*, with the purpose of producing oil, gas, or water. Completions can be built for *injection*, where injecting gas, water, steam, and waste products may be essential. A combination of the two types can be implemented, by producing up the tubing while injecting down the annulus.

Completions can be divided into the reservoir completion (lower completion, connection between the reservoir and wellbore), the middle completion (reservoir isolation barrier assembly) and the upper completion (conduit for fluids to surface facilities). Further, completion can be split in two techniques: open hole completion (OH) and cased and perforated completions (C&P).

2.4.1 Open Hole Completion

The common principle acts for all the open hole completions: the reservoir casing is not cemented in place, meaning no isolation seal and an open hole (OH) scenario between the reservoir and wellbore. The term *open hole* covers a variety of completion techniques:

- *Barefoot* – for competent, naturally fractured limestone and dolomite. Easiest and least complex completion method available due to minimal equipment and tubular in hole
- *Predrilled or pre-slotted liners* – liner in place to stop gross hole collapse, with fixed slot size for flow performance.
- *Sand control techniques* – a variety of screen completions, gravel pack completion, frac pack completions for sand control

2.4.2 Cased and Perforated Completion

Dissimilar from open hole, the cased and perforated provide a cased hole with cement as reservoir isolation. Perforation is performed to re-create a pathway for the reservoir fluids into the wellbore. The most standard forms of cased and perforated completion, is:

- *Cased and perforated on wireline* (WL) – electric cable perforations, performed through-tubing or without upper completion in place
- *Cased and perforated on coiled tubing* (CT) – coiled tubing operations often performed through-tubing
- *Cased and perforated on drill pipe (DP)* – run in hole without upper completion in place. Overbalanced pressure regime and well kill scenario
- *Cased and perforated on tubing (TCP)* – run in hole at the bottom of the production tubing. Option to shear off guns after fired, leaving guns in sump after perforation job is performed, or retrieve to surface.

Main advantages over open hole completion is the zonal isolation by cementing the liner and the potential to improve productivity with perforation length. Drilling-related formation damage can usually be bypassed. Perforated completions can be engineered to stimulate the drainage area, providing potentially greater productivity (Bellarby, 2009).

2.5 INFLOW PERFORMANCE

The inflow performance is highly related to well completion, mainly due to understanding the production-related pressure drop from the reservoir to the lower completion. The pressure-drop and flow performance are affected by multiple parameters, including viscosity, flow rate, cross-sectional area of the rock (area of the rock), length of the rock (distance) and permeability.

For completion purposes, the inflow performance is highly related to *skin prediction*. The near-wellbore region may be influenced by potential damage, which again will decrease the flow potential. Vertical flow barriers, permeability ratio (k_v/k_h), angle through the reservoir and reservoir exposure will all determine the well performance.

The *Completion Skin* in a deviated or vertical well is a combination of the *deviated skin* and *partial penetration skin.* The deviation skin will always decrease the skin, and is related to hole angle, reservoir thickness and permeability ratio. What influences the deviation skin the most, is the permeability ratio. Wells with good vertical flow characteristics will have increased flow potential in high angle wells. With a high horizontal flow potential, vertical wells will benefit more (Bellarby, 2009). Partial penetration skin always increases the skin and is in general influenced by how much of the reservoir is exposed and produced. The penetration height, well radius and the total reservoir height determine the partial penetration skin. For example, if a reservoir has a height of 150 ft, well radius of 0.25 ft, and partially penetrating only the top of the reservoir, the partial skin will be high. If, however, the reservoir of 150 ft with the same well radius of 0.25 ft has multiple production intervals, the partial penetration skin will decrease. The importance of predicting the permeability ratio will be highly essential for determining the angle of penetrating the reservoir (Bellarby, 2009)

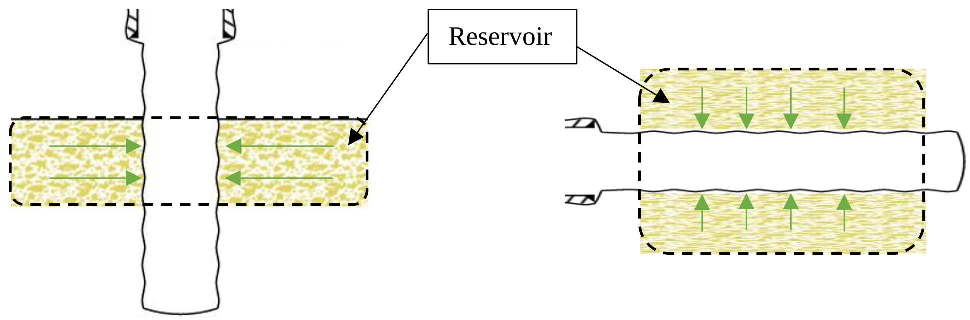


Figure 2-1: Vertical inflow performance

Figure 2-2: Horizontal inflow performance

Figure 2-1 and Figure 2-2 illustrate how the different drainage area works for vertical and horizontal producers. For high horizontal flow potential, vertical wells are commonly used. If, however, the flow potential is vertical, horizontal producers may have improved inflow performance. For open hole completions, inflow performance is related to pressure depletion, formation damage and reservoir exposure. For cased and perforated wells, the perforation length, spacing between perforations and shot density is highly influencing the overall skin. More skin predictions will be covered in the method assessment, chapter 4.

2.6 MATERIAL SELECTION

Completions are exposed to reservoir and completion fluids. Presence of corrosion on casing may call the need for recompletion, or in worst case, permanent abandonment of the well. Depending on where the corrosion occurs, the consequence varies. If the casing has a solid layer of cement with no permeable formation behind, the corrosion impact is low. For a liner or barriers close to the reservoir, the consequence of corrosion can be high. The choice of metallurgy is of great importance when designing the completion (Bellarby, 2009).

The most common material for well completion equipment is *steel*. Depending on the need of more robust metal, titanium, brass, copper, zinc, nickel (and more) can be introduced. *Low-alloy steels*, a combination of iron and carbon, is the most cost effective, therefore considered the most basic in regard to material selection. Alloy steels, often called corrosion-resistant-alloys (CRA), consists of metals improving the overall strength under high resistances (chromium), corrosion resistance (nickel) and higher temperature strength (molybdenum) (Bellarby, 2009).

Corrosion

Corrosion occurs with a combination of metal, water, or electrolyte, and a corrodent (oxygen, acid, H_2S). It is therefore very exposed in offshore wells, often HPHT wells containing carbon dioxide (CO_2) and hydrogen sulphide (H_2S). These wells need to consider both sour (H_2S) and sweet (CO_2) gasses when selecting materials. Corrosion can also be related to stress, for instance when displacing to packer fluids containing chloride and bromide. The stress obtained is highly local, and often combined with high temperatures (Bellarby, 2009).

2.7 LOAD CASES

As previously mentioned, load cases affect the completion design. When considering stress analysis, combinations of pressure, temperature, fluids, flow rates and annular conditions need to be considered. When implementing the use of load cases, both installation loads and life-of-field loads needs to be studied. The load cases are based around the *initial conditions*, often referred to as the base case. In order to test all the major possible combinations to prevent a potential disaster scenario, load case simulation intend to be applied. The most common are as following:

- **Pressure testing** – tubing, plugs, polished bore receptacle (PBR), hangers.
- **Production testing** – thermal changes during production
- **Tubing leak** – high-pressure, low-density fluid leaks into A-annulus (casing design)
- **Shut-in** – high pressure and temperature, high compression case
- **Injection** – cold fluids at high pressure, high tensile load scenario (well-kill)

The load case design is based on which kind of activity the operator is performing. For example, the case of “hot shut-in”, annulus pressure buildup, injection (fracturing, stimulation) and pressure testing is of high relevance for HPHT wells. When all the load cases for the well has been evaluated, a design limit plot will be generated (chapter 4.5). In order to ensure sufficient design, all the loads should be inside the minimum requirements. If this is not the case, equipment must be replaced by a more suitable design.

2.7.1 Tubing Design

The tubing is often mentioned as the main well completion component, and the majority of completion equipment and sizing is built around the tubing. The methodology of designing the tubing is software simulation and load case scenario. A well model will be created in the software, implementing all the needed information from the well. Tubing design first starts off by performing thermal and pressure modeling of the string length. The software provides pressure profiles along the well path, from surface to the bottom of tubing string. It is of great importance to use as realistic and accurate information as possible when performing this analysis. Every manufacturer equipment (tubing, packer, safety valves) has their limitation. The simulated thermal analysis will be linked up with the equipment limitations (Shahreyar & Finley, 2014).

2.8 COMPLETION FLUIDS

In general, reservoir-drilling fluids and completion fluids are used once entering the reservoir, meaning the fluids will connect with the reservoir fluids. Completion fluids serve many purposes. First of all, it has to function as a drilling fluid and obtain the hydrostatic pressure in the well. Well control and stability are important for operational safety and getting the reservoir section drilled with full integrity. The completion fluids have to provide a stable and well-engineered rheology, as in providing a sufficient density, filtration and provide wall-building properties to create a stable borehole wall. The reservoir drill-in fluid often contains solids (barite in Oil-Based-Mud (OBM)), which may compromise productivity by entering the reservoir rock. Formation damage may also occur by the hydration of formation grains (Wan, 2011). Completion fluid should during planning phase be developed to the basis of reservoir characteristics in order to secure the most sufficient rheology to optimize the fluid performance.

Completion fluids can be categorized in two types:

1. ***Water-Based Fluids.*** The dispersed liquid is water, and most commonly used in HPHT wells is a solid-free clean salt water (brine). Brine contains no particles and can be weighed up to fit more complex and deeper wells (calcium chloride, calcium bromide, zinc bromide and cesium formate can be used up to 2.3 sg).
   - Water-based fluids may also contain water-soluble systems, oil-soluble systems, and acid-soluble systems, which normally contains additives and polymers to gain sufficient and measurable densities (Wan, 2011).
2. ***Oil-Based Fluids.*** Flexible system which can easily increase and decrease density by adding solids. The system includes water-in-oil emulsion, and dispersed liquid is oil. For HPHT wells, the thermal stability is favorable, alongside preventing mud scaling and corrosion.

2.9 INCREASE IN DIFFICULTY: HPHT WELL COMPLETION

The definition identifies wells where pressure is greater than 10,000 psi (690 bar), and temperatures above 300 °F (150 °C) (Bellarby, 2009). The well need equipment, especially a Blowout Preventer (BOP) that can withhold and provide integrity at 690 bar and higher to account for downhole pressure conditions. Equipment must be able to operate in downhole conditions from 150 °C and higher.

HPHT fields offer challenges and considerations often due to high uncertainties, highly stressed reservoirs, and demanding material selection due to pressure and temperature control. When designing an HPHT well completion design, the optimization is relatively limited due to material limitations. The design envelope is small due to possible extreme conditions regarding pressure and temperature. Mitigating pressure control instabilities in HPHT reservoirs is more demanding. The consequences may be of severe impact if care is not taken (Bellarby, 2009).

2.9.1 Safety

For HPHT completions, the probability of failure is increased, together with larger consequence if the failure follows. Locating the source of failure is important, and can according to Hermansson and Low (2014), be divided in 4 parts:

- **Equipment failure.** Due to operating closer the operational limit, the probability of equipment failure increase for HPHT completions. Equipment experience higher unreliability above 300 °F, especially downhole tools, and electronic equipment (Hermansson & Low, 2014).
- **Software failure.** Production tubing design, packer design, trajectory simulations, perforation performance and temperature predictions, to mention a few, tend to be calibrated for conventional and standard well operations. The inaccuracy and unreliability of HPHT software predictions increase probability of errors (Hermansson & Low, 2014).
- **Organizational approach.** Less planning time is often given due to not fully appreciating the increased complexity of HPHT wells compared to standard wells. Knowledge of how HPHT considerations affect the operating window in regard to equipment is highly appreciated and fundamental for a more safe and reliant approach to completion planning.
- **Human failure.** Understanding of HPHT complexity. Low experience, weak interactions between contractors, non-aware of equipment limitations and methods used in HPHT operations may increase the probability of failure (Hermansson & Low, 2014).

Material design for HPHT wells are limited and conservative, with the intention for optimal safety. In previous HPHT wells in the North Sea, both tubing and tubing hangers have resulted in failure. By engaging reservoirs with corrosive fluids, the use of corrosion-resistance is necessary. High pressure in reservoir require tubular with increased yield strength to withhold the pressure differentials, especially load cases including “shut-in” and tubing leak at surface.

The combination of hostile reservoirs merged with high pressure and temperature produce difficulties of selecting appropriate optimal design. HPHT wells implement a principle called KIS (Keep It Simple), which summarize the need to focus on robustness, safety, and simplicity (Hermansson & Low, 2014).

2.9.2 HPHT Design Methodology

The approach towards HPHT well completion require highly skilled engineers, with a step-by-step methodology to obtain the most specific and important information for planning purposes. According to Hermansson and Low (2014), the following areas (but not limited to) require special attention:

Formation T&P	Offset Well Data	Risk Identification	Well Control
• Expected temperature and pressure	• Relevant offset wells to identify hazards	• Risks likely to occur should be listed early	• Model potential well control incidents

2.10 Life of Well Completion

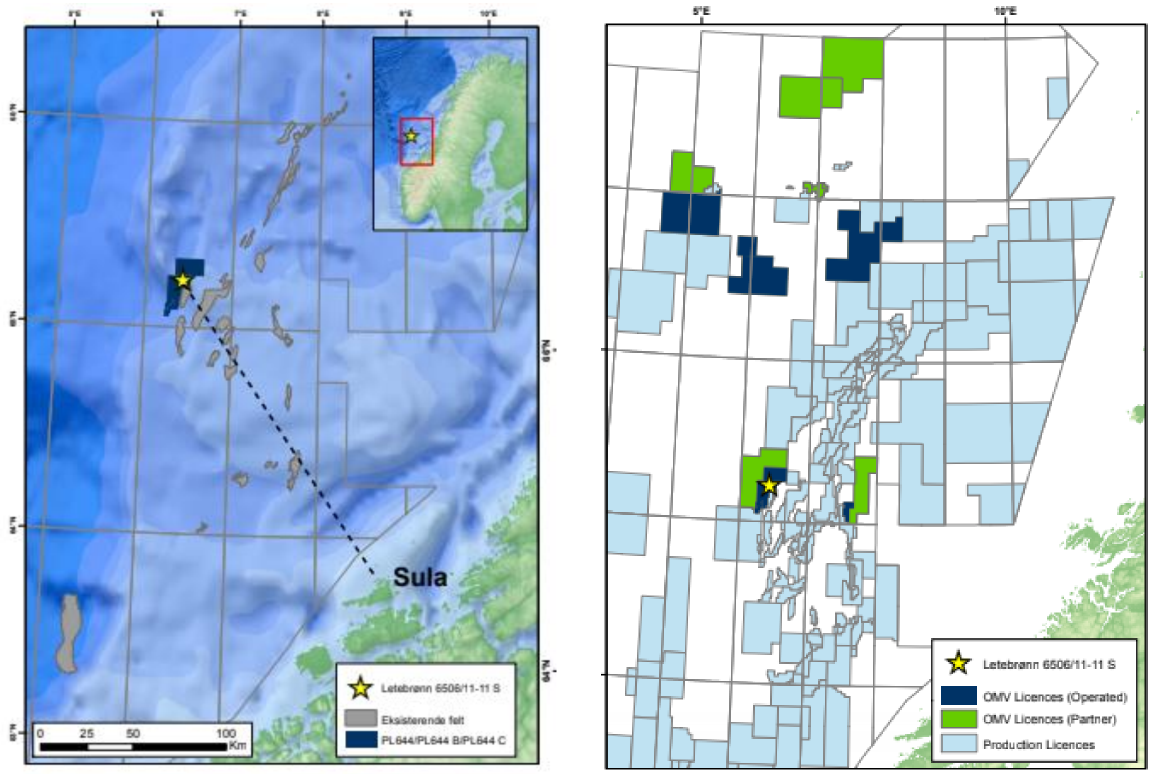
The ability to plan an intervention free well is in theory possible, but in practice much harder. Intervention has to be accounted for, even for subsea wells. The well design should account for the life of well operations, therefore implementing as many solutions as possible to minimize the need to do re-work at a later stage. The method selection is highly influenced by this. Nipple profiles, operational steps and time-saving operations should be applied to the design in order to optimize efficiency. Even if the completion is split in three parts (reservoir completion, reservoir isolation and upper completion), the need to combine the parts is essential. Tubing and liner size are a good example. If the completion team decides to set a 7" liner and a 5 ½" tubing, setting plugs in the liner will be challenging. Completion engineers need to plan ahead, find the no-go`s and link the weak-links together, and most importantly – make it work.

When selecting the most suited method for production in an HPHT field, the consideration scale is huge. The following chapters will introduce a majority of considerations and challenges the operator must consider when deciding on which method to select. The positive note is that both open hole and cased and perforated has been proven on the NCS. The use of downhole barrier assemblies has been tested and great experience has been provided. New technology has been qualified for use, and potential future solutions for optimization has been proposed.

CHAPTER 3

3 PL644 / PL644 B / PL644 C HADES / IRIS FIELD

The Hades/Iris Field is located north in the Halten Terrace Area, west of the Morvin Field, in the Norwegian Sea. The license partners are divided among OMV (Norge) AS (30%), Equinor (40%), Faroe Petroleum (20%) and Spirit Energy (10%).



(a) (b)

Figure 3-1: (a)*: 6506/11-11S Iris Appraisal Location.* (b)*: OMV Licenses (OMV, 2019a)*

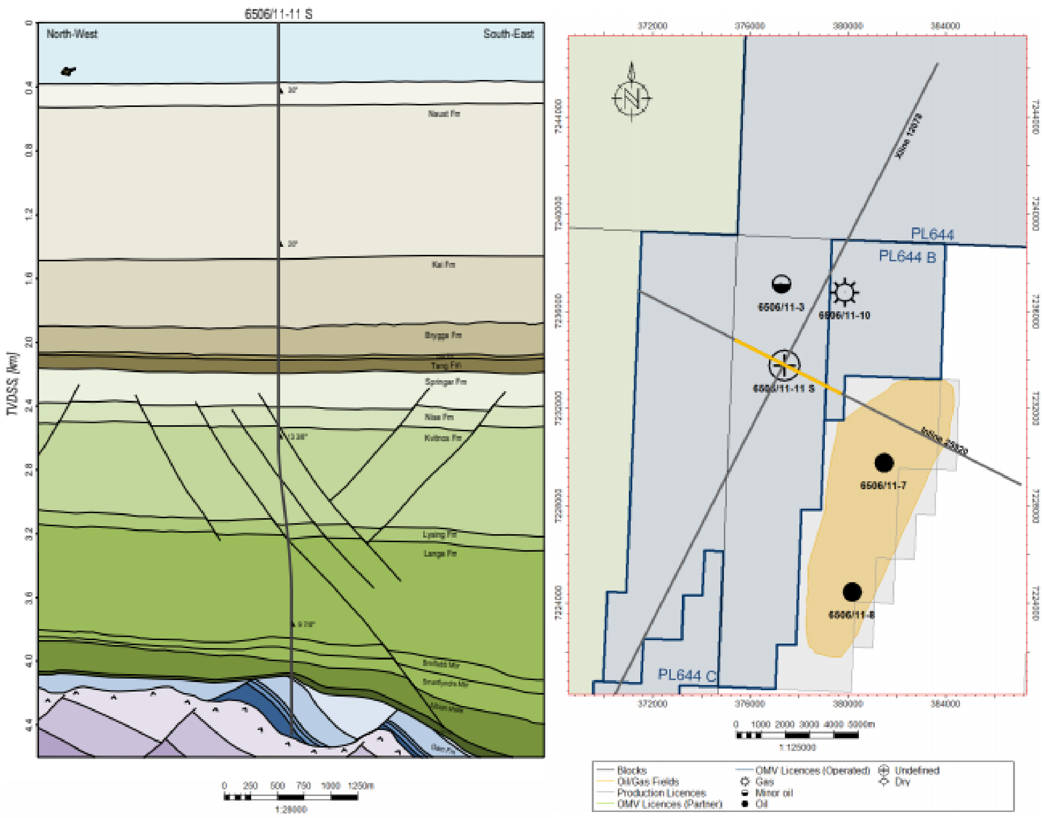
Figure 3-1 illustrate Iris Appraisal location and OMV operated and partnered licenses. OMV (Norge) AS has drilled two successful wells on the PL644 and PL644B license. In 2018, 6506/11-10 Hades & Iris exploration well was drilled to investigate the Hades reservoir (Lange Formation) and Iris reservoir (Garn Formation). To prove presence and depositional model for Iris reservoir, 6506/11-11S Iris Appraisal was drilled during summer of 2019. Starting early June 2020, 6506/11-12S Hades Appraisal is planned to prove hydrocarbons and depositional model for Hades reservoir.

3.1 Iris Reservoir Discovery

Iris reservoir is located approximately 230 m underneath the Hades reservoir. The reservoir target, Iris, is the Garn Formation of Middle Jurassic, Bajocian-Bathonian age. The established Middle Jurassic section in the western Halten Terrace area include reservoir with rotated fault blocks, which Iris is included (OMV, 2019a). The reservoir quality was proven to be good, with poor reservoir quality in between upper and lower Garn (OMV, 2019b). The hydrocarbon phase for Iris reservoir is gas and condensate.

3.2 6506/11-11S Iris Appraisal

The Iris Appraisal HPHT well was drilled by OMV (Norge) AS from May to October 2019. The well is a slanted near vertical well drilled by Deepsea Bergen in the OMV operated license PL644. The well was completed in the matter of 157 days. Well trajectory and location are illustrated in Figure 3-2:



(a) (b)

Figure 3-2: (a): *6506/11-11S Well Trajectory.* (b): *Field Location (OMV, 2019a)*

The well objectives were to prove presence of hydrocarbons in the Garn Formation (Iris reservoir discovery). If hydrocarbons are present within the Garn Formation, sufficient amount of core were to be cut to verify depositional model. The hydrocarbon contact should be verified, and to obtain image logs over the Iris reservoir of the Garn Formation to gain information of structural and depositional complexity.

The well was vertical down to the 12 ¼" section where an angle of up to 12 degrees was built. In the lower part of the 12 ¼" section the well steered back to vertical which was kept to the TD of the well. The well was drilled into the Ror Formation and TD was set at 4443 m Measured Depth (MD) from rotary kelly bushing (RKB).

Well Results

The Iris discovery is in the Garn Formation of the Middle Jurassic, with a gas discovery down to 4206 m MD RKB, indicating a column of 69 m. Three cores were cut, all in Garn Formation retrieving ~42 m of core for compositional analysis. Garn Formation can be separated in three intervals:

- Upper Garn with good reservoir properties
- Substantial middle part comprised of laminated sand-shale sequence and poorer reservoir quality
- Lower Garn with massive sandstone with good reservoir properties

(OMV, 2020)

In the Cretaceous Hades reservoir, the Breiflabb members of the Lange Formation, had traces of gas. The Smørflyndre member of the Lange Formation was water bearing. The well was classified as a discovery. Two Drill Stem Tests (DST) were performed in the Garn Formation before an extended leak-off test in the Lange Formation was performed. The well was plugged, and rig was off contract late October.

3.3 IRIS PRODUCTION WELL – BASE DESIGN

The fictive Iris Production well will be based on 6506/11-11S Iris Appraisal design and reservoir conditions. Available data from OMV (Norge) AS shall be reviewed, and a new well is designed at the same location as Iris Appraisal, for simplicity purposes. Software simulation has not been performed prior to the design, meaning the base case need to be widely assumed. However, elements from previous experience can be selected to provide a basic design.

3.3.1 Geology

Iris Production well shall be drilled near vertical down to target TD. However, great experience was learned during Iris Appraisal. The spud location had to be changed due to corrals in originally planned location. The use of slightly deviated 17 ½" drilling section was successfully performed. The Lyse Formation has potential of gas storage, therefore making the 9 7/8" cement job important for isolation purposes. Garn Formation (Iris reservoir) is located at 4141 m MD RKB. Table 3-1 illustrate the formation tops, age, and lithology:

Table 3-1: Formation tops, age, and lithology (OMV, 2019a)

Formation	Age	Lithology	Depth (mMD RKB)
Sea Floor	Quaternary	Sandy clay, claystone	**405**
Naust Formation	**Tertiary**	Silty Claystone	**552**
Kai Formation		Silty Claystone	**1516**
Brygge Formation		Claystone	**1933**
Tare Formation		Claystone wiith minor limestone stringers	**2101**
Tang Formation		Claystone, tr.of limestone, siltstone and sst	**2126**
Springar Formation	**Cretaceous**	Claystone	**2221**
Nise Formation		Claystone, sand, lst	**2420**
Kvitnos Formation		Claystone with stingers of sst and lst	**2535**
Fault			**/**
Fault			**/**
Blålange Formation (Lyse)		Mudstone/Claystone, sandstone	**3183**
Fault			**/**
Lange Formation		Claystone with stingers of carbonate and sst	**3254**
Top Breiflabb Mbr (Hades)		Sandstone, minor claystone interbeds	**3912**
Top Smørflyndre Mbr		Claystone	**3952**
Top Intra Lange		Sandstone, minor claystone interbeds	**|**
Langebarn Formation		Mudstone with limestone and rare sandstone	**4030**
Lyr Formation		Claystone	**4116**
Spekk & Melke Formation	**Jurassic**	Shale	**|**
Garn Formation (Iris)		**Sandstone, minor claystone interbeds**	**4141**
Not Formation		Claystone	**4208**
Ile Formation		Sandstone, minor claystone interbeds	**4242**
Ror Formation		Claystone with tight sandstone stringers	**4357**
Well TD			**4443**

Well Trajectory and Target

The main target for Iris Production well is the Jurassic Iris reservoir in the Garn Formation. The operation will drill through the Garn Formation and reach TD just below. Well trajectory can be seen in Figure 3-3. The overall inclination is close to vertical, with a small bend in the 12 ¼” section. It steers back to vertical before setting the 9 7/8” casing above Hades reservoir. The intention is to follow a previously proven trajectory, hence the vertical producer. This way, Hades reservoir needs to be isolated once drilled through. The complications with this represent personal learning potential and considerations for the future field development.

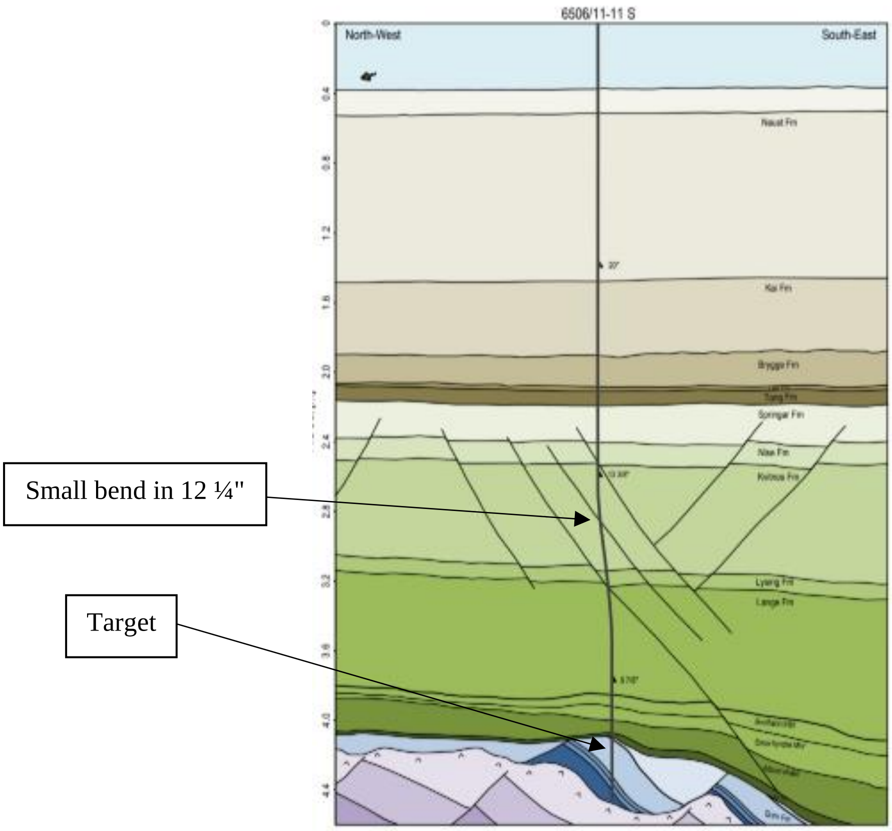


Figure 3-3: 6506/11-11S Iris Appraisal trajectory. Iris Production well based on same trajectory

Pore Pressure and Temperature

According to “*End of Well Report*” draft provided by OMV (Norge) AS, the pore pressure in Garn Formation was detected to be 1.93 sg. The temperature at sea bottom was measured to 2 °C. The Hades reservoir was measured at ~130 °C, while Iris reservoir was measured to ~150 °C. The temperature gradient is 3,5°/100 m (OMV, 2020).

Petrophysical Evaluation

While drilling Iris Appraisal, three cores were cut in the Garn Formation, retrieving ~42 m of core. Garn is divided into upper and lower, with a less permeable laminated sand-shale section in between. The logs have not confirmed a vertical flow barrier within the Garn Formation, and flow is therefore considered. The initial formation pressure at 4148 m TVD (Garn Formation) was equal to 755 bar (OMV, 2019b).

Two Drill Stem Tests (DST) were performed. DST#1A perforated an interval of ~10 m, from 4190 – 4200 m MD. Well performance wise, the flow was below expectations and a Productivity Index (PI) of ~2030 Sm^3/day/bar. The second DST, DST#2, was targeting the upper Garn, perforating an interval of ~22 m, from 4141 – 4163 m MD. Well performance wise, the flow was satisfactorily, with calculated PI of ~15200 Sm^3/day/bar. Intervals, length, and PI can be seen in Table 3-2:

Table 3-2: Petrophysical data from DST#1 and DST#2 at Iris Appraisal (OMV, 2019b)

Tests	Interval (MD)	Length (m)	PI (Sm^3/day/bar)
DST#1	4190.15 – 4199.97	9,82	2030
DST#2	4140.34 – 4162.68	22,34	15200

3.3.2 Casing Design

The casing design influence the completion equipment selection, especially the production casing. Integration of all the completion considerations and limitations is important when designing the casing strings (Hahn, Burke, Mackenzie, & Archibald, 2001).

The casing design for Iris Production well is highly assumed and based on considerations. The design is assumed to handle the stresses and is incorporated as the foundation for the well completion components. The rig selection will in most likelihood be a semi-submersible for the actual field development. When drilling a production well, rig capacity increases due to higher equipment and material component requirements. It involves more personnel on board (rig and boats) and storage availability. For rig selection, it is assumed a suitable floater with adequate capacity. The demand for supply boats and logistics are settled prior to operation start.

When implementing a casing design for drilling purposes, it is not guaranteed that string capacity can withhold production load cases. Looking at `tubing leak at surface`, production and intermediate casing strings might have to be switched with a tie-back to fully accommodate minimum requirements Verification of cement height will in most cases be required to accommodate for string integrity (Hahn et al., 2001).

Blowout and Well Kill Simulation

One of the observations analyzing the overall well completion was to set the production casing below Hades reservoir (Breiflabb member of Lange Formation). The reasoning for wanting a deep-set production casing is to isolate Hades reservoir before drilling the Garn reservoir section. Ranold AS, an independent well simulation company, studied the possibility of drilling Hades reservoir in the 12 ¼" section with a deep-set 13 3/8" intermediate casing. According to the "*Blowout and Dynamic WellKill Simulations*" report performed by Ranold AS, during well kill operation the pressure would not exceed, but be very close to fracture pressure (Dyb, 2019). In theory, the well would be able to be killed if all integrity were lost, but with a very low margin due to the possibility of an underground blowout. The fact that the simulated pressure reached when performing well kill operations was just 4 bara (674 bara, versus fracture pressure of 680.8 bara), makes the margin too small and therefore risk too high. For completion purposes, the production casing is set just above Hades reservoir.

Casing Metallurgy Selection

Operators need to account for the production period, and not only drilling operations with regard to metallurgy. The production casing, a 10 3/4" x 9 7/8" casing string will be of grade SM-125S, which accounts for the potential sour conditions. The alloy is a high strength 125k psi to accommodate for high burst scenario with a potential tubing leak. The modified 125k production casing has been previously selected for Kristin wells and Gudrun A-16 and was used during Iris Appraisal (OMV, 2019a). It is of great importance to mention the need for simulations to conclude on casing integrity, especially the production and intermediate casing with respect to Annular Pressure Buildup. The decision is based on previous experience and should be cross-checked with actual load cases with full thermal analysis to ensure integrity of casing string.

Without the ability to investigate load cases, the casing design is assumed to be adequate for both drilling and completion well operation. The difference in design is the following:

- The production casing now involves a 10 3/4” upper part. The reasoning for having a larger casing string in the top section of the well is to accommodate for a Surface-Controlled Subsurface Safety Valve (SCSSV).
- The SCSSV is intended to be placed roughly 60-100 meters below the wellhead.

Table 3-3: Production Casing string assumptions

Casing size (in)	From [m TVD RKB]	To [m TVD RKB]	Weight [lbs/ft]		Grade
10 3/4"	405	565	60.7	SM125S	VamTop
9 7/8"	565	3825	66.9	SM125S	VamTop

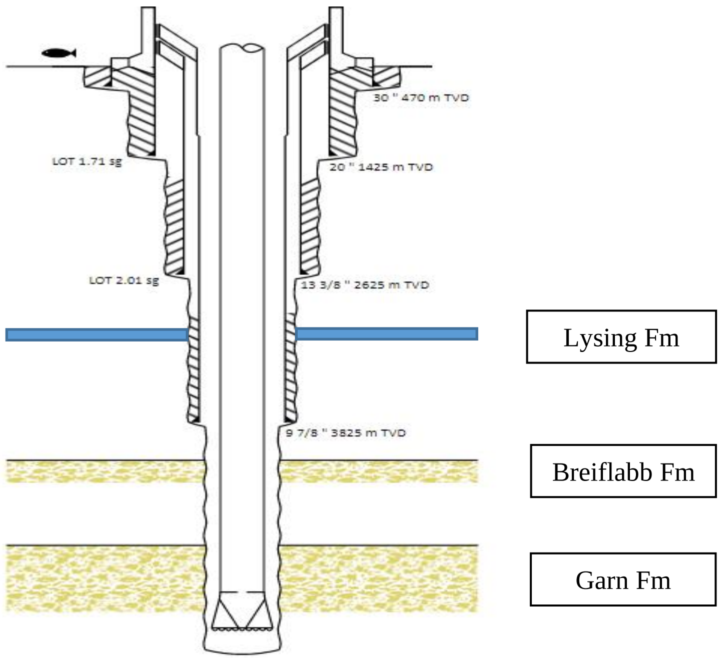


Figure 3-4: Casing Design. Drilling 8 1/2" section

3.3.3 Contingency Design Considerations

A fully completed 8 ½” reservoir section to TD is generally assumed but contingencies should be brought in for consideration as it affects the completion design. In some cases, the reservoir completion needs a slimmer sizing due to not able to fulfill requirements related to setting depth and cement verification. Two contingency cases will be reviewed:

1. Shallow set 9 7/8” casing shoe. A 7” liner is set to reach top reservoir. Hades and Iris is then further drilled with a 6” hole and a 4 ½” liner.

2. No cement behind 9 7/8” casing. Production packer original setting depth has to be changed, as it cannot be set without adequate cement behind casing.

Shallow set production casing

The production casing is shallow set, and this do not necessarily change the top completion design. Production packer can be set as approximately planned depth. The reservoir section is now drilled with a shallower hole (6”, instead of 8 ½”), meaning the reservoir liner is 4 ½”. The tubing size is minimally affected. Through-tubing operations (perforation guns) now needs to address the liner as the limiting ID, and smaller gun sizes must be accounted for (Hermansson & Low, 2014). Figure 3-5 illustrate contingency case:

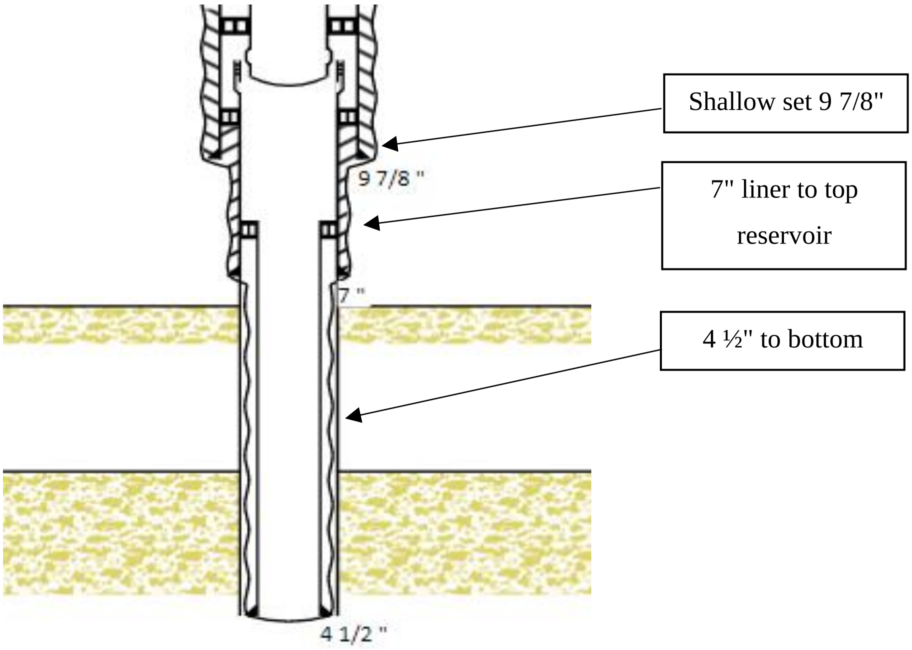


Figure 3-5: Shallow set 9 7/8" Casing. 7" liner set at original setting depth. Contingency 4 1/2" liner set in Iris. Based on Hermansson and Low (2014)

Missing cement behind production casing

With missing cement behind the production casing (Figure 3-6), a leak below the production packer may introduce formation break up below the 13 3/8” casing shoe. This scenario introduces a tapered tubing design, either 5 ½” x 4 ½” (subsea) or 7” x 4 ½” (platform), as the production packer is now set in the 7” liner interval. The production packer needs to be set with adequate cement verified, and this is introduced with a cemented 7” liner in the production casing interval down to top reservoir. The reservoir section involves a 4 ½” liner.

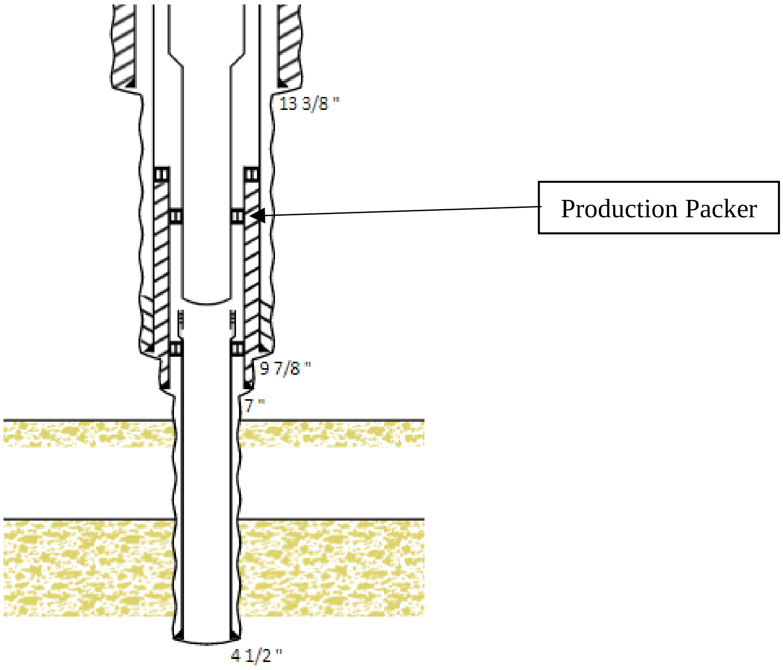


Figure 3-6: Tapered 5 ½" x 4 1/2" tubing. 7" liner cemented to original packer height. Production packer set in 7" liner. Based on Hermansson and Low (2014)

3.4 FUTURE FIELD OPERATIONS

As for now, 6506/11-12S Hades Appraisal shall be drilled during summer 2020 in order gain more data of the Hades reservoir. OMV (Norge) AS is currently reviewing a sand-study to determine the geological deposition of Iris sandstone. The combination of rock strength and pressure depletion will base a decision on the need for sand control for completion purposes. Reservoir targets are not defined for the field development; it is therefore unknown where the production wells will hit the reservoirs, hence well trajectory is still not concluded. The evaluation of using a subsea tie-back solution is being discussed as the field development plans are in an early planning stage.

CHAPTER 4

4 METHOD ASSESSMENT

The intention of a method assessment is to provide information about the concepts being evaluated. First, Iris reservoir properties will be reviewed, and all assumptions accounted for. The assessment shall then conduct a general concept description. Following, both general advantages and disadvantages is listed. The installation process will demonstrate the procedure differences with the intention to illustrate operational steps. The methods will be analyzed with regard to operational readiness in HPHT environment on the NCS, with respect to previous experience. Operational risks and challenges are listed, to finalize the assessment. The analysis will cover the following concepts:

- **Lower Completion**: *Open hole Predrilled Liner* vs *Cased and Perforated Liner*
- **Middle Completion**: *Middle Completion barrier assembly with internal plug/Isolation-valve* vs *Integrated Lower Completion barrier assembly*
- **Upper Completion**: *5 ½" tubing* vs *7" tubing* and *Permanent Packer* vs *Retrievable Packer*

4.1.1 Assumptions

The thesis will be based on numerous assumptions. The thesis has a general approach with identifying differences between the methods. Iris Production well is a vertical subsea HPHT well, drilled and completed from a semi-submersible rig, with the intention to produce from Iris reservoir. The reasoning for selecting a vertical well is implement the previously proven trajectory from Iris Appraisal well, assuming permeability suitable for a vertical producer. The well is assumed drilled to TD with an 8 ½" hole. The production interval is approximately a total of 30 meters, split in upper and lower Garn formation. The analysis covers the implementation of one single production well and will not consider a larger field development perspective. T&C operational rate is highly influenced by an OMV (Norge) AS perspective.

Hades reservoir shall be isolated and has no intention to be produced. The selected drill-in fluid and completion fluid (open hole fluid or perforation fluid) has not been determined and is assumed with the intention to be compatible with the formation to provide minimal formation damage. The DST performed at Iris Appraisal contributes with reservoir characteristics that follows the assessment. Subsea Christmas tree (XMT), downhole pressure and temperature gauges, SCSSV, tubing hanger and additional completion equipment not covered is assumed to be compatible and will not be reviewed. However, XMT solutions will influence the upper completion, and is therefore broadly reviewed in the upper completion assessment.

4.1.2 Reservoir Properties Evaluation

Based on previous field experience of Garn Formation, the sandstone shows little sand production, and the need for sand control is eliminated. After consultation, the removal of sand control completion was concluded, with focus on predrilled liner as an open hole completion method. Highlighted reservoir considerations are listed in Table 4-1 below:

Table 4-1: Data acquisition collected from "Well Test Report: Iris Appraisal 6506/11-11S" (OMV, 2019b)

	DST#1 - Lower Garn	**unit**	**DST#1 - Upper Garn**	**unit**
Depth Interval	4190 - 4200	m	4140 - 4162	m
CO_2	3	%	2,5	%
H_2S	5	ppm	5	ppm
pH	6,5	-	6,43	-
IBHP	755	bar	752	bar
kH	15.3	mD	45-65	mD
Skin	0 to 0,75	-	-1,4 to 0	-
Gas PI	2030	m^3/day/bar	15200	m^3/day/bar

Highlighted information from the table:

- According to DST#1 and DST#2, upper Garn contains substantially better reservoir conditions with higher permeability.
- The reservoir pressure is estimated to be roughly 755 bar.
- The reservoir temperature is measured to be 149 °C (300 °F).
- Total skin in Iris is ranging from -1,4 to 0,75. The skin factor provided from the DST may deviate and should not be taken as given.
- The sand is expected to be hard and highly stressed. Little to no sand production is expected.

4.2 LOWER COMPLETION: PREDRILLED LINER CONCEPT

4.2.1 General Concept

The term *open hole* is a form of completion concept where the lower completion is not cemented in place, or no completion is used below the production casing (barefoot). If tubular is in the hole below the production casing, the liner has been pre-slotted or predrilled and modified to fit operators design with regard to hole size, density (holes per meter) and hole pattern (angle). If needed, isolation packers and stability equipment can be implemented in the design for optimization purposes.

The completion purpose is to produce hydrocarbons with as low restrictions as possible, without compromising borehole integrity (Bybee, 2004). With the use of predrilled or pre-slotted liner, the gross hole collapse potential decrease due to mechanical structure in the hole. This open-hole completion is not considered a form of sand-control, as it has its natural structure too big to prevent the production of sand (Bellarby, 2009). The predrilled liner is typically run in hole with a reduced-solid or solid-free completion fluid, connecting to the liner hanger close to bottom of the production casing.

4.2.2 Liner Design

A predrilled liner design is based on how to achieve best inflow performance from reservoir through the liner without conceding the mechanical strength of the liner string (Fitnawan et al., 2011). The mechanical strength of the liner is proportional with creating open flow area. Bigger flow through the liner holes is resulting in reduced strength. The optimization of hole sizes, skin reduction and liner strength are simulated to achieve the best possible inflow performance. Figure 4-1 illustrate a simplified predrilled liner design:

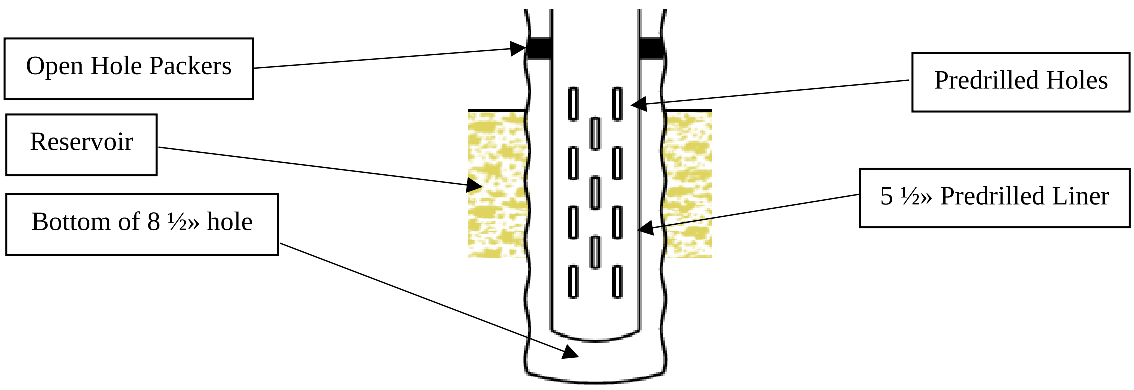


Figure 4-1: Predrilled Liner Design

The liner design considerations are as following:

- ***Hole pattern***. The phasing angle and design of the holes.
- The pattern can be either parallel or perpendicular to the axis of the liner. In HPHT wells, the strength of the liner is of great importance. Providing axial slots (parallel) will make sure the liner provides higher strength (Wan, 2011).
- ***Hole density***
- The liner consists of pre-drilled holes, unlike the slotted-liner. The number of holes per meter describes the density of the pattern.
- ***Hole size***
- Size of the pre-drilled holes. Important size to consider due to potential plugging or pressure loss from reservoir into the liner (Fitnawan et al., 2011).
- ***Open flow area***
- Measured in percentage. A flow area between two percentages will provide a range of optimization for reduced skin value consideration.

The total skin as a function of the predrilled hole pattern will be measured up against the open flow area. This is important to consider in HPHT wells, as previously mentioned, to account for the liner strength. The compromise of strength and open flow area is selected to give acceptable simulated skin. Alongside the predrilled liner skin, open hole skin is added.

Open Hole Damage Prediction

The near-wellbore region has importance for well completion. Every operation that may influence the area between reservoir and the tubular can potentially reduce the well performance. For open hole completions, this is mainly related to formation damage.

The skin factor is a dimensionless factor (S), meant to give a numerical representation of the permeability in the near-wellbore region. If the well is completely blocked, the skin factor has infinite positive skin. A negative skin factor is associated with exceptional inflow performance. Skin can be calculated with regard to inflow performance (gas well):

$$q_g = \frac{7.03x10^{-4} k_g h(\bar{p}_r{}^2 - p_w{}^2)}{\mu_g zT[\ln\left(\frac{0.472 r_e}{r_w}\right) + S]}$$

(Bellarby, 2009)

where q_g is gas flow rate (Mscf/D), μ_g is gas viscosity (cP), T is reservoir temperature (R), z is gas compressibility factor, k_g is permeability to gas (mD), $\bar{p}_r{}^2 - p_w{}^2$ equals the Darcy pressure drop between reservoir and wellbore (psi), r_e is effective drainage area of the well (ft), r_w is the wellbore radius (ft) and h is net thickness of the reservoir interval. According to Bellarby (2009), the total skin factor can be shown as:

$$\acute{S} = S + D\mathrm{q}$$

where D is the non-Darcy coefficient and q is flow rate (Mscf/D). The non-Darcy coefficient can be conducted from well tests or empirical correlations. The reasoning for combining flow with the coefficient is due to turbulence and high velocities near wellbore, often seen in gas wells or damaged wells. The turbulence coefficient (β) is related to the Non-Darcy flow, and in an undamaged open hole gas well, the relationship between the two is:

$$D = 2.22 \text{ x } 10^{-15} \frac{\beta \gamma_g}{h_p{}^2 r_w} \frac{kh}{\mu}$$

(Bellarby, 2009)

where the turbulence coefficient, permeability *(k)*, average viscosity (μ), height of completed interval (ft), h_p and gas gravity, γ_g, is all related to the Non-Darcy flow.

By combining the rate-independent term (S) and rate-dependent term (D), the total skin can be calculated. The total skin is measured in flowrate (Mscf/D) with comparison to different pressure values. For demonstration purposes, Bellarby (2009) presented an example of a gas well. Figure 4-2 represents a well with two equations determining D, as in a "no-damage" well and a "damaged" well. It illustrates the difference in inflow performance based on how much damage and turbulence is apparent in the well.

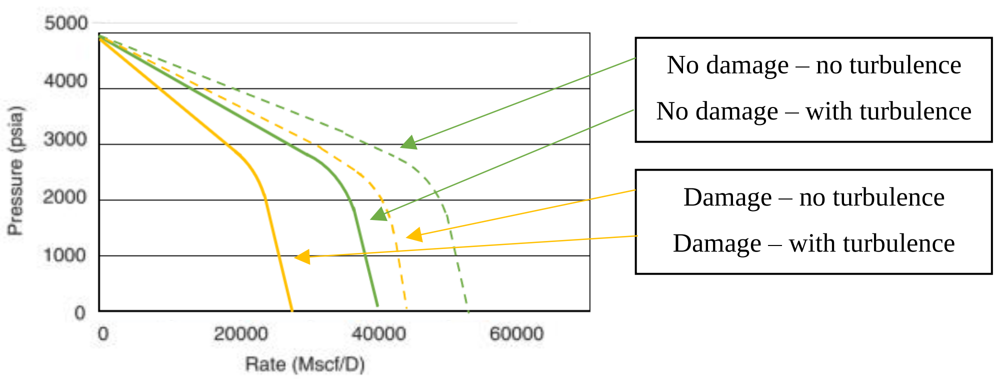


Figure 4-2: Example of inflow performance in an open hole completion (courtesy of Bellarby (2009))

Open hole completions are not able to bypass formation damage as a cased and perforated completion potentially can. The identification of formation damage and its severity will greatly influence the method selection. The combination of formation damage and skin from the predrilled hole design will together provide skin factor for open hole completions. Important consideration to lower the formation damage, thus lowering the overall skin, is fluid selection.

Open Hole Completion Fluids

The use of a compatible completion fluid when entering the reservoir is important for open hole completions. For optimization purposes, the fluid used to drill into the reservoir should introduce as little damage as possible to the permeability of the reservoir. The number of variables to consider when selecting fluids for open hole completions make the process tough (Davidson & Stewart, 1997). Unlike a perforated liner, no perforations are made to bypass formation damage. A well-suited drill-in and completion fluid for HPHT conditions need to account for many factors:

- ***Temperature and pressure.*** The selected fluid needs to be stable at bottom hole conditions. The fluid will be introduced to longer static periods.
- ***Fluid loss control.*** Bridging particles or fluid-loss polymers is required to avoid loss of filtrate into the reservoir formation. The mud or mud filtrate has to be compatible to reduce damaging effects on the rock wettability (Davidson & Stewart, 1997).
- ***Cleanliness for equipment running.*** Completion equipment is run in a solid free environment.

For fluid loss control purposes, a core from the reservoir should be tested to optimize the fluid loss polymer concentration and distribution of particle sizing in the mud (Davidson & Stewart, 1997). Once the testing has commenced, optimization of drill-in and **completion** fluids will start. To achieve the overall best performance, a compromise between fluid performance in regard to drilling operation and the fluid loss performance may be required.

Zonal Isolation

If the reservoir consists of two reservoirs, like Iris Production well, the need for an open hole isolation packer is beneficial and upmost important for zonal isolation. In some cases, two reservoirs produce from the same interval. For Iris Production well, only Iris will be producing. Open hole isolation is of great concern in HPHT scenario. The use of open hole swell packers has become more common. Swellable elastomer packers eliminate the wash-pipe by not needing to inflate, as External Casing Packers would require. However, running clearance can be minimal (about 0.15 in. radial clearance) (Bellarby, 2009). Swell packers can be expanded by diffusion as a response to hydrocarbon contact (Bellarby, 2009). Swelling in high temperature can initiate swelling more effectively, and for gas wells, the need to circulate in a base oil can be initiated. This way, the open hole packers are run in hole as an integrated part of the pre-drilled liner assembly and placed below Hades and above Iris.

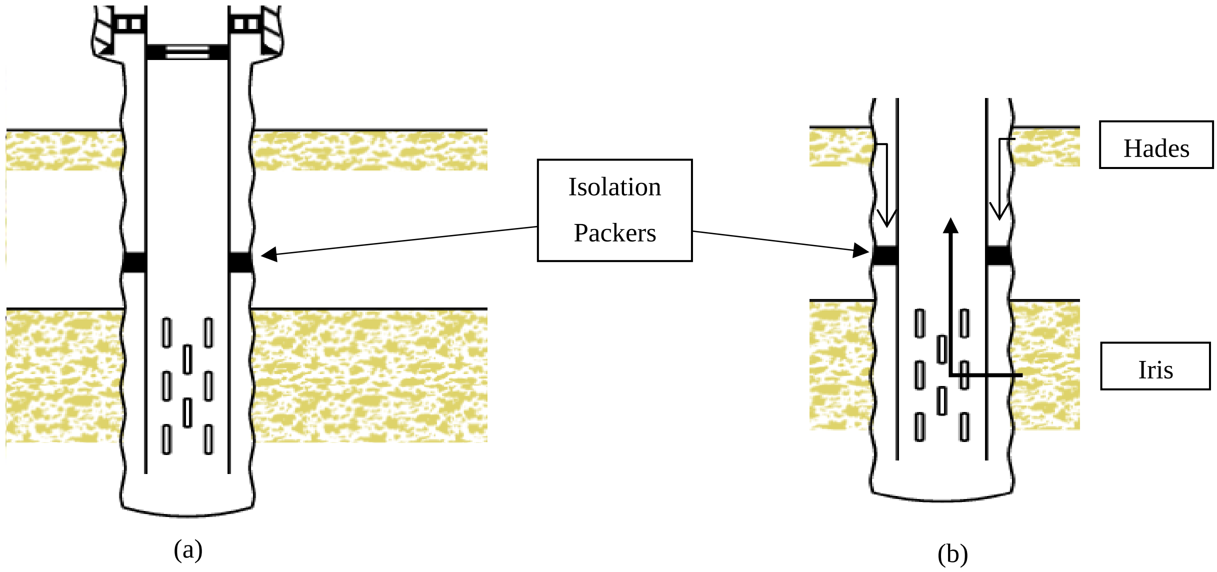


Figure 4-3: (a): Swellable Isolation packers placed below Hades reservoir to prevent cross flow. (b): Packers placed above Iris reservoir, with predrilled liner design below.

Figure 4-3 illustrate the positioning of isolation packers between Iris and Hades reservoir (a). The distance from reservoir tops is approximately 230 m. The predrilled holes will commence below the isolation packers to provide flow from Iris into the predrilled holes (b).

4.2.3 Installation Procedure

Once the reservoir section is drilled, bit is pulled to surface. The next operational steps may differ from operator and wells. HPHT completions tend to use heavy fluids to balance the hydrostatic pressure when running in hole. The well is displaced from drilling fluid to a cleaner, less solid liner-running fluid. The predrilled liner with isolation packers is next run in hole. A downhole barrier assembly (reservoir isolation) will either be run integrated on the liner or in a separate run. The downhole barrier assembly assessment will be reviewed in chapter 4.3.

The liner is run and hang off near bottom of the production casing. As Table 4-2 present, the lower completion is run in a filtrated drilling mud (brine or OBM) which has found to be most compatible with the reservoir characteristics. Once the lower completion has landed, completion fluid will be displaced for plug- and equipment running operations.

Table 4-2: Lower Completion installation procedure with Liner Hanger Packer (Fitnawan, Hovland, Schiefloe, & Møller, 2011)

1
- **Hole cleaning and solids filtration of drilling fluid prior to running completion**
- Casing scraping, displace well from drilling fluid (brine/OBM) to completion running fluid (brine/reduced-solids OBM)

2
- **Run and set lower completion**
- Make up pre-drilled liner and run in hole with liner hanger-packer and PBR/tailpipe attached. Set liner hanger and pressure test same

3
- **Perform scraper run and displace to completion fluid**
- Scrape packer-setting areas and general cleaning of casing

4
- **Run and set Integrated Lower Completion barrier assembly**
- Run internal plug on wireline. Set plug and pressure test lower completion barrier assembly. Confirm integrity

5
- **Run and set upper completion**
- Run in hole with production tubing, production packer, pressure & temperature gauge, TRSCSSV, test lines, tubing hanger

6
- **Complete the well**
- Land, lock and test TH. Circulate to packer fluid. Set production packer. Disconnect and pull BOP

The following installation involves an Integrated Lower Completion barrier assembly (ILCBA), which consist of a V0-rated liner hanger packer. The downhole barrier assembly is integrity tested to confirm reservoir isolation, and upper completion running can begin. As illustrated in Figure 4-4, tubing will land in the integrated lower completion PBR. Tubing hanger is pressure tested, well displaced to packer fluid and the production packer can be set and verified.

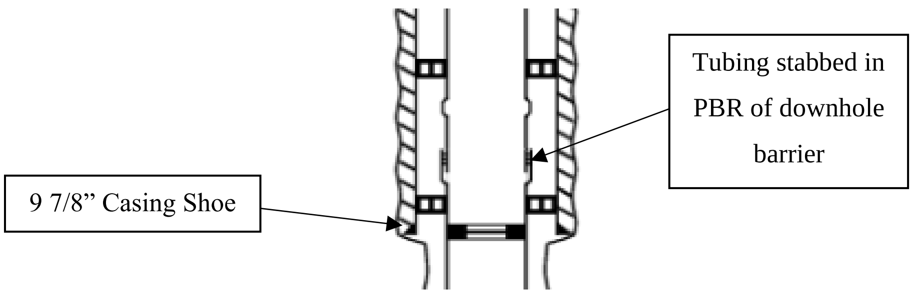


Figure 4-4: Tubing stabbed into downhole barrier assembly

Once the upper completion has landed, the permanent completion can be inflow tested. BOP disconnected and pulled with riser. After integrity insurance of packers, hangers, safety valve and control lines, the installation procedure is finished up.

The running of open hole lower completion is about well stability. Running predrilled liner in a vertical well require monitoring of potential pressure differentials when running in hole in an HPHT well. By using a separate downhole barrier assembly, the sequence is replaced by:

Table 4-3: Lower Completion installation procedure with Middle Completion

1	• **Hole cleaning prior to running completion** • Casing scraping, displace well from OBM drilling fluid to completion running fluid (brine, reduced-solids OBM)
2	• **Run and set Lower Completion** • Make up predrilled liner and run in hole with liner hanger and PBR attached. Land completion in liner hanger
3	• **Perform scraper run** • Scrape packer-setting areas and general cleaning of casing.
4	• **Run and set Middle Completion downhole barrier assembly** • Run annular packer and integrated internal plug. Stab in PBR. Pressure test packer. Pressure test downhole barrier assembly
5	• **Displace to completion fluids. Run and set upper completion** • Run in hole with production tubing, production packer, pressure & temperature gauge, TRSCSSV, test lines, tubing hanger
6	• **Complete the well** • Land, lock and test TH. Circulate to packer fluid. Set production packer. Disconnect and pull BOP.

The difference is the elimination of liner hanger packer and use of a standard liner hanger. A Middle Completion (MC) assembly is instead run. The running of this downhole barrier assembly requires a separate run and involves an annular packer with integrated plug. The downhole barrier is stabbed into the lower completion PBR, as illustrated in Figure 4-5. The MC is not a direct part of the lower completion, but stabs into the top of the predrilled liner. The installation procedure of open hole completions increases with adding this additional run.

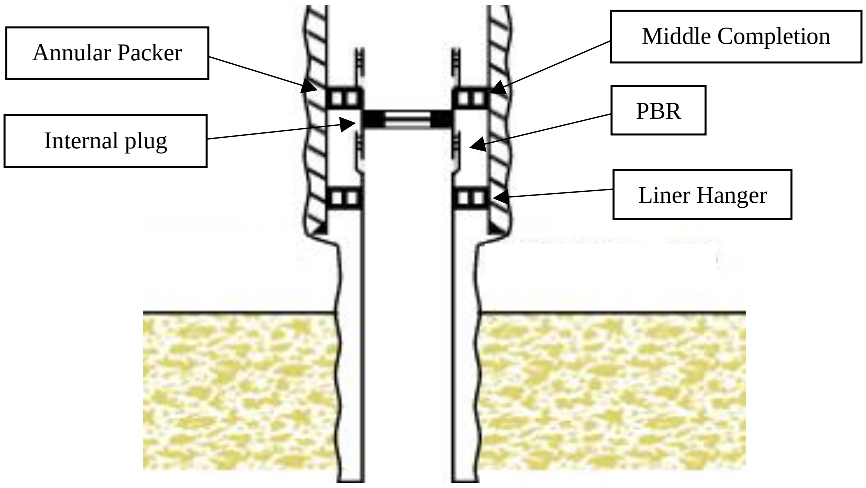


Figure 4-5: Middle Completion barrier assembly

Advantages

Open hole completions reduce the operational risk due to bypassing perforation activities. All operational steps related to perforating (perforation rig-up, explosives on rig-floor, running of explosives, perforating) reduces the operational risk with respect to HS&E and T&C. The overall time of installing the lower completion is reduced, as the operational steps include well displacement and liner running. Perforation debris is left out, and the potential perforation skin is not considered.

Disadvantages

Open hole completions involve risk related to well performance and well control. Drilling and fluid displacement may increase formation damage, which cannot be bypassed and will ultimately reduce the productivity. Mud filtrate losses to the reservoir can create wellbore instability with loss scenario (Davidson & Stewart, 1997). Open hole completions in HPHT environment introduce a live well scenario without providing a physical barrier (cement), and is more prone to formation damage (Bellarby, 2009). 5 ½” open hole isolation packers have been proven in Morvin Field with pressures above 800 bar (11600 psi). Yet, during a life-of-well HPHT scenario, swell packers still need to be proven (Olsvik & Hermansson, 2013).

4.2.4 Operational Readiness: Open Hole HPHT Implementation

The use of OH completions with predrilled liner has been implemented on the NCS, in fact, in an HPHT environment close to PL644 Hades/Iris Field. Morvin HPHT Field, operated by Equinor, has by the time the thesis was written documented three drilled and completed HPHT wells with an open hole predrilled liner solution:

- Morvin HPHT field has similar conditions as Hades/Iris with a reservoir temperature and pressure of 162 °C and 819 bar.
- The main reservoirs produced by the wells are Garn Formation and Ile Formation (Fitnawan et al., 2011), making the reservoir properties relatively similar in terms of flow potential and geological structure.

Field Experience

The Morvin Field completions were implemented in 2011, all of the wells are horizontal. Experiences and design can still be of great importance learning from their challenges and success. The liner used in the Morvin wells is made from *Super 13%Cr-110 5-½" (26 lb-ft)* tubing on 9-7/8" x 5 ½" V0-rated liner hanger packer. Internal studies were made to conclude on optimum liner design with regards to hole pattern, size, and density (Fitnawan et al., 2011). If OMV (Norge) AS were to select a predrilled liner for Hades/Iris field, a study needs to be performed in order to estimate the most optimal liner design.

The use of open hole swelling packers were applied to provide zonal isolation during Morvin. The packer was run as an integrated part of the predrilled liner assembly. Both Kvitebjørn field and Kristin field used HPHT qualified swell packers, in respectively both cesium formate and OBM fluid environment. During Morvin field development, the swell packers were set in a shale environment between the two reservoirs (Fitnawan et al., 2011).

A plug-prong solution is according to Fitnawan et al. (2011), a "*conventional yet simple method to establish barrier during well completion and found to be the proven solution in Morvin HPHT wells*" (p. 6). Morvin field installed a nipple profile in the lower completion in order to be able to run the plug. Tubing and casing plugs will be covered in chapter 4.4.

Fluid Selection

The majority of Kristin wells have a higher inclination (>45°), providing a high inclination/horizontal wellbore. The effect and purpose of fluid selection is therefore different from vertical wells. Formate brine systems is preferred due to elimination of potential barite-sagging and stable fluid properties in HPHT conditions (Downs, 2006), especially with focus on borehole stability in highly inclined wells. Formate brines was conducted in the early 90's to function as a stability-fluid in HPHT wells, with the intention to provide a more stable completion fluid when preparing the well for production (Downs, 2006). Meanwhile, experienced at Kristin, higher inclination wells could not be possible with the use of a high-density cesium formate due to hole instability and washout in the shale section above the reservoir. However, the first two wells drilled on Kristin were low inclination, where particle free brine cesium formate system was used. The cesium formate system did not experience washout and provided a stable completion fluid without particle sagging (Gjonnes & Myhre, 2005).

Morvin wells implemented a newly tested high-density completion fluid, specific for optimizing well conditions at the field. The reasoning was to create a combination of OBM and a heavy-weight brine, limiting the instability issues encountered at Kristin by maintaining an oil-based environment. The difference from previous wells was the reduced-solids perspective. An effort was made to formulate and test a Reduced Solid-Oil Based Completion Fluid (RS-OBCF), constraining the solids, reducing the chance of blocking the predrilled holes (Fitnawan et al., 2011). This was performed in a horizontal well, but the potential effects of sagging and density-drop can still be present in vertical wells. The well was displaced to cesium formate prior to running the plug prong on wireline, reducing the chance of stuck plug due to debris forming above plug.

Cesium formate has a very stable record of success on the NCS, with Equinor using it in 44 HPHT wells the past 5 years the paper was written (Downs, 2006). However, Formate brines is mainly associated with high density to remain hole stability combined with low Equivalent Circulating Density (ECD) in high angle wells. However, based on reservoir characteristics, the fluid system selected should provide minimum formation damage, but also consider HS&E, time, and cost. Despite the good records provided, cesium formate is known to be associated with extreme costs (Gjonnes & Myhre, 2005).

According to Fitnawan et al (2011), *"the lower completion solution using predrilled liner assembly combined with RS-OBCF has helped the wells to deliver their productivity as expected"* (p. 6). The measured skin was comparable and close with the predicted skin.

4.2.5 Operational Risks

For HS&E purposes, displacing the well to a solid-free fluid (brine, low-solids OBM) can lead to instability issues (well control). Surge, swab, and losses are all scenarios associated with displacing and equipment running in HPHT wells. Important element to consider, is the fact that the well is being completed from a semi-submersible rig. All running of equipment is subjected to heave and potentially harsh weather conditions. If the operation needs to stop due to weather, the well has to be shut in for longer periods of time. If the need to run a separate reservoir isolation assembly, the added equipment running in an open well can lead to more surge, swab, and losses.

Open hole completions include less personnel risk exposure, due to fewer lifts, less manual work on rig floor, less high-pressure testing and chemical usage (Olsvik & Hermansson, 2013). However, zonal isolation still needs to be proven for a full life-of-well. Packers have been proven and functionally placed in HPHT wells on NCS with pressures above 690 bar (10.000 psi), but monitoring should provide answers to reliability in longer periods of production time. Swell packers and metal expandable annular sealing packers will be accounted as one of the main risks for open hole completions. Hades reservoir should be isolated from above and below, meaning two packers are run. If mechanically set, ball-drop or plug-running will be implemented to set the packers. Again, elements of potential failure are brought to the operation.

Fluid management provide high operational risk to open hole HPHT completions. NCS HPHT experience show, for multiple Stand Alone Screens (SAS) operations, skin from 0 to 5 (Olsvik & Hermansson, 2013). This is highly influenced by fluid compatibility. If not handled correctly, skin can be higher. The most compatible fluid for Iris Production well needs to be highly prioritized in order to secure a sufficient open hole completion fluid. By using multiple fluid systems, each system needs to be tested to analyze formation damage. Fluid-to-screen and fluid-to-formation is two scenarios important for the operation.

Lastly, installing open hole completions are generally fast. However, fluid compositions in HPHT completions are expensive. The process of providing a compatible fluid needs to go through a comprehensive testing and qualification process. Heavy brines (cesium formate, cesium chloride) provide additional cost to the operation, which is not seen through the installation time. Table 4-4 illustrate the highlighted operational risks and challenges:

Table 4-4: Highlighted operational risks and challenges

Zonal isolation - open hole isolation packer for Hades reservoir
• Hades reservoir is located at 3912 m MD RKB, providing a 95 m sandstone column. If decided to drill and complete vertically, Hades need to be isolated to prevent differential pressure and potential crossflow when producing. Zonal isolation packers must be placed in open hole above and below Hades reservoir. This will provide operational risks regards to HS&E, well stability and well performance (cross-flow, pressure differentials). Swell packers or mechanical open hole packers must be proven for a full life-span of a well.
Open hole completion require multiple fluid systems
• To reduce the risk of formation damage, the reservoir drill-in fluid should provide similar properties as the completion fluid. It will in many cases be incompatible to displace a heavy brine directly into an OBM filled well. The need for multiple fluid systems contribute to logistical and storage challenges. All fluid systems need to be tested with reservoir characteristic core samples to avoid compatability issues. Fluid systems used: Drilling mud, screens to filtrate the solids, heavy-brine, light packer fluid.
Minimum inflow performance due to high formation damage and high skin
• The productivity may be reduced due to high initial drilling damage, making perforations a more valid solutions to buypass the damage. The formation damage and flow potential from reservoir to wellbore must be evaluated. The reservoir structure and directional flow potential must be studied in order to conclude at what inclination the production liner should enter the reservoir and reach TD.
Excessive loss of filtrate introduce well control instability
• The importance of a compatible drill-in and completion fluid bring both well performance and HS&E risk to open hole completions. A well control incident due to losses may influence the operation to look into other methods. If fluid is not compatible, filtrate can cause damage to the reservoir. For OBM, solids particles can plug and reduce the flow area, while brine introduce polymer hydration and thermal stability
Expensive fluid combinations
• Process of testing and qualifying fluids with relevant reservoir characteristics is time consuming and adds additional costs to the operation.

4.3 Lower Completion: Perforated Liner Concept

4.3.1 General Concept

Perforating a cemented liner is a common lower completion method, widely used on the NCS. A liner is run in hole as the lower completion and cemented in place to provide a barrier from the reservoir. A number of explosives is then lowered down in the well either on a drillpipe, or on a cable (electric line, slickline, often through the tubing), into a pre-selected interval in the reservoir. The purpose of perforations is for the explosives to detonate and to provide a pathway for hydrocarbons through the tubing, fluids, cement, and formation. This way, the potential formation damage caused by drilling can generally be discharged – that is, if the perforation execution is well engineered (Bellarby, 2009)

4.3.2 Perforation Evaluation

Geometry and Size

The *perforation geometry and size* cover the end result of the explosive shot – the hole created, size and geometry of it. The gun is typically lowered in the hole, with different clearance to the casing. The perforated interval is affected accordingly, creating potential longer intervals where the gun has lower clearance to the casing.

Reservoir parameters and gun size selection are important for the perforation depth. Rock strength, charge weight, gun clearance and which perforation fluid used will all influence the length of the perforation (Bellarby, 2009). Figure 4-6 illustrate the geometry of a perforation:

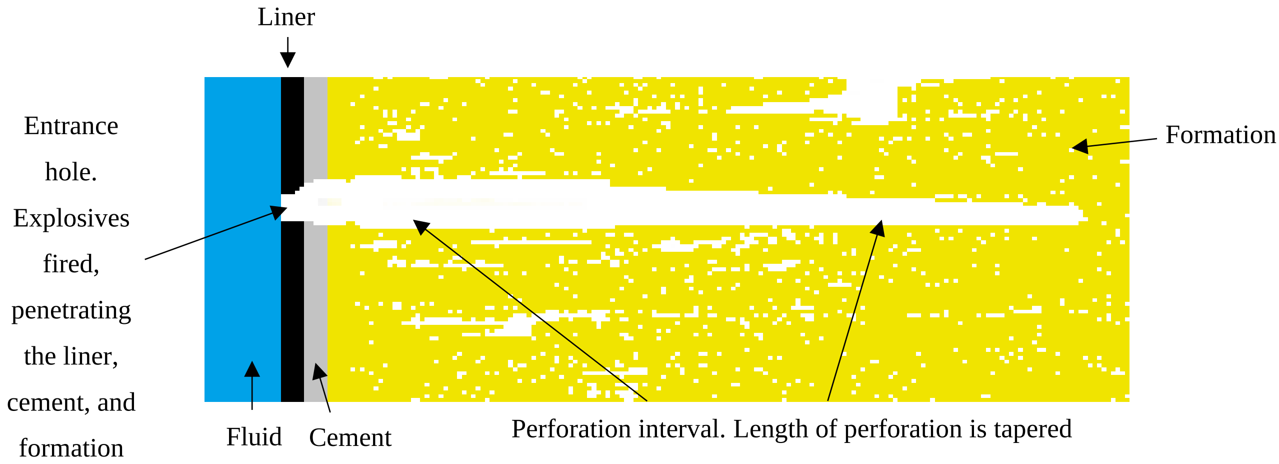


Figure 4-6: Geometry of a perforation (courtesy of Bellarby (2009))

Perforation Performance

In order to design the perforation for a given well, input parameters must be selected. The parameters in Table 4-5 influence the overall well performance. The knowledge of a single perforation shot can be modelled and optimized for a given rock strength, but the combination of a longer perforation interval with multiple shots will be determining the overall productivity.

Table 4-5: Input parameters and description for perforation design (Bellarby, 2009)

Parameter	Units	Description
rw	in	Open hole well radius
h	in	Spacing between perforations (12/shots per foot)
Phasing	Degrees	Angle between perforations
Dp	in	Perforation depth
rp	in	Perforation radius
rc	in	Crushed zone radius around perforation
Kc	mD	Crushed zone permeability
rd	in	Damaged zone radius (from centre of well)
Ld	in	Damaged zone length
K	mD	Permeability
Kd	MmD	Damaged zone permeability
Kv/hv		Vertical to horizontal permeability ratio

Perforation Skin Evaluation

Well productivity is based on skin. Skin is referred to as how the pressure drop in near-wellbore region affects well productivity and injectivity. If the near-wellbore pressure drop is high, the skin is high (Mohammadsalehi, Saghafi, & Teymaarishamasbi, 2011). The skin factor, a variable used to measure the extent of damage, is used to quantify the pressure-drop effect for completion purposes. With respect to perforation productivity evaluation, the combination of skin caused my drilling damage and perforations is important to consider.

Perforation skin (S_p) is measurable and can be calculated. The combination of *horizontal skin* (S_h), *wellbore skin* (S_{wb}), *vertical skin* (S_v) and the *crushed zone skin* (S_c), calculations can be made to generate the overall perforation skin factor:

$$S_p = S_h + S_{wb} + S_v + S_c$$

(Bellarby, 2009)

A high perforation skin demonstrates lower productivity, due to a more damaged well. With a low skin factor, the productivity increase as the well damage is low. The *overall skin* of formation damage and perforations (S_{dp}) can be conducted. When analyzing the productivity of perforations, a common way is to compare it to an undamaged open hole completion (Bellarby, 2009). The *productivity ratio* function as a comparison tool for different parameters. It is important to note that each well case is different. The comparison tool is of great purpose to see how much the perforation can contribute to well productivity. For perforation skin calculations, following parameters can be compared for productivity analysis:

1. **Perforation *depth (Dp)***
- It is essential to penetrate the formation further than the formation damage caused by drilling (Bellarby, 2009). Further perforation length has the potential to result in lower damaged skin factor. Depending on how fatal the damaged zone is, the higher need for the perforated interval to extend the length. If the well is nearly undamaged, the skin factor will initially be low.

2. ***Phasing* of the shaped charges (angle)**
- The angle varies from 0° to 180°. The phasing may be restricted by cables on the outside of casing, pre-determining the phasing due to safety of the control lines (Bellarby, 2009). The overall phasing is simulated to optimize reservoir exposure. It may be necessary to position the guns towards the casing in order to fully achieve deepest penetration (Schechter, 1992).

3. ***Spacing between perforations (spf)***
- The density of shots on the perforation interval, as how many shots per feet or meter. The amount of shots per foot is selected based on gun size and reservoir exposure. According to Schechter (1992), "*in hard formation where deep penetration is difficult to obtain, at least 4 and possibly more shots per foot are recommended*" (p. 230-231).

Important to consider, is that open-hole completions do normally have damaged formation, which is caused by drilling the reservoir. The main goal by using perforation as a lower completion method is to increase the productivity which would be given in an open-hole scenario. By lowering the overall skin factor, it will make the productivity better when bypassing or minimizing the formation damage skin (Bellarby, 2009).

Explosives

The explosives used in a perforation job can vary in performance and stability, often related to exposure time versus temperature. A detonation is required for explosives to penetrate into the formation, which is normally initiated by pressure, temperature, or friction. For a HPHT well, the explosives must be capable of being exposed to higher temperatures for longer periods (Bellarby, 2009). Following explosives are ranged from high to lower temperature stability:

- PYX (*Picrylaminodinitropyridine*) – reduced penetration, but high temperature stability
- HNS (*Hexanitrostilbene*) – comparable temperature stability with PYX, yet higher performance
- HMX (*High molecular weight RDX*) – lower temperature stability than HNS; better penetration performance
- RDX (*Research department composition X*) – Most common downhole explosive

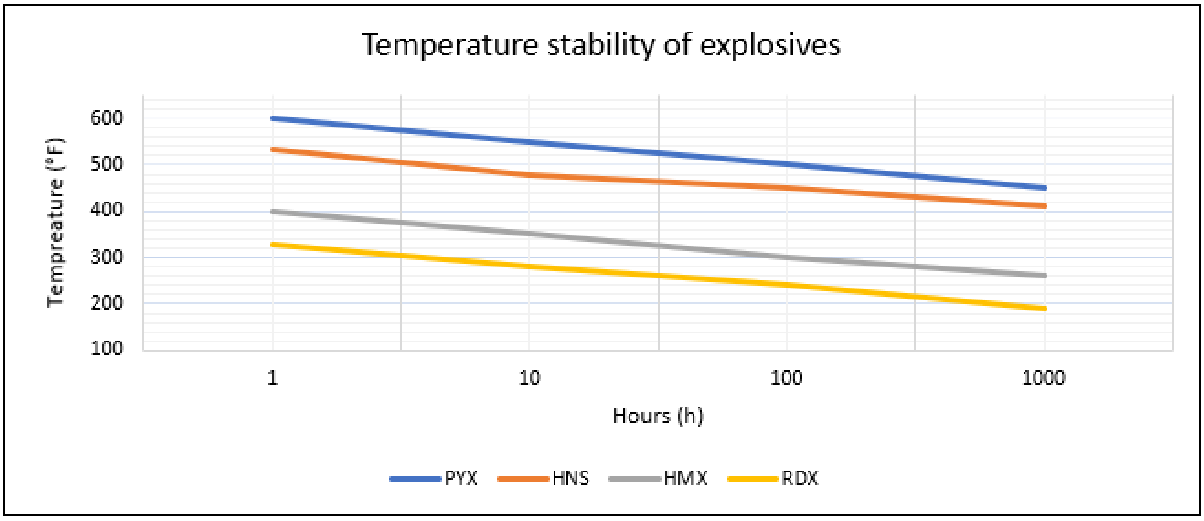


Figure 4-7: Temperature stability of explosives (courtesy of Bellarby (2009))

Over the span of 1000 hours, the explosives power will deteriorate and potentially misfire or not detonate. For electric-line deployment, the hours can be less than deploying guns on the end of a completion. Contingency planning is vital for a perforation job. If the operation must wait on weather for a longer period of time, the stability degrade must be accounted for.

Perforation Debris and Cleanup

The crushed formation combined with charge debris can potentially block the flow path, causing lower productivity. For production purposes, the debris must be removed.

In order to clean out the well after a perforation job is done, an underbalanced pressure regime, or a dynamic underbalanced pressure regime (DUB), is often selected. As the guns are fired in an underbalanced pressure regime, a surge of both formation fluid and wellbore fluid will bring debris away from the perforated area, cleaning the perforations and enhancing the overall well productivity (Robson, 1990). The differential pressure has to be evaluated for optimal performance. In gas wells and wells with low permeability, a higher differential pressure is needed (Schechter, 1992).

If not able to create an underbalanced environment, the perforation-, drilling or completion fluid may impact the perforated interval. Debris may influence the well performance if not removed. The perforation can in fact cause a negative impact on well performance, despite having the purpose of increasing it.

Conveyance Systems

The perforation guns need to be run in hole. The choice of conveyance may depend on:

- Length of the interval to be perforated
- Geometry and inclination of the wellbore
- Size and weight of guns

As previously mentioned, perforation of casing can be performed in multiple ways, all with different advantages and disadvantages. The conveyance systems evaluated for this method selection will be:

- *Tubing-Conveyed Perforation* – guns attached to the end of the tubing, with or without completion barriers in place. The guns have the option to be dropped in the hole after fired or retrieved to surface
- *Wireline-Conveyed Perforation* – perforations performed on wireline with all barriers in place. The guns will have the option to be conveyed through-tubing or with an anchor.

4.3.3 Gun-system Evaluation

Once all the parameters are presented, a simulation software is used to simulate the most optimal composition. Knowing which conveyance system to use, gun size and charge weight can be selected. Thereafter, the selection of phasing angle, shots per feet and potential perforation length will be conducted. When the simulation is completed, the skin factor and theoretical well flow can be obtained. From here, the next step is to optimize the selected input parameters to find the most optimal design. For HS&E purposes, having the permanent completion already in place is assumed when evaluating gun-system for Iris Production well. The selection of guns depends on the following:

1. ***Completion dimensions***. Guns are lowered down on bottom of tubing or through-tubing, meaning they enter the smallest production casing/liner section. The outer diameter (OD) of guns need to be smaller than the inner diameter (ID) of the casing (or tubing).

- The liner size selected for Iris Production well if cemented is assumed to be 7”. This provide a large range of guns to be selected if conveyed on bottom of tubing or anchored. Tubing OD size is set to either 7” or 5 ½”. Through-tubing perforation may need to address the tubing as the limiting factor, adjusting the gun size to provide sufficient clearance. By using a through-tubing approach with wireline, the gun size will be smaller, if a 5 ½” tubing is selected. However, if a 7” tubing is qualified, a through-tubing perspective with upper completion in place can provide same, or close to same, perforation guns as tubing conveyed perforations.

2. ***Perforation geometry***. Natural depletion require deep penetration (Robson, 1990).

- Iris reservoir contains sufficient reservoir pressure to produce hydrocarbons by pressure depletion. Due to sand studies being performed at this time, the conclusion on potential sand production cannot be achieved. Assumption of very little to zero sand production has been made for this thesis. According to Wood et al. (2018),

  “*natural completion wells suit perforating solutions using hollow-steel carriergun systems containing deep-penetrating shaped charges to maximize penetration past the fluid invasion damage, minimize near-wellbore skin, and maximize productivity*” (p. 12).

Due to hard sand with high permeability, a deep penetration should be designed. For natural completions, large charges with reduced shot density provide effective perforating (Robson, 1990).

3. ***Density and phasing***. Perforation-modeling with relevant reservoir properties. A smaller gun size provides less density than a bigger gun size.

- Phasing orientation can vary from 0 – 180°. A study phasing angle must be performed to conclude on phasing angle for maximum penetration. In some scenarios, cables are extended to the tubing, preferably avoided by the shaped charges detonation. In other cases, a phasing angle for highest productivity is selected (Wood et al., 2018). Shot density must be evaluated to reduce the skin but optimized with gun size selection. A 3 3/8" gun may be rigged with the same charges and explosives as a 4 ½" - 4 5/8" gun, but the density (shot per foot) will be decreased.

4. ***Environmental conditions***. Important factor for HPHT well scenario. Guns have limitations with pressure and temperature, and the combined exposure time under these conditions (Robson, 1990).

- Perforating interval highly relevant case for Iris Production well. Should determine and conclude on wireline cable strength limitations or if tubing-conveyed perforation can handle longer shut-in periods. Explosives should be selected to withhold the reservoir temperature for a longer period. Firing-head mechanism need to be simulated to choose most optimal design (pressure-activated or drop-bar-activated).

Gun Size Options

Conveyance systems can carry different gun sizes. Table 4-6 provide the most general gun sizes available for the different liner and tubing sizes:

Table 4-6: Gun size options with 7" and 5 1/2" liner (Hermansson & Low, 2014)

Tubular Design	Tubular ID (in)	Available Gun Size (in)	Recommended spf
7", 35 lbs, P-110	6.004	4 5/8	12
		4 ½	
5 ½", 26 lbs, P-110	4.548	≤ 3 3/8	6

The reasoning for not selecting a 4 5/8" or 4 ½" gun-size for a 5 ½" liner or tubing is because of ID restrictions. As per reviewed in upper completion assessment (chapter 4.5), the use of 5

½” OD tubular requires a thicker pipe due to burst and collapse requirements. The ID of a 26 lb-ft 5 ½” casing is 4.548”. The clearance is minimal making the conveyance of a 4 ½” gun not possible. However, if the cemented liner is 7” and the selected tubing is 7”, the available gun sizes increase. The ID of a 35 lb-ft 7” casing is 6.004”. The biggest gun size is therefore available.

4.3.4 Tubing-Conveyed Perforation (TCP)

By perforating the liner using the tubing, the firing guns will be exported to designated area of interest at the base of the tubing or drill string. The guns then have the option to be released – dumping the fired explosives down in the hole once the perforation is completed or retrieved to surface. The firing mechanism can consist of a differential pressure detonation, absolute pressure, mechanical manipulation, or electric firing system. The sizing of guns using TCP is based on completion design, usually lowest liner, or tubing size. The liner size is 7”, providing selected gun sizes up to 4 5/8”, which allows the largest and best performing shaped charges to be used (Wood et al., 2018).

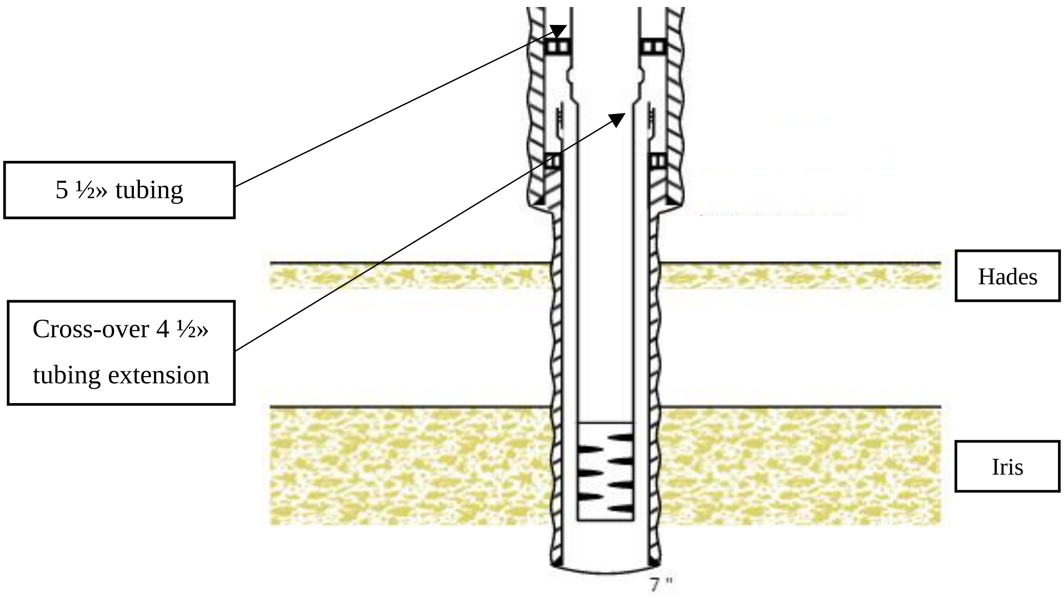


Figure 4-8: Tubing-Conveyed Perforations. Guns in hole attached to tubing

Although a TCP can be performed with a long interval simultaneously, often in a single run, as illustrated in Figure 4-8, the guns are exposed to HPHT temperatures through the reservoir for a longer period. The guns can either be run in hole on pipe with or without the barriers in place. As for the majority of wells on NCS, horizontal perforating is done tubing-conveyed prior to setting the upper completion and reservoir isolation. This is mainly due to longer horizontal section where guns had to be retrieved. For this thesis, the assessment will assume perforation activities with the upper completion and reservoir isolation in place.

In order to not retrieve the guns post perforation, the guns need to be dropped by using a release-tool. The release-tool can be positioned at two locations in the well. First option is to place the release tool just above the guns. This enables the guns to be dropped, but the gun-running string is left above Iris and connected to the end of tubing, as illustrated in Figure 4-9:

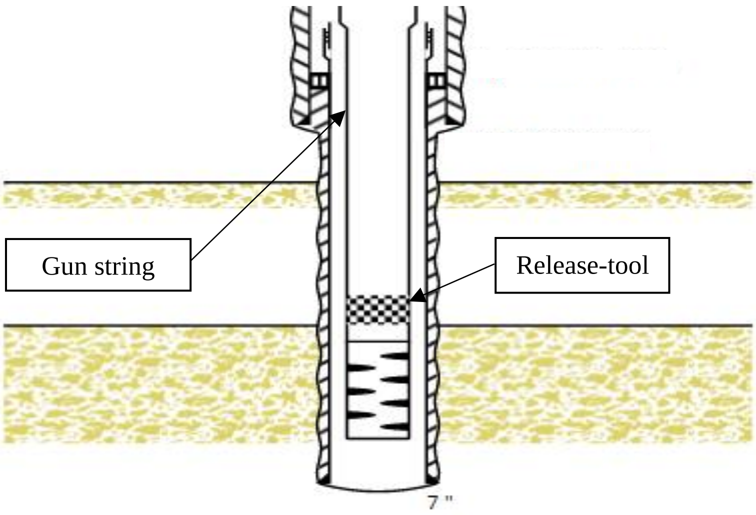


Figure 4-9: Release-tool just above guns

The second option is to place the release-tool just below the tubing tailpipe, as illustrated in Figure 4-10. This provide the entire running-string and perforations to be dropped in hole. However, the need for a longer rathole is required.

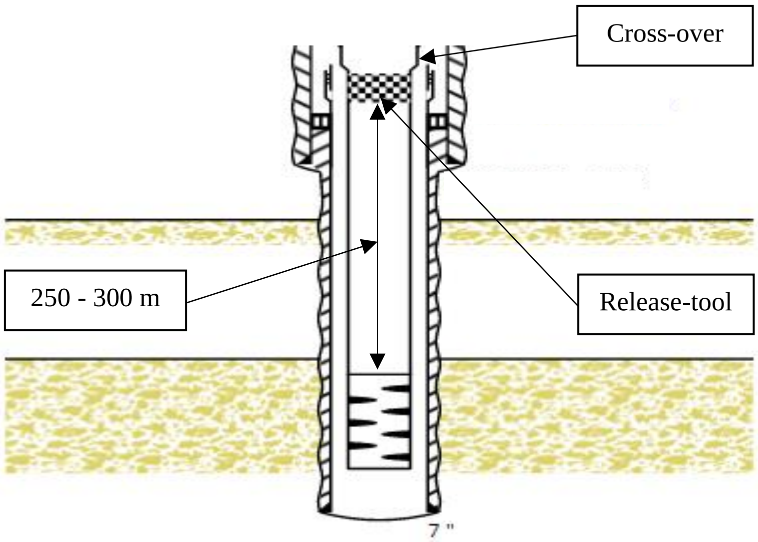


Figure 4-10: Release-tool in crossover 4 1/2" x 5 1/2"

The 8 ½” reservoir drilling section needs to provide sufficient depth for the guns and running-string to be dropped and not limit well production. The rathole must in this case potentially be 300-350 m TVD for the entire running-string and length of guns to be out of the perforated interval.

Advantages

Using a tubing-conveyed perforation with completion means no limit to weight of guns. As the guns are run below the tubing, the only size limitation is the casing ID, making the availability and perforation sizing more viable. Experienced perforation method on the NCS.

Disadvantages

For Iris Production well, the need of lowering the guns down to Iris reservoir means long section of guns and pipe to be dropped in hole. Having the guns at the bottom of a fully installed completion with the risk of misfire or release-tool failure can cause severe challenges for the operation. If decided to perforate before installing the permanent completion, the need for a reservoir isolation assembly needs to be introduced to the completion.

4.3.5 Wireline-Conveyed Perforations (WCP)

Wireline has greatly improved string efficiency and can provide high-strength cables for perforating operations (Aboelnaga, Martin, Ugalde, & Contreras, 2017). By using wireline as perforation gun conveyance, cable tension must be simulated to account for weight limitations to maintain cable integrity. As the weight of guns will influence the tension, the length of

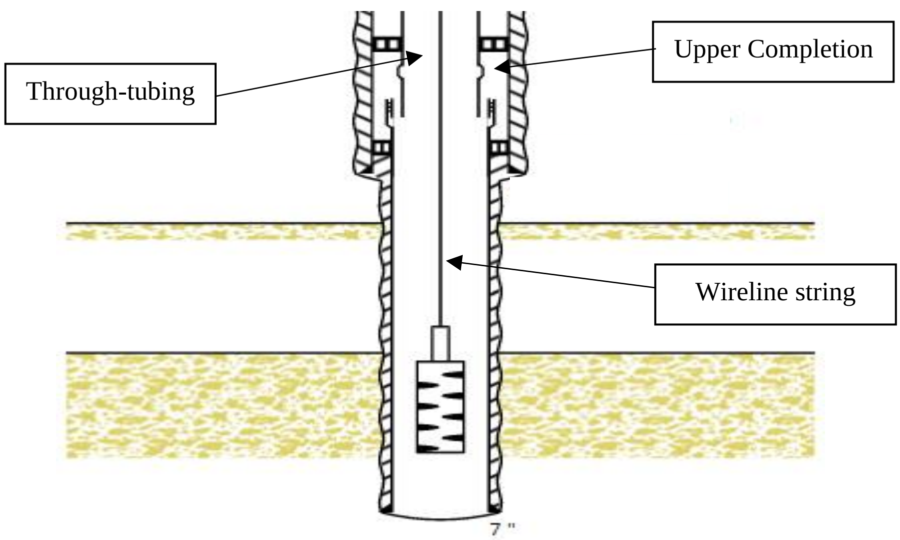


Figure 4-11: Wireline-Conveyed Perforations

perforation interval and gun size will determine the boundaries. If the operator wants to pull the guns to surface post perforating, the maximum overpull capacity must be ensured.

The perforation guns are lowered down in the well on a wireline cable. The guns are conveyed through-tubing and placed in the interval preselected for perforations to be performed. For depth correlation, gamma ray can be installed. For protection purposes, the gun string can be equipped with shock absorbers (Aboelnaga et al., 2017). As illustrated previously in Figure 4-11, the wireline string is lowered in an already sealed reservoir. Hades is behind cement. Upper completion is run in hole, landed, and tested.

There are many risks related to wireline perforation in HPHT conditions. First, the string needs to be qualified for use. Second, gun shock can potentially cause guns to be blown up-hole. To avoid perforating with cable, an option is to lower the guns with an anchor mechanism (release-tool), to place the guns at perforation target prior to running the completion. After the completion is landed, the guns can be pressure cycled up or mechanically manipulated to trigger the detonation, as illustrated in Figure 4-12:

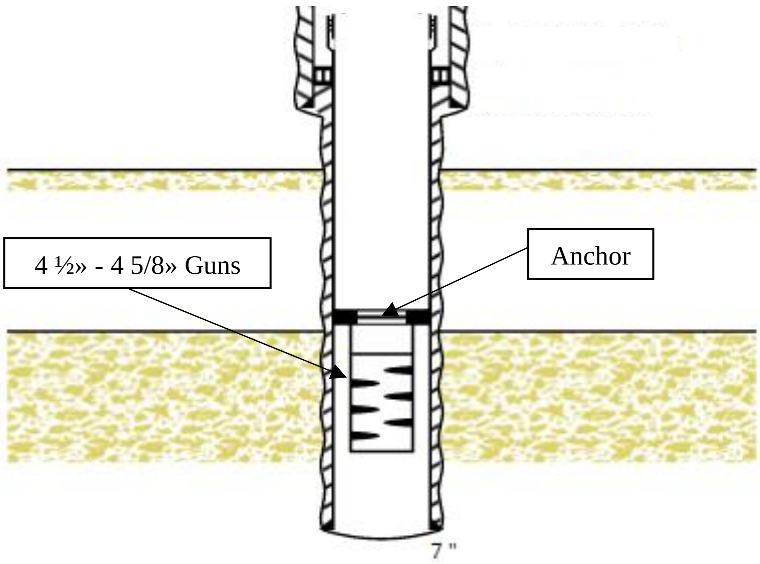


Figure 4-12: Anchored perforation guns

Advantages

Rig-time saving is of great interest due to faster tripping on cable than drill pipe. The use of wireline is a common and experienced operation done offshore, and with improved cable tension strength has become a method for HPHT perforations in vertical wells. Through-tubing perforation can be done with increased tripping speed due to wireline, which will reduce rig-time, alongside having the upper completion already in place, with the ability to pull guns.

Disadvantages

The limitations of wireline are related to length of perforation interval, gun size selection and weight capacity. Wireline is limited to fairly vertical producers with a shorter perforation interval. Cable design and weak points may impair the method in a HPHT scenario. Same scenario as TCP, if the release-tool is malfunctioning, the guns will be stuck in the perforated interval. This may cause highly impactful consequences for well performance. Wireline equipment is prone to leakage, and is in general imposing high safety risk in HPHT well scenarios (Hermansson & Low, 2014)

4.3.6 Operational Readiness: Perforated Liner HPHT Implementation

Cased and perforated liner in a HPHT environment has been performed on several HPHT fields on the NCS. Important experiences have been made:

- Equinor experienced relatively weak permeability and productivity in Garn Formation on Kristin wells. The need to open up the formation to potentially increase productivity made them conclude on perforated liner concept. Majority of Garn reservoirs are assumed to *not* produce sands.
- Both 5 ½" and 7" liner sizes have been used. A variety of gun range (3 3/8 – 4 5/8") has be implemented. Subsea wells have only used 5 ½" tubing.
- Equinor conducted laboratory testing for a more cost-efficient perforation fluid. A cesium formate completion fluid has been proven as a perforation fluid but comes with a great cost. A more economical OBM was qualified, as it was the preferred fluid type for drilling and completion operation (Fleming et al., 2018).
- Both DUB and overbalanced (OB) perforations have been made. On Kristin wells, the OB perforations with OBM showed high uncertainty in potential formation damage (Svela & Wennberg, 2006).
- Morvin Field original well concept was to perforate. The planned operational time was 70 days but was reduced to 49 days with open hole completion. Perforated liner is highly time-consuming operation.

Field Experience

Experience from the NCS show the majority of wells being perforated with pipe. Kristin, Kvitebjørn, Visund, Huldra and Gudrun, all Equinor operated fields have wells perforated on tubing. A reason for this, is the fact that majority of HPHT producers have a high inclination (>

45-60°) or are close to horizontal. Wireline-conveyed perforation will in these scenarios often be inapplicable due to hole angle restrictions.

Table 4-7: Gudrun, Kristin and Iris Appraisal wells perforation experience and results

	Gudrun A-16 well (Platform)	Kristin R-3 H (Semi)	Iris Appraisal (Semi)
Reservoir Properties	776 bara 149 °C Poor, low productivity, average permeability of 15 mD	894 bara 170 °C Garn Fm Relatively low productivity and permeability	755 bara 149 °C Upper Garn good Lower Garn bad Permeability range from 15-45 mD
Production Performance	6000 std m^3/d	-	Upper: 2030 m^3/d Lower: 15300 m^3/d
Liner size	5 ½”	7”	7”
Perforating Method	TCP	TCP	DST / Landing String
Completion Fluid	OBM	OBM	$CaBr_2$
Perforating Fluid	OBM	OBM	NaCl brine
Gun Size	3 3/8”	4 5/8”	4.72”
Geometry	Unoriented 60° angle 6 spf	Oriented 0 - 180° 4 spf	- 72° angle 5 spf
Pressure Regime	DUB	OB	DUB
Explosives	-	HNS	HNS
Skin	8 - 11	8	0,75

Vertical well perforations are less common on NCS than horizontal well perforations. Reasons for that may be the reduction of skin when perforating a long horizontal section. K_v/k_h ratio is highly affecting the completion skin with respect to how sensitive mechanical skin is to the horizontal section. Shorter horizontal section means potentially higher overall completion skin (Bellarby, 2009).

The ability to perform a well-designed dynamic underbalanced is difficult, especially on a semi-submersible. Experiences at Kristin show that the well was perforated overbalanced, with the main goal of performing a dynamic underbalanced perforation. The risk of perforating in overbalance can potentially cause higher formation damage than anticipated.

The installation of a cased and perforated liner contributes majorly to the overall rig day-rate. Statistics from North Sea HPHT platform wells show that cased and perforated wells take up to 20+ more days to install than open hole completions (Olsvik & Hermansson, 2013). For subsea wells, the numbers can be higher. The installation time of wells are relative and may vary, but overall statistics show increased installation time. The time and cost increase for using perforated liner as lower completion method needs to be accounted for.

Fluid Selection

HPHT wells on NCS has been drilled and completed with both particle free brine systems and OBM. During Kristin field development, the low-inclination wells were drilled with cesium formate, mainly due to quick kick detection and low ECD (Gjonnes & Myhre, 2005). For higher inclination wells, the use of OBM was selected due to wellbore instability in shale sections. The brine system experienced high fluid loss scenario, up to 10 times higher than conventional OBM (Gjonnes & Myhre, 2005). OBM introduced other challenges, as of barite sag, particularly if the well is without circulation for days. Kristin experienced wells with original mud weights of 2.05 sg down to 1.80 sg (Gjonnes & Myhre, 2005).

The cost of cesium formate is mentioned in multiple papers as an operational risk related to cost. During Gudrun Field development, after completing the Draupne Fm 1 producer, the potassium/cesium fluid contributed majorly to the total cost of completion (Fleming et al., 2018) . The qualification of more cost-effective drill-in, completion and perforation fluids were therefore prioritized.

The perforation pill/fluid differs from open hole completions. The pill displaced is mainly to prevent fluid loss by creating a filter cake around the perforation tunnels. Perforating fluid is an important consideration for well performance. The use of a clear brine has been implemented due to low chance of plugging perforation tunnels surface, but slowly traded off with a more cost-effective OBM (Gudrun A-16 and Kristin R-3 H testing).

4.3.7 Operational Risks

Operational risks found from field experience is highly related to deviated and horizontal wells. The majority of wells have been perforated without the upper completion and reservoir isolation assembly. If perforated on drill pipe, a well-kill scenario must be applied, potentially increasing formation damage (Bellarby, 2009). If decided to perforate prior to running the completion, the potential of surge, swab and losses is introduced. If the completion has been installed, the perforations is attached to the end on the tubing or drillpipe. In case of misfire, the completion must be pulled or sheared (Bellarby, 2009).

Perforations with wireline can be done pre- and post-upper completion installation. Wireline conveyance risks are related to cable strength and integrity. The cable integrity must be simulated and tested prior to performing the operation. As for the detonation, the generation of gun shock is more common in deep- and high-pressure wells (Sabbagh, Blalock, Melvan, & Leung, 2008). Once the gun carrier is filled with completion fluid, the movement of fluid can create shock waves, influencing the packer and tailpipe of the downhole barrier assembly. The introduction of formation surge from the reservoir post perforations may produce a high impact HS&E risk, as the guns can be rapidly blown up the hole by the reservoir fluids (Sabbagh et al., 2008).

One of the main advantages with perforating is to provide better productivity than open hole completions. If a well-kill scenario by perforating on tubing increases the formation damage, or guns selected by a through-tubing approach does not generate the desired perforation depth, the anticipated productivity may be reduced. The result will be a lower completion method with high cost and under-expected performance.

Insufficient cleaning of debris can potentially limit well performance. By perforating in sufficient underbalanced pressure regime given the expected reservoir permeability, the plugged perforations can be avoided (Bellarby, 2009).

Perforating on a semi-submersible floater can increase the installation time. Compared to open hole completions, the installation procedure may add additional 14-30 days (Olsvik & Hermansson, 2013). For a vertical well, the perforation installations can be less time consuming, but greatly influence the overall cost of a well. Highlighted operational risks are presented in Table 4-8:

Table 4-8: Highlighted operational risks and challenges

High perforation skin and vertical well performance

- HPHT formations has previous experience of being a hard sandstone with high formation stress. The *penetration depth* may be influenced by the high stresses. Penetration penalty is higher in high pressure formations, potentially decreasing the perforated interval depth (Grove, DeHart, McGregor, Dennis, & Christopher, 2019). As the well is vertical, the perforation intervals may be introduced to high stresses, compromising the geometry. The perforated interval will be introduced to vertical stress over time, which may promote sand production.

Explosives selection in HPHT environment

- The selection of explosives highly depend on conveyance method. For a longer type of convance (TCP), a more thermally stable explosive must be selected to withhold temperature for longer periods. By selecting wireline as conveyance method, a less thermally stable explosive can be evaluated, potentially providing higher performance. For example, according to Grove, DeHart, McGregor, Dennis, and Christopher (2019), laboratory testing of HMX and HNS charges provided great outperformance of HMX charges in HPHT conditions (320°F, 1000 bar*)* (p. 11). Naturally, the overburden stress, reservoir pressure and wellbore pressure must implement Iris Production well values and simulate performance.

Conveyance of perforation guns from a floater in HPHT conditions

- Iris Production well is an offshore well with the intention to use a semi-submersible rig for the perforations. The use of coiled tubing is therefore highly unrelevant. Both tubing conveyed and wireline conveyed perforation provide HS&E, well objective and time & cost (T&C) risks. Due to having the permanent barriers in place, the restriction of gun sizes can influence the well performance.

Anchor/Release-tool malfunction

- The release-tool may malfunction post-perforation. The guns will be stuck in perforation interval and limit well flow. The guns limit productivity and require milling to remove. Alternative is to run smaller guns on wireline. This require wireline cable to be qualified.

Cost of selecting C&P as Lower Completion method

- Installing the lower completion can increase the overall cost of the well. The added rig time is correspondant to cementing the liner, perforation job, perforation fluids, debris clean-out. The added time can potentially be 10+ days of rig time (100+ MNOK).

4.4 MIDDLE COMPLETION CONCEPT: DOWNHOLE BARRIER ASSEMBLY

4.4.1 General Concept

A Middle Completion (MC) is referred to as a downhole barrier system in between the lower completion (liner hanger, liner, cement) and upper completion (production packer, tubing, XMT). A MC is a common barrier system with the intention to protect the formation from unwarranted pressure (Fitnawan et al., 2011). As for running the upper completion, the downhole barrier system works as increased safety during the installation. In some situations, the well need to be displaced to a light packer fluid prior to production. The middle completion assembly isolates the reservoir when performing the displacement.

The barrier assembly can consist of a full casing bore packer for annular isolation with an internal plug, normally glass/bridge plug, to isolate both inner string (tubing) and annulus. A Downhole Isolation Valve (DIV) may be used to isolate the inner string, with the intention to isolate lower completion while drilling, displacing, or running completion. A new integrated lower completion barrier system has been qualified and implemented in a HPHT environment. All three types of barrier and flow isolation systems will be analyzed:

- **Middle Completion:** Annular packer with an internal plug (Glass Barrier Plug / Bridge Plug)
- **Middle Completion**: Annular Packer with a Downhole Isolation Valve
- **Integrated Lower Completion barrier assembly**: Liner Hanger Packer with an internal plug (Glass Barrier Plug / Bridge Plug)

The base of the assessment will be a theoretical approach combined with field experience. A HPHT relevant perspective will be highlighted, with the intention to find operational advantages and disadvantages with each method.

4.4.2 Middle Completion: Annular packer with internal plug

Once the completion liner is cemented and perforated, or in open hole completions landed in liner hanger, it provides a flow path for formation fluids into the wellbore. In order to run the upper completion, barriers need to be set to isolate the reservoir. For pressure control, a downhole barrier system is used. The annular isolation consists of a packer element. For older developments as Kristin wells, the preferred annular packer was a permanent packer due to the annular packer working as a barrier for the production interval (Fitnawan et al., 2011). A Glass Barrier Plug (GBP) has been designed with the purpose of establishing inner bore diameter, due to the capability of through-tubing intervention. The GBP is a preferable downhole isolation plug in HPHT environment due to being qualified and rated as an ISO 14310 V0 gas tight seal (Gimre, 2012). As shown in Figure 4-13, a middle completion annular packer and removable internal plug has been used as the downhole barrier assembly.

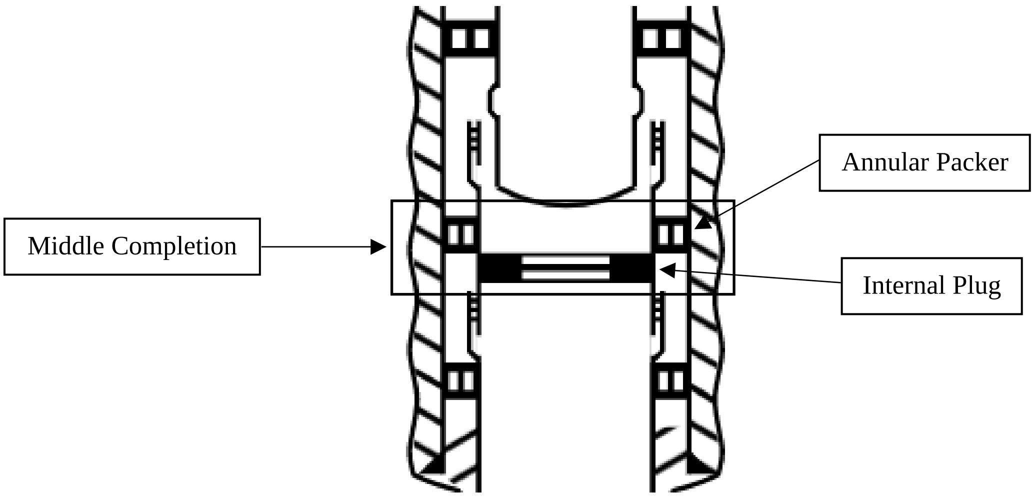


Figure 4-13: Based on Gudrun A-16 Production Well Schematic. Middle Completion. (Fleming, Karunakaran, & Hireche, 2018)

Annular Packer – Sealing Element

The annular packer consists of a sealing element, intentionally qualified for HPHT conditions. According to Ren, Gerrard, Duan, Vu, and Leung (2012), the most normal high temperature-rated elastomeric material in the marked is made of:

- Propylene/tetrafluoro ethylene (Aflas® packers, trademark of Asahi Glass Co.)
- Fluoro elastomer (FKM)
- Perfluoro elastomer (FFKM)

The sealing elements of these elastomeric materials have been tested up to 232 °C and 20,000 psi (1379 bar) (Ren et al., 2012). For operational experience, the Aflas®-elastomer packers has proven sealing capacity in HPHT wells on the NCS with higher temperature and pressure on both Kristin and Morvin Field. However, long-term sealing capacity is still under development and is an important element for well integrity in HPHT wells.

Internal Plug – Glass Barrier Plug

The Glass Plug consists of laminated glass layers and elastomeric seals, illustrated in Figure 4-14. According to Gimre (2012), "*any forces acting on the glass layers are transmitted to the metal body of the plug through shoulders in two of the layers of glass*" (p. 2).

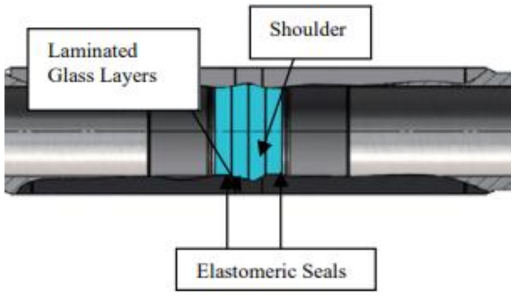


Figure 4-14: First generation Glass Barrier Plug: Glass layers, shoulder, elastomeric seals (Gimre, 2012)

The first-generation plug was upgraded with the intent to increase debris tolerance. To open the plug, pressure cycling can be done manually or electronic. Debris from settled completion fluid or perforation tends to settle on the low side of the plug, restricting the cycling mechanism. The ability to tolerate debris has forced manufacturers to upgrade the plug performance. The newest generation of GBP now accommodate for higher tolerance of debris with an integrated debris extension (Gimre, 2012). For interventional purposes, the plug can be milled out using electrical line with a tractor, coiled tubing, drill pipe or to spear open (slickline).

Internal Plug – Bridge Plug

The need to improve and qualify bridge plugs for long-term HPHT isolation has forced manufacturers to improve the previously developed permanent bridge plug. A bridge plug can be set in a range of casing sizes, with the intention to isolate reservoir pressures unaccompanied, without the need for cement as an additional barrier. The bridge plug is also needed to withhold the pressure differential of downhole conditions, equal to the casing, tubing, or liner it is set (Ruffo et al., 2013). For Iris Production well, the intention is to run the bridge plug on wireline or integrated in the tubing. The need for a reliable plug is crucial for running efficiency, as well as stability and long-term performance. The bridge plug is, as the annular packer, dependent on expandable elastomer. Sealing performance, elastomer availability, corrosion-resistance and a continuous sealing in HPHT environment is important considerations.

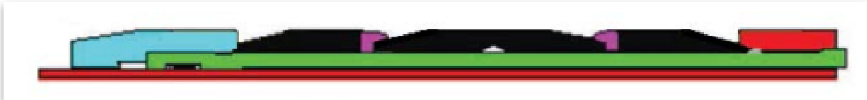


Figure 4-15: Three-Piece Packing Element (Ruffo et al., 2013)

Figure 4-15 illustrate the packer element which consists of elastomer elements that ultimately expands to the casing wall. A pin is sheared by pressure activation, forcing an element to pressure against the elastomer, eventually expanding the elastomer. The introduction of potentially failing elastomer due to insufficient debris clean-up is introduced, alongside the uncertainty of life-time sealing capacity in HPHT conditions.

Installation Procedure

The annular packer element and GBP / Bridge Plug has to be installed in a separate run than the lower completion. Depending on production casing and liner size, the barrier system needs to seal the entire string in order to provide full isolation from the reservoir. The completion can be run on an electric-line (wireline, slickline) or a drill pipe. Once the packer element is in place, it can be triggered by manipulation, expanding the elastomer, providing a seal to the casing. For internal isolation, the glass plug is installed. The plug can be installed with the annular packer or run in a separate run through the packer with wireline. For bridge plug installation, the plug is run on wireline till designated depth. The expanding of elastomer is initiated, locking the bridge plug in place. The downhole assembly is stabbed in the lower completion, isolating the reservoir. Table 4-9 and Table 4-10 lists the installation procedures:

1. **Cased hole Middle Completion** installation, perforating w/o upper completion:

Table 4-9: Cased hole Middle Completion installation

1	• Run liner, cement in place. Perform cement bond logs to verify cement height and quality
2	• Run in hole with perforation guns on tubing. Perforate, kill, and clean well
3	• Run in hole with MC. Install GBP, test and verify. Test and verify annular seal
4	• Displace well to a clear solid-free completion fluid prior to running the upper completion
5	• Run in hole with upper completion. Land in entry guide of middle completion
6	• Complete the well

2. **Open hole Middle Completion** installation:

Table 4-10: Open hole Middle Completion installation

1	• Run predrilled liner, land in liner hanger. Verify landed liner
2	• Run in hole with MC. Install GBP, test and verify. Test and verify annular seal
3	• Displace well to a clear solid-free completion fluid prior to running upper completion
4	• Run in hole with upper completion. Land in entry guide of middle completion
5	• Complete the well

Advantages

The annular sealing elements have been proven in HPHT fields relevant to PL644. Aflas® packers have been set and performed at Kristin Field, and as a contingency isolation method on Morvin Field. The GBP has been upgraded and used in HPHT scenarios on the NCS. The plug provides a non-corrodible seal with high differential-pressure levels, often relevant to the displacement from completion fluid to a light packer fluid. The GBP can be run as an integrated part of the tubing or liner, making it available for both middle completion and integrated lower completion barrier installation.

Disadvantages

Running a Middle Completion is time consuming, potentially adding 4 days of rig time (Fitnawan et al., 2011). The completion method is reliant on pressure cycling to open the plug, which may result in failure. By running an integrated plug with the annular packer, the completion may need to be milled out. By having a permanent annular packer, worst case scenario is to mill out the packer to pull the plug, in case of failing to open.

4.4.3 Middle Completion: Annular packer with a Downhole Isolation Valve

The use of a Downhole Isolation Valve has been implemented on the NCS in HPHT environment, respectively on Kristin Field and Kvitebjørn Field. DIV can be implemented for drilling operations to ensure faster and safe tripping speed by isolating the reservoir, or by isolation purposes when running upper completion (Sasongko et al., 2011).

Internal Plug – Downhole Isolation Valve (DIV)

The DIV can be designed with different opening mechanism - the most common being flapper- and isolation ball-valve. Manipulation of the valve can be done hydraulically, by applying control lines running from surface to the valve. Another option would be to use pressure, by a number of cycles to shear a sleeve which again will move the flapper or ball down (Bellarby, 2009).

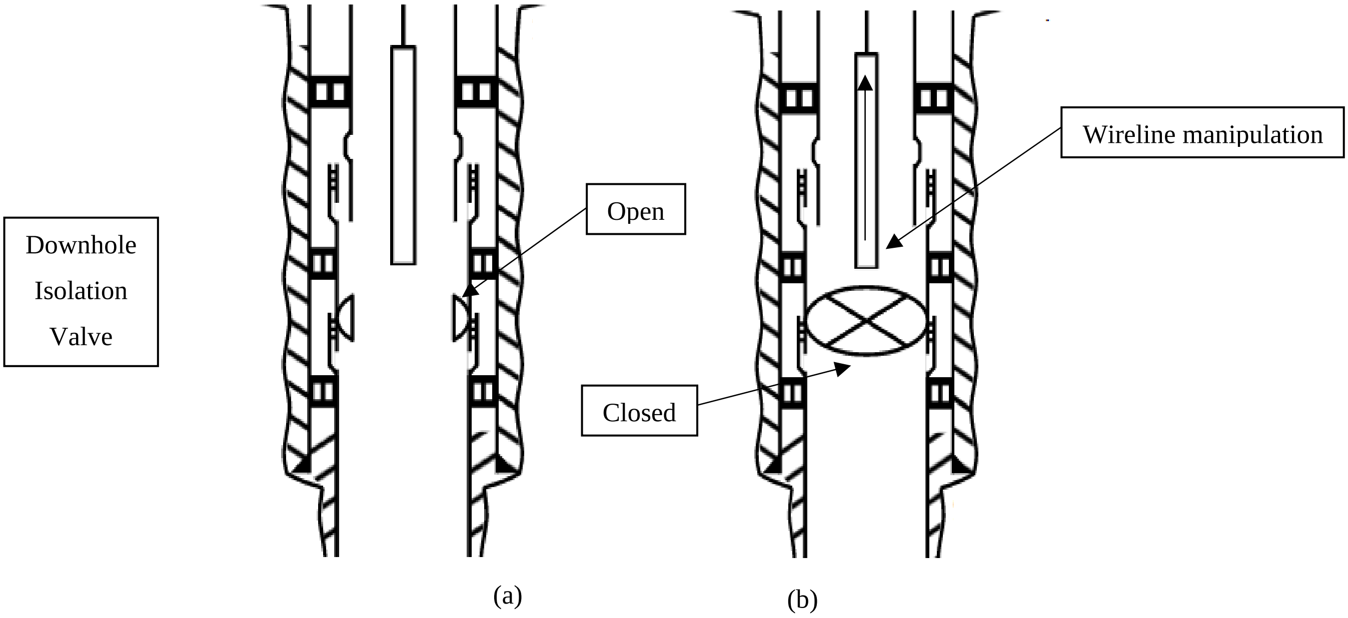


Figure 4-16: DIV. (a): Shifting tool in position to pull up. (b): Shifting tool pulling out, engaging the shifter, closing the valve (Bellarby, 2009)

Another option, as shown in Figure 4-16, a shifting tool can be to mechanically push the sleeve in position. This shifting mechanism can be a flapper or ball. If unable to pressure or hydraulically open/close the valve, wireline can be used to mechanically override.

Installation Procedure

For completion purposes, the valve can either be run with the production casing, or as an integrated middle completion component. As for reference completion wells, the DIV has been used to isolate the inner string (tubing). If the installation process involves an open hole completion, the installation procedure would be like presented in Table 4-11:

Table 4-11: Middle Completion OH installation with Downhole Isolation Valve

1	• Run predrilled liner in hole, land in liner hanger
2	• Run the MC with annular packer and DIV. Mechanically close the isolation valve
3	• Inflow test or pressure test downhole barrier assembly for integrity
4	• Perform cleaning and fluid displace. Area below middle completion should now be sealed
5	• Run upper completion, land in tubing hanger and stab in middle completion entry guide

Advantages

The isolation valve provides internal string isolation which can be used both in drilling and completion operations (Sasongko et al., 2011). DIV can be manipulated in many ways as to open and close the valve; hydraulic control lines to surface, pressure cycling or mechanical intervention with wireline.

Disadvantages

The use of DIV in an HPHT environment has a weak track record on NCS. During Kristin Field, 4 out of 6 installations failed (Fitnawan et al., 2011). The mechanism to open or close the valve can malfunction, making the operator unable to control valve position. The need for milling operation might be required if the valve fails to open in a stuck position.

4.4.4 Integrated Lower Completion Barrier Assembly (ILCBA)

By securing both annular and internal space within the lower completion, the need for a separate Middle Completion can be eliminated. New downhole barrier assemblies and equipment are being qualified for use in HPHT environment, making the barrier situation different from today's wells compared to older HPHT wells, for example Kristin and Kvitebjørn. A new downhole barrier assembly consist of an ISO 14310-V0 verified liner hanger-packer with an integrated plug nipple, all which sits on the liner. The annular packer, which normally is run with a Middle Completion, now consist of a sealed liner hanger located at the top of liner. The internal seal consists of a retrievable plug, where the plug will be run in with wireline. Figure 4-17 illustrate both annular and internal seal:

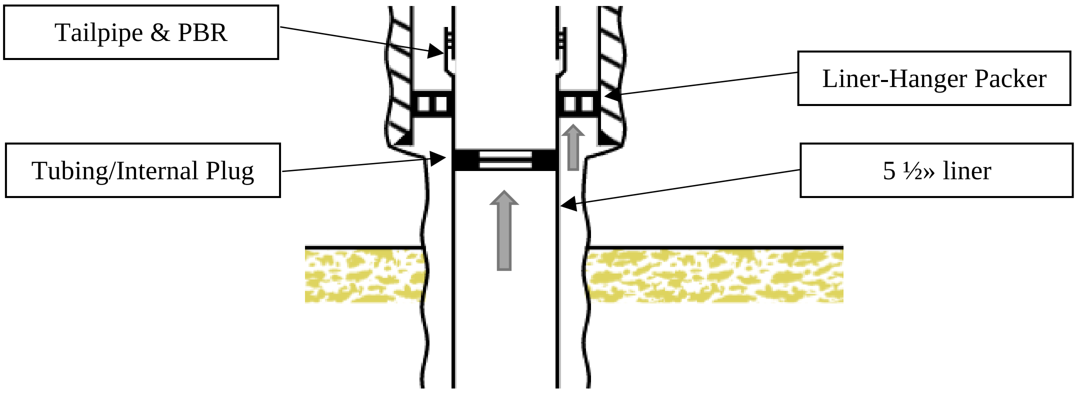


Figure 4-17: Integrated Lower Completion barrier assembly

Annular Sealing – Liner Hanger Packer

Technology evolution in liner hanger systems has provided gas-tight and sealing liner hanger systems, with the intention to provide reservoir isolation. The hanger can consist of a conventional liner or expandable liner hanger system. The use of a liner hanger/packer solution is mainly used to avoid running a separate barrier assembly – the Middle Completion.

Liner hanger-packer solutions contains elastomeric sealing elements on the outer diameter, which is sealed towards the casing. A conventional liner top (Figure 4-18) normally requires mechanical manipulation to utilize slips and cone components, which require interpretation of the slips onto the cone. The weight of drill string will initiate the sealing element to generate the annular seal between liner top and casing (Royer & Turney, 2019). For expandable liner systems, the annular sealing is similarly generated by elastomeric sealing, but without the slips system presented in a conventional liner hanger packer. Instead, hydraulic pressure is initiated to move an anvil through the hanger body inner diameter (Royer & Turney, 2019). The interference between hanger body and the anvil results in radial growth of the liner hanger, which again results in interference with the casing. The anvil is retrieved with the running tool.

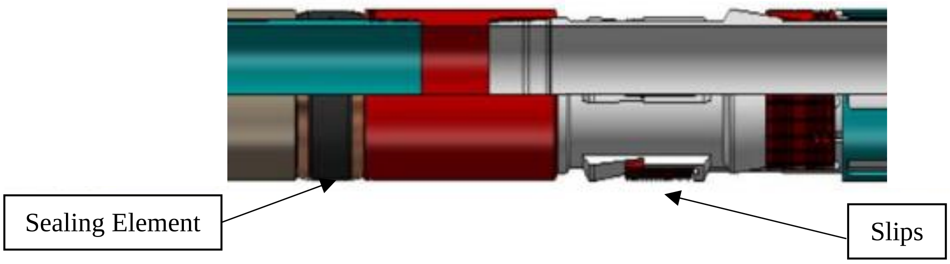


Figure 4-18: Conventional Liner Hanger Packer (Royer & Turney, 2019)

Installation Procedure

The integrated lower completion can be used in both open hole and cased hole completions. Wireline is needed to run the internal plug after the liner hanger packer has been pressure tested for integrity. The completion sequence for open hole completion illustrated in Table 4-12:

Table 4-12: ILCBA installation for open hole

1	• Scrape casing, displace well from drilling fluid to liner-running fluid
2	• Run lower completion string with liner hanger packer. Set liner and packer, pressure test same
3	• Run in hole with plug on wireline, set plug. Pressure test lower completion downhole barrier
4	• Run upper completion assembly - prod packer, tubing, T/P gauges. Land, lock and test TH
5	• Pressure and inflow test upper completion

Advantages

The elimination of MC can potentially save 4 days of rig time, as the separate MC run is no longer needed. New technology can justify integrated lower completion barriers for HPHT scenario. The assembly is intervention capable, with no inner diameter restrictions. Eliminates an additional MC run.

Disadvantages

The barrier assembly is quite unexperienced and has newly been tested in an HPHT field development. Contingency planning if failure to retrieve inner plug will add complexity to well proposal. If the liner size is 7” and tubing size 5 ½”, the internal plug adds complexity to the operation if to be set in the liner, due to tubing size restriction.

4.4.5 Operational Readiness: Downhole Barrier HPHT Implementation

All the three mentioned downhole barrier systems have been implemented on the NCS. Information about success rate is presented in Table 4-13. Highlights:

- Remote-operated DIVs failed on 4 out of 6 installations on Kristin.
- Pressure-cycled isolation ball-valve failed during Kvitebjørn 34/11-A-9 T2 well
- 2 of 4 installations failed to land and pressure test V0-rated liner hanger packer at Morvin Field development. Contingency plan to run MC was initiated.

Table 4-13: Downhole Barrier assembly experience on the NCS

	Kvitebjørn 34/11-A 9	Gudrun A-16	Morvin Field	Unit
Pressure	770	776	819	bar
Temperature	160	149	162	Celsius
Reservoir Depth	4000	4200-4700	4650	m TVD
Lower Completion	C&P (perforated pre-upper completion)	C&P (perforated pre-upper completion)	OH	-
Annular Barrier	Middle Completion Packer	Middle Completion Packer	Gas tight Liner Hanger Packer	-
Contingency	Punch hole Mill valve due to low productivity	-	Ran Middle Completion in 2 of 3 wells	
Internal Barrier	DIV	Glass Plug	Plug-prong	-

Field Experience

During Morvin Field development, a HPHT field close to PL644, it was decided to run with the integrated lower downhole barrier assembly. The V0-liner hanger packer failed to provide sufficient pressure test, which occurred in two wells. The operator decided to run an extra bottom up circulation, but liner hanger packer would not obtain positive pressure test. The contingency plan had to be implemented (MC), causing the operation to require 3 more days of rig time.

During Kristin Field completion development, the design involved Downhole Isolation Valves in multiple production wells. The use of a remote-operated DIV failed in 4 out of 6 installations. During well 34/11-A-9 T2, the isolation ball-valve was stuck in a closed position. The operator was not able to cycle open the valve by applying pressure and tried mechanically to force open the valve by wireline. After several failed attempts, the decision was to punch holes in the pipe above the valve. The production would then be routed around the DIV, through the annulus, in between the 9 7/8” casing and 5 ½” tailpipe. The performance was poor, and the decision was made to mill out the valve with coiled tubing (Ridene et al., 2012). Figure 4-19 illustrate the re-direction of flow as the valve is closed. The pre-perforated joint let flow into annulus before entering the tubing above the closed valve by punched tailpipe.

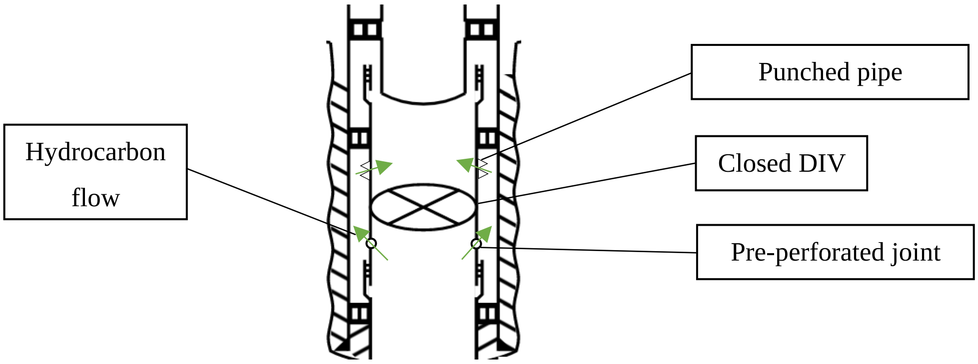


Figure 4-19: Based on 34/11-A-9 T2. Well Completion schematic (Ridene, Stragiotti, Holst, Baardsen, & Effiong, 2012)

4.4.6 Operational Risks

The use of a Middle Completion barrier assembly in an HPHT well before running the upper completion when perforating is common and used on NCS. For open hole completions, the use of downhole barrier assembly is crucial to maintain well control for completion running purposes. However, the implementation of a barrier assembly means added rig-time and can in some scenarios be prevented. Running middle completion means adding a separate barrier run, which again introduce potential surge/swab effects. The risk of well control instability and formation damage may increase. New technology can look promising to save time but may add risks related to reliability and qualification. Operators look into the solution that provide the lowest cost, but still provide a safe and reliable environment.

Debris settlement on the plug may compromise plug reliability. Not capable of retrieving the plug can potentially cause major implications. Previously experienced, the need to mill or remove the internal valve is a time-consuming operation. For ILCBA in open hole completions, this will further complicate the operation. If a milling operation is required, the exposure of Hades may introduce cross-flow. The need to set additional isolation packers will introduce more leak paths and adds operational risk.

If decided to run a 7” liner, limitations of tubing sizes may create plug-running restrictions. If tubing size is set to 5 ½”, running ILCBA plug in the liner will be more complicated due to tubing being smaller than the liner. If decided to go for a bottleneck design, retrieving the plug from the liner will greatly introduce operational risk. Middle Completion adds additional time to the operation. Time and cost will naturally increase with an additional run. The evaluation of cost saving with running ILCBA versus the additional time to run the MC is influencing the selection.

Table 4-14: Highlighted operational risks and challenges

Installation time and cost

- The integrated lower completion barrier assembly can be run together with the lower completion. This eliminate the need to do a separate run, the Middle Completion.

HPHT reservoir exposure time

- If decided to run a middle completion downhole barrier assembly, the exposure time of both reservoirs will be longer. The downhole barrier assembly should be set as fast as possible to isolate the reservoirs. Once the reservoirs are isolated, the upper completion can be run.

Failure of acessing internal plug/valve

- Once the downhole barrier assembly has been set, excess debris can settle on top of plug or valve. Debris is a huge contributor for downtime related to well completion, as completion tools are not designed to be operated in debris-filled environment. Failure of acessing and pulling plugs and closing/opening isolation valves is a major risk for reservoir isolation barrier assemblies

Life of well sealing capacity of elastomers in HPHT conditions

- Elastomer sealing in HPHT conditions have been proven for conditions up to 20,000 psi and to 232°C. However, sealing capacity over a life-time of a production well in HPHT conditions lacks field experience. For equipment bigger than 5 1/2", sealing qualification is lacking.

Running downhole barrier assembly can increase formation damage due to surge and swab effects

- Running string in hole may generate instabillity issues in a HPHT well. The Middle Completion barrier assembly has tight ID restrictions, making the surge and swab pressure differential a point to consider. If running a Middle Completion, the liner has already been run. This means two full running procedures.

4.5 UPPER COMPLETION CONCEPT – TUBING AND PRODUCTION PACKER SELECTION

4.5.1 General Concept

The upper completion consists of all necessary tools in between the tubing string to the tubing hanger and XMT. Once the lower completion and downhole barrier assembly has been set, the remaining of the completion can be run in hole. First, the production tubing is lowered in the hole. Working as an annular seal, the production packer is run at a designed setting depth. The production packer in HPHT wells have from previous, older fields been a permanent solution with the intention to withhold high pressure and temperature differentials. New technology is making retrievable packers available for use. Pressure and temperature gauges can be of great importance in HPHT wells, and can be installed above the production packer for monitoring purposes. A safety valve, Tubing Retrievable Surface-Controlled Subsurface Valve (TRSCSSV) is installed just below the mudline. The string is run in hole with the intention to sting into the PBR, which connects the lower/middle completion to the upper completion. Upper completion is finished with the landing of tubing hanger in the XMT. The well can then be completed and prepared to flow.

For the upper completion method assessment, the following will be analyzed and further investigated:

- **Tubing size** and **material** selection. Analysis of **5 ½"** and **7"** tubing, with the intention to present general material qualification and considerations.
- **Permanent** production packer versus **retrievable/removable** production packer.

The combination of field experience and assumptions will deduct the upper completion assessment. Components as pressure/temperature gauges, safety valves, tubing hanger and XMT will be assumed qualified and implemented in the operation. The assessment covers a general description of tubing size selection for subsea HPHT wells and the innovative changes of packer solutions. Elastomeric sealing and liner-top packer solutions has been previously reviewed in chapter 4.3. Chapter 4.4 will generally focus on production packers, and the difference between permanent and retrievable solutions in regard to previous field experience on the NCS.

4.5.2 Tubing Design Selection

As the casing design is often decided at an earlier stage, the first step of tubing design is the size. A production engineering study (analytical approach) will be performed. Available data will then be selected to simulate the most optimal flow with different tubing sizes. The well trajectory, fluids and reservoir properties all come together to simulate the highest productivity index and flow rate (Shahreyar & Finley, 2014).

Manufacturers provide tubing design criteria for different types of tubing size and strength. Based on the output of thermal simulation (thermal and stress-analysis), the data obtained is put in a tension and compression "limit-envelope", as shown in Figure 4-20:

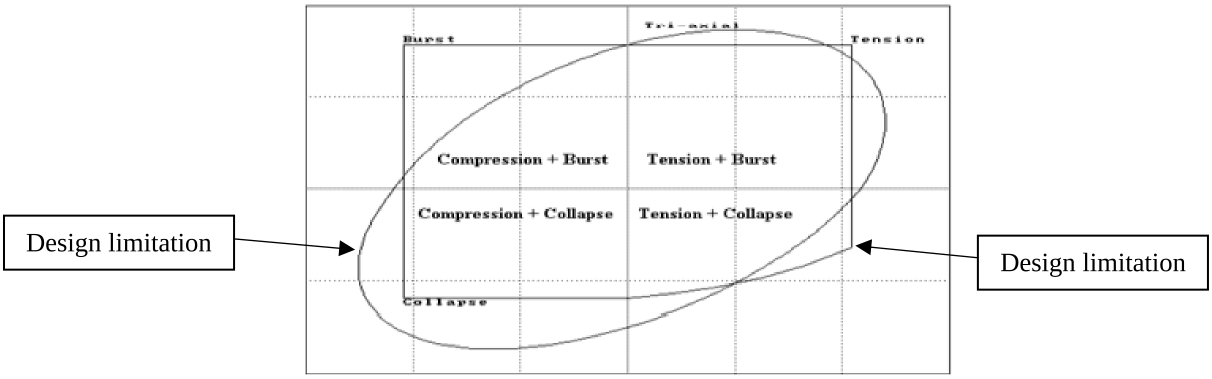


Figure 4-20: Tubing design limit envelope. General presentation (Shahreyar & Finley, 2014)

The output is the calculation of pressure profiles at vertical depth of tubing. Pressure profiles are used to determine not only for the tubing. According to Shahreyar and Finley (2014) the pressure profiles estimate "*also for the tubing material selection, packer selection, seal-assembly design, design of surface facilities, and design of stimulation treatments*" (p. 3).

Tubing Material Selection

There is a balance between conservatism regarding reliability and potential of relatively small recovery when selecting material for HPHT. A general approach is to first get to know the corrosive levels experienced in previous wells to conclude on expected values. For Iris Appraisal, the H_2S and CO_2 were 5 ppm and 3% respectively, with a pH of 6.5 average obtained from the DST's. For guidelines regarding material selection for use in H_2S-containing environments, the NACE MR 0175 / ISO 15156 recommendation can be used to select proper design. The selected material will then be implemented in tubing design simulations to see if the grading can withhold the pressure profile. Performance of materials is governed by:

- In-situ pH and chloride concentration of the produced water phase
- H_2S and CO_2 concentrations of produced fluids
- Temperature of produced fluids

(Zeringue, 2005).

The material selection can consist of following approaches:

1. Economical approach - availability at low initial cost
2. Literature approach - manufacturers knowledge and paper documentation
3. Test program – qualification or testing in adequate environment to optimize and conclude
4. Limited test program after reviewing available literature of few CRA candidates

A limited test program (point 4) for new HPHT applications can provide a cost-effective design. A full test program (point 3) may result in longer time and higher cost (Brownlee, Flesner, Riggs, & Miglin, 2005). Without the ability to simulate tubing design, assumptions have to be made. Morvin Field completed four production wells with similar, pressure, temperature, and corrosive environment as PL644. Equinor, the operator at Morvin, based their design of a partial pressure of 0.01 bar H_2S and a pH between 4.4 – 4.7, which concluded on a slightly sour service region of 1 (see Figure 4-21). The need for corrosion-resistant alloys (CRA) was required. Table 4-15 is an overview of what operator Equinor used at Morvin, Gudrun, Kvitebjørn and Kristin:

Table 4-15: Tubing design properties at HPHT field on NCS

Tubing Design	Morvin Field	Gudrun A-16	Kvitebjørn 34/11-A9 T2	Kristin R-3 H	Iris Production well
Size	5 ½”	5 ½”	7”	5 ½”	5 ½” or 7”
Well Type	Subsea	Subsea	Platform	Subsea	Subsea
Material	Super 13%	13%	13%	13%	Super 13% - 13%
Grade & weight	Cr-110, 26 ppf	CRS-110, 26 ppf	Cr-110, 35 ppf	Cr-110, 26 ppf	Cr-110, 26 ppf or 35 ppf
Connections	Premium M2M	Vam Top HC	-	-	Premium M2M

For Iris Production well, the assumptions will be based on fields with similar reservoir properties as Hades/Iris. A 5 ½" or 7" tubing with corrosion-resistant alloys is a natural decision point to bring into further considerations. Note that it is unrealistic and not accurate to only base tubing selection on offset wells. Simulations may show other values making a bigger or smaller tubing design more suitable with regard to production. The actual measurement from Hades/Iris field can be very different and should be taken into the consideration. Relying too much on similar field data may affect the material selection process in a negative way.

Design Considerations: Downhole Corrosion

The challenge with material selection is to find the optimized design by implementing as many accurate considerations with regards to downhole conditions. In general, a high-strength tubular with high yield-strength is required to withhold high burst ratings due to high pressure differentials and extreme load cases.

Carbon dioxide (CO_2) *corrosion,* also named sweet corrosion, exposes metal to carbonic acid causing potential damage. The corrosion rate increases up to approximately 200 °F, before declining. The corrosion rate is picked up again at roughly 400 °F. By adding chromium to the steel, the potential corrosive damage is greatly reduced due to presence of chromium oxides. For CO_2 purposes, if present and below a pH of 4, martensitic steel may suffer from pitting (Brownlee et al., 2005). The challenge with selecting the amount of chromium to add is how the corrosion rate develops with increased temperature. For instance, at 300 °F, 13%Cr is substantially lower than 9%Cr, but reaching temperature up to 400 °F, the 9%Cr provide less corrosion rate per year than a 13%Cr (Bellarby, 2009). For Iris Production well, looking at a **13%Cr** would be natural for further investigation.

Hydrogen sulphide (H_2S), potentially causing pitting of steel due to produced fluids reacting with steel. Pitting is fortunately rare and is infrequently introduced as a concern. Sulphide stress cracking (SSC) is cracking of material in relatively low concentrations of sulphide. The presence of hydrogen sulphide define regions identified as "sour service", with regions from zero to three. The range is based on partial pressure of H_2S with the corresponding pH. Generally, the higher sour service region and presence of H_2S, the higher chance of sulphide stress cracking on high-strength tubulars. This is where the presence of H_2S combined with high burst potential and worst-case scenario in HPHT wells and CO_2 considerations require specific considerations. Figure 4-21 represent the sour service regions:

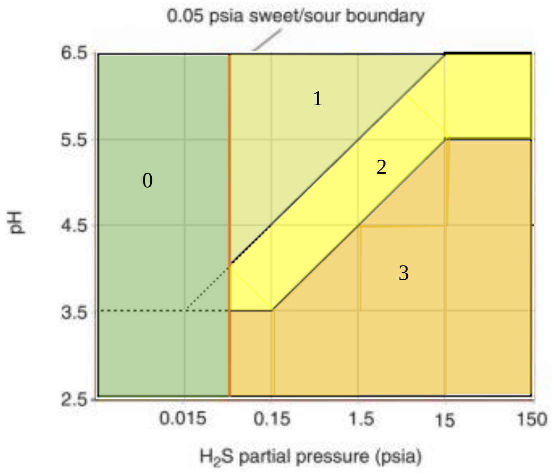


Figure 4-21: Sour service regions (courtesy of Bellarby (2009))

The DST at Iris Appraisal gave accurate measurements on expected environment. The use of a martensitic stainless-steel type, for example 13Cr, could provide difficulties with regards to crevice corrosion and cracking in general at higher temperatures (Brownlee et al., 2005). It is, however, controversy over limitations set by manufacturers and NACE MR 0175/ISO 15156 with temperature limitations and cracking. In particular, the Super 13Cr has been selected as a sufficient resistant alloy for Morvin Field production. According to (Fitnawan et al., 2011), "*Super 13%Cr-110 grade tubing has been widely used in HPHT wells because it can play as an intermediate role between conventional 13%Cr and duplex stainless steels with regards to both corrosion resistance and the material cost*" (p. 2-3). The need for a high strength alloy (P-110 or Q-125) is often common and necessary to fulfill the load cases that require high burst and collapse requirements (a "hot"-shut in and tubing leak with heavy packer fluid). The presence of CO_2 requires special attention to introduce chromium to the steel. Based on the level of H_2S and pH level, the need to down-grade yield strength to compensate for potential SSC will naturally put the tubular so the test when putting all the parameters together.

Based on available field experience, two tubular sizes will be further investigated. When selecting tubing size, all relevant load cases to HPHT conditions should and need to be implemented to account for well integrity during life span of the well. The chance of a showstopper concerning tubing size may limit the use of a 7" tubing, but for investigational purposes with regard to method selection, a general selection will be presented in chapter 4.5.4.

4.5.3 Production Packers

The production packer has multiple functionalities. The most obvious is isolating the annular space between production tubing and casing. The packer also contributes with stabilization with respect to tubing movement. Forces from tubing is transferred to the packer, and into the casing string (Bellarby, 2009). It is important that packer simulations are done with respect to HPHT conditions in order to qualify the packer for use. The ISO 14310-standard rating has multiple grading standards (V6-V1) which require testing in worst-case scenario environment. For HPHT specific considerations, a special standard (V0) utilizes testing the element in a gas-filled environment with axial loads and temperature cycling. Retrievable packers require testing of the retrieving mechanism (Bellarby, 2009).

Packer Design

Packer selection for HPHT wells provide a certain philosophy when it comes to designing the system. The focus will primarily be on well control, and how to maximize well integrity with acceptable time and cost. The HPHT packer design has been primarily focusing on minimizing downhole equipment and moving parts. The elastomers need to be qualified and tested for completion fluids and a higher differential pressure. Fluid selection suggests a higher compatibility of packers to accommodate for heavy brines, OBM and produced fluids.

Production packers for HPHT environment has grown in availability. During Kristin Field development, the only available production packer type was *permanent packers* (Fitnawan et al., 2011). If the permanent packer prematurely sets, a milling operation is needed. The top part of the packer is then milled out before pulling the remaining body to surface.

The use of a *retrievable packer* would in theory avoid a milling operation if a workover is scheduled or pulling of the upper completion. During the Morvin Field development, the decision was to use a retrievable HPHT packer. The packer was at that time newly been qualified and rated in accordance with ISO 14310-V0 grade. By cutting the mandrel inside the packer, the packer would release and be pulled to surface with the tailpipe (Fitnawan et al., 2011). The qualification testing of *removable packers* is increasing and are packer systems that can be used in offshore deep-water wells (Triolo, Anderson, & Smith, 2002). The retrievable and removable packers count as retrievable packers, as they have the ability to be retrieved from the well, as opposite to the permanent packer.

Installation Procedure

Installation process of a packer will briefly be explained due to functionality and use with different completion methods:

1. ***Hydraulic set packer***. A packer can by hydraulically set, which means a nipple can be installed below the packer. A plug is run beforehand, securing conditions to hydraulically set the packer with differential pressure between the tubing and annulus. Eventually, a ball can be dropped to isolate and pressure up against. By using hydraulic set packer installation procedure, care must be taken if expansion device is located between the plug and packer. Upward piston force can potentially move the packer upwards while setting, making the actual depth of packer unreliable. For HPHT wells, the use of a hydraulically set packer has an advantage due to reduced tubing buckling during hot production due to pre-tension when setting the packer.
2. ***Hydrostatic set packer.*** By use of atmospheric chamber pressure differential to the tubing, the packer can be set. The packer in this scenario can be modified to set at absolute pressure predetermined before running. Lower completion packers (middle completion annular packers, liner hanger packers) can benefit of this method, if isolation form reservoir is maintained (unperforated liner).

(Bellarby, 2009)

Advantages

A ***permanent*** packer provides more reliability in hostile environments (Triolo et al., 2002). The packer consists of less moving parts, provide simplified installation, and is mainly selected as a proven barrier and seal with regard to cost and integrity. The permanent packer is an experienced packer solution for HPHT completions.

Retrievable packers provide more flexibility for the well with regard to removal opportunities. If retrieving the packer is anticipated to be repeated during the life span of the well, the retrievable packer provides great flexibility and intervention compatibility. ***Removable*** packers provide one-trip setting mechanics and easier removal of packer if prematurely set while running in hole. The insurance of removability makes the packer flexible. The removable packer system has been qualified for V0 ISO 14310 ratings. The design is comparable with permanent packer with the ability for easier removal (Triolo et al., 2002).

Disadvantages

If upper completion needs a workover or the packer prematurely sets while running in hole, the permanent packer require milling for removal. A milling operation is time demanding and require more equipment, personnel, and rig-time.

A retrievable packer provides specification limitations with internal diameter when it comes for internal bypassing or retrieving the packer (Triolo et al., 2002). The use of a retrievable packer in HPHT scenario is relatively new and require field testing to validate reliability. The removable packer requires more field-testing to provide reliability as for cutting specific metallurgies. As the removal of the packer is operated through-tubing, the ID restrictions may influence the operation due to limitations of retrieving tools.

Field Experience

The use of production packers has during HPHT field development provided mixed experiences. During Kristin Field development, the use of permanent packers was experienced to prematurely set in three cases. The reasoning for why the packers prematurely set is linked to the operational specter of running completion in harsh weather on a semi-submersible floater. Well cleaning and casing scraping has been evaluated to possibly improve packer running efficiency (Fitnawan et al., 2011).

Morvin Field development qualified and implemented a new retrievable packer with anti-preset mechanism. The packer itself could be retrieved by cutting operations through-tubing. It was not reported of any premature setting of the packer during Morvin Field development (Fitnawan et al., 2011). A summary of advantages and disadvantage is presented in Table 4-16:

Table 4-16: Summary Packer: Advantages and Disadvantages

Packer Type	Advantages	Disadvantages
Permanent Packer	- High reliability once packer is set - Less moving parts, simplified installation - Robust and suitable for HPHT completions	- Milling operation required to remove packer
Retrievable Packer	- Provide greater flexibility - Easier to remove/replace in case of prematurely set - Intervention compatible	- Internal diameter limitations - Field experience in HPHT scenario
Removable Packer	- Robustness of a permanent packer and flexibility of a retrievable packer - Qualified ISO 14310 V0 rated packer - Easier removal of packer in case of prematurely set	- Require more field testing in HPHT environments - Through-tubing removal, ID-restrictions

4.5.4 Operational Readiness: Tubing and Packer HPHT Implementation

When selecting a tubing candidate for this thesis, the considerations will be as following:

- Tubing leak and "hot shut-in"
- Can the tubular provide a high yield strength measured with the highest Shut-In Wellhead Pressure (SIWH) with safety factor to account for potential burst and collapse?
- How much will temperature degradation affect the tubular yield strength?
- Reservoir properties and production potential
- Intervention compatibility and equipment limitations for HXMT subsea wells

Iris Production well is expected a maximum SIWH to be 755 bar. Adding the safety factor of 1.1, typically for burst and collapse requirements, the minimum SIWH the tubular must withhold is 831 bar. According to Table 4-17, which refers to Baker Hughes, a GE company technical information handbook (Baker Hughes, 2018), two sizes are presented:

Table 4-17: Tubing selection (Baker Hughes, 2018)

Size (in)	**Weight w/coupling** (lb-ft)	**Wall Thickness** (in)	**ID** (in)	**Grade**	**Collapse** (bar)	**Burst** (bar)	**SIWHP** (110%)
7”	35.0	0.498	6.004	P-110	**987**	**1073**	831
5 ½”	26.0	0.476	4.548	P-110	**1200**	**1149**	831

The intention is to provide a basic overview of tubing size selection based on highly related risks and considerations for HPHT well scenario. Further simulation and quality insurance must be provided before finalizing the decision of tubing size selection. However, some considerations and calculations to provide entry-level qualification is educational. If the simulated design show weakness and exceed the minimum requirements, another weight must be considered. It is desired to mention that more load cases should be reviewed.

NORSOK (2004) has conducted a list of load cases that shall be considered when designing for burst, collapse, and axial load. Important stress analysis elements:

1. *“Leak testing of the completion string and annulus”*
2. *“Short shut-in and long shut-in after production”*
3. *Bullheading and pumping kill fluid*

Case 1: Tubing Leak

The risk of applying a heavy packer fluid in a HPHT well can cause severe well integrity concerns for casing design. If the inner tubing is filled with gas, the hydrostatic pressure in tubing is lowered, providing high shut in pressures near surface when the well is closed in. If experiencing tubing leak, the pressure will be transmitted into annulus A. The pressure regime now considers the following:

- Gas filled well, hydrostatic pressure lowered, wellhead pressure feeling the reservoir pressure minus hydrostatic head full of gas.
- Leak through tubing into annulus. High-density packer fluid. The pressure felt at leak path in annulus is wellhead pressure plus the hydrostatic load of heavy annular fluid.
- The high pressure felt inside annulus will cause two scenarios: high burst load on casing and high collapse load on tubing.

The pressure differential is defined as the vertical length of the pressure in annulus minus the tubing pressure:

$$\Delta p = TVD(\rho_{annulus} - \rho_{tubing})$$

(Bellarby, 2009)

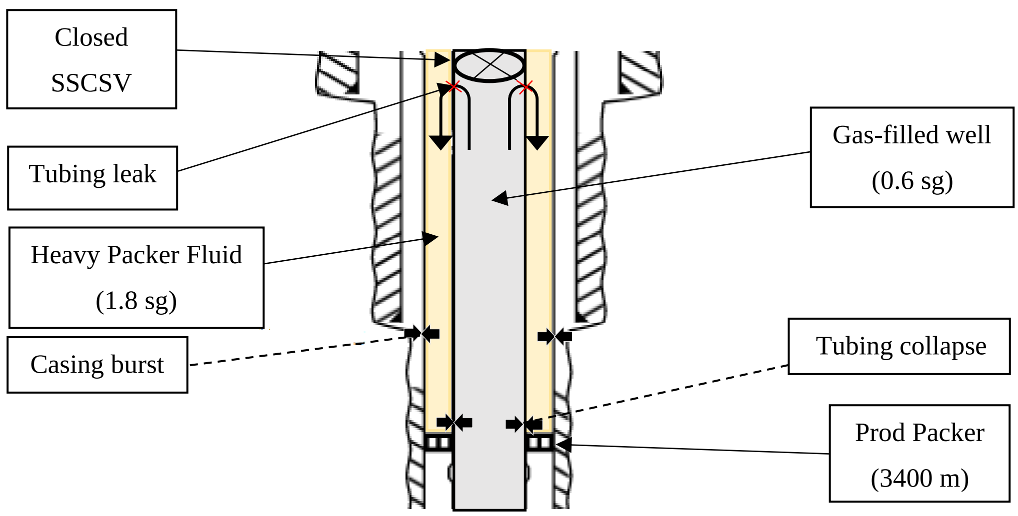


Figure 4-22: Tubing leak near wellhead (below closed safety valve). Heavy annular fluid, gas filled tubing column.

Example from Figure 4-22: Reservoir pressure of 755 bar, gas density of 0.6 sg and packer fluid of 1.8 sg (heavy packer fluid). Reservoir is located at 4137 m TVD and WH at 405 m TVD. The production packer is located at 3400 m TVD. Tubing is filled with gas. The tubing leaks *below the closed safety valve*, and pressure is felt in the annulus.

- Internal pressure (**reservoir**) = 755 bar

- Internal pressure (**WH**) = 755 bar – (0.6 sg * 0.0981 * (4137 m - 405 m)) = 535 bar

- Internal pressure (**packer**) = 755 bar – (0.6 sg * 0.0981 * (4137 m - 3400 m)) = 734 bar

- Applying the safety factor of 1.1, we get: 588 bar (**WH**), 807 bar (**packer**)

- Internal pressure at wellhead is 535 bar

The annular space contains a high-density packer fluid of 1.8 sg. The wellhead pressure is now 535 bar, and because of the tubing leak, this is felt in annulus. The pressure at packer is now the pressure felt at wellhead plus the hydrostatic column of the heavy packer fluid.

- Annular pressure at 3400 m (packer depth) = p = 535 bar + (1.8 sg * 0.0981 * (3400 - 405) m) = **1064 bar**

- However, if the packer fluid is 1,15 sg light fluid, the pressure becomes p = 535 bar + (1.15 sg * 0.0981 * (3400 - 405) m) = **873 bar**

Production casing is designed with high burst and collapse ratings for this reason. It has to be prepared for potential tubing leak with gas filled casing. A heavy packer fluid is therefore often bypassed and reduced prior to setting the packers. For simplicity reasons, the pressure is calculated at WH instead of safety valve. However, the equation accounts *the pressure differential* between annulus and tubing. The total pressure felt will be the pressure differential, and not only the internal or external pressure. In reality, Δp is lower.

Temperature Degradation

Reduction in yield due to high temperatures is common in HPHT wells. According to Bellarby (2009), "*For 13Cr, one manufacturer quotes 0.05%/°F"* (p. 478). Starting at 70°F, temperature will reduce the yield strength up to 0.05% per Fahrenheit. The degree of strength reduction is manufacturer dependent and should be evaluated closer. Note that the degradation can be different with other manufacturer's products. Quick calculations provide:

- P-110 13Cr 26 lb-ft at 300°F
- 300°F - 70°F = 230°F
- 230 °F x 0.05 = 11.5%

- Yield stress at 300 °F for P-110 13Cr
- 110 x (100-11.5) / 100 = **97.35 ksi**
- *Results: from 110 ksi to 97,35 ksi because of temperature degradation*

Still, temperature degradation is affecting the casing/tubing at the designated depth. The temperature at wellhead is significantly lower. The tubular strength will be less degraded. Temperature degradation will however weaken the tubular yield in the reservoir section and need further simulation.

Hot Shut-in

A shut-in case is relevant for a HPHT well scenario. Once the well is producing in a steady state, the need for a quick shut-in can provide a combination of high temperature and pressures (Bellarby, 2009). This can potentially cause pressure-build up when the well is shut-in. For a lower permeability reservoir, the temperature will not rise as quickly. Iris permeability is according to the DST between 35-45 mD. However, a hot shut-in scenario needs further simulations to conclude on severity.

Tubing sizing considerations

Tubing is generally selected based on flow potential, production rate requirements, compatibility with casing design, material, installation, and life-of-well requirements. For normal pressured wells, a 7” tubing is often used. For HPHT wells, a smaller tubing size is normally selected. Running of a smaller tubing is easier, alongside the ID restrictions when running with pressure & temperature gauges. A monobore completion is harder to obtain for a 7” tubing (Hermansson & Low, 2014).

The decision to have a HXMT is often favorable for HPHT subsea wells. The reasoning for this can be related to workover riser systems, which involves elastomeric seals. VXT involve more operational risks related to completing the well (workover riser, pulling of TH if leak), which a HXMT easier can solve (Hermansson & Low, 2014).

The majority of HPHT subsea wells on NCS is accessed with a 5 ½” tubing. The major cause for this is horizontal XMT limitations with sizing in HPHT conditions. The most common tubing size is 5 ½”. Qualification of a 7” tubing hanger size needs implementation if Hades/Iris field require a larger tubing to accommodate for flow improvements. The qualification process is heavily time consuming and require the need for new technology to be eligible. The limitation is highly influencing the tubing sizing design, indirectly affecting lower completion selection.

4.5.5 Operational Risks

For tubing design, the majority of operational risks are simulated and mitigated pre-completion. Selecting the most optimal material for the downhole conditions combined with load case scenario simulation will be crucial to obtain sufficient tubing for the operation. Yet, manufacturer's equipment availability can promote long lead times and potential increased material cost. Tubing, and HPHT equipment in general, should be selected at an early stage to avoid limitations with lead times and availability. Risks related to tubing in general, as in scaling, localized corrosion, and risks related to load cases (buckling, expansion) will not be reviewed.

Both 7" and 5 ½" tubing passes the general entry-level qualification, but still need a comprehensive load case simulation study to check compatibility. Nonetheless, for subsea wells, limitations in HPHT certified equipment not only limits, but also eliminates the use of a 7" tubing at given date. A qualification process of an XMT compatible for 7" tubing in a subsea well must be performed.

Upper completion can limit and crumble well objective related to lower completion. For a cased and perforated liner, the 5 ½" tubing will be the limiting tubular as the liner is 7", given the fact that a contingency liner (4 ½") is not run. This restriction limits the cased and perforated lower completion case, either forcing the guns to perforate without the completion (biggest gun size), lowering the guns and anchoring them to the liner wall, or run guns through-tubing.

From a production packer standpoint, the use of permanent packers is common due to low complexity and few moving parts. Prematurely setting in subsea wells are still common and has been experienced at multiple cases on the NCS. However, retrievable packers are of high concern as the increased moving parts provide reliability risk in HPHT conditions. Morvin Field implemented the use of retrievable packers to mitigate risks related to Kristin Field. The completion will be run from a semi-submersible, meaning pre-maturely setting will be a risk. Time and cost are of great concern, as a milling operation requires additional equipment and resources. The benefits of a retrievable packer must be further evaluated. The packer selection requires additional risk management, as the implementation of retrievable packers require a special attention to design and field development status.

Operational risks for upper completion for tubing size and production packer selection can be seen in Table 4-18:

Table 4-18: Highlighted operational risks and challenges

XMT limitations for 7" tubing
• Comprehensive qualification program needed to provide a 7" tubing compatible christmas three. The use of a 7" tubing is a high well objective risk for subsea HPHT wells on NCS.

Tubing size limits the gun size selection for C&P concept
• For a cased and perforated liner, the 5 ½” tubing will be the limiting tubular as the liner is 7”. This restriction limits the cased and perforated lower completion case, forcing the guns to either perforate without the permanent completion (biggest gun size), lowering the guns and anchoring them to the liner wall, or running through-tubing.

Tubing size selected require earlier well intervention
• Due to more rapid production, a bigger might tubing require earlier intervention (scaling, water production, sand production). The need to open the well and perform intervention operations enhances HS&E risk and needs to provide smart and effective solutions to perform interventions to not limit the well performance.

Packer elastomer not compatible with downhole conditions
• Retrievable packers have been proven as an open hole packer during Morvin field. However, the need to prove the packer functionality during a life-span of a well is important to consider when selecting packer type. Degradation of elastomer may introduce additional risk when looking at a longer production perspective.

Pre-mature set of packer when running in hole
• Pre-maturely set packers can be tracked back to Kristin field development. The need to adapt and overcome previously experienced scenarios should be focused in order to minimize the risk of the event occuring. Pre-maturely set packers bring risk related to HS&E and well objective (milling, well stability) and T&C (intervention)

CHAPTER 5

5 PROBABILITY AND IMPACT MATRIX

In order to decide which completion method is the most suitable for the operation, a variety of factors and considerations need to be evaluated. Understanding relevant risks associated with the concepts assessed is necessary to optimize completion strategy. By utilizing the "*Probability and Impact Matrix",* which implement mapping of risks, its probability and impact, the vulnerability of a completion scenario can be determined (Curtis & Carey, 2012).

The activities of well completion involve risks. Risks are events caused by uncertainties, which is directly affecting the project objectives. Risk management is a widely used tool in the industry to study and mitigate uncertainties. Designing completion with respect to maintaining well integrity and sufficient barriers is important throughout the life cycle of a well. In respect to well engineering, it is common practice to integrate a form of risk assessment. The degree of assessment can vary from a single component to a full method selection for a well. In order to justify and select a method for completing the new Iris Production well, a risk management plan is introduced.

5.1 RISK IDENTIFICATION

The potential first step of a risk management plan involves identifying possible risks in order to respond to and control the projects most significant threats. In well engineering, risk assessment is highly dependent on field experience, available data and both operator- and service company experience, which may be acquired through brainstorming, interviews or expert opinions (Lester, 2013). Companies may have internal procedures, guidelines, or recommendations on how to identify risks. Concerning Iris Production well, HPHT relevant experience and operational risk from the method assessment has strongly affected the risk identification process, alongside the assurance of expert opinions for adequate risk levels.

Following the identification, the next step will present a qualitative *risk assessment*, which involves estimating the likelihood of a risk occurring, the *probability,* and to how big of a consequence brought upon the project if the risk occurs, the *impact.*

5.1.1 Probability

The probability is defined as the possibility of a risk event occurring. Probability is a synonym for likelihood, which often is spoken about in the industry as for how possible or how often it is for events to happen. Probability is normally expressed qualitatively, using previous experience or statistical data (Lester, 2013). For the oil and gas industry, probability can be more specific with respect to relevant industry, as in this case the NCS. Table 5-1 illustrates the probability measurements used in the thesis.

Table 5-1: Probability Scale (Lester, 2013). Relevant industry description based on OMV operational HS&E risk register.

Proabability Scale			
Likelihood		**General description**	**Relevant industry description** **Norwegian Continental Shelf**
Relative	**Score**		
Very Unlikely	P1	Highly unlikely to occur	Never occurred in the industry
Rare	P2	Will most likely not occur	Heard of in the industry
Possibly	P3	Possible to occur	Incident could happen in our company
Likely	P4	Likely to occur	Incident could happen during the operation
Frequently	P5	Highly likely to occur	Incident could happen more than once during the operation

To make it more specific and realistic for this case, the relevance will be pinned down mainly to the Norwegian Continental Shelf. The NCS contains a numerous HPHT fields with already installed completions with published material, with operational risk assessed in chapter 4. The majority of probability decisions will involve common HPHT fields with similar completion methods and reservoir characteristics. This way, the probability can act as a more realistic approach for method selection.

5.1.2 Impact

The impact is commonly used as the effects of a risk event on the project objectives. It is often referred to as the consequences, and the level of consequence of the identified risks. The impact of a risk event can affect more than one objective. For instance, a scenario where well performance is evaluated due to completion fluids selection, HS&E will most likely also be considered. In order to meet the probability scale, the impact can be categorized in a five-point scale, with a numerical and relative number. Each level of impact will have its own explanation and consequence level. By sorting and defining the scale grades, expertise is required, and companies can create recommendations or guidelines, in some cases mandatory requirements for the personnel to follow. For this thesis, a combination of previous operational experience, individual counseling, and personal assumptions will base the scale points. Given in Table 5-2 below is a demonstration of a general impact scale example for HS&E with respect to environment. A more detailed scale with comprehensive focus on well completion will be provided later in this chapter.

Table 5-2: General impact categorization (based on OMV HS&E Risk Assessment)

Objective	Impact					
	Description	**Incidental**	**Minor**	**Moderate**	**Major**	**Extreme**
		I1	**I2**	**I3**	**I4**	**I5**
HS&E - Environmental - Spill - Safety	Environmental management, personnel safety & health	Slight reversible environmental damage within the boundaries Actions for restoration may be required	Slight reversible environmental damage outside the boundaries Actions for restoration may be required	Short term environmental damage within a limited area outside the boundaries Actions for restoration may be required	Mid-term, major environmental damage Actions are required for restoration	**Massive long-term, environmental damage on a large area** Major actions are required to restore environment

5.2 RISK ASSESSMENT – QUALITATIVE ANALYSIS

The assessment process is carried out by developing a set of criteria – *value drivers* –, which the company or personnel in charge of the assessment mutually agree on. The criteria set by a company may be different from another – this is what makes risk assessment and method selection vary based on what factors decided. The weighting and priority of the set criteria can be changed or re-evaluated along the way – resulting in a different method selection.

The assessment process is often divided into two stages – *qualitative* and *quantitative*, the first being the focus for this thesis. The process is not necessarily providing a direct measurement or estimation, but rather a greater overview with a broad spectrum of considerations for further decision making (Dumbravă & Iacob, 2013). To successfully provide a fulfilling qualitative analysis, data collection and previously documented experience is important. Qualitative assessments can further proceed into a *"Probability and Impact Matrix"*. For this thesis, the matrix will be the foundation and methodology to determine and differentiate the various levels of risk obtained.

5.2.1 Probability and Impact Matrix

Because of the simplicity and extend of overview, the *"Probability and Impact Matrix"* is widely used in qualitatively risk assessments in the industry. The method is common and bring a great view of the mapped risks, the probability and impact level. By determining the *risk*, which ultimately determine the grading and need for mitigation, the probability and impact is multiplied (Dumbravă & Iacob, 2013):

$$Risk = Probability * Impact$$

In order to get a functional matrix, it is important to justify probability and impact. It has to be set clear criteria and value-drivers for the company in regard to the risk assessment. To optimize method selection, understanding what risks to consider, how probable the risks are, and the effect of impact, determine the grading. For newly graduated engineers, this matrix may be challenging to conclude on the risk level. However, it is a great tool to map and analyze risk for each activity. Table 5-3 visualize the colorization of risks with respect to impact and probability, which illustrate the exposure rating, the *risk level* (Lester, 2013).

Table 5-3: Probability and Impact Matrix – exposure table (Lester, 2013)

			Impact				
			Incidental	Minor	Moderate	Major	Extreme
			I1	**I2**	**I3**	**I4**	**I5**
Probability	Frequent	**P5**					
	Likely	**P4**					
	Possible	**P3**					
	Rare	**P2**					
	Very Unlikely	**P1**					

The following three definitions: *Unacceptable* (red), *ALARP (*yellow) and *Acceptable* (green) have been defined to differentiate the risk level. The three definitions and content are highly influenced by OMV (Norge) AS HS&E risk register procedure. The document is used during drilling operations by the well engineering team and introduce the company with guidelines during the operation. Chapter 5.2.2 provide additional information about OMV (Norge) AS practices.

Frequent Probability – Extreme Impact: A higher number (the red zone) indicates risks with a high likelihood of occurrence and with a high impact. Risks located in the red zone may be a "show-stopping" risk if not mitigated. The challenge is to determine if the risk is manageable; and if not, what measured needed to lower it to an acceptable level (Council, 2005). Risks of high impact and high probability need priority actions and can often be seen as the determining factor for excluding certain methods for well completion. Figure 5-1 define the red zone:

	Red **6 / 25**	**INTOLERABLE** Unacceptable risks (red region in the risk matrix). Additional measures **are required** to reduce them to at least ALARP (yellow). These measures have to be implemented even if they require significant resources or fundamental changes in the activities and systems.

Figure 5-1: Intolerable Risk Definition

Very Unlikely Probability - Extreme Impact & ***Frequent Probability - Incidental Impact:*** Moving towards the middle section of the Probability and Impact Matrix, situations more moderate is considered. This tend to be a combination of "*High Impact – Low Probability"* and "*Low Impact – High Probability"*. This is where the situational cases may determine to use a specific method over the other, and yet again personal experience can dictate the amount of focus needed for mitigation purposes. A situation where the probability is low and impact is extreme, may often be based on uncertainties due to little historical experience of such events (Council, 2005). Example could be the cost of materials, or time consumption of activities. Events caused by incidental impact, but with a higher probability of occurrence, is often overlooked due to being of very small risks seen individually (Council, 2005). Combining a high amount of incidental impact risks may cause challenging situations during the life span of a well completion. The yellow zone is defined in Figure 5-2:

	Yellow **13 / 25**	**ALARP** Tolerable risks (yellow region in the risk matrix). ***As low as reasonably possible***. The cost of risk reduction is related to benefits obtained. The risk is measured and involves a comprehensive study of situations regarding high disproportionate spend in comparison with risk reduction achieved.

Figure 5-2: Tolerable Risk Definition

Very Unlikely Probability – Incidental Impact: These are risks characterized with both low probability and impact. These risks are considered not to affect the overall completion strategy but has to be considered and monitored for learning purposes. The majority of these risks are unavoidable, but with good engineering can be monitored to determine if the likelihood or impact of the risks increase (Council, 2005) Green zone definition is presented in Figure 5-3:

	Green **6 / 25**	**ACCEPTABLE** These are broadly acceptable risks (green region in the risk matrix). Comparable to average daily living risks. Further risk reduction can be requested for continuous improvement and optimization.

Figure 5-3: Acceptable Risk Definition

5.2.2 Recommendations and practices from OMV

OMV has conducted recommendations for Risk Management in regard to well engineering (Colt, 2014). The objective is, according to OMV (Norge) AS Risk Management document, to

> "*Set out the framework of an appropriate risk management strategy specific to well engineering activities and ensure consistency of practice against existing OMV HSSE standards, guidance and procedures"* (p. 1).

Further, the document states use of a standard approach including a Risk Management Plan, a breakdown structure, risk register template, risk matrix and a summary of the process. This way the well engineering team can summarize and document the risk identification and process, which is defined as an integrated part of the well planning process.

A “*Wells Project Risk Screening Tool*” (WPRST) provides a number of areas to identify where weaknesses can threaten success of the project. In each area of interest (HS&E, T&C etc.), definitions are provided that allow the team to judge the degree of risk to which the project is exposed.

A “Well-specific Risk Assessment” (WSRA, aka HAZID) is *recommended* to be carried out during the define phase, due to absence of guidance relevant and specific to well engineering activities. According to Colt (2014), “*It is an examination of the technical risk that impacts the basis of design for the well for which design or procedural solutions must be found*” (p. 8). A detailed offset well analysis to ensure that specific aspects of the regional environment are captured and used to calibrate the outcome of the WSRA itself.

The OMV recommended guidelines for risk management within the well engineering team is a qualitative method, with continuous tracking of identified risks. The WSRA is broken down and documented using the WPRST. This is used in live drilling scenario, where continuous monitoring of operation is required. The process is also viable for a completion perspective. OMV is using a worksheet of the risks; coded with green, yellow, and red, to visualize in terms of impact against manageability.

As OMV has no requirements to Risk Management, but only recommendations, the thesis tend to follow the recommendations and incorporate them as much as possible with the risk matrix. By implementing a risk register, not only does it provide an overview and gradation of risks, it also provides a widely used methodology in well engineering of risk identification and mitigation procedures. The use of a risk register and probability- and impact matrix gives a relevant perspective for well completion.

5.3 VALUE DRIVERS – METHOD SELECTION SCOPING TOOL

As mentioned early in the risk assessment introduction, companies, or personnel in charge of the method selection scoping will early determine which factors or criteria that values the most. Criteria prioritization can be different from operation to operation. Well engineering will always consider HS&E when basing design. Personnel safety, health, and environmental management is and will always be of utter importance. Equipment selection, working conditions in the red zone, safety procedures, follow-up and responsibilities from both operator and service-companies all need to be considered and prioritized. The possibility of creating a massive long-term environmental challenge will always influence the outcome. Choosing well objective as a value-driver for this thesis is to get a better understanding of how completion methods control the production potential. Creating the safest well can limit the well performance – at what cost can the performance increase and not affect the operational safety? Time and cost will and has always been factors to consider for well engineering. This is a solid opportunity to get company insight in cost estimation based on rig-time, running of different completion types and components. HPHT well design, equipment selection, intervention compatibility and the fact that the well has no complexity limitations is important to consider. The value-drivers and priority are presented in Table 5-4:

Table 5-4: Value Drivers for Iris Production Well Method Selection

Iris Production Method Selection - Value Drivers		
Main Issue	**Explanation / Remarks**	**Priority**
HS&E	- Environmental management, personnel safety & health, company reputation - The chosen design shall be of outstanding HS&E values - HS&E need and will always be the focus, but without necessarily compromising well performance. - Personnel safety and environmental damage is of high focus - Well integrity: minimizing potential well problems (Annular Pressure Buildup, corrosion, gas migration, reservoir isolation, equipment running)	**1**
Well Objective	- Optimizing the recovery of hydrocarbons - Highest regularity and reliability: well integrity and performance - Focus on uncompromised productivity design - Intervention compatibility: designing a life of well - HPHT maturity: operational readiness for HPHT on NCS	**2**
Time & Cost	- Constructive and think-through solutions based on saving rig time - Time of planning, mobilizing, operation and demobilization - Operational costs: equipment, metallurgy, installation, contingency planning, personnel, rig-rate - End goal always to aim at making a cost-effective completion by optimization of equipment and rig usage	**3**

5.3.1 HS&E

The impact levels chosen for HS&E relates to personnel, environment, and company reputation. HS&E should in all drilling and completion operations be considered the foremost important value driver. For completion procedures, **safety** should be highest priority. Hazards related to completion is often linked to fluid selection (solvents, brines, produced well fluids), well control (barrier selection, potential for gas kick or blow-out), explosives (perforations), pressure testing and heavy lifts (Bellarby, 2009). When measuring level of impact, the personnel category will involve how affected the crew is to the given hazards. If the operation provides high exposure to toxic fluids, the personnel impact level rises due to a potentially higher impact. If the operation involves heavy lifting, the potential impact increase compared to an operation where less heavy lifting is required.

Environmental impact aims at consequences related to spill and links closely up with well control incidents. If the method involves high risk of potentially losing well control and releasing hydrocarbons to seafloor, the following environmental consequence can potentially be major.

Safety and environmental focus are highly relevant to company appearance. The **reputation** speaks for itself and is something all companies strive to optimize. The potential impact of an HS&E related risk could in some cases be picked up and displayed for the world to see. The goal of this value-driver is always be aware of the consequence companies is up against in a fast-changing world.

HS&E impact links up with OMV (Norge) AS practices for drilling operations. When implementing HS&E impact definition, the approach will be as following:

- *Personnel influence evaluation*. Concerning personnel health and safety, how much of an impact will the operational sequence cause?
- *Equipment and procedure*. Does the method involve use of highly toxic fluids, potential heavy lifts, or explosives at rig floor?
- *Field experience*. Published material of HS&E related incidents in similar working environment.
- *Well control*. Does the procedure involve fragile or unproven elements?

See Table 5-5 for impact levels for HS&E:

Table 5-5: HS&E Impact levels

		HS&E		
		Personnel safety	**Environment**	**Reputation**
Decreasing Consequence	**5**	**Multiple fatalities (>1)** **Multiple heavy lifting operations** **High amount of toxic fluids exposed** More than 6 people of workforce and/or public hospitalized	**Massive long-term, environmental damage on a large area** Major actions are required to restore environment	Legal proceedings Extensive negative worldwide news coverage. **Possible loss of license to operate.**
	4	1 fatality of workforce Heavy lifting operations High amount of toxic fluids exposed Single person of workforce with onset /signs of severe irreversible health effect	Mid-term, major environmental damage Actions are required for restoration	Negative worldwide news coverage in media. Negative attention from important organizations.
	3	Single person of workforce at least 3 workdays lost Multiple lifting operations Toxic fluids exposed Single person of workforce with onset /signs of moderate irreversible health effect	Short term environmental damage within a limited area outside the boundaries Actions for restoration may be required	National negative exposure in mass media. Negative exposure from national authorities/ regulators.
	2	Single person of workforce 1 or 2 days off work Less lifting operations Single person of workforce with moderate reversible mid-term health effect	Slight reversible environmental damage outside the boundaries Actions for restoration may be required	Local/regional negative exposure in mass media or from authorities and partners.
	1	Single person of workforce injured but able to continue work, first aid needed Single person of workforce with minor reversible short- term health effect	Slight reversible environmental damage within the boundaries Actions for restoration may be required	Negative exposure with limited importance.

5.3.2 Well Objective

The well objective for production wells with regard to completion include the following: to complete the well with the best-suited concept with lowest downtime, highest reliability, alongside highest productivity. For well completion, the production phase must also be considered. Having the highest possible productivity is demanding in HPHT wells, and require special attention to design. As for the thesis, the thesis will look into the implementation of a HPHT environment design. The focus for well objective should be to install the completion with high focus on well control. Even with the best flow potential, the completion needs to provide a mature concept for HPHT environment. See **Error! Reference source not found.** for impact levels for well objective.

Reliability is mainly to identify incidents and hick-ups related to the completion method. If experience show multiple well integrity challenges associated with the use of a specific method in similar environment, considerations must be evaluated. Field-tested and proven equipment in similar conditions is a great reference point when designing the completion. A mature completion setup with positive published content is useful for justifying use in regard to well control and equipment selection.

The subsea template has access to intervention and workover if needed. Intervention affects design and tubular size limitations. Focusing on the capability of intervention is for learning purposes. Providing a **flexible** well design is thinking about the future possibilities, for example Hades reservoir or re-perforating Iris reservoir.

Well Performance dictate the overall objective of the well – the production of hydrocarbons. A good well performance indicates low skin, high flow, and uncompromised productivity. Well performance measures how the different methods respond to previously experienced well performance in similar environment. For well objective, the selection of impact level will be approached as following:

- *Well control reliability.* Reported downtime and workover operations from previous experiences. It is important to consider reliability and maturity of concepts and learn from what others have done. Equipment selection, fluid considerations and previously experienced well performance increase/decrease will be contemplated. Most importantly, well control and barrier selection are considered.
- *Opportunity.* Flexibility in regard to workover, repair, and intervention. Smart and innovative solutions will be considered.

- *Well Performance.* Formation damage, perforation damage, skin, productivity index and relevant parameters that dictate the well performance.

Table 5-6: Well Objective Impact levels

		Well Objective		
		HPHT Reliability & Maturity	**Flexibility**	**Well Performance**
Decreasing Consequence	**5**	**Not proven concept in HPHT well** Major downtime related to well problems and well integrity High complexity of installation process and little knowledge of installation process. Unreliable completion	Well construction not compatible for intervention procedures	**Completion designs provide compromised productivity** Extreme formation damage, recompletion needed > 30
	4	Not suited concept in an HPHT environment High numbers reported downtime related to well problems and well integrity. High complexity with regard to low knowledge of installation procedure. Unreliable completion with low chance of success	Major reconstruction modifications necessary for intervention compatibility	Completion designs provide compromised to little productivity High formation damage, potential recompletion considered > 10-30
	3	Uncommon completion concept in an HPHT environment Moderate downtime related to well problems, well integrity. Moderate complexity based on installation process and knowledge. Reliable completion with moderate chance of success	Modifications necessary for intervention compatibility	Completion designs provide less productivity Moderate to high formation damage > 5-10
	2	Common completion concept in an **HPHT environment** Field proven equipment and well-known installation process. Low downtime related to well problems, well integrity. Low complexity. Reliable completion	Minor modification for intervention compatibility	Completion designs provide uncompromised productivity Low to moderate formation damage > 2-5
	1	Common completion concept on **NCS in an HPHT environment** Field proven equipment and well-known installation process. Good field reputation and low failure rate Minimum complexity. Reliable completion with high chance of success	Intervention compatible	Uncompromised productivity Low to very low formation damage < 0-2

5.3.3 Time & Cost

The operational cost considered will be for completion procedures only. Cost is highly related to time due to day-to-day rental of equipment and personnel with fixed day rates, with the main contributor being the rig-rate. Equipment or fluids can have an impact on the overall cost, for example completion or perforation fluids. The more specific cost of these elements can be challenging to track from a theoretical perspective and will therefore be mentioned if the difference in cost is substantial.

For this thesis, the selected overall operational day rate (including rig-rate and all expenses) is **8 MNOK/day**. The operational rate is difficult to determine, due to general deviations from operator to operator. General consultation with experienced personnel is influencing the time and cost output, with an OMV (Norge) AS cost perspective. The rig-rate is highly influencing the overall cost, alongside completion services from contractors. The drilling and completion contracts with service companies deviate between operators, which again is influencing the cost per day. Logistics and location matter, together with the fact that Iris Production well is carrying the cost as a single well, not in a field development perspective.

In order to add specific impact levels, a **comparison** perspective will be introduced. The number of days is highly variable from operation to operation. For instance, looking at a case where open hole versus cased and perforated scenario is relevant, the time and cost differences will be between the two methods. By running a middle completion barrier assembly versus integrated lower completion barrier assembly, the time and cost differential will be visualized.

Important to consider is the fact that many operational sequences are involved when completing a well. The focus is to differentiate the total time spent between the methods. For differentiating the time and cost into impact levels, each completion sequence must be seen individually. When implementing impact selection for time and cost, the following approach is used:

- *Lower Completion* – comparison of open hole versus cased hole. The general idea is to present the additional cost of adding the cemented liner and perforations in an operation.
- *Middle Completion* – the barrier assembly can be used in both open hole and cased hole completion. The added rig-time of running the completion will therefore make an impact on time and cost.
- *Upper Completion* – Running upper completion is time consuming. The time of running the completion is in general not affected by lower completion method selection.

See Table 5-7 for impact levels for time and cost:

Table 5-7: Time and Cost Impact levels

Decreasing Consequence		Time			Cost		
		Time (Description)	**Added operational time (days)**	**Time of total completion (%)**	**Cost (Description)**	**Cost of total completion (%)**	**Cost (MNOK)**
	5	Long operational time of performing completion Above 40% of total well completion schedule	**> 12**	> 40%	Operational cost increased drastically Over 40% of total completion cost	> 40%	**> MNOK 96**
	4	Long operational time of performing operation 20-40% of total completion schedule	**6,0 - 12,0**	20-40%	20-40% of total completion cost	20-40%	**> MNOK 48**
	3	10-20% increase in completion schedule	**3,0 - 6,0**	10-20%	10-20% of total completion cost	10-20%	**> MNOK 24**
	2	Operational time inside limit and acceptable measure < 10% increase in schedule	**1,5 - 3,0**	5-10%	5-10% of total completion cost	5-10%	**> MNOK 12**
	1	Insignificant change in completion schedule Operational time inside planned estimate	**0 - 1,5**	<5%	Insignificant change in completion cost Operational cost inside acceptable limit	<5%	**< MNOK 12**

CHAPTER 6

6 METHOD SELECTION

The method selection will be based on two lower completion scenarios: open hole predrilled liner concept versus cased and perforated liner concept. Both middle and upper completion is presented and incorporated with both lower completion methods. First, the risk assessment shall be illustrated separating each method and looking at operational difference in risk. The most highlighted risks are then presented in the selection. Once the highlighted risks are presented, two design proposals will be offered. The reasoning for presenting two designs is to give a wider understanding of each to spot weaknesses for both methods. When the designs are reviewed, the method most suitable based on the risk assessment will be presented for further evaluation.

6.1 IMPLEMENTATION OF RISK MATRIX

Following is a table of a general value driver's consequence level, where the consequence is listed for HS&E, T&C and WOBJ. A risk is identified and described, as presented in Figure 6-1. Following, a probability is given for the risk event to occur. The value drivers will then be listed and given an impact level. The impact level and colors are finally generated and registered. Example for C&P concept with regards to a contingency slimhole:

Risk	Description	Probability	Impact		
			HSE	T&C	WOBJ
Contingency slimhole compatibility	Small gun selection due to a 4 ½" liner. Biggest available gun size is 2 7/8"	P2	I1	I1	I3

Figure 6-1: Risk Example

All the methods for lower-, middle- and upper completion is listed with the respective risk level, with the intention for the viewer to see differences in impact and probability. For example, a scenario with a different well objective impact can be clear, as shown in Figure 6-2:

<table>
<tr><td></td><td colspan="5">Open Hole Completion – Predrilled Liner</td></tr>
<tr><td rowspan="2">Risk</td><td rowspan="2">Description</td><td rowspan="2">P</td><td colspan="3">I</td></tr>
<tr><td>HS&E</td><td>T&C</td><td>WOBJ</td></tr>
<tr><td rowspan="6">Plugging of predrilled holes</td><td>If unable to clean the predrilled holes, well performance may be compromised. The need for an extra cleaning run might be needed. Possible if liner running fluid is OBM, barite sagging</td><td>P3</td><td>I1</td><td>I1</td><td>I3</td></tr>
<tr><td colspan="5">Cased Hole Completion – Perforated Liner</td></tr>
<tr><td rowspan="2">Description</td><td rowspan="2">P</td><td colspan="3">I</td></tr>
<tr><td>HS&E</td><td>T&C</td><td>WOBJ</td></tr>
<tr><td>Only relevant for predrilled liner completion</td><td>P1</td><td>I1</td><td>I1</td><td>I1</td></tr>
</table>

Figure 6-2: Risk Assessment Example

What can be normal in risk evaluation, is to provide a color of *opportunity (Lester, 2013)*. For this thesis, instead of introducing the opportunity spectrum, the method, which is not a contributor of opportunity, receives a lower score. The justification is relatively the same, but instead of giving a score as in opportunity, the other method will receive a higher impact level, therefore showing a clearer difference in impact.

The full assessment is conducted and presented in **Appendix B**. The highlighted risks which introduce high impact and clear difference in HS&E, well objective, time and cost will be accessible in the selection. The risk identification process has provided risks related to each value driver based on a qualitative approach, with focus on theory and field experience.

6.1.1 Lower Completion Risk Assessment

Both open hole predrilled liner and perforated liner bring considerable risks to the assessment. Open hole completion involves risks related to well control and well performance, with high focus on completion fluids and zonal isolation. Perforated liner introduce risk associated with explosives and perforation activities in an HPHT well on a floater.

The potential formation damage by excessive loss of filtrate may impact the HS&E and well objective and is considered an impactful risk for open hole completions. Perforations bring natural risks with explosives and the complexity of perforating with permanent completion in place. Open hole completions are faster to install but contribute with high fluid costs. Perforated liner may eliminate the need for reservoir isolation. However, according to the risk assessment, the highest impact is the time and cost of perforated liner proposal due to long installation time. The added time perforating on a floater can be from 8-15 days (64-120 MNOK).

	Open Hole Completion – Predrilled Liner				
Risk	Description	**P**	**I**		
			HS&E	T&C	WOBJ
Lower Completion time and cost	Displace to liner-running fluid. Run liner and set in 9 7/8" hanger. Pressure test of liner hanger packer. *High cost of fluids*.	P4	I1	I3	I1
	Cased Hole Completion – Perforated Liner				
	Description	**P**	**I**		
			HS&E	T&C	WOBJ
	Running liner, circulate cement, cement liner, verify and test cement, drill excessive cement, verify annular cement. Full perforation activities on a semi-submersible. Added rig-time from 8 – 15 days (64-120 MNOK)	P4	I1	I4	I1

	Open Hole Completion – Predrilled Liner				
Risk	Description	**P**	**I**		
			HS&E	T&C	WOBJ
Perforation penetration depth in HPHT wells	Only relevant with the use of guns in hole	P1	I1	I1	I1
	Cased Hole Completion – Perforated Liner				
	Description	**P**	**I**		
			HS&E	T&C	WOBJ
	Highly pressured formations introduce perforation depth penalty. The combination of lower density guns (through-tubing) and highly stressed sandstone may compromise productivity. Reduced performance due to high temperature-stable explosives, which combined with highly stressed formation show reduced penetration	P3	I1	I1	I3

	Open Hole Completion – Predrilled Liner				
Risk	Description	**P**	**I**		
			HS&E	T&C	WOBJ
Gun shock and formation surge effects cause well instability	Only relevant for perforated liner	P1	I1	I1	I1
	Cased Hole Completion – Perforated Liner				
	Description	**P**	**I**		
			HS&E	T&C	WOBJ
	Wireline perforations. Detonation can cause gun shock. Formation sure can cause upward force of guns, resulting in guns being blown up-hole. HS&E exposure and damaged well scenario	P2	I3	I1	I4

<table>
<tr><th></th><th colspan="5">Open Hole Completion – Predrilled Liner</th></tr>
<tr><th rowspan="2">Risk</th><td rowspan="2">Description</td><th rowspan="2">P</th><th colspan="3">I</th></tr>
<tr><td>HS&E</td><td>T&C</td><td>WOBJ</td></tr>
<tr><th rowspan="5">Excessive loss of filtrate into reservoir can cause high formation damage</th><td>Formation damage can limit well productivity. If open hole skin factor is high, inflow performance is low. Can cause severe impact on well performance</td><td>P3</td><td>I1</td><td>I1</td><td>I4</td></tr>
<tr><th colspan="5">Cased Hole Completion – Perforated Liner</th></tr>
<tr><td rowspan="2">Description</td><th rowspan="2">P</th><th colspan="3">I</th></tr>
<tr><td>HS&E</td><td>T&C</td><td>WOBJ</td></tr>
<tr><td>Liner cement. Formation damage can be bypassed with C&P concept</td><td>P1</td><td>I1</td><td>I1</td><td>I1</td></tr>
</table>

<table>
<tr><th></th><th colspan="5">Open Hole Completion – Predrilled Liner</th></tr>
<tr><th rowspan="2">Risk</th><td rowspan="2">Description</td><th rowspan="2">P</th><th colspan="3">I</th></tr>
<tr><td>HS&E</td><td>T&C</td><td>WOBJ</td></tr>
<tr><th rowspan="5">Perforation-guns release-tool malfunction. Guns cannot be dropped in hole post-perforation</th><td>Gun size is bypassed with OH concept</td><td>P1</td><td>I1</td><td>I1</td><td>I1</td></tr>
<tr><th colspan="5">Cased Hole Completion – Perforated Liner</th></tr>
<tr><td rowspan="2">Description</td><th rowspan="2">P</th><th colspan="3">I</th></tr>
<tr><td>HS&E</td><td>T&C</td><td>WOBJ</td></tr>
<tr><td>Anchor release-tool malfunction, guns are stuck after detonation. The guns limit productivity and require advanced milling to remove</td><td>P2</td><td>I1</td><td>I3</td><td>I4</td></tr>
</table>

<table>
<tr><th></th><th colspan="5">Open Hole Completion – Predrilled Liner</th></tr>
<tr><th rowspan="2">Risk</th><td rowspan="2">Description</td><th rowspan="2">P</th><th colspan="3">I</th></tr>
<tr><td>HS&E</td><td>T&C</td><td>WOBJ</td></tr>
<tr><th rowspan="5">Zonal isolation for Hades reservoir fails (leak)</th><td>OH completion weak-point. No physical barrier in cement, depending on open hole isolation packers. Swell packers proven in Morvin, yet not proven for a full life of well field operation. Potential leaks</td><td>P2</td><td>I3</td><td>I3</td><td>I2</td></tr>
<tr><th colspan="5">Cased Hole Completion – Perforated Liner</th></tr>
<tr><td rowspan="2">Description</td><th rowspan="2">P</th><th colspan="3">I</th></tr>
<tr><td>HS&E</td><td>T&C</td><td>WOBJ</td></tr>
<tr><td>Zonal isolation provided with cement.</td><td>P2</td><td>I1</td><td>I1</td><td>I1</td></tr>
</table>

6.1.2 Middle Completion Risk Assessment

Both isolation assemblies can be run in an HPHT well. The choice of barrier system should be decided based on reliability, well stability and installation cost. The ILCBA is based on experience a less reliable solution, but further testing and qualification should be implemented. The elimination of a second installation run will decrease the risk of well stability challenges with reduced swab, surge, and losses potential. By successfully installing an ILCBA, a Middle Completion can be eliminated. This can save the operation from 2 to 4 days (16-32 MNOK). Reducing the number of equipment and running operations will reduce the risk associated with tight clearances and well control while installing the completion.

Running a separate barrier is punished in this thesis. Operators should aim at reducing the numbers of equipment running to minimize wellbore instability and formation damage.

<table>
<tr><td></td><td colspan="5">Middle Completion Barrier Assembly</td></tr>
<tr><td>Risk</td><td rowspan="2">Description</td><td rowspan="2">P</td><td colspan="3">I</td></tr>
<tr><td rowspan="7">Barrier assembly installation time and cost</td><td>HS&E</td><td>T&C</td><td>WOBJ</td></tr>
<tr><td>Middle Completion require a separate run. Potential added rig time is from 2-4 days (16-32 MNOK)</td><td>P3</td><td>I1</td><td>I3</td><td>I1</td></tr>
<tr><td colspan="5">Integrated Lower Completion Barrier Assembly</td></tr>
<tr><td rowspan="2">Description</td><td rowspan="2">P</td><td colspan="3">I</td></tr>
<tr><td>HS&E</td><td>T&C</td><td>WOBJ</td></tr>
<tr><td>ILCBA is run as an integrated part of the lower completion</td><td>P3</td><td>I1</td><td>I1</td><td>I1</td></tr>
</table>

<table>
<tr><td></td><td colspan="5">Middle Completion Barrier Assembly</td></tr>
<tr><td>Risk</td><td rowspan="2">Description</td><td rowspan="2">P</td><td colspan="3">I</td></tr>
<tr><td rowspan="7">Failure of accessing internal plug/valve due to debris settlement</td><td>HS&E</td><td>T&C</td><td>WOBJ</td></tr>
<tr><td>Multiple contingencies. Stab/break plug, punch hole in pipe to access inner-bore, or milling operation. Assembly located in 9 7/8” casing</td><td>P3</td><td>I1</td><td>I3</td><td>I2</td></tr>
<tr><td colspan="5">Integrated Lower Completion Barrier Assembly</td></tr>
<tr><td rowspan="2">Description</td><td rowspan="2">P</td><td colspan="3">I</td></tr>
<tr><td>HS&E</td><td>T&C</td><td>WOBJ</td></tr>
<tr><td>Require the need for multiple open hole packers due to Hades isolation. Same contingencies as Middle Completion packer. Increased complexity with more open hole packers set close to reservoirs</td><td>P3</td><td>I1</td><td>I3</td><td>I3</td></tr>
</table>

	Middle Completion Barrier Assembly				
Risk	Description	P	I		
			HS&E	T&C	WOBJ
Historical reliability in HPHT environment on NCS	Common and field proven concept. Increased cost due to installation. Pre-setting of packers reported. DIV high failure rate	P3	I1	I3	I2
	Integrated Lower Completion Barrier Assembly				
	Description	P	I		
			HS&E	T&C	WOBJ
	Morvin Field experiences lower reliability with liner hanger-packer pressure testing. 2/3 operations had to use contingency (MC), which increased overall cost	P3	I1	I2	I3

	Middle Completion Barrier Assembly				
Risk	Description	P	I		
			HS&E	T&C	WOBJ
Wellbore instability and formation damage caused by surge, swab and losses when running completion	Middle Completion require a separate run. The swab/surge and losses potential increase due to more barrier-running operations. Punished	P3	I3	I1	I3
	Integrated Lower Completion Barrier Assembly				
	Description	P	I		
			HS&E	T&C	WOBJ
	Swab/Surge and losses as expected when running a liner	P3	I1	I1	I1

	Middle Completion Barrier Assembly				
Risk	Description	P	I		
			HS&E	T&C	WOBJ
ID restrictions with bottleneck design (5 ½” tubing and 7” liner)	Middle Completion is set with a 9 7/8” x 5 ½” packer and internal plug inside tubing. No ID restrictions with a bottleneck design	P3	I1	I1	I1
	Integrated Lower Completion Barrier Assembly				
	Description	P	I		
			HS&E	T&C	WOBJ
	If liner is 7”, the 5 ½” tubing will provide complexity with internal plug running. ILCBA require expandable internal plug if liner is 7”. Complex well objective for plug-running and intervention in C&P (7” liner)	P3	I1	I1	I3

6.1.3 Upper Completion Risk Assessment

The 5 ½” tubing is selected simply because of lack of 7” HXMT availability. This gives the 7” tubing a high impact. However, it does not say that a 7” tubing would be a worse pick if it was available. For this thesis, the 7” tubing is very limited and lacks qualification for a subsea XMT.

Both permanent and retrievable packers can be used in HPHT. Field experience and packer reliability in HPHT fields are a major contributor for the selection. Newly qualified packers can function in field testing, but ultimately, the life of well is important. Permanent packers are the most common and provide higher reliability and safety than retrievable packers.

	5 ½” tubing				
Risk	Description	**P**	**I**		
			HS&E	T&C	WOBJ
Historical reliability and sizing in HPHT environment on NCS	Experience from NCS show subsea wells are normally completed with 5 ½” tubing.	P3	I1	I1	I1
	7” tubing				
	Description	**P**	**I**		
			HS&E	T&C	WOBJ
	The use of a 7” tubing is limited to platform operations. Subsea wells use HXMT (simplicity and better designed for subsea wells). 7”	P3	I1	I1	I5

	5 ½” tubing				
Risk	Description	**P**	**I**		
			HS&E	T&C	WOBJ
Subsea equipment (HXMT) limitations in subsea HPHT wells	5 ½” tubing provides minimal equipment restrictions	P2	I1	I1	I1
	7” tubing				
	Description	**P**	**I**		
			HS&E	T&C	WOBJ
	Need product development of a 15K HXMT tubing hanger sizing. Common and used on the NCS is 15K HXMT with 5 ½” ID tubing hanger (Aker trees)	P4	I1	I4	I4

	5 ½” tubing				
Risk	Description	P	I		
			HS&E	T&C	WOBJ
ID clearance and installation procedure	5 ½” tubing easier to run due to higher ID clearance from tubing to casing.	P3	I1	I1	I1
	7” tubing				
	Description	P	I		
			HS&E	T&C	WOBJ
	7” tubing introduces potential clearance issues in 9 7/8” casing with pressure & temperature gauges, control lines. ID clearance very small	P3	I1	I1	I3

	Permanent Packer				
Risk	Description	P	I		
			HS&E	T&C	WOBJ
Packer reliability in HPHT conditions	History of pre-maturely setting. Operation performed at floater in potential harsh environment. Pre-setting of packer common in older HPHT fields on NCS.	P2	I1	I1	I3
	Retrievable Packer				
	Description	P	I		
			HS&E	T&C	WOBJ
	Less experienced packer solutions from older fields on NCS. New packers’ elastomers quality proven for HPHT conditions. Proven easier concept for pulling and retrieving in case of stuck	P2	I3	I1	I3

	Permanent Packer				
Risk	Description	P	I		
			HS&E	T&C	WOBJ
HPHT field experience on the NCS	Production packers is commonly permanent. Low complexity, simple, and robust solution. Field proven. Pre-setting WOBJ issue	P3	I1	I1	I2
	Retrievable Packer				
	Description	P	I		
			HS&E	T&C	WOBJ
	Less experienced packer solution on the NCS in HPHT environment	P2	I3	I2	I3

6.2 Full Design Proposals

The upper completion is the same for both open hole and perforated liner concepts. Lower- and middle completion proposals will be presented with differences.

Table 6-1: Upper completion equipment selection

Section	Equipment
Tree	Horizontal XMT (5 ½»)
Tubing	5 ½», 26 lb-ft, Super 13% P-110
Safety Valve	Tubing Retrievable
Production Packer	9 7/8” x 5 ½” Retrievable Packer
Casing body	Wireline retrievable Bridge/Glass Plug

Table 6-1 present the upper completion equipment selection. The tubing size will be **5 ½”**, **26 lb-ft** with added chromium, **13%** or **Super13%** to accommodate for CO_2. For H_2S mitigation and yield strength requirements, the **P-110** grade is selected. Again, the need for an absolute equipment quality check need to be conducted. Horizontal XMT is selected due to being more compatible with subsea wells for field development purposes, as Vertical trees are not available.

Permanent packers will be selected to accommodate for the lower reliability and higher safety risk associated with retrievable packers. Latest well reports from Morvin Field reported no negative experiences with the use of retrievable packers in HPHT environment, and looking into retrievable packer solutions for Hades/Iris field development is recommended.

6.2.1 Open Hole Predrilled Liner Proposal

Without the ability to simulate the predrilled liner design to achieve hole size, hole density, open flow area and fluid compatibility, the actual flow performance and skin of open hole completion cannot be determined. However, addressing the actions necessary to provide a functional design for further development is possible.

The reservoir-drilling fluid is of great importance when considering open hole completions. For the sake of reservoir permeability and reduced formation damage, the completion fluid should contain the same properties as the reservoir drilling fluid (Downs, 2006). When considering drilling fluid filtrate, it should be compatible with the completion fluid filtrate to minimize leak-off and damage the formation. In practice, the completion fluid should be designed as the drilling fluid, without or with reduced solids (Downs, 2006).

A fluid study should be conducted to which drill-in fluid to be used as most compatible with the reservoir with respect to bridging, filter cake, wellbore stability and liner-running conditions. For a vertical well, ECD and hole stability is less of concern compared with a long horizontal section. The use of OBM drilling fluid can be considered to reduce the fluid costs associated with cesium formate (CsCOOH, up to 2.3 sg). However, if the necessary density to drill the 8 ½" section is below 2.0 sg, the evaluation of KCOOH (potassium formate, 1.59 sg) and $CaBr_2$ (calcium bromide, 1.79 sg) should be considered as a solid-free drill-in and completion fluid. However, the density may be too low. Still, cesium formate has a good track record and is highly experienced as a drill-in and completion fluid in HPHT fields on NCS (Downs, 2006).

Once the reservoir is drilled, the well should be conditioned and displaced to a reduced-solid completion fluid. The completion fluid should represent similar properties as the drill-in fluid. In order to secure optimum liner-running conditions, the fluid is removed of solids, while keeping the weight.

The liner will include an **ILCBA** to eliminate the use of a Middle Completion barrier assembly. This will reduce the swab/surge potential in an additional run. However, the need to further study the pressure testing of the liner hanger-packer need to be conducted to reduce the risk of failing the integrity test. Conventional HPHT liner hanger packers provide a conservative mechanical manipulation mechanism. However, expandable liner hanger systems provide hydraulic internal pressure stimulation. The need to further study the use of liner hanger packer and conclude on systems should be initiated by OMV (Norge) with regard to annular reservoir isolation and liner running efficiency. Table 6-2 present the reservoir isolation assembly:

Table 6-2: Downhole barrier assembly for OH completion

Section: 5 ½"	Mechanical Barrier	Physical Barrier
Top of liner	Liner Hanger 15 ksi V0-rated	**N/A**
Liner body	Premium Connections (M2M)	
Liner Bottom	Bridge / Glass plug 15 ksi V0-rated	

A noticeable detail was encountered while analyzing the use of downhole barrier assembly with open hole completion. If the open hole completion is decided to run with an ILCBA, the need to retrieve or break the internal liner plug is of utter importance. Normally, a contingency plan would be to punch the pipe above the plug to re-gain flow. This will not be possible with only one isolation packer, as Hades will then be exposed. A milling operation would be challenging. Figure 6-3 illustrate the complex contingency case for open hole lower completion if unable to retrieve internal plug without the isolation packers above Hades.

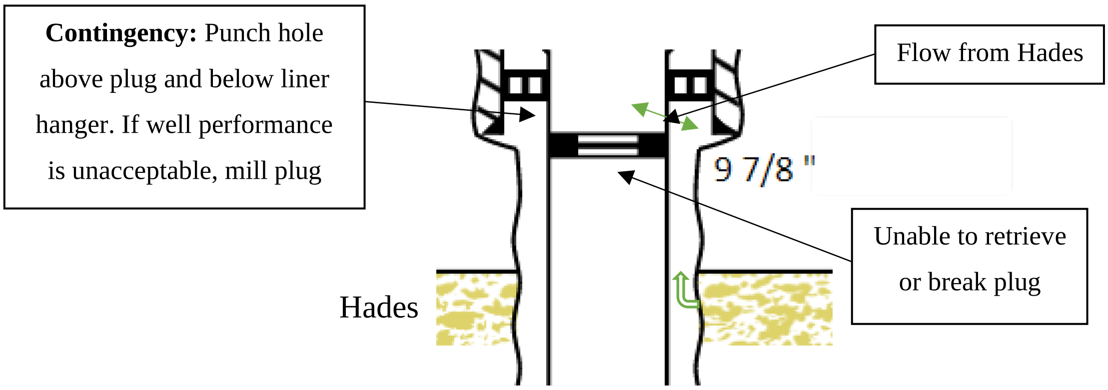


Figure 6-3: Contingency planning for open hole lower completion

However, the option to eliminate this issue is to place a new set of open hole isolation packers above Hades, illustrated in Figure 6-4. This way, a milling operation can be conducted without the risk of exposing the reservoir. This will in return increase the risk associated with running open hole isolation packers. Finally, Figure 6-5 present the full open hole completion proposal.

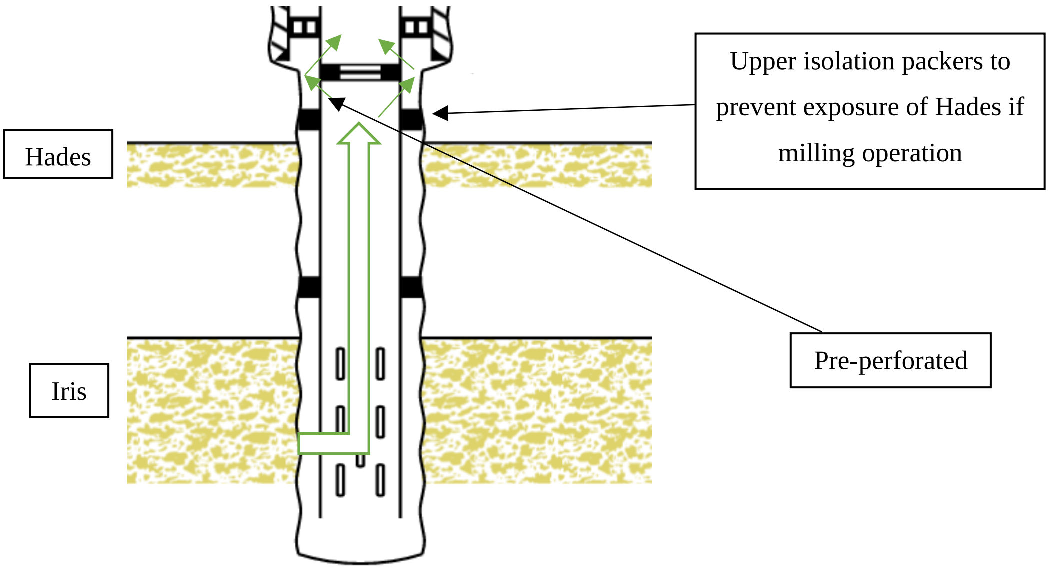


Figure 6-4: Punched hole with double isolation packers. Pipe below plug is pre-perforated. Pipe above is punched hole

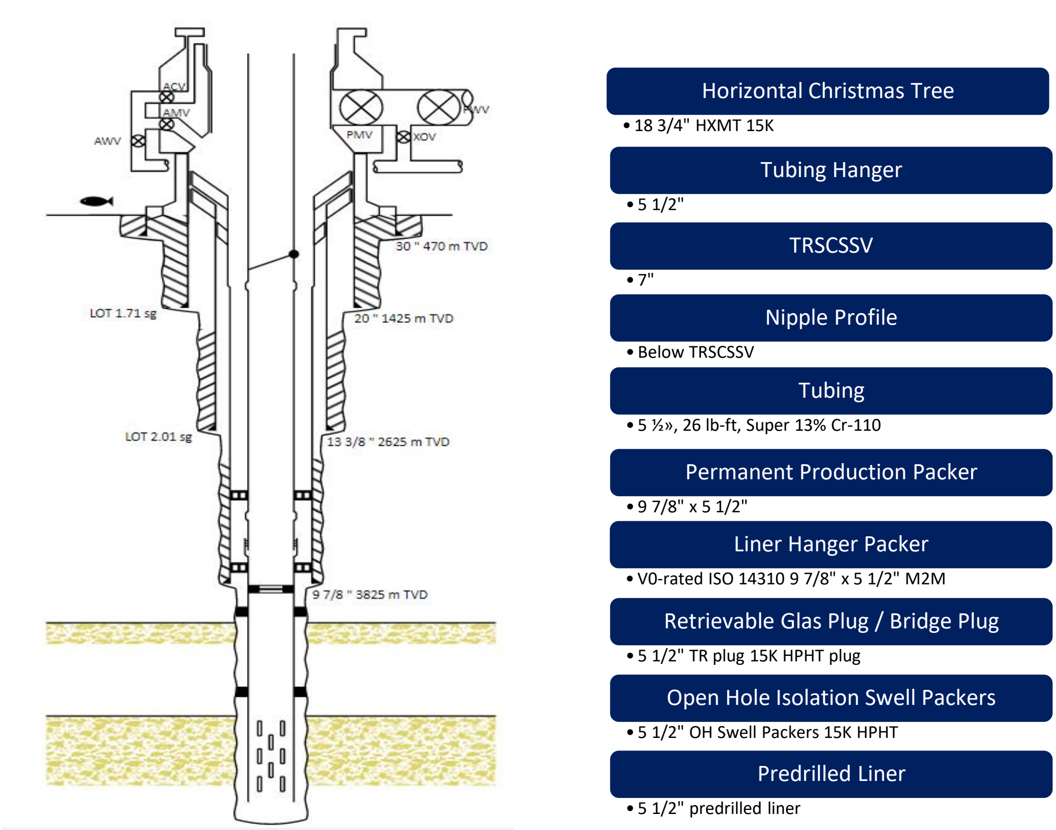


Figure 6-5: Full Open Hole Predrilled Liner Concept

6.2.2 Cased and Perforated Liner Proposal

For a C&P well, Iris Production well can be perforated with a semi-submersible drilling rig. As the intention of the thesis is to look at this as a single operation, and not necessarily a field development, the utilization of a Light-Intervention Vessel to perforate multiple wells in an underbalanced pressure regime is not evaluated. The perforation must be done on the floater, in potentially harsh environment during winter. The first consideration is to decide on which conveyance method is most suitable for the operation. In an HPHT related well operation, integrity and well control will be of great importance. Perforating in an overbalanced pressure regime following a well kill has previous experience of potential well damage and compromised well productivity. By perforating on drill pipe following by pulling out of hole can introduce wellbore instability. By utilizing a dynamic underbalanced pressure regime, the removal of perforation and well debris can potentially clean the perforation interval, hence obtaining sufficient skin levels. To introduce a safer running operation, the upper completion *should* be run in hole prior to perforating. This introduce the use of two conveyance methods: Tubing-conveyed (TCP) and wireline-conveyed perforations (WCP).

TCP can provide the biggest guns for the operation, as the guns are run in hole at the end of tubing, as illustrated in Figure 6-6. However, Iris reservoir is located approximately 300 meters below 9 7/8” casing shoe. The distance from tubing end down to the perforation interval is long. The guns can be dropped in hole if a sufficient rat hole is created, but for this to be practical, it required a rathole approximately 300-350 m below perforation target.

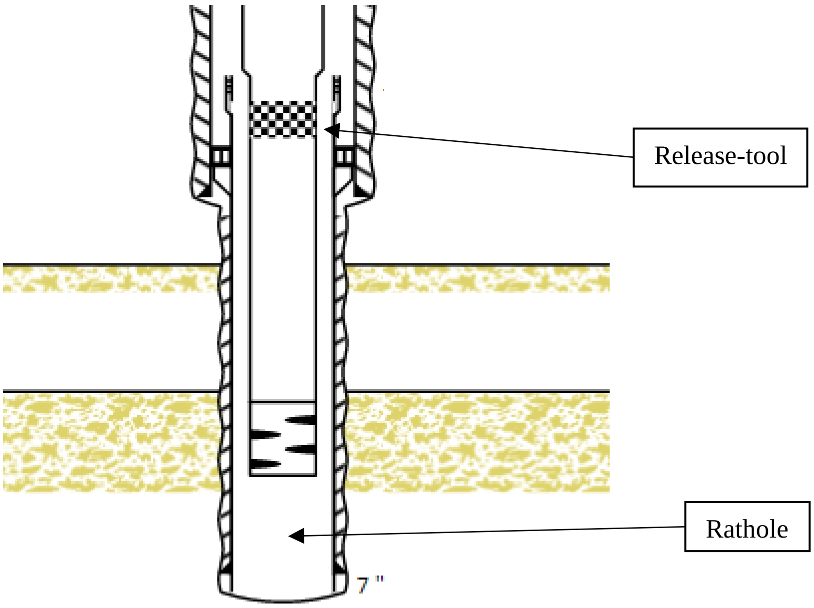


Figure 6-6: Guns attached with release-tool at the end of tubing

The release-tool naturally need to be placed just above the guns. This will leave a 250-300 m long blank pipe of 4 ½” tubing left in the hole. As the intention is not to retrieve the guns, using tubing conveyed will be screened out.

WCP can access the reservoir section due to low inclination. Gun weight must be simulated in HPHT conditions to account for running the perforations to target depth. It is, by great importance, critical to mention the need for simulating the wireline tension cable and weak-point limitations. This may be a potential showstopper. The advantage with using wireline conveyed through-tubing or anchoring of perforation guns, is that all the necessary barriers can be run pre-perforating. The well will be displaced to potential low-solids OBM or a heavy brine (potassium/cesium formate).

A noticeable detail must be reviewed; the use of reservoir isolation is not needed due to the reservoir being isolated by cement. If, however, the operator wants to perforate before setting the permanent completion, two options can be supplied:

1. An ILCBA can be run if the liner size is the same as the tubing. If liner is bigger than tubing, ID restrictions will limit the use of internal plugs in the lower completion. Setting plugs will therefore be complex.
2. If the liner is 7” and tubing is 5 ½”, a MC will provide reservoir isolation without the complexity presented in the point above, as it is set in the production casing (9 7/8”).

Table 6-3: Middle Completion barrier assembly for C&P concept

Section	Mechanical Barrier	Physical Barrier
Annular Barrier	Permanent Packer 15 ksi V0-rated	**Cement**
Liner body	Premium Connections	
Internal	Bridge / Glass plug 15 ksi V0-rated	
Production Casing	Premium Connections	

The cased and perforated reservoir isolation is summarized in Table 6-3. The reservoir is isolated by cement. The need for a separate barrier assembly is therefore ***not needed*** for the original cased and perforated method. This is highly beneficial, as it eliminates the risk associated with running the barrier assembly. However, if the need for re-perforation, intervention activities or opening up Hades for production, the barrier assembly needs to be run. The reservoir is then open, and isolation is needed if wanting to re-run upper completion. Running a MC with a nipple spot for deep plug setting can be considered for further operations, but the need for MC is in this case not considered.

Through-Tubing Approach

Once the upper completion is set and pressure tested, the gun-string is lowered in the hole through-tubing. By utilizing the through-tubing, the OD of guns is limited depending on tubing size. The evaluation of using smaller gun size with a less thermally stable but better performing explosive with wireline perforations should be studied further. According to Grove, DeHart, McGregor, Dennis, and Christopher (2019), “*the operator recognized that HNS charges typically exhibit lower performance (reduced penetration depth, etc.) than comparable HMX charges because of reduced output energy”* (p. 10). The explosives are less exposed to HPHT conditions if run on wireline, therefore introducing the availability of a less thermally stable explosive to potentially create deeper penetrations. Table 6-4 illustrate the wireline-conveyed perforations through-tubing approach:

1. Wireline-Conveyed Perforations with **through-tubing approach:**

Table 6-4: Through-tubing approach

1	• Cement production liner. Log and verify cement quality
2	• Clean liner, scrape packer setting areas. Displace well to brine completion fluid
3	• RIH with upper completion. Set TH, pressure test. Circulate packer fluid, set and inflow packer
4	• RIH with perforation guns on wireline through-tubing. Verify setting depth and place guns
5	• Perform perforation operation in (prefarebly) DUB pressure regime
6	• Flow debris and clean well. Open up well for flow. Complete well

The guns used in this scenario is 2 7/8” – 3 3/8” due to tubing being 5 ½”. Guns are lowered through-tubing to perforation interval. Gun is fired, wireline cable retrieved to surface with remaining of guns. Well is flowed and debris removed. Figure 6-7 show the cemented liner with a 5 ½” tubing attached to the PBR and liner hanger. The reservoir is isolated prior to running the gun string. The permanent completion is run in hole before opening up the reservoir.

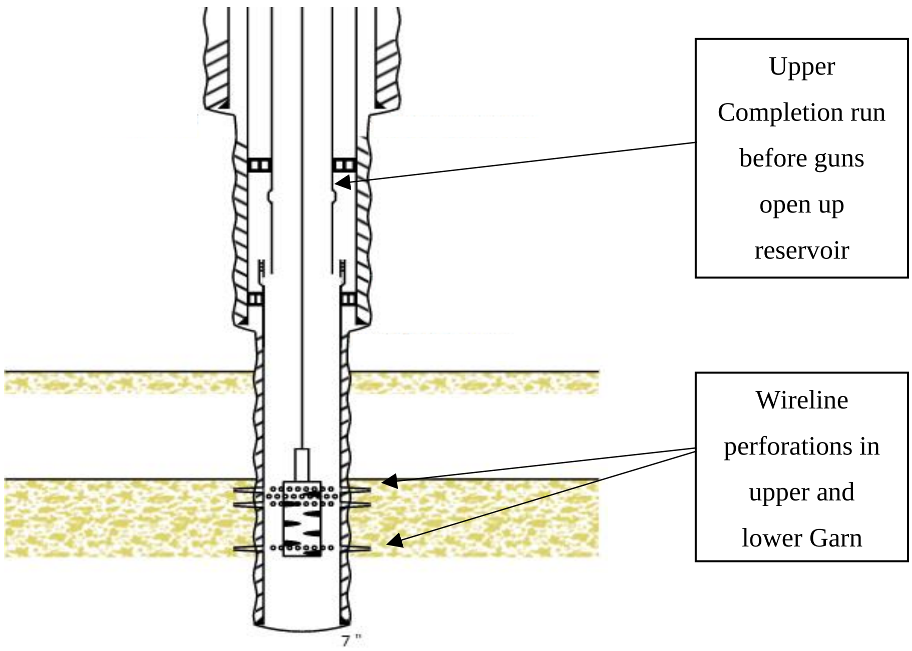


Figure 6-7: Through-tubing wireline perforation

Anchored Perforations Approach

However, the through-tubing solution provide a smaller gun-size as the selected tubing is smaller than the production liner. New field experience show that the wireline-conveyed perforations can be done without through-tubing. Instead, the gun-string is lowered down to perforation setting depth and anchored to the casing with the ability to automatically drop-off once detonated (Aboelnaga et al., 2017). Table 6-5 illustrate the approach:

1. Wireline-Conveyed Perforation with anchored gun-string with **automatic release approach**

Table 6-5: Automatic guns-release approach

1	• Cement production liner. Log and verify cement quality
2	• Clean liner, scrape packer setting areas. Displace well to a brine completion fluid
3	• Run in hole with perforation guns and anchor with release device. Verify setting depth
4	• RIH with upper completion. Set, pressure test and inflow test upper completion
5	• Engage perforation operation by pressuring up to detonation-pressure. Perforate and drop guns
6	• Flow debris and clean well. Open up well for flow

The second approach implies that the guns are lowered down in the hole with wireline before the upper completion is installed. This adds for longer exposure time, but bigger gun size. The need for a more thermally stable explosive must be considered, but a bigger gun can be used. The guns are anchored in the liner with a release-tool to drop the guns once perforated. Guns will be attached to the casing as illustrated in Figure 6-8:

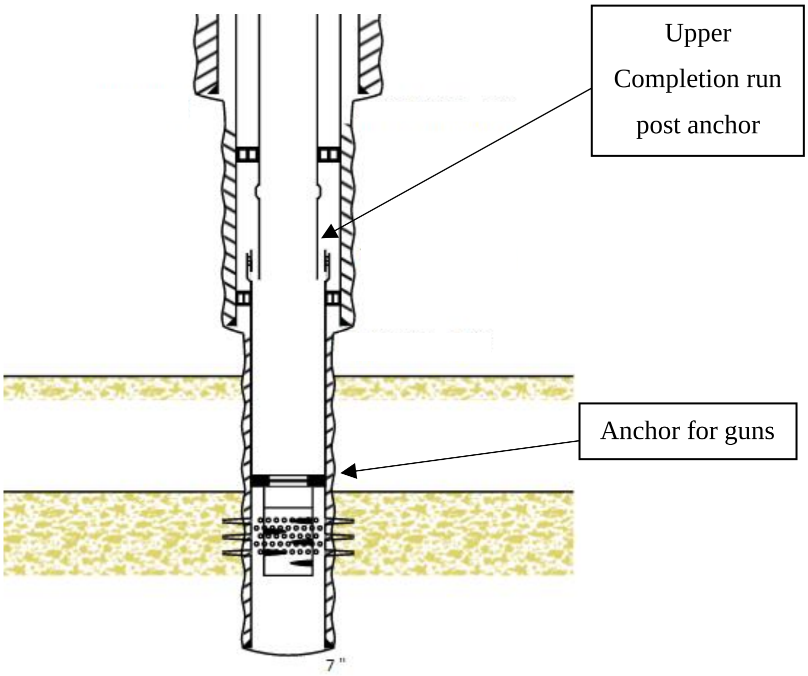


Figure 6-8: Anchored perforation guns

Upper completion will then be installed, pressure- and inflow tested. Once the upper completion is tested, the perforation sequence can begin. The perforations will be activated by pressure cycling up the guns. Once the guns have perforated, the release-tool engages, and guns dropped to bottom (Figure 6-9).

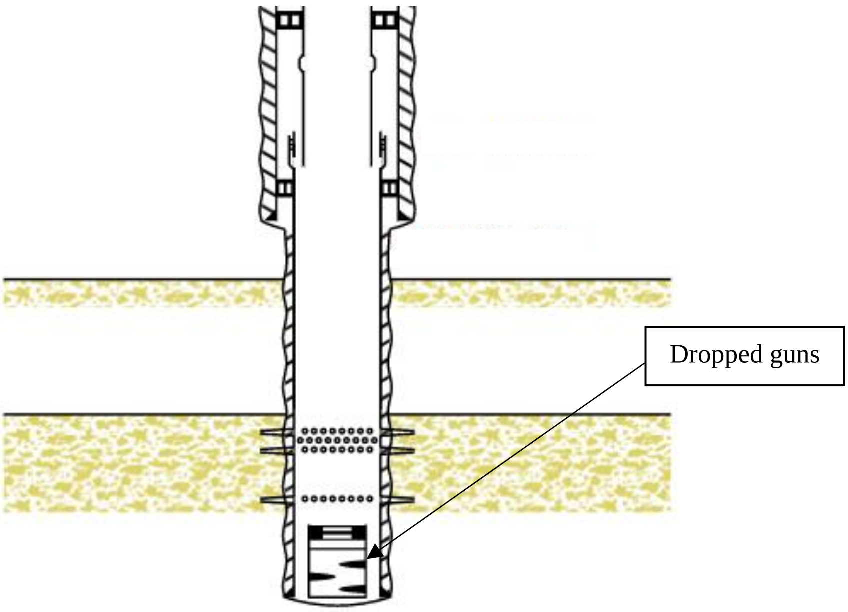


Figure 6-9: Guns dropped to bottom

The risk of a malfunction in the release-tool provide challenges with well performance and intervention/fishing activities. The guns can potentially block the flow path, therefore reducing the inflow performance. The release-tool and guns need to be milled out. The million operation is highly critical to re-gain an acceptable inflow performance.

Due to uncertainty in stuck guns with the anchored approach, wireline conveyed perforation will be selected as C&P concept. The tradeoff between wireline risk versus milling the anchored guns is hard to determine. If wireline perforations cannot be achieved, conventional perforations with pipe prior to running the completion needs to be evaluated. Well schematic for cased and perforated method is presented in Figure 6-10:

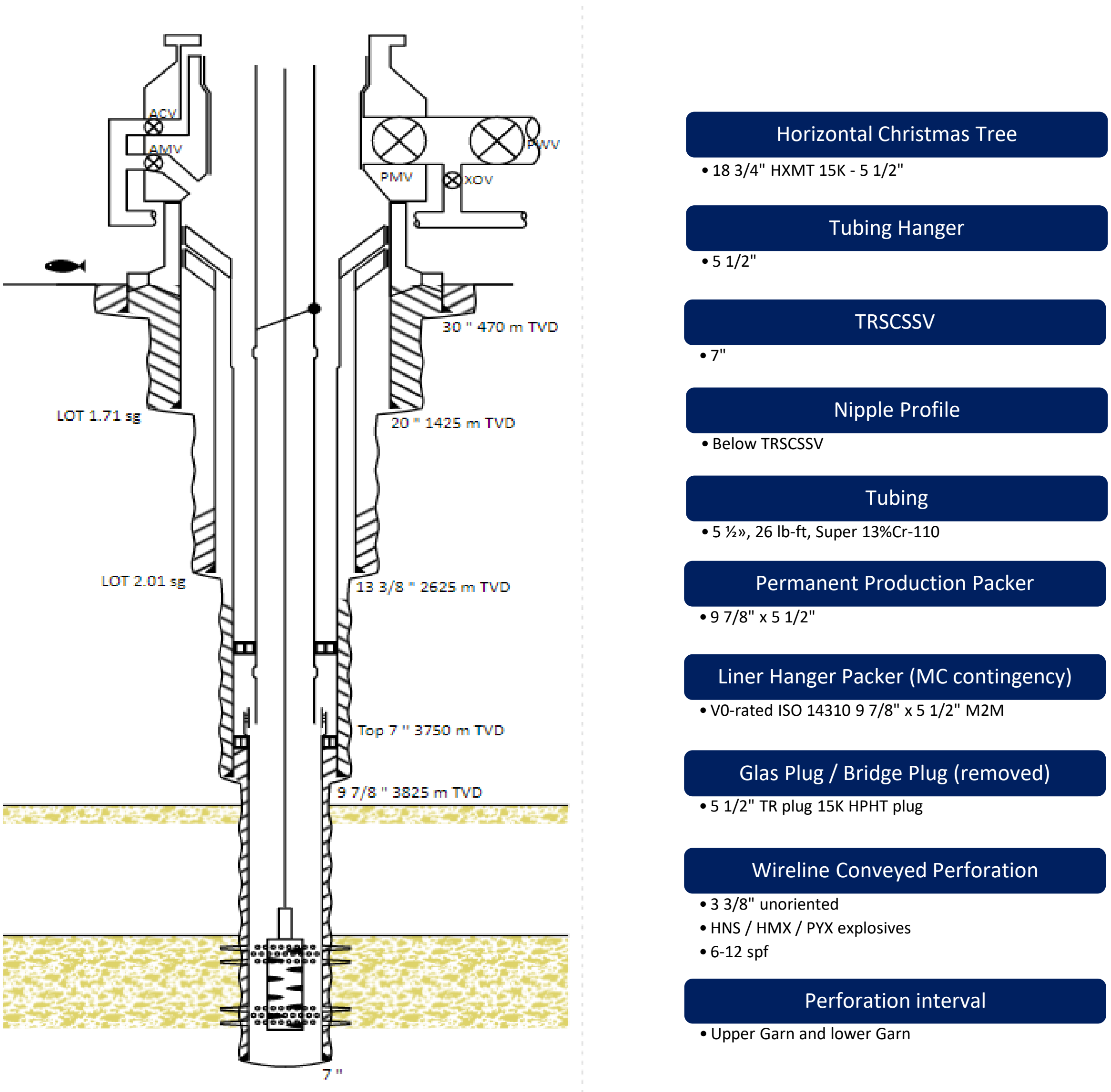


Figure 6-10: Cased and perforated liner proposal

CHAPTER 7

7 Conclusion and Recommendations for Future Work

The final proposal comes with finalized rationale of HS&E, WOBJ and T&C considerations. *The lower, middle, and upper completion concept chosen* is illustrated in Table 7-1:

Table 7-1: Final Proposal

Proposal	
Lower	Open Hole Predrilled Liner
Middle	Integrated Lower Completion Barrier Assembly
Tubing	5 ½”, 26 lb-ft, Super13%Cr-110
Packer	9 7/8” x 5 ½” Permanent Packer

HS&E

The HS&E has between the methods very different perspectives. For open hole completion, well control is in focus. For perforated liner, the use of explosives adds operational risk. Wellbore stability should be the absolute focus when performing an open hole completion. Total loss scenario, gas migration and filter-cake removal should have the highest priority. However, if perforations can be avoided, it will remove all explosives from the operation, alongside perforation risk with regard to well control. Eliminating explosives is valued highly in the thesis. Open hole completion is considered less HS&E exposed than C&P concept.

1. ***Elimination of perforations***

- By eliminating the perforations, no explosives will be exposed to personnel on rig-floor. The risk of pre-maturely firing will be eliminated, influencing the overall personnel HS&E risk positively.

Risk	**Description**	**Impact**	
		Open Hole Predrilled Liner	Cased and Perforated Liner
HS&E	Perforations eliminated from operation		

2. Perforating operations – gun shock, formation surge and release-tool malfunction

- Operational risks related to wireline perforation greatly impacts the operation. If the anchored guns are not dropped, the inflow performance may be greatly reduced. The contingency operation involves milling of guns. If decided to go for wireline conveyed perforations, the guns blowing up-hole scenario will cause major well control issues.

Risk	**Description**	**Impact**	
		Open Hole Predrilled Liner	Cased and Perforated Liner
HS&E	Gun shock, formation surge, release-tool malfunction, wireline perforations		

3. Exposure time and additional running of equipment in HPHT conditions

- Running Middle Completion require an additional run. It is naturally to be avoided if possible. However, ILCBA needs further qualification to improve the reliability. For HS&E purposes, eliminating the MC will decrease the exposure time and limit equipment running in a live well scenario.

Risk	**Description**	**Impact**	
		ILCBA	Middle Completion
HS&E	Exposure time and additional equipment running		

4. Packer experience and reliability in HPHT conditions on NCS

- Removable packers are less experienced on NCS, greatly punishing the concept HS&E wise. More moving parts introduce both HS&E and well objective risks

Risk	**Description**	**Impact**	
		Permanent	Retrievable
HS&E	Packer HS&E experience in HPHT conditions on NCS		

Well Objective

Experience, reliability, and maturity was of great focus for determining which method to select. Cased and perforated liner is a highly experienced method on the NCS, but the fact that Morvin did a successful completion with predrilled liner in similar environment is a huge contributor to further study the method. As HXMT's do not provide 7" tubing compatibility, the need to qualify a 15k XMT is set as a high impact on HPHT maturity in the thesis. This effects the well objective with limiting gun size selection for perforated liner concept.

5. ***Lower Completion experience in similar or comparable HPHT environment***

- Based on positive experiences at Morvin Field, the completion technique has proven to be a successful method for HPHT scenario with comparable reservoir qualities as Hades/Iris. The implementation of a Predrilled liner contributes to learning and implementation for OMV (Norge) AS for future field development.

Risk	**Description**	**Impact**	
		Open Hole Predrilled Liner	Cased and Perforated Liner
Well Objective	Lower Completion method HPHT experience on the NCS		

6. ***Subsea equipment limitations for using 7" upper completion***

- Extended work is required to qualify an HXMT to provide 7" tubing-hangers. The 5 ½" is the dominant tubing size for subsea wells and floater-operations in HPHT environment in NCS. This eliminate the use of wireline-conveyed perforations with the biggest guns.

Risk	**Description**	**Impact**	
		5 ½" tubing	7" tubing
Well Objective	Subsea HXMT limitations for using 7" tubing		
Risk	**Description**	**Impact**	
		Open Hole Predrilled Liner	Cased and Perforated Liner
Well Objective	Bottleneck design		

7. Vertical well inflow performance – open hole versus cased and perforated

- Perforation operations in HPHT wells are from NCS experience performed in majority of the high inclination and horizontal wells. The perforation tunnels will be subjected to high vertical stresses, potentially increasing the risk of producing sands or hole collapse. Vertical well performance in HPHT scenario is by experience related to OH completions (SAS).

Risk	Description	Impact	
		Open Hole Predrilled Liner	Cased and Perforated liner
Well Objective	Vertical well inflow performance		

Time & Cost

Time and cost are set to be the lowest priority in the thesis, but impact wise it really hit the lower completion decision. The cost of perforating on a semi-submersible is expected to bring a very impactful change on the total operational cost. If perforated with permanent barriers in place, the elimination of reservoir isolation will promote cased and perforated option. However, due to potentially re-opening the well, a sort of isolation must be installed at a later stage.

8. Lower Completion time and cost

- The extra 8-15 days of installation and perforation job greatly impacts the well cost. Based on the day-rate, the cost can potentially increase with 64-120+ MNOK if perforations are added. Time and cost are valued as a third priority, but due to very high impact, was one of the major differences observed. Open hole completion adds the cost of expensive completion fluids but has reduced impact due to faster installation procedure.

Risk	Description	Impact	
		Open Hole Predrilled Liner	Cased and Perforated Liner
T&C	Lower Completion time and cost		

9. Elimination of a Middle Completion

- Weak performance of V0 rated liner-hanger packer gives a high probability of unsuccessful running of an integrated lower completion. However, qualifying a liner-hanger packer with higher reliability will outweigh a middle completion by dropping a second run (HS&E). In both barrier assemblies, the liner has to be run. If not obtaining a good pressure test and sealing confirmation, the middle completion can be run as contingency.

Risk	Description	Impact	
		ILCBA	Middle Completion
T&C	Lower Completion time and cost		

10. Contingency planning

- Operational experience introduces contingencies for different methods with various results. ILCBA may deliver an insufficient seal or pressure test, meaning the Middle Completion can be run as contingency. But, if the Middle Completion fails, it needs to be re-run. Contingency planning is vital for well completion with regards to time and efficiency.

- Slimhole completions (4 ½” reservoir liner) crumble the lower completion method. For slimhole completions, open hole predrilled liner concept is more compatible. For cased and perforated concept, this will greatly punish the gun size, thus reducing the penetration depth.

Risk	Description	Impact	
		ILCBA	Middle Completion
T&C	Contingency planning for reservoir isolation		
Risk	**Description**	**Impact**	
		Open Hole Predrilled Liner	Cased and Perforated Liner
T&C	Slimhole completion (4 ½” reservoir section)		

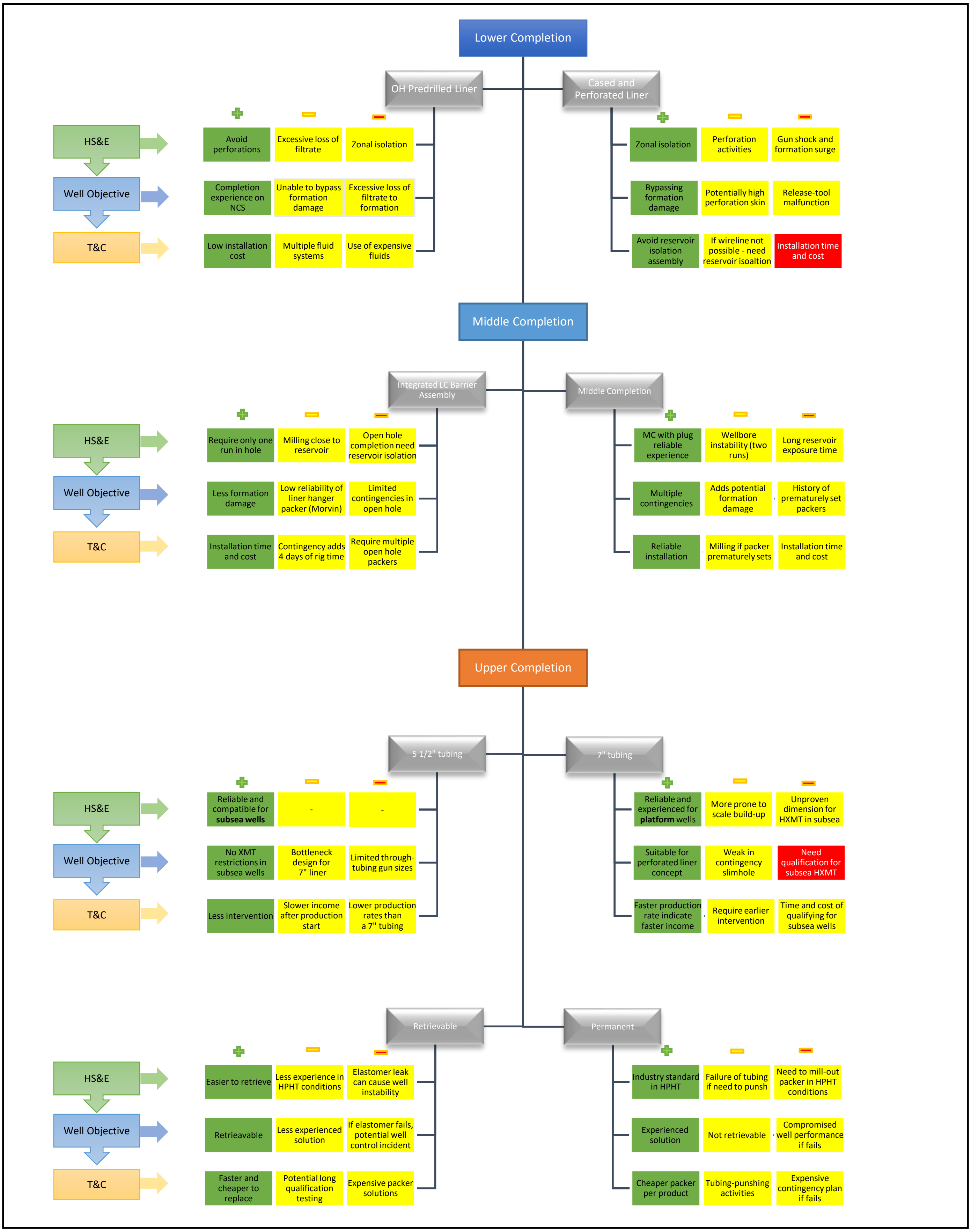


Figure 7-1: Full overview of advantages and disadvantages for the full method selection

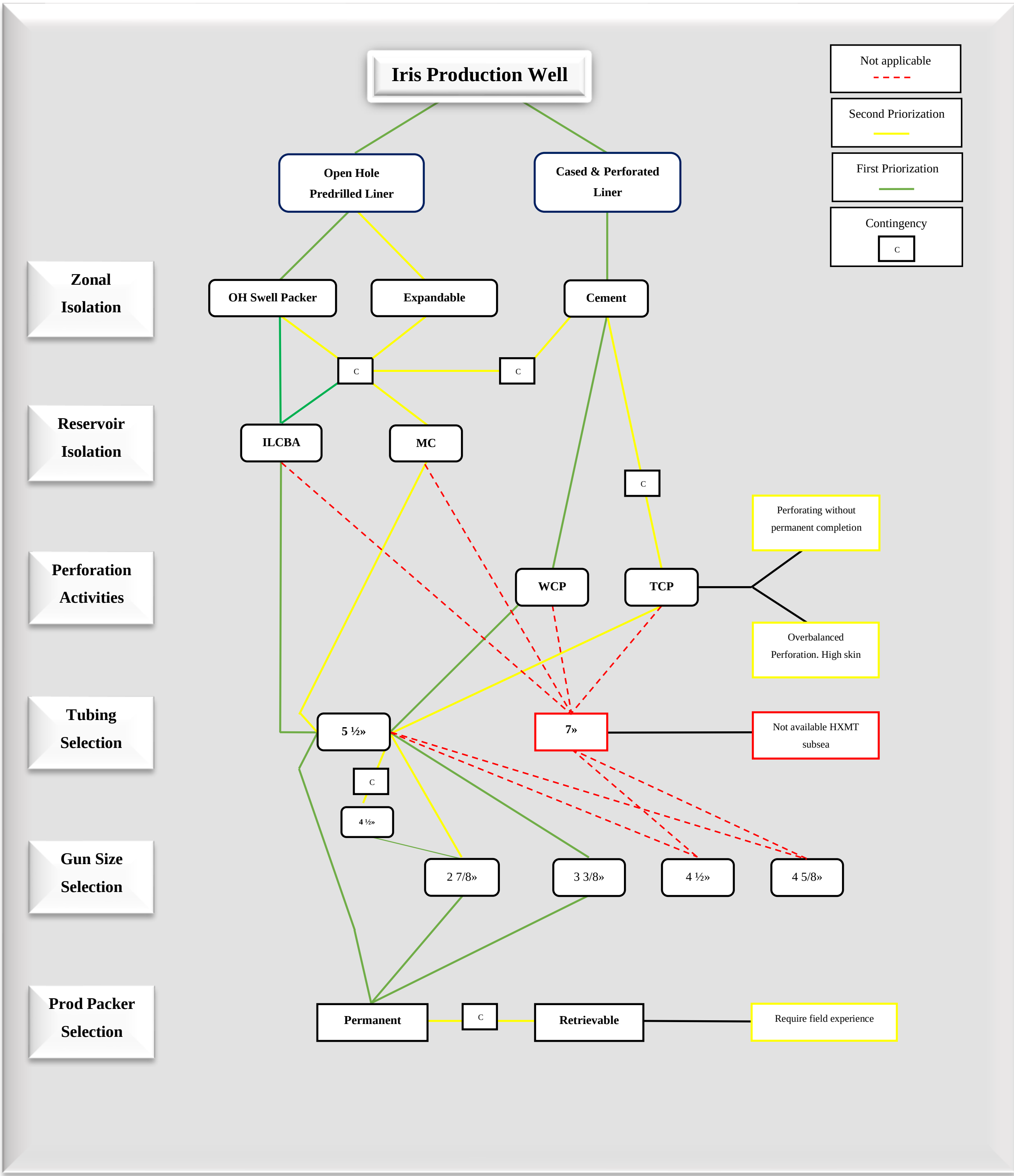


Figure 7-2: Decision tree for the full method selection

7.1 RECOMMENDATIONS FOR FUTURE WORK

Iris Production well contribute with many considerations for the future field development of PL 644 Hades/Iris HPHT field. Below is a list of observations from the final proposal alongside suggestions and considerations for future development of production wells targeting Iris reservoir:

1. **Well Trajectory.** Iris Production well is presented as a vertical production well with close to zero dogleg. A possible improvement in well design is to implement a horizontal well design, in order to eliminate the need to isolate Hades reservoir. By studying reservoir characteristics, Hades can be avoided by finding a zone where Hades is minimal (or non-present). The reservoir exposure may increase with longer horizontal sections of the reservoir now being open for flow. The horizontal well trajectory is already a proven open hole producer solution in Morvin well but may also introduce perforations as horizontal wells provide potentially more stable perforation tunnels.
2. **Perforation performance.** One of the main risks identified was the penetration penalty obtained in highly stressed formations. It is expected shorter depth than "normal" stressed formation. This, alongside the experience behind vertical perforations in stressed formations will either exclude the concept or force the completion engineers to look into a horizontal well trajectory for future field development.
3. **Qualification study for a Liner Hanger Packer.** In order to eliminate the need for a Middle Completion, optimization of a Liner Hanger Packer would be a natural point to increase the reliability of ILCBA annular sealing. This will enhance HS&E, T&C and well objective. However, the qualification and field testing of the packer may be time consuming. If determined to eliminate the need for a MC barrier, OMV (Norge) AS should look into improving the reliability of liner hanger packers to increase the probability of success.
4. **Keep It Simple and increased planning time.** The term Keep It Simple (KIS) is highly applicable to HPHT completions. However, the need to fully comprehend the necessary time to plan adequately may promote improved concept and performance. Communication is key, and will always minimize human failure, therefore minimizing risks in all the specters of consequence level. Less is more is highly appreciated in HPHT well planning.

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APPENDIX A – RISK REGISTER GUIDELINES

The Appendix covers the risk register for lower, middle, and upper completion for the master thesis. The guide was created to document and access the risks throughout the thesis.

Risk Description

Introducing the risk, the cause of risk and description of how it affects the selected method.

1. Risk Title, cause of risk and description of risk relative to method is presented		
Risk Title	**Cause**	**Description**
Explosives exposed to personnel on rig floor, causing potential pre-fire before running in well	Prior to running in hole, explosives from perforations must be prepared and installed. The guns can fire before intended	Only relevant with the use of guns in hole. For open hole completions without any form of perforations, this can be eliminated

Determination of probability

Following the introduction of risk, the probability will be concluded.

2. Once the risk is understood, the probability of risk will be determined

The use of probability can be as following:

If a general description is more accurate, the description can be used. For example: "The risk is likely to occur", or, "The hisk is highly unlickely to occur"
-If a specific description related to Norwegian Continental Shelf experience is accurate, the specific description can be used. For example: "The risk could happen during our operation", or "the risk has never occured in the history"

Likelihood		General description
Relative	**Numerical**	
Very Low	P1	Highly unlikely to occur
Low	P2	Will most likely not occur
Moderate	P3	Possible to occur
High	P4	Likely to occur
Very High	P5	Highly likely to occur

- Possibility of a risk event ocurring
- Qualitative manner, relative and numerical
- The description is based on the likeliness of occurence

Likelihood		Well Engineering (NCS) related description
Relative	**Numerical**	
Very Low	P1	Never occured in the industry
Low	P2	Heard of in the industry
Moderate	P3	Incident could happen in our company
High	P4	Incident could happen during our operation
Very High	P5	Incident could happen more than once during this operation

Determination of impact

Following the probability, the impact will be concluded.

3. Once the probability has been determined, the impact level will be analyzed

The impact is based on value-drivers. The value-drivers are divided in sub-genre, like following:

Value Driver	Sub-issue
HS&E	Personnel Environment Reputation
T&C	Installation Equipment & Fluids Contingency
Well Objective	HPHT Maturity & Reliability Flexibility Well Performance

Impact level will range from 1 to 5, where 1 is incidental and 5 is extreme

Decreasing Consequence	5
	4
	3
	2
	1

All the impact levels and description is located in chapter 5

Implementation of risk matrix

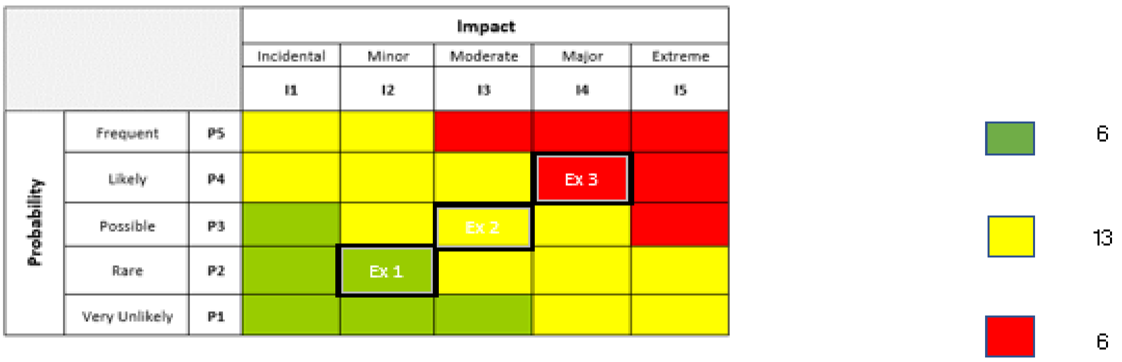
4. Once the impact level has been determined, the next step is to implement the risk matrix

Example 1:
If a probability of **P2** and impact of **I2** is given, the following score will be: **P2** x **I2** =

Example 2:
If a probability of **P3** and impact of **I3** is given, the following score will be: **P3** x **I3** =

Example 3:
If a probability of **P4** and impact of **I4** is given, the following score will be: **P4** x **I4** =

Example of P4 x I4



APPENDIX B – RISK REGISTER

Lower Completion Risk Register

Risk Title	Cause	Open Hole – Predrilled Liner: Description	P	I: HS&E	I: T&C	I: WOBJ	Cased Hole – Perforated Liner: Description	P	I: HS&E	I: T&C	I: WOBJ
Explosives exposed to personnel on rig floor	Prior to running in hole, explosives from perforations must be prepared and installed. The guns can fire before intended, causing danger to personnel	Only relevant with the use of guns in hole.	P1	I1	I1	I1	Gun pre-fire at surface can cause high personnel damage. Perforating is a normal procedure on NCS.	P1	I4	I2	I1
Gun shock and formation surge effects post perforation	Carrier flooded by completion fluid post perforation, creating shock waves. Tool can be pulled off the line due to downward force reflecting off packer and tailpipe	Only relevant with the use of guns in hole	P1	I1	I1	I1	Potential wireline conveyed perforation risk due to high pressures. Wireline cable can be blown up hole due to formation surge post perforation. Upward movement of shock wave: knot cable or wedge gun. Downward movement: shock wave reflecting off packer or tailpipe. Well control risk, re-gaining access to wellbore can be challenging	P2	I3	I1	I4
Lower completion installation involves use of toxic fluids (solvents, additives, brines)	Drilling, completion, and perforation fluid may contain toxic or environmentally damaging fluids which will be exposed to personnel on rig. The chance of personnel damage increases with the amount of toxic fluids used in the operation	Potential heavy brine drill-in fluid, CaBr2/Cesium Formate completion fluid, packer fluid. Should avoid zinc due to toxicity	P3	I2	I2	I1	Perforation pill, potentially reduced-solids OBM or brine, packer fluid.	P3	I2	I2	I1
Multiple fluid systems required	The operation requires multiple fluid systems to achieve expected production performance and well stability, introducing heavy logistics and rig capacity issues	Reservoir drilling fluid (brine or OBM), liner-running fluid (brine or reduced-solids OBM), completion fluids (brine), packer fluid, wash-outs, additives, solvents. Probability of fluid filtrate increased.	P4	I2	I1	I2	Drilling fluid (OBM), cement, perforating pill (brine), completion fluid (brine), packer fluid. Cement still needed for reservoir isolation	P3	I1	I1	I2
Well control instability (gas migration) when installing completion	Lower completion installation when reservoir is open can introduce well control instability and potential gas migration	Vertical well - running predrilled liner could potentially meet tight spots. Liner running in OBM can cause unseen gas migration	P3	I2	I1	I1	Vertical well - running predrilled liner could potentially meet tight spots. Liner running in OBM can cause unseen gas migration	P3	I2	I1	I1
Hades reservoir need to be isolated to prevent influx and potential cross-flow	Hades reservoir need to be isolated due to being drilled in the same section as Iris. Depth difference between the two reservoirs is approximately 230 m TVD.	Zonal isolation packer set in shale section between Hades and Iris. No physical barrier (cement). Introduction of open hole swell packers will introduce potential malfunction or be non-sealing, influencing well objective	P3	I2	I1	I2	Cement will provide a physical barrier, isolating Hades reservoir. Need to test cement quality and height in order to verify Hades isolation. Increased rig-time. Insufficient cement may introduce complexity of zonal isolation	P3	I1	I2	I2

Risk Title	Cause	Open Hole – Predrilled Liner: Description	P	I: HS&E	I: T&C	I: WOBJ	Cased Hole – Perforated Liner: Description	P	I: HS&E	I: T&C	I: WOBJ
Lower Completion method HPHT experience on NCS	HPHT relevant experience from offset wells. Contribute with important data and considerations	Morvin Field. Low reported downtime and good well performance. Low skin, RS-OBCF, OH swell packers. Yet, low operational experience with predrilled liners. Screens more common	P3	I1	I1	I2	Experienced lower completion method on Kristin, Kvitebjørn, Gudrun, etc. Perforation in hard sandstone showing weak penetration depth. Reduced explosive performance due to HPHT. Overbalanced perforating potentially reduces inflow performance. High costs	P3	I1	I3	I3
Vertical well inflow performance in HPHT conditions	Perforation operations in HPHT wells are from NCS experience performed in majority of the high inclination and horizontal wells. The perforation tunnels will be subjected to high vertical stresses, potentially increasing the risk of producing sands or hole collapse	Low to mid-angel wells (0-45°) commonly open hole (SAS) on NCS. Experience show good well performance	P2	I1	I1	I1	Vertical well perforations uncommon on NCS. High-angle wells (60-90°) more common. Horizontal perforations introduce less sand potential in high stressed formations.	P2	I1	I1	I3
Lower Completion time and cost	Time and cost comparison from after 8 1/2" hole are drilled to lower completion activities are completed	Displace to liner-running fluid. Run liner and set hanger. 2 - 3 days (16-24 MNOK). Fluid introduce additional cost which is not seen with rig-usage. Expensive fluids. Added time for reservoir isolation barrier assembly	P4	I1	I3	I1	Running liner, circulate cement, cement liner, verify integrity of cement, drill shoe-cement, full perforation activities on a floater. The added time varies from 8 - 15 days (64 - 120 MNOK)	P4	I1	I4	I1
Perforation penetration depth in HPHT wells	HPHT formations have previous experience of being a hard sandstone with high formation stress. The penetration depth may be influenced by the high stresses. Penetration penalty is higher in high pressure formations, potentially decreasing the perforated interval depth	Only relevant with the use of guns in hole	P1	I1	I1	I1	High pressure formations introduce perforation depth penalty. The combination of lower density guns (through-tubing) and highly stressed sandstone may compromise well productivity	P3	I1	I1	I3
Overbalanced perforation introduces high perforation skin	When perforating, the total skin factor can potentially decrease the productivity. The skin may be higher than initially encountered	Only relevant with the use of guns in hole	P1	I1	I1	I1	Overbalanced perforating show higher perforation skin. If high perforation skin, well performance can be compromised.	P3	I1	I1	I3
Through-tubing approach may limit the penetration depth due to less density (smaller perforation guns)	The need for bigger guns is crucial for obtaining sufficient perforation length	Only relevant with the use of guns in hole	P1	I1	I1	I1	5 1/2" tubing, the biggest available guns are 2 7/8" - 3 3/8". If contingency liner has to be run (4 1/2"), even smaller guns	P3	I1	I1	I3
Formation damage caused by drilling and completion fluids can provide decreased flow potential and well performance due to high damage	Formation damage caused by heavy drilling fluids and completion fluids. Incompatible fluids and solids from drilling fluid may compromise productivity	Formation damage can potentially limit well productivity. If the formation damage is very high, the predrilled liner will not bypass this zone. Well performance can have severe impact	P3	I1	I1	I3	Ability to bypass drilling damage due to perforations	P1	I1	I1	I1

Risk Title	Cause	Open Hole – Predrilled Liner: Description	P	I: HS&E	I: T&C	I: WOBJ	Cased Hole – Perforated Liner: Description	P	I: HS&E	I: T&C	I: WOBJ
Excessive loss of filtrate into reservoir	Insufficient fluid system can cause a loss scenario. This will cause formation damage and well control instability	Formation damage can limit well productivity. If open hole skin factor is high, inflow performance is low. Can cause severe impact on well performance if filtrate leaks and compromise formation permeability	P3	I1	I1	I4	Relevant for drilling damage, but normally bypassed by perforations	P2	I1	I1	I1
Zonal isolation fails due to swell packer malfunction/leaking. Cross-flow between Hades and Iris reservoir	Swell packers are set in shale section between Hades and Iris. If the swell packers fail to seal the bore, potential leak paths may be expected. Weak contingency planning if upper isolation packers fail	For open hole completions, the risk of using swell packers are present. The consequence may be re-running completion and potentially mill the packers. The operation is time consuming. Experience from Kvitebjørn, Kristin and Morvin Field show good record of reliable swell packers.	P2	I3	I3	I2	Zonal isolation is provided by cement job. Need to ensure sufficient cement job prior to landing lower completion. If cement is confirmed, Hades is isolated.	P2	I1	I1	I1
Anchor/Release-tool malfunction. Guns not dropped post-perforation	The release-tool may malfunction post-perforation. The guns will be stuck in perforation interval and limit well flow	Only relevant with the use of guns in hole	P1	I1	I1	I1	Anchor release-tool malfunction, guns are stuck after detonation. The guns limit productivity and require milling to remove. Alternative is to run smaller guns on wireline if cable is qualified	P2	I1	I3	I4
Through-tubing perforation experience on HPHT wells on the NCS	Experience on the NCS may enhance or crumble the method due to identified risks and its impact	Only relevant with the use of guns in hole	P1	I1	I1	I1	Limited wells reported with through-tubing perforating in HPHT wells on the NCS. Majority of wells perforated on pipe due to high angle	P3	I1	I1	I3
Contingency slimhole compatibility	The need to set a 4 ½” liner in reservoir may compromise well design with regard to method selection	Open hole completion is more compatible with slimhole contingency solutions. 4 ½” liner common production liner for open hole	P2	I1	I1	I1	Small gun selection in a slimhole contingency case. Reduced perforations. 4 ½” liner size introduces 2 7/8” as biggest guns (clearance)	P2	I1	I1	I3
Logging compatibility	Reservoir logging and data acquisition may be required or necessary to improve data gathering	Open hole completions are more prone to weak logging quality. High density Formate brines introduce weak values by previous experience	P3	I1	I1	I3	Cement normal and qualified for logging. Wireline capable of performing logging operation	P2	I1	I1	I1
Rathole requirement	Rathole is required in order to drop guns if decided to run on permanent completion (TCP with permanent completion)	Only relevant with the use of guns in hole	P1	I1	I1	I1	Require a 250-300 m rathole in order to drop guns. Time consuming and increase risk related to well control incidents (gas migration), solid settlement, formation damage and potentially stuck pipe	P3	I3	I2	I3
Contingency weak points	The operation method must provide sufficient contingency plans	1. Zonal isolation - insufficient swelling cause complex milling or re-rerun packers 2. Formation damage - high skin promote weak production 3. Sand control with pressure depletion	P3	I2	I2	I3	1. Contingency liner provide smaller guns 2. Re-perforation require reservoir isolation 3. Complex milling operation if anchor stuck in hole 4. Fishing operation if WL cable stuck in hole	P3	I2	I3	I3

Middle Completion Risk Register

The Middle Completion risk register starts with covering the impact on lower completion. The second register is covering the difference between a Middle Completion assembly versus Integrated Lower Completion assembly.

		Reservoir isolation – Lower Completion considerations									
		Open Hole – Predrilled Liner					Cased Hole – Perforated Liner				
Risk Title	Cause	Description	P	I			Description	P	I		
				HS&E	T&C	WOBJ			HS&E	T&C	WOBJ
Reservoir isolation can be eliminated	Cased and perforated liner concept has already sealed reservoir prior to running the Upper Completion. The need for reservoir isolation is not presented	OH completion need reservoir isolation. This can be done with an Integrated Lower Completion to minimize	P2	I1	I3	I1	Eliminate the need for reservoir isolation barrier assembly	P1	I1	I1	I1
Wellbore instability and formation damage caused by surge, swab and losses when running completion	Running string in hole generate well instability issues	If ILCBA fails to set, a MC needs to be run. This increases the wellbore instability and potential formation damage	P3	I2	I1	I3	Cemented liner isolated hole	P3	I1	I1	I1
Failure to open/retrieve/break internal plug	Contingency operation close to reservoir (ILCBA) is more complex than milling in production casing (MC)	1. ILCBA: Deep set plug require punching hole or milling operation close to reservoir 2. MC require milling completion in production casing	P2	I1	I1	I3	Cemented liner isolates hole	P2	I1	I1	I1
ID restrictions with 7" liner	Subsea well tubing limitations causing ID restrictions with 7" liners	OH completions involve a 5 1/2" liner. This provide monobore and no ID restrictions.	P3	I1	I1	I1	If decide to go with a C&P concept, the liner size is normally 7". The use of an ILCBA will therefore not be available. Need to consider 5 1/2" liner. The need for MC if decided to re-perforate is essential.	P3	I1	I1	I3

		Middle Completion					Integrated Lower Barrier Assembly				
Risk Title	Cause	Description	P	I			Description	P	I		
				HS&E	T&C	WOBJ			HS&E	T&C	WOBJ
Barrier assembly installation time and cost	The middle completion barrier assembly adds potentially 4 days of rig time	Annular barrier, tailpipe, plug or isolation valve, perforated pup, PBR. Punished due to ILBA is integrated with lower completion	P3	I1	I3	I1	Integrated liner hanger packer and plug. No MC. Plug needs to be run with wireline.	P3	I1	I1	I1
Failed inflow test	Inflow testing is required to confirm integrity and no leak from reservoir prior to running the upper completion. If inflow test fails, contingency needs to be initiated	Completion pulled. Use of retrievable packer should be considered, as it eliminates heavy milling operation (time consuming). Internal plug must be pulled to surface. The completion will be re-run	P2	I1	I3	I3	Failed pressure test of annular packer requires running of MC. If internal plug cannot provide positive test, retrieve on wireline and re-run. Less complex	P2	I1	I3	I2
Wellbore instability and formation damage caused by surge, swab and losses when running completion	Running string in hole generate well instability issues	Middle Completion require a separate run. The swab/surge and losses potential increase due to more barrier-running operations	P2	I3	I1	I3	Swab/surge and losses as expected when running liner	P3	I1	I1	I1
Exposure time	Running the completion exposes the hole with high pressure and high temperature (HS&E). Well is live prior to inflow testing the barrier assembly	Installation: RIH with liner, retrieve liner-running equipment, M/U barrier assembly, RIH with assembly, land, and pressure test	P3	I3	I1	I1	Installation: RIH with liner, set and pressure test.	P3	I1	I1	I1
Historical reliability in HPHT environment on NCS	All HPHT fields introduce downhole barrier assembly for reservoir isolation purpose. The reliability can provide great information for future decision making	Common concept. DIV reported with low reliability with 4/6 failed installations. Glass plug improved concept. Bridge Plug common retrievable plug	P3	I1	I3	I2	Morvin Field experienced lower reliability with liner hanger-packer pressure testing. 2/3 operations had to run MC as contingency. Glass plug improved concept. Bridge Plug common retrievable plug	P3	I1	I2	I3
Failure of accessing internal plug/valve due to debris settlement	Valves can be stuck in closed position based on field experience. If unable to open valves, production will be limited. Glass / Bridge plugs may stuck and be un-retrievable	Multiple contingencies. Stab/break plug, punch hole in pipe to access inner-bore, or milling operation	P3	I1	I3	I1	Require the need for multiple open hole packers due to Hades isolation. Same contingencies as MC packer, Increased complexity with more open hole packers	P3	I1	I3	I3
Use of annular packer may result in pre-maturely set downhole barrier	Packers run in harsh environment from floater can pre-maturely set	Small clearance may introduce pre-maturely setting of packer. Kristin Field experienced multiple pre-maturely set packers.	P3	I1	I3	I3	Expandable liner hanger packers have bigger clearance, lower chance of stuck. Expanding once set. Potentially eliminating the pre-maturely setting	P2	I1	I1	I1
Contingency weak points	The operation method must provide sufficient contingency plans	1. Barrier assembly has to be re-run. Time consuming	P3	I1	I3	I1	1. Failed pressure testing means run Middle Completion 2. Extended milling operation if internal plug fails	P3	I1	I1	I3

Upper Completion Risk Register

		5 ½» tubing		I			7» tubing		I		
Risk Title	Cause	Description	P	HS&E	T&C	WOBJ	Description	P	HS&E	T&C	WOBJ
The selected tubing size will provide a more balanced hydrocarbon flow in the well lifetime	A smaller size will potentially have a smaller Production Rate (PR). The flow will be evenly spread, delaying potential intervention activities (gas lift, nitrogen injection)	5 1/2" tubing will provide a more balanced production rate. Well intervention will be delayed. Lower PR.	P3	I1	I2	I1	7" will provide a more rapid production rate which declines over time. More frequent intervention	P4	I1	I1	I2
HPHT field experience on NCS	Subsea wells have 5 1/2" tubing. Platform wells have both 7" and 5 1/2"	Experience from NCS show subsea wells are limited to 5 1/2" tubing	P2	I1	I1	I1	Only used at permanent platforms. Subsea wells use Aker HXMT not compatible for 7" tubing. Use of HXMT most common for subsea wells	P3	I1	I1	I5
The tubing size provide a bottleneck design, making through-tubing activities more complex	The reasoning for complexity is if the selected liner is 7", and the tubing is smaller. The need to set plugs or intervention (scrape, mill) require the tubing to be removed	7" liner with 5 1/2" tubing provide challenges with access to the liner. Intervention of liner will be more complex. Running plugs will increase complexity	P3	I1	I1	I3	Liner is same size as tubing	P3	I1	I1	I1
The tubing design provide limited through-tubing sizes for perforation guns	Tubing selection affects the perforation performance with size limitations	5 1/2" tubing provide size limitations to guns. Perforations length of 3 3/8" is lower and must be evaluated. If not able to bypass drilling damage, well performance will be heavily affected. Concept punished	P3	I1	I1	I3	7" tubing provide no limitation to gun size. 4 1/2"-4 5/8" guns can be used. The overall skin factor will be reduced.	P1	I1	I1	I1
Subsea well intervention	7" tubing require earlier well intervention than a 5 1/2" tubing	5 1/2" tubing potentially require intervention at a later stage due to slower production curve. The need for intervention due to water production will be less probable than 7" tubing	P3	I1	I1	I1	7" tubing potentially require intervention at an earlier stage due to faster production curve. The need for intervention due to water production or gas-lift will increase	P3	I1	I2	I3
XMT availability for HPHT subsea wells	HPHT subsea wells have sizing limitations. 5 1/2" tubing is the only option for HPHT HXMT subsea wells	5 1/2" tubing provides minimal equipment restrictions with 15K HPHT subsea wells	P1	I1	I1	I1	Need comprehensive and time-consuming qualification testing of 15K HXMT tubing hanger. Common and used on the NCS is 15K XMT with 5 1/2" ID tubing hanger	P4	I1	I4	I4
Risk of sand failure due to high pressure drawdown	Maximum drawdown on the sandface completion may limit the sizing. However, a 7" tubing is more prone to high drawdown	5 ½" tubing less prone to high drawdown, and the potential sand failure is lower.	P2	I1	I1	I1	7" tubing provides higher pressure drawdown, and the probability of sand failure is higher.	P2	I1	I1	I3
ID clearance and installation procedure	Running the tubing with pressure & temperature gauges provide tight ID clearances	5 ½" tubing easier to run. Bigger ID clearances	P3	I1	I1	I1	7" tubing may have clearance issues in 9 7/8" casing with pressure & temperature gauges + control lines.	P3	I1	I1	I3

		Permanent Packer					Retrievable Packer				
Risk Title	Cause	Description	P	I			Description	P	I		
				HS&E	T&C	WOBJ			HS&E	T&C	WOBJ
Failing elastomers causing leak paths	HPHT conditions can impact the elastomers	Minimal moving parts and metal-to-metal sealing.	P1	I1	I1	I1	Use of elastomers. HPHT conditions not extreme, can use well qualified elastomers. However, long term can promote leaks	P3	I2	I2	I2
Packer reliability in HPHT conditions	Based on previous experience on the NCS	History of pre-maturely setting. Operation performed at floater in potential harsh environment. Pre-setting of packer common in older HPHT fields on NCS	P2	I1	I1	I3	Less experiences packer solution from older fields on NCS. New packers' elastomers quality proven for HPHT conditions. Proven easier concept for pulling and retrieving in case of stuck	P2	I3	I1	I3
HPHT field experience on the NCS	HPHT fields are commonly completed with production packers as upper completion barriers for fluid displacement and tubing loads.	Production packers on the NCS is commonly permanent. This is due to low complexity, simple and robust solutions	P3	I1	I1	I2	Less commonly used on the NCS due to more moving parts. Not as robust as the permanent packer	P3	I3	I1	I3
Contingency planning for setting packer pre-maturely when running in hole	For permanent packer: milling operation Retrievable packer: Mechanical manipulation	Mill top of packer and retrieve/fish remaining in hole. Re-run packer. Time consuming operation	P2	I1	I3	I3	Cut mandrel and pull packer and tailpipe to surface. Re-run packer	P2	I1	I1	I1
Running packer element in harsh weather conditions on a floater during winter	Use of floater may impact the packer solution based on previous experience	Permanent packer weak point. Tendency to get stuck and time-consuming milling operation	P2	I2	I3	I3	Easier to retrieve to surface without the need for a time-consuming milling operation	P2	I1	I1	I1