GABRYELLA CAROLINA DA SILVA ALVES

CONCEPTUAL ENGINEERING DESIGN OF SUBSEA PRODUCTION SYSTEM

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Trabalho apresentado à Escola Politécnica da Universidade de São Paulo para obtenção do diploma de Engenharia de Petróleo.

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Área de Concentração:
Engenharia de Petróleo

Orientador:
Profa. Dra Nara Policarpo

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2025

I dedicate this work to my parents, Fátima and Agostinho, who, enduring the heat of the sun, allowed me to reach this place of shade

AGRADECIMENTOS

The first thanks is to God for guiding me and allowing me to complete this work even in the midst of so much turbulence. The second is my family: my mother Fátima, my father Agostinho and my sister Pamela, who were by my side throughout this entire journey, supporting me and giving me all the necessary structure so that I could make my dream come true.

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Finally, I would like to extend my sincere thanks to Instituto Superior Técnico for providing me with the opportunity to graduate as an engineer from such a prestigious institution of global renown.

"I rise. I rise. I rise."

-- Maya Angelou

RESUMO

Este estudo apresenta uma análise de viabilidade técnico-econômica para o desenvolvimento de um sistema de produção submarina, com o objetivo de apoiar a tomada de decisões durante a fase de design conceitual. A metodologia aplicada baseia-se nos princípios da Engenharia de Sistemas, buscando otimizar o processo decisório ao dividir o problema em partes menores e gerenciáveis, garantindo uma abordagem mais estruturada para decisões complexas.

O estudo foca em três configurações de design para um campo hipotético no Mar de Barents, considerando diferentes equipamentos e instalações submarinas. A análise técnica começa com a avaliação do número de poços, métodos de perfuração e completação, layout e equipamentos necessários para cada alternativa, proporcionando uma visão detalhada da funcionalidade do sistema em cada configuração.

Do ponto de vista econômico, a viabilidade é avaliada com base nos custos associados a cada configuração, incluindo equipamentos, perfuração, instalação e FPSO. Ao comparar esses custos, o estudo identifica as implicações financeiras de cada design, destacando os trade-offs entre desempenho técnico e eficiência de custos.

Os resultados revelam que a escolha da configuração ideal é fortemente influenciada pelas características específicas do campo e pelos custos vinculados a cada componente do sistema. Por fim, a análise integrada de viabilidade técnica e econômica proposta neste trabalho contribui para um processo decisório mais informado e eficiente, oferecendo valiosos insights para o desenvolvimento de sistemas de produção submarina.

Palavras-Chave – Viabilidade Técnico-Econômica, Sistema de Produção Submarina, *Layouts*, Mar de Barents.

ABSTRACT

This study presents a technical-economic feasibility analysis for the development of a subsea production system, aimed at supporting decision-making during the conceptual design phase. By applying Systems Engineering principles, the methodology seeks to optimize the decision-making process by breaking down the problem into smaller, manageable components, ensuring a more structured approach to complex decisions.

Focusing on three design configurations for a hypothetical field in the Barents Sea, the study examines different subsea equipment and facilities. The technical analysis begins with an assessment of the number of wells, drilling and completion methods, layout, and equipment required for each alternative, providing a detailed overview of the system's functionality in each configuration.

From an economic perspective, the feasibility is evaluated based on the costs associated with each configuration, including equipment, drilling, installation and FPSO. By comparing these costs, the study identifies the financial implications of each design, highlighting the trade-offs between technical performance and cost efficiency.

The results reveal that the choice of the optimal configuration is heavily influenced by the specific characteristics of the field and the costs linked to each system component. Ultimately, the integrated technical and economic feasibility analysis proposed in this work supports a more informed and efficient decision-making process, offering valuable insights for the development of subsea production systems.

Keywords – Technical-Economic Feasibility, Subsea Production System, Layouts, Barents Sea.

LISTA DE FIGURAS

LISTA DE TABELAS

SUMÁRIO

1 INTRODUCTION

For millions of years, sediment deposition has accumulated organic matter from plants, algae and animals. With the passage of time and the influence of mild pressures, temperatures and the compression caused by the deposition of rocks, this organic matter was transformed into Kerogen, a dispersed Organic Matter (OM) of ancient sediments insoluble in the usual organic solvents, and bitumen, a dark material with a solid structure made up of complex non-volatile mixtures. This transformation process is called diagenesis. (TURGEON; MORSE, 2022) (VANDENBROUCKE; LARGEAU, 2007); (PORTO *et al.*, 2019)

Then, as temperatures and pressures increase, the catagenesis process begins, which is the thermal degradation of kerogen to form chains and hydrocarbons. The conditions under which this process occurs determine the type of product, that is, if catagenesis occurs at higher temperatures and pressures, the breakdown will be complete and the hydrocarbons produced will be smaller and lighter, favoring, for example, the formation of natural gas. (SUKUMAR, 2018)

In this way, if the conditions of pressure and temperature are favorable, oil is formed. The word comes from the combination of *petra* ("rock") and *oleum* ("oil"), a liquid that was commercially produced in the early 19th century, but only from random infiltrations. In 1859 was the first well drilled in Pennsylvania, United States, with a depth of 21m and an estimated flow of 800 gallons per day. (SUKUMAR, 2018)

Just a few years later, in 1896, the first offshore wells were drilled in the Summerland oilfield in Santa Barbara County, California, using the same technology used for drilling onshore. That's because the depth of the reservoir was 100 meters out into the shallow waters of the Pacific. In a short period of time after the first offshore operation, the company experienced exponential commercial growth and sufficient enough energy to maintain its activities. This is how advanced technologies for offshore drilling, production, storage and transport of oil and gas led to the production of hydrocarbons at ever greater depths, which today exceed 3500 meters. (SEYYEDATTAR; ZENDEHBOUDI; BUTT,

2020)

However, the advancement of hydrocarbon production in the offshore environment is still a challenging task, since as the depth at which the reservoir is found increases and harsher environments are encountered, the more complex the oilfield development planning can be. Harsher marine environments, including higher pressures and lower temperatures, low-energy reservoirs, longer offsets, and unstable oil and gas market, are also important challenges to overcome. Due to these factors, the industry has been working on the development of fields using subsea production systems, a feasible engineering solution associated with the overall process and all the equipment involved in drilling, field development and field operation. (BAI; BAI, 2010) (GONZÁLEZ, 2020) (SUKUMAR, 2018)

The subsea production system begins when a reservoir is evaluated as economically viable through oil exploration methods such as geological and geophysical processes (LIU; GJERSVIK, T.; FAANES, 2021). After this step, it is necessary to do the conceptual design phase of the field, which is the most critical phase of the project, as it requires an evaluation of the viability of the proposed solution. (SILVA; SOARES, 2023)

Nevertheless, for each field, there are thousands of possible solutions, but not all are technically viable or cost-effective, so decisions must be made about how the field can be produced and operated. Thus, the goal of field development planning (FDP) is to identify the best strategy for the system to be essembled, aiming for the option that best combines technical and economic viability. (GONZÁLEZ, 2020)

Regarding technical viability, the positive and negative aspects of each component of equipment are studied. For example, if two closely spaced wells are drilled, their connection to the platform may occur individually (i.e., satellite wells) or be connected to a manifold, equipment composed of valves and accessories that direct the production from more than one well to a gathering line. In addition to the manifold, various equipment configurations create different layouts. Regarding economic viability, factors such as production profile, oil price and infrastructure costs, which vary according to the layout configuration, should be taken into account. ((BAI; BAI, 2010); (GONZÁLEZ, 2020))

1.1 Objective

The present work attempts to develop a techno-economic feasibility study, describing the advantages, disadvantages and limitations of the different subsea layout concepts, aiming o improve the decision-making process during the conceptual design phase to define the most viable subsea production system.

The objective of this work is to enhances the design planning of a subsea production system in the most efficient and expeditious manner at the early stage of an oilfield development contributing t an informed decision-making process.

In this way, this work delivers different layouts for the same field, considering different equipment and facilities according to the technical and economic aspects. In the end, it should be useful as a basis for generating layouts for other fields, as the document compiles all the technical and economic information necessary for the application.

1.2 Motivation

As previously mentioned, the complex challenges in the offshore have boosted the demand for the subsea production and processing systems. One of the main reasons for this surge is the growth of activities in deep and ultra-deep waters, which have dominated the production and exploration market since 2019 and represent around 2% of the projected global growth between 2020 and 2025. This trend of moving into deeper and deeper waters became prominent in 2014, when, after the drop in oil prices, many countries such as Brazil, the United States, and Egypt, some of the world's leading producers, decided to shift their projects back to onshore. However, they found that the payback period was between 4 and 9 years longer than for offshore projects, demonstrating that, in addition to technical challenges, economic efficiency is a key reason why optimizing offshore systems, particularly subsea systems, is important. ((INTELLIGENCE, s.d.); (PERETA; FURTADO; COSTA, 2022))

Additionally, another important factor contributing to the increase in this type of production is the transformation of the energy matrix. In projections of possible transition scenarios, countries with significant natural gas resources become crucial for the supply of energy, since this resource emits less CO_2 during production than oil, precisely the main reason for the important occurrence of the transition energy. However, the world's large reserves of this emerging resource are located in regions with deep and ultra-deep waters and environments of greater complexity, either geographically or geologically. In this context, it is necessary to develop and improve technological solutions not only to reduce gas emissions, but also to increase production efficiency in these types of reservoirs. (PERETA; FURTADO; COSTA, 2022)

Finally, as all these factors are intrinsically related to the ocean and its resources, it is important to highlight that Ocean Engineering plays a fundamental role in this field, as it involves engineering activities that include the design, construction and installation of systems related to subsea production, such as platforms, subsea equipment and power generation systems. Consequently, it can be said that the development of decision-making techniques for subsea production systems is directly connected to Petroleum, Naval and Ocean Engineering. (UFRJ, s.d.); (CENTEC, s.d.)

1.3 Thesis Outline

This thesis is structured as a monograph, and the content of each chapter is presented below.

Chapter 2 presents a review of the existing literature on the subject, separating it into three topics: documents that address only technical feasibility, those that address both technical and economic feasibility, and those that deal with optimization models, which are not looking for the viable alternatives anymore, but refining all the viable alternatives to find the optimal one.

Chapter 3 is divided into sub-chapters to clarify the methods and materials employed in the research. In this way, in the description of the methodology, both technical and economic analysis are addressed. Subsequently, the essential elements of the oilfield conceptual design phase will be described, covering all the necessary steps from installing a Subsea Production System to the equipment used, associating each development step with the technical characteristics of the field.

Chapter 4 presents the case study, where the concepts and methodology described in the previous chapter are applied to generate three different design layouts. This chapter also outlines the results of the technical feasibility analysis, which includes the number of wells, facilities locations, field concept, drilling and completion methods, layout, and equipment for each alternative. Additionally, the economic viability of each alternative is evaluated, with a focus on the costs associated with the entire installation process.

Finally, Chapter 6 provides a summary of the results obtained and the relevant conclusions drawn from this work.

2 LITERATURE REVIEW

The methodology used to develop the present work was studied by Yasseri (2014). This methodology consists of applying Systems Engineering (SE) principles, a suitable tool for managing complex problems by breaking them into manageable parts, in the development of one or more layouts for subsea production systems, which vary in number, type and arrangement of equipment and facilities. The system inputs, also called subsystems, are field data, production capacity and infrastructure, technical limitations, client needs and objectives and the main constraints, which can be related to budget, time and physical characteristics of the area, such as depth, climate, environmental conditions, among others. (YASSERI, 2014)

In this way, the scope of this methodology establishes the requirements to develop and implement the best subsea production design, manage its development and assess whether the predicted performance is achieved. According to Yasseri (2014), it is essential that the SE application define the system output and the way it will operate; address risks as early as possible, avoiding major technical and economic impacts; focus on the interface between subsystems; and verify and validate the physical system at all stages of progress. (YASSERI, 2014)

With regard to technical feasibility, which is directly related to the characteristics of the oilfield and its challenges, several works have been developed covering different challenges related, for example, to the presence of ice in the sea where the system will be installed, the development of the pre-salt and reservoir modeling and simulation.

In the study developed by Ivanova and Shabalov (2021), the authors presented some problems associated with subsea production in regions where the main factor directly affecting the development of oil and gas fields on a larger scale is the presence of ice, in addiction to factors such as depth, classification of oil and gas fields by recoverable reserves, the distance from the field to the coast, the level of infrastructure in which the transport is developed and the geological complexity of the field. (IVANOVA; SHABALOV, 2021)

To select the best subsea layout for a given field, Ivanova and Shabalov (2021) developed a software that considers the values of six types of factors that affect the layout, as mentioned above. For example, for presence of ice factor, the duration of the ice season is considered, which can last up to 3 months, between 3 and 6 months to more than 6 months. For another factor, such as the distance from the field to the coast, there are three possible values: up to 2 km, between 2 and 60 km and more than 60 km. After entering all the values associated with the six factors, the software generates options considered optimal, based on associated methodology. For example, regarding the ice season, if it lasts longer than 3 months, it must be analyzed whether the remoteness of the field from the coast can influence system's recoil. If so, the next step evaluates whether the level of transport infrastructure development also impacts on this choice, and so on, until all factors are considered. (IVANOVA; SHABALOV, 2021)

In the end, the tool produces up to three different types of configurations, taking into account the responses based on the physical characteristics of the field. This operating algorithm helps avoid wasting time and materials, mitigates possible risks when choosing an inappropriate layout and reduce costs in the preliminary planning stages, making important contributions to engineering. (IVANOVA; SHABALOV, 2021)

In another study on the influence of ice on field development, Pribytkov (2013) examined all of the elements that affect field development in the Arctic region and the solutions that help to mitigate these factors. For example, more than in any other area, the remote location of production requires thorough study due to logistics: the need for supplies, personnel transfer/evacuation, climatic conditions, high costs, emergency response times and, of course, the training of ice that can further affect all previous conditions. Therefore, in this case, as much as the economic study is important, the technical and risk analysis is indispensable, requiring the consultation of layout possibilities previously developed in similar regions and attempting to apply them to the new conditions. (PRIBYTKOV; ZOLOTUKHIN; GUDMESTAD, 2013)

After organizing some of the viable technical solutions related to the platform, wells distribution and operations, the economic study was carried out considering only the installation cost and the execution time of this stage, excluding operating costs and financial returns. In addition, a risk matrix was generated in accordance with risk management papers and the risk assessment program, along with a risk assessment document prepared before executing the decision gate. Once again, the authors conclude that selecting the optimal subsea structure configuration is a long and complex process that requires extensive analysis, especially in regions with greater challenges, such as the Arctic. (PRIBYTKOV;

ZOLOTUKHIN; GUDMESTAD, 2013)

Similarly to the two previous studies, which focused on regions with ice seasons, Beltrão et al. (2009) examined the technical challenges in subsea production settings in the pre-salt region, specifically in Brazil. Beltrão et al. (2009) discussed key challenges in the region, including wax formation, inorganic scaling, and hydrate formation, all of which intensify with increasing depth due to temperature. They also highlighted the higher risk of material corrosion and the specific technologies required for drilling and well installation in such reservoirs. (BELTRÃO *et al.*, 2009)

For each problem, a technical solution wasproposed to minimize its effects on production, resulting in a final layout that incorporates the best technical combination. However, this article did not address economic aspects, including equipment costs or the financial return from oil and gas production. (BELTRÃO *et al.*, 2009)

Still addressing the technical challenges, Santana (2012) developed a study that explores the use of computational tools that employ statistical techniques and use a low volume of computational processing, after reservoir simulation results. It integrates several works done previously with the objective of determining an effective solution for a field development strategy, focusing on the location of wells and the platform as a single step. However, the approach the author uses to develop the solutions is different, as it adopts a study based on the production capacity of a reservoir through its simulation. That is, it is possible to select configurations based on reservoir modeling and simulation, reducing costs from the early stages. (SANTANA, 2012)

Adding another dimension to technical feasibility, some authors highlight the inclusion of economic aspects and their importance in selecting the final layout configuration. Sánchez et al. (2012), for example, ivestigated the impact of economic viability when evaluating the most feasible subsea production system. The authors aimed to demonstrate that choosing a particular subsea production based on either the Net Present Value (NPV) method or the Multuattribute Decision Model (MDM) can yield divergent results. For example, when choosing a layout based on NPV, the technical risks associated with the configuration, which may render it inapplicable, are disregard. Similarly, a combined production of oil and gas transported by a tanker may be economically viable, but cannot be applied in real life, as gases cannot be transported by ship. (SANCHEZ; ALCANTAR; ANTONIO, 2012)

After studying of the all variables involving both methods, Sánchez et. al (2012) concluded that it is necessary to combine economic feasibility, prioritizing NPV optimization, with technical feasibility, by analyzing possible cases where the configuration can be applied in real life with a lower risk of failure or production stoppage. In addition, the authors propose a third method, which involves considering similar experiences from previous industry projects,providing a more informed perspective for decision making. (SANCHEZ; ALCANTAR; ANTONIO, 2012)

Using the same integrated methodology combing NPV and MDM, Aslie and Falk (2021) also confirm that the analysis of both technical and economic aspects is necessary and indispensable for developing an optimal design of equipment and facilities in subsea production. The authors applied both methods to a small company they work with and concluded that the company could benefit from implementing a concept design based on consistency and efficiency. They also noted that several aspects should be considered when evaluating the concepts to determine which is better, including in addition to technical-economic aspects, schedule, project risk, flow assurance and operational challenges. (ÅSLIE; FALK, 2021)

In the context of optimization, but still considering costs as the maindecision factor, Rosa (2006) studied the optimization of platform location based on the cost of installed pipelines, with the objective of maximizing the NPV of the offshore oil field development project. (ROSA, 2006)

After addressing viable models both technically and economically, the process of refining the alternatives in search of the optimal layout begins. Silva and Guedes Soares (2019) proposed a mathematical model that optmizes the offshore production system, in which the parameters considered are the number and location of wells and the estimated maximum flow rates of each well. The mathematical programming model developed by the authors serves as a screening tool for possible initial capital expenditures, highlighting installation and equipment costs, technology selection and the location, number and capacity of platforms and manifolds, as well as the optimal assignment of wells to these facilities, while aiming to minimize global investment costs. (SILVA; SOARES, 2019)

Combining numerical optimization with uncertainty analysis, González et al. (2019) studied a methodology that identified a selection of a improved subsea production models. The first step in this methodology is to create efficient proxy models of field production performance and project cost estimated. Next, numerical optimization is performed to find the ideal profile and production schedule that maximizes the net present value of the strategies considered. In the final stage, an evaluation is conducted on the effect that the uncertainties on the results produced in the two previous stages applied in the final choice. Finally, this method produced nine different scenario models and provided decision support through field planning.The optimal option among these nine was determined using NPV as the primary decision factor, along with total oil production and the drilling schedule. This approach successfully identified the most efficient resources in an automated manner, while also quantifying the impact of uncertainties. (GONZÁLEZ; STANKO; HOFFMANN, 2020)

One aspect that directly influences the optimization of a subsea production system layout design is the pipeline route, as this infrastructure is responsible for loading production (oil, water and/or gas), injection and chemical additives into the system . Thus, Hong et al. (2018) studied, along with two other factors, the location of subsea installations and the determination of subsea topology, the influence of the pipeline location. These factors are considered together to determine the ideal number and position manifolds, position of risers and the topology of the pipe network. (HONG *et al.*, 2018)

In the model proposed by the authors, the layout of a wellhead-manifold-FPSO system is optimized to minimize the total length of pipe, taking into account feasible distances between equipment, seabed topography, and physical obstacles. When compared to a model that does not consider these factors, the difference in the suggested pipe length is significant. This, in addition to affecting the technical feasibility of the layout—due to pipe overlap and installation complexities—also impacts the costs, as a larger network results in higher expenses. (HONG *et al.*, 2018)

Another important area of optimization is the oil gathering and transportation system, where manifolds and pipelines are allocated to capture and transport fluids from subsea wells to floating processing terminals. Both Hong et al. (2023) and Liu et al. (2022) use the MINLP (Mixed Integer Nonlinear Programming) model to reduce the installation costs of the subsea production system. (HONG; WANG; ESTEFEN, 2023) (LIU; GJERSVIK, T. B.; FAANES, 2022a)

The first one considers the topographical structure, which affects the location of wells, manifolds and facilities, as well as the pipeline route, preventing crossings that could interfere with flow and cause accidents or financial losses in the oilfield. Meanwhile, Liu et al. (2022) presents an efficient method for subsea field layout optimization regarding the allocation of manifolds. (LIU; GJERSVIK, T. B.; FAANES, 2022a)

The third article in a series of papers by Liu et al. (2022) proposes a graphical and mathematical method that combines 3D Dubins Curve and Binary Linear Programming (BLP) to optimize the allocation of drilling sites and minimize the overall cost of field development. (LIU; GJERSVIK, T. B.; FAANES, 2022b)

Based on the literature review, it is necessary to create a document that assembles both the technical specifications required for oilfield development and the costs related to each technical characteristic, so that the combination of these factors generates a layout, technical design and economically viable. Furthermore, with the addition of graphical and mathematical models it is also possible to obtain the optimal layout for a given oilfield.

3 MATERIALS AND METHODS

3.1 Materials

3.1.1 3D Modeling Software

The main software used in this work was Rhinoceros 8 (Rhino 8), a three-dimensional modeling tool used in various areas of engineering, industrial design, and architecture, due to its flexibility and precision. The software allows the creation of complex and detailed models such as subsea layouts with a wide variety of equipment, including platforms, pipelines, and risers, and is compatible with various data formats and extensions.

Due to its advanced modeling capabilities, such as the manipulation of surfaces, curves and solids of complex shapes, some successful articles and projects have used this software, such as (FOSU; PEPRAH; OSEI, 2023), proving that Rhino 8 is the ideal tool for modeling subsea systems. It allowed the creation of accurate representations of the components, adapting well to the different shapes and characteristics of these elements. In addition, the software was essential for the visualization of complete layouts, facilitating the realization of adjustments and optimizations in the arrangement of the system components, which was crucial for the development of the project.

3.1.2 Economic Calculation Software

Microsoft Excel was employed for the economic analysis of the project, primarily due to its practicality and ease of use. While not required for processing large datasets or performing complex calculations, its efficiency in organizing and presenting data made it an ideal tool for the task. Using spreadsheets, key information about the system components—such as the quantities of pipelines, risers, platforms, and other equipment—was organized, along with unit cost estimates for each item. Based on this data, economic analyses were conducted taking into account direct costs. This enabled a detailed financial evaluation of the project, allowing for an objective comparison of different layouts.

3.1.3 Hadrware

The 3D modeling and economic analysis for this project were carried out using a workstation with the specifications detailed in Table 1.

Tabela 1: Operating System and Hardware specifications used in the project

Hardware Informations	
Processor	11th Gen Intel(R) Core(TM) i5-11260H @ 2.60GHz, 2611 Mhz
RAM	8GB
Graphic Card	Windows 10, 22631 ver.
Operating System	Intel(R) UHD Graphics NVIDIA GeForce GTX 1650

Source: Data extracted from Windows 10 Pro, 22631 version, collected on October 15, 2024.

These configurations were adequate and efficient for running both Rhinoceros 8 and Microsoft Excel, allowing smooth use for modeling systems with high graphic performance and creating spreadsheets for comparative cost analyses.

3.1.4 Input data

Most of the data presented in this paper are based on real information from subsea operations in the region, including field characteristics, operating costs and specifications of the equipment used. The sources of this information include company reports, case studies and public data from operations in the region. Other data was created based on known information from the region especially for this case study.

3.1.4.1 Field Technical Data

The subsea field analyzed is located in the Norwegian part of the Barents Sea, in a shallow water area that varies between 360 and 390 meters in depth. Regarding the geological composition, the reservoir is composed mainly of sedimentary rocks and limestones, with some shale layers, geological characteristics that directly influence the choice of drilling methods and subsea technologies used in the operation.

3.1.4.2 Environmental and climate data

The water temperature at the operational depths of the subsea field in the Barents Sea ranges from -1°C to 4°C, critical conditions for material selection (e.g. manifolds, pipelines and others), which must be engineered to resist corrosion and endure the region's low temperatures. Additionally, they must prevent the formation of hydrates and waxes. Subsea pressure, meanwhile, can vary from 300 bar to 1,100 bar, depending on the depth and proximity to the reservoirs. (SMEDSRUD, 2013)

3.1.4.3 Data Source

The main source of data was the Handbook of Offshore Oil and Gas Operations (CHAKRABARTI, 2005), but operational reports from Equinor and Statoil, which operate in the Barents Sea, including data from the Goliat and Aasta Hansteen fields as examples, were also used. In addition, reports from the Norwegian Petroleum Agency (NPD) provide valuable information on operating costs, water depth and geological profile of subsea fields in the region. Case studies from DNV GL, which performs technical and economic feasibility analyses of subsea projects in the Arctic region, were also consulted. Additionally, public climate projection data for the Barents Sea, published by the Norwegian Meteorological Institute, were used to understand the environmental conditions that impact subsea operations in the region.

3.2 Methodology Discription

This study applies the Systems Engineering approach to the development of a subsea production system, considering the needs and requirements of the project, together with a technical and economic analysis. The methodology follows a life cycle, starting with the definition of the system and going through stages such as conceptual design, feasibility assessment and identification of alternatives. The proposed methodology allows the identification of the ideal configuration for field development, considering technical and economic variables in an integrated manner.

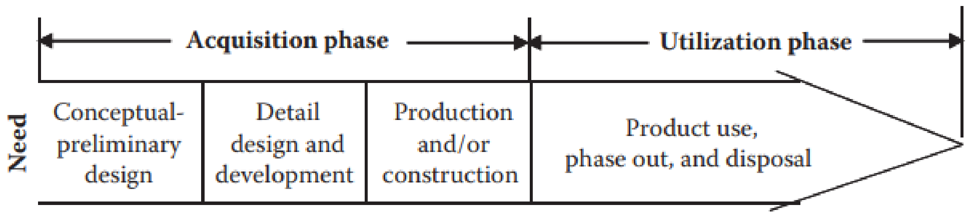
3.2.1 System Engineering

The current challenges that oil and gas projects face are mainly centered on technical, managerial and human resource challenges. To mitigate these challenges, the project management technique, which consists of managing, allocating and timing efficient resources to achieve a goal quickly and efficiently, can be applied. The System Engineering schematically approach aims to reveals unexpected opportunities for creating new systems and improved products that will serve as better competitors in the world economy. According to INCOSE (2014), the system engineering is defined as "an engineering discipline whose responsibility is creating and executing an interdisciplinary process to ensure that the needs of costumers and stakeholders are met in a high quality, trustworthy, cost efficient and schedule compliant manner throughout a system's entire life cycle."(BADIRU; OSISANYA, 2013) (FAULCONBRIDGE; RYAN, 2002)

First, before defining the process steps, it is necessary to define whether a given tool can be classified as a system. To be classified as such, it is necessary to have a functional relationship, interaction between various components and a useful purpose.

Once classified as a system, the application of systems engineering is done through a life cycle, where the process follows a certain order of execution of steps. This cycle is exemplified on Figure 1. (BADIRU; OSISANYA, 2013) (FAULCONBRIDGE; RYAN, 2002)

Figura 1: Life cycle of a system engineering



Source: (BLANCHARD; FABRYCKY, 2010)

The life cycle starts from conceptual development and extends to engineering requirements and system architecture. In general, as in the case of this work, engineering focuses mainly on the initial performance and design parts of the product as the main objective, not on its development, which involves the construction and installation of the product. (BADIRU; OSISANYA, 2013)

However, this initial part of preliminary development leads the project to cost reduction in the following phases and, consequently, a cost reduction throughout the product's life cycle, making it more competitive and economical. That is why it is important in a subsea production system to look for conceptual designs that, in addition to satisfying the technical conditions, also satisfy the economic ones. (FAULCONBRIDGE; RYAN,

2002)

3.2.1.1 Conceptual and preliminary design

The first stage of the life cycle carried out by engineering is the conceptual design. The main objectives of conceptual design are to articulate the need, analyze and document the system-level requirements arising from the need, and complete a functional design of the system. However, despite defining the main requirements for the project to work, if this phase is not carried out correctly, it causes direct problems when the project is being developed, producing, in addition to the financial loss, the Lag time, defined as the delay required for a successor activity is required to be delayed with respect to a predecessor activity. (BADIRU; OSISANYA, 2013) (FAULCONBRIDGE; RYAN, 2002)

The first step of the conceptual design stage is the identification of needs. At this stage, the owner of the facility, which in the case of oil exploration, is a public or private sector company, clearly defines the requirements and objectives of the project, which in general comprise: cost optimization (that is, greater profit at reasonable cost), on-time completion and on-budget completion. (FAULCONBRIDGE; RYAN, 2002)

Based on the client's needs, the first actitivity executed by the company is the formulation of the problem. Usually this step is done by making a graphical representation of the system of interest illustrating the boundaries and input from the client and it is crucial to ensure that the responsible to develop the conceptual design understood the problem correctly and can communicate this understanding to all personnel involved. (ENGEN; FALK, 2018)

Once the owner's need is identified and the problem is formulated, a feasibility study and economic evaluation takes place, taking into account relevant social, environmental, and technical constraints. This is precisely the main point of this project, which aims to study this feasibility in a given reservoir with the objective of defining the best possible configuration of a field development looking for the most feasible susbsea production system to be carried out. The project outline, the study of new requirements and risks, the sources of materials, the access routes, and an estimate of capital costs are part of the scope of the investigation. The outcome of this phase is the selection of a defined project that meets the stated objectives. (FAULCONBRIDGE; RYAN, 2002)

The next stage of the conceptual design is the identification of alternatives, that is, after all the technical and economic study, which projects present the best possible alternative considering the two main factors, along with the social and environmental impacts generated, the functional capacity of each alternative, security and reliability. In this work, neither environmental impacts nor reliability will be considered. (FAULCONBRIDGE; RYAN, 2002)

With all these stages defined, multiple conceptual designs must be generated so that the best possible characteristics are achieved both in the technical and in the economic part. Therefore, the generation of conceptual designs is done using predefined domain-independent production rules in the knowledge base, that is, searches are carried out in existing databases, applied to fields and reservoirs with similar characteristics (FAULCONBRIDGE; RYAN, 2002). For concept generation, according to Woldemichael and Hashim (WOLDEMICHAEL; HASHIM, 2009), there are two types of rules to follow: the first refers to mapping, where the system searches for concepts whose function has already been performed previously and, if there is no alternative concept for the case studied, the second rule is applied. This consists of manually generating concepts that will be added to the database in the future. In this work, applications in fields with similar characteristics will be considered and analyzed, then the first rule will be applied.

Following the choice of alternatives, the next two phases are financial implications/resources and time schedule. In the first case, there is no involvement of any company in the case study of this project, so there are no financial implications. Regarding the time schedule, no development and installation deadline will be set, so none of these steps will be taken into account specifically for this project. (BADIRU; OSISANYA, 2013)

Finally, the best developed alternative must be chosen and verified, checking whether the final concept is in accordance with the needs and requirements of the interested parties, linking the functionalities and features for the chosen concept to the need or requirement it fulfills. (BADIRU; OSISANYA, 2013)

Hydrocarbon Characteristics

Crude oil is a natural mixture of hydrocarbons, generally in a liquid state, and also includes other components such as sulfur, nitrogen, oxygen, and metals, as well as inorganic material and water, varying in amounts. The difference in composition, as well as other factors, interfere with the classification of the fluid and consequently have an impact on the drill and oil production. (AL., 2014)

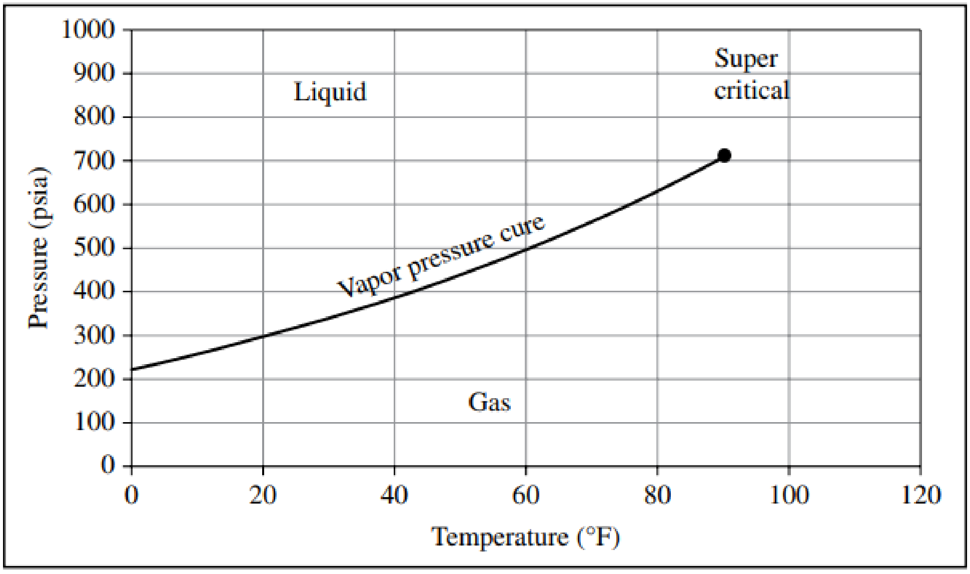
The first classification that impacts production refers to hydrocarbon resource. Thus, oil can be classified as naturally occurring, such as petroleum, natural gas and natural waxes, or as sources of hydrocarbons, that is, those that can generate hydrocarbons from the application of chemical conversion processes, such as oil shale kerogen and coal. (AL., 2014)

Regarding the composition, this is related to the nature of the organic material present and is also subject to the influence of natural processes such as oil migration, contact with water, among others, thus resulting in a mixture of products as a result of chemical and physical changes caused by conditions present at the local. These conditions, such as temperature and saturation, can change the composition in the same field, reservoir or even the same well. (FANCHI; CHRISTIANSEN, 2016)

Consequently, oil receives three possible classes in relation to the relative amount of different types of hydrocarbon molecules, specifically: paraffins, naphthenes and aromatics. The first receives this name because it is saturated (indicates that all carbon–carbon bonds are single bonds) of hydrocarbons with linear and/or branched chains; the second, naphthenes, are hydrocarbons that contain one or more aromatic rings, that is, compounds with a closed carbon chain with a molecular structure containing a benzene, naphthalene or phenanthrene ring, with paraffin side chairs; while aromatics are unsaturated hydrocarbons with only ring systems. (AL., 2014) (FANCHI; CHRISTIANSEN, 2016)

Still in terms of composition, oil can exist in the reservoir in liquid, gaseous or solid states, also depending on temperature and pressure. The identification of the state of a sample is presented by a pressure-temperature (P–T) diagram, which also serves as a classification tool. The Figure 2 is an example of such a diagram, where the curve is called the vapor pressure curve. For ethane, the hydrocarbon in the Figure 2, at the points above the curve, ethane is in a liquid state, while below, it exists as a gas. If it exists at a temperature and pressure above the critical point, the end of the curve, there is no way to distinguish between liquid and gas, and it is called a supercritical fluid. (FANCHI; CHRISTIANSEN, 2016)

Figura 2: P-T diagram for ethan



Source: (FANCHI; CHRISTIANSEN, 2016)

Based on these diagrams, 5 behavior patterns were identified according to the dominant phase in which the fluid is in the reservoir, the reservoir temperature and the phases at separator pressure and temperature. This classification is useful in anticipating changes in phase behavior when a pressure change is identified in the reservoir. Therefore, through these characteristics, the oil is classified into black oil, volatile oil, condensate (retrograde gas), wet gas, and dry gas, where each of these types of fluid requires a different approach during oil production. (FANCHI; CHRISTIANSEN, 2016)

The first type is black oil, marked by the presence of large, heavy and non-volatile particles. A reduction in pressure releases gas to form a free gas phase within the reservoir and as the oil moves towards the surface, additional gas evolves from the oil. However, as separator conditions lie well within the phase envelope, a large amount of black liquid oil reaches the surface. (JIRJEES, 2018)

The volatile type oil contains far fewer heavy molecules than black oil and has more molecules of intermediate size. The critical temperature, the point at which both liquid and gas phases coexist, is much lower than that of black oil and in this case is close to the reservoir temperature. As the reservoir temperature approaches the critical temperature, the volatile oil will become more than 50% of gas. (JIRJEES, 2018)

Next one, the retrograde gas is contained fewer of the heavy hydrocarbons than the oil. As the pressure reduces, liquid condenses from the gas to form a free liquid in the reservoir, which will normally not flow and cannot be produced. At the separator, the percent of liquid is lower than gas at reservoir conditions. (JIRJEES, 2018)

While the wet gas exists as a gas in the reservoir throughout the reduction in reservoir pressure and in all it phases and the hydrocarbon mixture is predominantely formed by smaller molecules that lie below reservoir temperature, tn the separator conditions, it is still possible to some liquid be formed at the surface, the dry gas is predominantly methane with a few intermediate molecules and in this case, both in the reservoir and on the surface, its physical state does not change with the difference in pressure or temperature, remaining gas throughout its existence. (JIRJEES, 2018)

Another important classification is based on API gravity, short for American Petroleum Institute gravity, a measure used to determine the weight of oil compared to the weight of water. While API gravity essentially measures the relative density of petroleum liquid and water it is primarily used to evaluate and contrast the relative densities of petroleum liquids. API values range from 10 to 70, as shown in Figure 3. (FANCHI; CHRISTIANSEN, 2016)

Figura 3: Classification of crude oil according to API gravity

Fraction 250°C-300°C (480°F-570°F)		**250°C-300°C (480°F-570°F)**		
API Gravity	***Type***	***API Gravity***	***Type***	***Classification***
>40.0	**Parrafin**	>30.0	**Paraffin**	**Paraffin**
>40.0	**Parrafin**	20.1-29.9	**Intermediate**	**Paraffin-intermedite**
33.1-39.9	**Intermediate**	>30.0	**Paraffin**	**Intermediate-paraffin**
33.1-39.9	**Intermediate**	20.1-29.9	**Intermediate**	**Intermediate**
33.1-39.9	**Intermediate**	<20.0	**Naphthene**	**Intermediate-naphthene**
<33.0	**Naphthene**	20.1-29.9	**Intermediate**	**Naphthene-intermediate**
<33.0	**Naphthene**	<20.0	**Naphthene**	**Naphthene**
>40.0	**Parrafin**	<20.0	**Naphthene**	**Paraffin-naphthene**
33.0	**Naphthene**	>30.0	**Paraffin**	**Naphthene-paraffin**

Source: (FANCHI; CHRISTIANSEN, 2016)

There is also the classification according to viscosity, which is important to define the quality of the oil because it defines it as heavy, intermediate or medium and this is directly linked to the products that can be produced, as well as their quality. It is also posible to find other classifications, such as density, carbon distribution and pour point. However, all existing classifications allow the identification of the economic viability of that oil, as they provide information on its production quality. (FANCHI; CHRISTIANSEN, 2016)

Recovery of Oil

In addition to the hydrocarbon classification, it is also important to understand the mechanism of hydrocarbon movement from the pores into the wellbore. Understanding drive mechanism is essential for reservoir engineers to develop strategies for each type of mechanism, ensuring the maximization of oil and gas recovery from that well. (SMITHSON, n.d)

It is known that in a common rock formation, permeable and without barriers, the reservoir fluids can migrate freely and the action of gravity will cause the fluids to be separated according to density, which in most cases promotes a distribution of gas at the top, oil in the middle and then water at the bottom. However, if there is an imbalance in pressure caused by properties of the rock and the fluids present, such as density, viscosity, mobility and capillary pressure, the fluids move towards regions of lower pressure, changing the disposition and condition of the fluids inside the reservoir. (SMITHSON, n.d) (GLOVER, 2010)

Aditionally to these properties, there are also drive mechanisms, which are a source of energy responsible for transporting hydrocarbons into and out of production wells. One of the energy sources comes from an aquifer connected to the reservoir, refered to as Waterdrive mechanism. In this type, as the hydrocarbon is extracted by drilling, the aquifer expands into the reservoir and displaces the remaining oil. If the production rate is low and the size and permeability of the aquifer are high, all the well oil produced will be replaced by water at about the same time, keeping pressure high and allowing production to continue. When there is no more oil recovery from this corresponding well, it can be closed or converted into water injection wells for adjacent wells, producing a secondary recovery. In this waterdrive system the oil recovery factors are relatively high, ranging from 35% to 75% of the Original Oil In Place (OOIP). (SMITHSON, n.d) (GLOVER, 2010)

In the Solution Gas Drive mechanism, as oil is produced, the pressure in the reservoir drops below the bubble point, forming gas bubbles that expand in the oil. These gas bubbles can help reduce the viscosity of the oil, making it easier for oil to flow from the reservoir to the well, even if more gas is produced than oil. Recovery factors in this system vary from 3% to 30%, which is considered low. (SMITHSON, n.d)

Another source of energy comes from the use of gas at the top of the reservoir, whose mechanism is called Gas Cap Drive. The gas begins to expand as the reservoir pressure drops, so the pore volume that before production contained production fluids begins to be occupied by the gas, whose stored energy is released, maintaining the reservoir pressure. This pressure reduction is considered late compared to the solution gas drive (from 20% to 40% of OOIP) and this results in much higher oil production rates and the need for artificial lift for much later second recovery. ((SMITHSON, n.d); (GLOVER, 2010))

A fourth mechanism is known as Gravity Drives, found in reservoirs that have both gas cap and water drives. The energy in this case comes from two different directions, the first upward from the hydrostatic pressure in the oil column and the second downward from an expanding gas cap, and this is why it is known as a combined mechanism. In this case, depending on which trigger has more influence on the recovery, it varies from 5% to 85% of the OOIP. (SMITHSON, n.d)

After the start of the production, variations in conditions are monitored in order to understand the performance of the reservoir, avoiding everything from early water production to pressure management to prevent it from falling below the bubbluepoint and producing much more gas than oil. However, after a while of production, the primary recovery is no longer effective, requiring the search for secondary recovery techniques, which involve human intervention in the supplementation of the energy source. (SMITHSON, n.d) (GLOVER, 2010)

When the natural energy source that allows oil recovery is exhausted or the oil is classified as too heavy and natural energy is not capable of producing it, a process of energy supplementation begins, artificially injecting gas, water or other chemicals that allow this recovery, in a process called IOR (Improved Oil Recovery). (MONTALVO, 2008)

One of the most common artificial recovery methods in conventional reservoirs is waterflooding, a water injection process with the function of displacing oil in an adjacent well according with Energy Glossary (SCHLUMBEGER, n.d). However, this technique has some associated problems, such as variable permeability, which can lead to inefficient recovery because the oil is not completely displaced, and the premature advance of water, causing the production of water instead of oil. (IMPROVED. . . , n.d)

Another method for this type of recovery is the gas lift, a process that involves injecting compressed gas through the casing of the well. The oil displacement process in this case happens through the formation of bubbles inside the oil, injected by gas lift valves at different depths, reducing the hydrostatic pressure of the fluid column and consequently allowing the oil to move to the surface more quickly. (LAVIS, 2018)

Meanwhile, the so-called gas injection takes place during EOR (Enhanced Oil Recovery), a type of recovery in which the oil is trapped in regions of low permeability or difficult access and natural or less severe recoveries are no longer effective, in which it is nn inert gas is injected, most often carbon dioxide and nitrogen, creating a higher pressure inside the reservoir and pushing the hydrocarbon. This technique is most often used in tight, old wells where primary recovery has worked previously. It is important to emphasize that the injection of carbon dioxide is also an important method for the environment, since the CO2 used can come from industrial production, alcohol, ethanol and fertilizers.(LAVIS, 2018) (ENHANCED..., 2022) (ENHANCED..., n.d)

In addition to this technique, EOR can also be performed from thermal recovery, involving a value injection to decrease the viscosity of the oil and increase its fluidity, and chemical injection, which involves the use of polymers or surfactants combined with the method of waterflooding. (ENHANCED..., n.d)

In this way, even after the reservoir's natural energy source has been depleted, it is possible to increase the percentage of oil recovered using other methods of applying artificial energies, generating an increase in production and a late abandonment of the well.

Oilfield Characteristics

One of the important characteristics of the oilfield that interferes with oil production conditions is the water depth. In this sense, subsea field development is divided into 3 categories according to the depth of the field.

The first category is defined for when the depth of the site is less than 200m and is called shallow-water. In this case, the installation requirement is limited by the size of the vessel, a smaller umbilical system is needed and there is no need for long pipeline installations, as the distance between the well and the platform is short, and small mudline trees are used. . In addition, at this depth it is possible for the technical assistance of the subsea equipment to be done by divers, so there is no need for remotely controlled tools. (BAI; BAI, 2010)

Meanwhile, when the field is more than 200m deep, it is considered a deepwater subsea development. In this case, there is a need for a remote installation process for pipelines and umbilicals due to high pressure and temperature, as well as remote assistance for problems with equipment on the seabed. Also, the risers and mooring system are an even greater challenge in this category, as they require specific materials such as synthetic fiber ropes (polyester) which, because they are lighter and stronger, have a much higher price. Besides that, there are also higher risk of incidents. (BAI; BAI, 2010) (MUEHLENBACHS; COHEN; GERARDEN, 2013) (CHAKRABARTI, 2005)

Another characteristic of the sea that affects the installation of facilities and equipment is the seabed. Ideally, for pipelines and umbilicals to be installed securely, the seabed should be as flat as possible. It turns out that most of the time due to geological formations, the ground ends up being very irregular and the installation in this type of place can cause risk of spanning and overstressing. However, there is a way to mitigate this problem through seabed intervention, composed of techniques with different actions: displace sediments to better fix the pipelines; digging a trench with the optimal size of the pipeline; and leveling the ground. In this way, the ground is prepared to receive the safe installation of the equipment. (GUO *et al.*, 2013)

In addition to these effects, those produced by the hostile environmental conditions in which the oilfield is found can also cause major problems, such as failures in offshore infrastructure, difficulties during operation and even transportation. (ADUMENE; IKUE-JOHN, 2022)

Wind, for example, is one of those conditions that affects the offshore system. Its critical speed and direction of propagation affect not only the floating system, causing rocking, shock, flooding on the deck, but also support activities, such as assistance made using helicopters or cranes, putting the installation and personnel at risk. (ADUMENE; IKUE-JOHN, 2022) (SZELANGIEWICZ; WISNIEWSKI; ZELAZNY, 2014)

Another condition that affects the natural state of the system is waves. Typically, wave modeling is defined by height and period and is used to create the wave pattern to generally create a 100 year payback period analysis. However, this limitation of having a short return period has an effect called swells, waves with gradually increasing height and period, causing strong oscillations in the vessel, disturbing the floating system if there is no orientation of the platform or ship in the direction of the waves to avoid the effects. (ADUMENE; IKUE-JOHN, 2022)

In addition to wave effects, the sloshing phenomenon can also occur, which happens when the natural frequency of the flow becomes close to the ship's motion response, causing discomfort and excitement in the vessel. The so-called green water can also happen, which occurs in rough weather, causing deck flooding and even shipwreck and destruction of structures. (ADUMENE; IKUE-JOHN, 2022) (COELHO *et al.*, 2015)

The effects of the water current can also be felt by both the floating system and the risers, mooring cables and umbilicals. During a storm, this current effect increases, caused by the large-scale rise in sea level causing impact on structures and generating an often destructive effect. (ADUMENE; IKUE-JOHN, 2022)

Another factor that can greatly affect the physical integrity of the structure is the formation of ice, especially icebergs. The level of damage depends on the strength, geometry of the interaction and the speed of the moving ice sheet, but the shock produced by the encounter between an iceberg and a floating system always causes damage. Furthermore, a major impact takes place on flexible structures such as risers and umbilicals which, under these ice conditions, suffer large vibrations and can end up in total equipment failure. (ADUMENE; IKUE-JOHN, 2022)

According to Adumene and Ikue-John (2022) (ADUMENE; IKUE-JOHN, 2022), in addition to the ice condition acting on risers and pipelines, corrosion caused in harsh environments must be considered, as production is vastly reduced and impairs the reliability of the equipment. In the umbilical system, it is possible that a vortex-induced vibration is induced, worsening the effects.

Also, it should be noted that these conditions also affect the transport and logistics of products. In general, waves, current and ice disrupt communication between land and the floating system, whether through pipelines or ships. Even if there is sophisticated technology to predict the weather, none is capable of predicting the exact size, location and strength of a polar ice cap when it is still forming, for example, and this can cause major problems such as the fracture of pipelines and the consequent leakage of Oil. (GUDMESTAD; ZOLOTUKHIN; JARLSBY, 2010)

In places with very low temperatures, the weather conditions can still cause other problems due to the high humidity of the air, cold rain and accumulation of mist, which restricts the visibility of assistance helicopters and cargo ships, delaying the process and consequently making the production phase more expensive. (ADUMENE; IKUE-JOHN, 2022)

It is also important to highlight the influence of the distance between the production system and the shore. One of the effects is the possibility of fluid conditions starting to become unstable, loss of production and even causing slugging, as the pressure drops at long distances from shore. With regard to umbilicals, for long distances it is recommended to produce them in parts and connect each section during installation, with the aim of reducing risks in terms of pressure and offering an opportunity to insert optical amplifiers or repeaters, improving the signal of communication. There is also an influence on the transport of products, an issue that will be addressed in the next section. (MADDAHI; MORTAVAZI, 2011)

3.2.1.2 Oilfield Development Concept

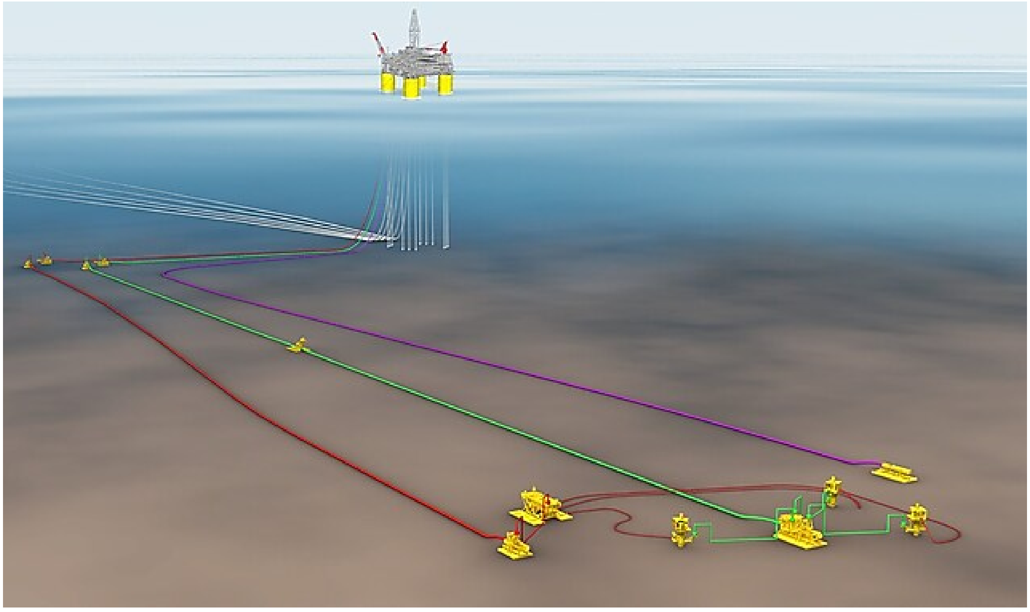
According to the oilfield location characteristics, such as distance to shore, water depth, reservoir size and amount of oil in place, combined with investment costs and economic return, it is possible to consider three development concepts: the first, in which the facility is directly connected to an exclusive FPSO for that field, known as stand-alone; the second, in which the production platform is connected through pipelines to an existing structure that serves another field located relatively close, called tie-back; and the third, less used, for facilities connected to an onshore receiving terminal, when the distance makes this connection possible. (LU *et al.*, 2006)

These concepts have different characteristics and background and therefore it is necessary to analyze the advantages and disadvantages, as well as the capability to feed the costs generated by a new platform or if there is an option to associate the production to a existing facility in orfer do optimize costs. (BAI; BAI, 2010) (LU *et al.*, 2006)

Tie-back concept development

The tie-back concept is chosen when the production of a new reservoir to be explored can be tied to a reservoir already in production that has the entire production system, connecting wells from a reservoir to a remote processing facility that already works for another reservoir (BAI; BAI, 2010), like it is shown in Figure 4, where it is possible to see that the platform is not exclusive for one reservoir and it is little bit far from it.

Figura 4: Tie-back concept



Source: (SKOPLJAK, 2022)

For the oil to reach the remote platform easily and safely, two flowlines with a loop are installed, to allow the operation of equipment that restricts the formation of hydrates, waxes and asphaltenes. In addition, subsea boosting techniques are also used to increase the flow of fluid from the reservoir to the facility and also fears such as gas-lift, gas injection into a flowline or riser with the aim of pumping oil to the platform, stabilizing the flow, depressurize the flowline and control the slugging - accumulation of water or oil in a gas pipeline. (BAI; BAI, 2010) (SCHLUMBEGER, n.d)

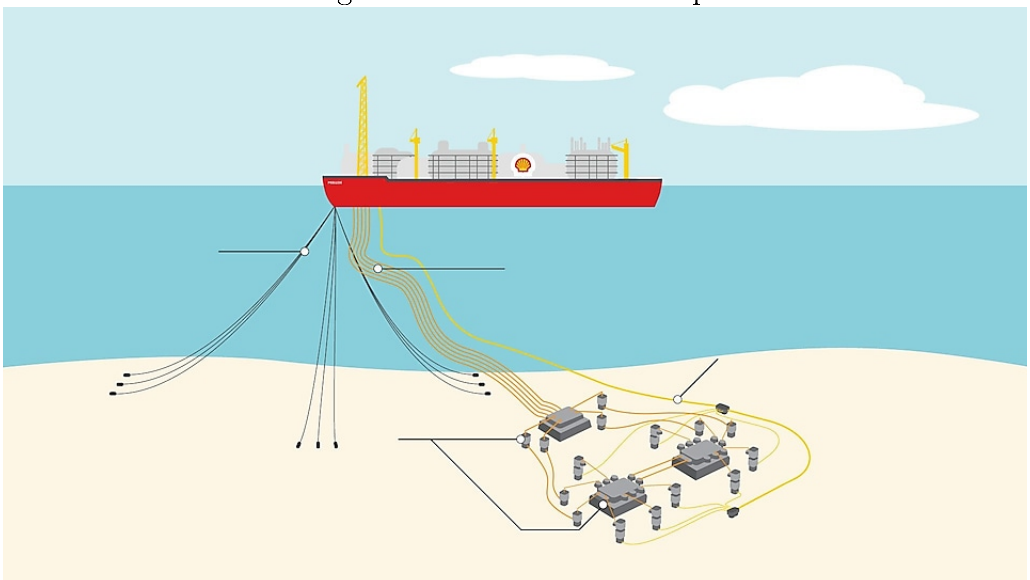
When it is possible to get this concept applied, it saves a significant initial investment, considering that there will be no construction or installation of a new platform. But apart of the cost advantage, some other features make this model often preferred, such as personnel safety, less impact on the environment by taking advantage of a construction that has already been completed and the application of technology that has already been used. (BAI; BAI, 2010)

However, according with Bai and Bai (2010), some other factors must be considered based on the production capaciry of the existing platform, the enough pressure of the oil for a commercially viable production, the intention intention to promote chemical and energy solutions trying to conserve the production necessary heat, since if the path is long it is possible that this heat is dissipated into the ocean, promoting the formation of hydrates, asphalt, paraffins and increasing viscosity of product, and considering the fact that when, for some reason, happen a sudden shutdown caused by the main reservoir, the facility can also stop producing the secondary one, harming not only one but two sources of oil. (BAI; BAI, 2010) (LU *et al.*, 2006)

Stand-alone concept development

The other concept option is called stand-alone, which is basically the installation of a new autonomous facility, which will only serve that reservoir. Generally this model is chosen when the capacity of the nearby existing installation is not sufficient, when the recoverable volume justifies the need for a new installation, as the recovery rate in subsea tie-backs is lower or when there is no installation nearby, and if it has, this culminates in high flowline costs due to distance (BAI; BAI, 2010). This model can be seen in Figure 5.

Figura 5: Stand-alone concept



Source: (SCHLUMBEGER, n.d)

It is important to make some considerations about stand-alone field development that can impact the project, as optimizing flowline configuration, access pigging requirements, needs for pumping, if the facility is still far from the reservoir. And even tho the costs are higher and project is bigger and takes more time to be done, in the case of this concept, more than one field can be connected and provides flexibility for new wells drilling. (BAI; BAI, 2010)

3.2.1.3 Drilling and Completion

After the presence of oil in a given area is indicated, drilling is performed. The first stage of this process consists of exploration drilling, whose objective is to confirm the evidence that there is oil and/or gas and subsequently its commerciality. (SUKUMAR, 2018)

The drilling process is carried out through a set of steps that begins with cutting, using a drill bit, a large hole with a circular section in the rock, salt or whatever is found before the reservoir. After this process, a casing is made, called a conductor, and as the process progresses, there is an increase in the pressure at the bottom of the well, allowing the drilling of smaller holes along this column. As the cutting progresses, the previous casings are replaced by smaller and stronger ones. Once the desired end point is reached, it is installed a conduct pipe that will allow the circulation of mud, drilling fluid that contributes to the generation of hydraulic energy and cooling of the drill bit, allowing the bit to roll inside the geological formations and a stable wellbore by forming an impermeable filter cake. (NABHANI, 2018) (ABDELGAWAD *et al.*, 2019)

In the initial drilling, the process is known as spudding, which is the act of drilling using a high viscosity fluid known as spud mud. The main function of this viscous fluid is to take the cuttings from the drilled rocks to the surface through the casing. On the surface, the fluid and cuttings are separated using shakers and thus can receive the necessary processing for each one of them. The fluid is degassed to eliminate gas and chemically treated to make it reusable, while drilled cuttings, which are solid, require recovery for disposal on land or in the ocean if no radioactive elements are identified. (NABHANI, 2018)

At the end of the drilling process, Blowout Preventers (BOPs) are installed below the drilling rig in order to prevent kicks, an action that occurs when the pressure exerted by the rock around the well is stronger than the pressure inside the well, making the process safer. (NABHANI, 2018)

After drilling the first wellbore, flow tests begin to check the productivity of the reservoir and also if there are any effects that could disrupt production in the short and long term. Data and system characteristics from the pressure rise stage are collected and studied. Once it is known the issues and the reservoir potential, production drilling begins, carrying out the same process but now for a larger number of wells, which will be defined in the stage of evaluating the size of the reservoir. After this evaluation, the drilling configuration must be decided, as these are capable of producing different amounts of oil, in addition to having different costs. (SUKUMAR, 2018) (CHAKRABARTI, 2005)

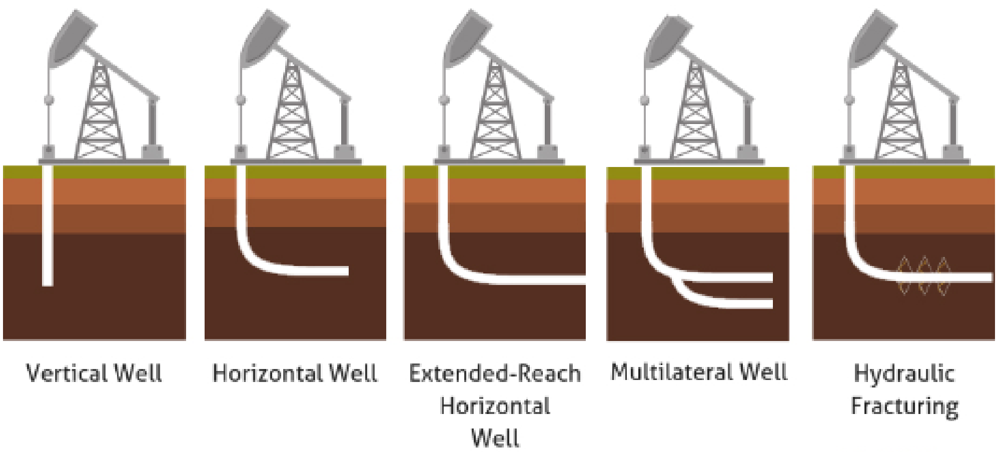
The first and oldest configuration is the vertical one, which when they have small deviations to reach the reservoir are called directional, they are drilled using standard equipment and technologies. Because they are simple, they have a lower cost but the production capacity is also limited because the absorption area is circular. (SUKUMAR, 2018)

Then, horizontal wells came out with refined function. They are drilled with an inclination greater than 80º, that is, in a direction almost parallel to the reservoir and requires more advanced technology such as Rotary Steerable Assemblies (RSA), including measurement while drilling (MWD). Because it requires more sophisticated technologies, this model is more expensive than the previous one, but its capacity to suck oil is almost twice as high as the vertical well, because now the absorption area is ellipsoidal. An extension of this type is known as extended horizontal wells, in which the bit basically enters the reservoir at a distance a little further from the vertical position in which it is inserted. (SUKUMAR, 2018)

In addition to these, it is also possible to find the multilateral type, in which there are basically two or more horizontal wells starting from the same original well (mother borehole), with the aim of producing oil in different areas of the same reservoir, hydraulic fracturing, which is a technique used to stimulate the production of hydrocarbons, creating a network of fractures capable of conducting more oil in the area around the wellbore, and other models that are being put into practice little by little to test the benefits they can offer. (Barati and Liang, 2014; (SUKUMAR, 2018))

All types of wells can be seen in the Figure 6.

Figura 6: Types of well drillings



Source: (BAI; BAI, 2010)

Once the drilling and tests are performed and the configuration is chosen, it is necessary to install an equipment that will control the rise of the desired fluids to the surface and also allow the installation of any necessary monitoring equipment in the well. This process is called completion and its complexity is directed according to the reservoir pressure, the presence of production water, the existence of multiple zones for production, among others. For offshore production, completion is divided into two main types: dry and wet. These terms refers to the condition in which the subsea christmas trees will be installed, i.e 'wet' if the tree is on the seabed and 'dry' on the sea surface. (SUKUMAR, 2018)

In deep water, normally the wet completion is chosen, as the dry completion has some limitations with the size of the water dept. Also, the dry completion is adequate when the geometry of the reservoir allows a single drilling location to reach all well locations. (SUKUMAR, 2018)

However, for a subsea system to exist, it is necessary that the completion be of the wet type, where the system is suitable for all reservoir geometries and area sizes, allowing greater flexibility in the design of field layouts. Despite that, one negative point is that wells located at greater distances from a host facility may have reduced performance due to pressure drops in the flowlines. In terms of benefits, in addition to layout flexibility, as wet tree systems are separated from production operations, pre-drilling and completion of wells can be done more quickly, in addition to the fact that fewer risers are needed because flowlines are grouped and directed to a limited number of risers, that is, a riser can receive production from different flowlines in this case. Therefore, fewer risers required means greater flexibility in choosing the ship's hull, topside weight, layout and space for future expansions. (STELL, 2015)

Finally, it is necessary to emphasize once again that in order to have subsea production, only the completion of the wet type is feasible and therefore this will be used in all conceptual designs of the case studies performed in this work. Furthermore, during the execution of the conceptual design, only horizontal and vertical wells will be considered due to simplification.

3.2.1.4 Wells configurations

Once the reservoir is mapped, it is possible to create models with different numbers, types and location of wells, as this arrangement is intended to provide a balance between the need for good recovery of fluids from the reservoir and the cost savings that can be generated in the grouping of wells. However, associating a large number of wells can generate a very high production flow and risks can start to appear and if a certain cluster with several wells has to be repaired due to some technical problem, it is necessary to have in mind that all production will stop and there will be both cost in preparation and loss of earnings while production is stopped. (BAI; BAI, 2010)

In this way, it is necessary to analyze the concepts, advantages and protection of each type of grouping, which are: clustered, template and daisy chain. Also there is another option that is not a group of wells but it is consisted in separated wells sending their production to the facility one by one through different pipelines and it is is called satellite wells.

This configuration know as satellite are normally used for small reservoirs that require few wells or when these are at very great distances from each other. The production of each one of them is delivered by a single flowline to a manifold, with the objective of controlling the production, or directly to the platform. To choose this type, the distance between the wells, the cost of the flowline, umbilical, installation and flow guarantee problems that may arise must be evaluated. (BAI; BAI, 2010)

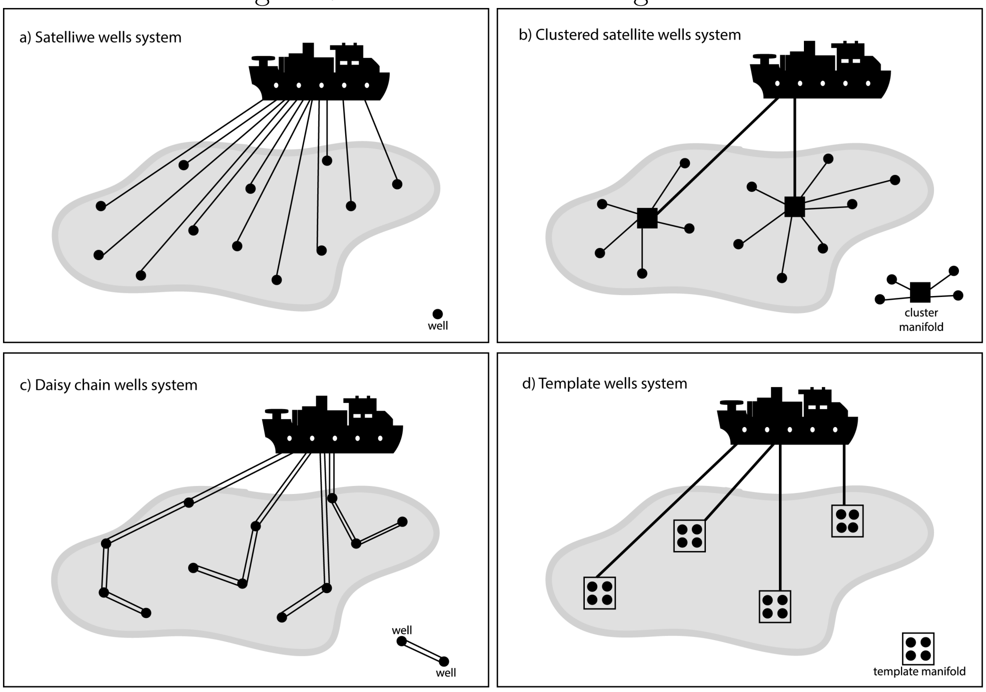
The clustered type groups satellite wells that are physically close together through a production manifold, which collects the production from all the wells and delivers them to a single flowline connected to the production facility. In this way, this grouping produces technical and financial savings in the installation of flowlines and umbilicals. (BAI; BAI, 2010)

Another way to group wells is through a well template, a metal structure on the seabed responsible for grouping wellheads and other equipment such as manifolds, risers, drilling and completion equipment, and connecting lines. The advantages of this model are the incorporation of different tools and accessories in a single structure, in addition to reducing the amount of flowlines used connecting the wells to the production unit. In addition, the fact that the distances that the flowlines travel are shorter reduces problems associated with guaranteeing flow, such as the appearance of wax and hydrate. However, there is less flexibility in determining well locations, as they must be sufficiently close to each other. (BAI; BAI, 2010)

The last type of configuration is the daisy chain, which consists of two satellite wells joined by two common flowlines, as if they were connected in series, allowing the application of round trip pigging (in case there is a problem with the formation of wax), the diversion of both production flows to a single line if the second one is damaged and the individual testing of two wells whenever necessary through independent lines. In this model, the disadvantage is mainly the displacement of the drilling rig to reach the second well and the increase in the cost of installing two flowlines between the wells. (BAI; BAI, 2010)

The representation of the four models is shown in the Figure. In the case studies addressed in this work, different types of wells configurations will be used in the same layout design, taking into account that they all have advantages and disadvantages, with the aim of creating a more technically optimized layout and with the lowest possible costs.

Figura 7: Different wells configurations



Source: (SILVA; SOARES, 2019)

3.2.1.5 Subsea Facilities and Equipments

Installation Vessels

Regarding the ships and facilities present in subsea production, these are separated according to the function they perform, which can be transport of structures, drilling, pipe-laying and umbilical-laying, heavy lift vessels, offshore support vessels and of course, the offshore production facility. (BAI; BAI, 2010)

The most important choices lie in drilling rigs and the production itself. In the first case, Mobile Offshore Drilling Units (MODUs) are used, which can be:

1. Barge: can act in a depth of just 50m, so usually it is used in extremely shallow and calm waters. On the barge's deck are steel posts that extend above the water line and the drilling platform is located exactly on these steel posts. (THE. . . , 2019)

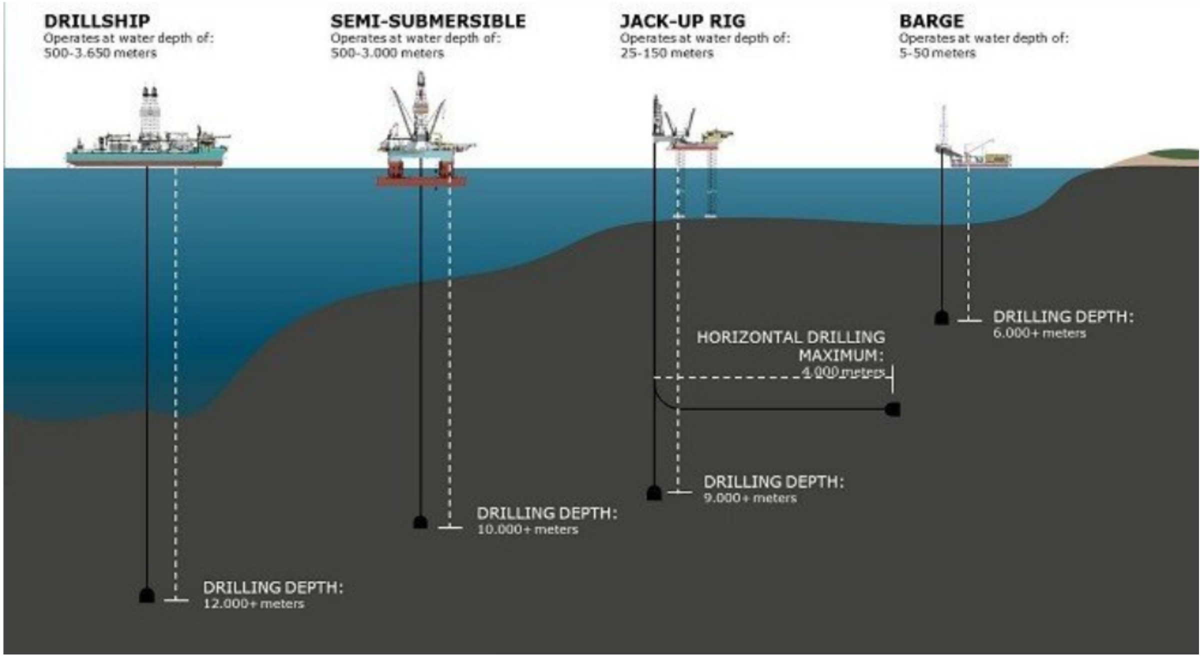
2. Jack-up rig: These platforms can only operate in water depths of around 100m or less and are therefore most commonly used in the shallower waters of the southern North Sea. Basically, the platform is positioned and extends its legs to the seabed , so that they do not penetrate the seabed, but that they are firmly supported and with the deck raised above the water level, keeping the equipment protected against tidal movements and waves.(TRADE; UNITED KINGDOM, 2001) (THE. . . , 2019)

3. Semisubmersible: platforms which float all the time and are used in deeper water. They can be positioned using tugs or their own propulsion system and are maintained by anchors or by dynamic positioning using a series of computer controller thrusters. (TRADE; UNITED KINGDOM, 2001) (THE. . . , 2019)

4. Drillships: conventional drill adapted to allow the drill bit to be implanted through the case. It is the type of MODU with the greatest depth capability, but due to the shape of the hull they are more affected by wind and wave motion than semisubmersible platforms and, as a result, are more likely to suffer over time. (THE. . . , 2019)

These types of platforms used in drilling are shown in Figure 8.

Figura 8: Different types of MODUs and characteristics to be used



Source: (SUKUMAR, 2018)

In addition to drilling installations, it is also necessary to install pipelines, a tool responsible for taking the produced fluids to the platform or from a well to equipment. They are usually made of carbon steel with an anti-corrosion coating and can be rigid or flexible, as will be seen a little later. (SUKUMAR, 2018) (CHAKRABARTI, 2005)

The installation of a pipeline depends on a combination of factors provided by production demand, such as diameter and weight, and physical characteristics, such as depth. One of these models is the S-Lay, when the pipeline curves forming an S. (CHAKRABARTI, 2005)

This deposition of this type of pipeline is carried out by a barge that carries the tubes all separated into smaller parts inside a compartment and as it is installed, one part is welded to another and tested before being definitively installed in the sea. Normally this type is used in shallow water and in order for this configuration to remain in shape, the pipe is kept under stress distribution during the laying operation. (CHAKRABARTI, 2005) (BAI; BAI, 2010)

The second type is known as J-Lay, precisely because it was formed from the letter J, which, unlike the previous one, is more applied to deep waters. Voltage requirements are much lower and the pipeline in this case is mounted in a nearly vertical plane at the vessel outlet. (CHAKRABARTI, 2005) (BAI; BAI, 2010)

There are also Reel-Lay and Towed installation types. The first is applied to pipelines with longer lengths whose welding is done on land and is wound on a kind of spool in the installation vessel, which allows to increase the laying speed. The second is used for small pipelines and in systems close to shore, as the pipeline is launched into the water and towed to the installation site by tugs, kept afloat during operation and subject to hydrodynamic loads, weight and buoyancy of the material. (CHAKRABARTI, 2005) (BAI; BAI, 2010) (SUKUMAR, 2018)

Meanwhile, the installation of risers depends, in addition to water depth, on flexibility. In the case of the shallow water rigid riser, the installation takes place after the pipeline, where the riser is lifted vertically by a crane from the vessel and connected to the pipeline in the air and then laid down on the seabed using also crane and davits. (CHAKRABARTI, 2005)

In a different way, deep water rigid risers are suspended from the production platform in the form of a catenary that meets the platform at an angle and is connected to this by a flexible joint to allow for changes in this angle. In this case, the installation of the riser and the pipeline happen at the same time, that is, both are connected and placed on the seabed until the production platform is built and allocated for the connection to be made. (CHAKRABARTI, 2005)

Flexible risers, on the other hand, are constructed from several layers, one of which is elastomer, allowing the pipeline to assume different shapes. In this situation, they are installed from a TLP, a floating platform that has hydrocarbon production, processing and transhipment systems attached. (CHAKRABARTI, 2005) (BAI; BAI, 2010)

Finally, the installation of the umbilicals, which take energy from the platform towards different equipment, are installed by reel-lay vessels, which have an attached spool. The umbilicals are flexible and have an installation very similar to that of a pipeline of the same type. (BAI; BAI, 2010)

Fixed and Floating Platforms

First, it is necessary to define what a platform is, that is, an offshore structure that does not have access to dry land and must remain in its defined position under all conditions until production is complete. These structures can be fixed or floating. (CHAKRABARTI, 2005)

Fixed and floating platforms have many differences, such as the way they are built, transported and installed, what excitation forces they are subject to, in response to this motivation and the way they are decommissioned and discarded when they end their life cycle. However, the main characteristics that define which platform will be used in that system are the load capacity and maximum working depth. (CHAKRABARTI, 2005)

While the fixed platform has, as the name suggests, its metallic structure fixed to the seabed, floating platforms may or may not have a connection with the seabed. If the water depth is small, that is, production in shallow waters, it is possible to secure the platform using the anchoring system. However, if the water depth is too large, the anchor loses its position restitution force due to the weight of the platform, not preventing its horizontal movement. In this case, dynamic positioning is used, where the platform's position is maintained by satellite and controlled through an internal panel. (CHAKRABARTI, 2005)

The main types of production platforms and the main differences between them are highlighted and exemplified in the items below, followed by the Figure 9, where it is possible to see each one.

1. Fixed: Also used in drilling, this type of platform is only viable in shallow waters of up to 300m. In addition to the production system, it is necessary to build additional infrastructure when using this type of platform, such as underwater pipelines, onshore storage tanks and port loading facilities, due to their capacity. (CARDARELLI, 2021) (MODEC, n.d)

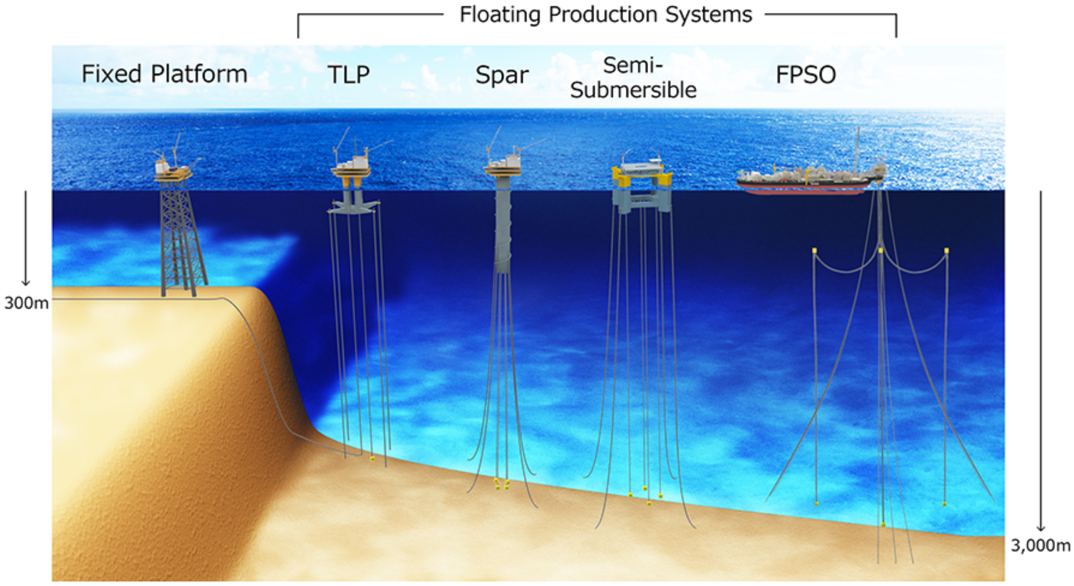
2. Semi-submersible: Also used for drilling, this type of installation can also be used for production, but not at the same time and this choice is made in advance, that is, the vessel leaves the shipyard already prepared for one of the two purposes. The unit is anchored and can move easily and quickly, also used in shallow waters due to the use of anchors. (CARDARELLI, 2021)

3. Tension Leg Wellhead Platform (TLWP): its structure is similar to that of a semi-submersible, but with tensioned steel cables that fasten it to stakes driven into the bottom of the sea, the mooring system. This technology made it possible to create a stable platform with a "dry" production system, however, in water depths of up to 1,000m. (CARDARELLI, 2021)

4. Floating Production Storage Offloading (FPSO): it is basically a large tanker with storage capacity that does all the work of extracting the oil and storing it until it is

transferred to the transporter. It is capable of operating from shallow to ultra-deep waters, which is why it is currently the most used. In this case, the use of dynamic positioning is preferred. (CARDARELLI, 2021)

Figura 9: Various types of offshore platforms



Source: (MODEC, n.d)

Wellheads

The term wellhead refers to the equipment responsible for containing the surface pressure of a drilling well, providing the interface for drilling, completion and testing during the subsea operation phases. The wellhead is located exactly where the hole is drilled and will lead to the installation of a subsea christmas tree. (BAI; BAI, 2010)

The main functions of this equipment are to provide the suspension point and pressure seals for the casing strings running from the bottom of the borehole sections to the surface pressure control equipment, serve as an interface and support for the Christmas tree and BOP (Blow Out Preventor) system, receive the loads imposed by operations, ensure the alignment and concentric of some kick and blowout prevention system equipment, such as the low-pressure conductor housing and the high-pressure wellhead housing. (BAI; BAI, 2010) (SOUZA, 2018)

Subsea Christmas Tree

A subsea tree, or Christmas tree, is an arrangement of valves, pipes, fittings and connections placed on top of a wellhead, which the function is to monitor and control the production of a subsea well. The equipment is positioned on the seabed and can be controlled by electrical and hydraulic signals on board the platform or by external vehicles, ROVs, ensuring safe and efficient management. (BAI; BAI, 2010) (CRUMPTON, 2018)

A subsea tree connects directly to the wellhead and directs production flow to the flowline. Additionally, it is also used to isolate or regulate flow as well as provide direct access to the well during disciplines. (CRUMPTON, 2018)

Regarding types, it is possible to find 2 main groups: vertical trees and horizontal trees, sometimes called spool trees. In the vertical one the main valves are located above the piping support. The design of this type of tree requires the use of a coupled double hole riser and the handling and operation of this type of system is more complex, time consuming and more expensive than the single hole. Despite this, the main advantages of this type include that well control barriers can be configured to allow the tree to be installed after rig departure, saving time and money on rig rental. (CRUMPTON, 2018) (SOTOODEH, 2021)

Unlike the vertical Christmas tree, the horizontal's valves are located on the sides of the tree, allowing for easier intervention in wells and pipeline recovery. In this type of design, operations are carried out with a less complex riser, offering advantages mainly in deep waters, where manual adjustments are almost impossible. Advantages include having large bore if large tubing size is required, possibility of installing the tree before drilling if necessary and the fact that the tree has an integral and precise guidance system, without the need to modify the BOP. However, the acquisition cost of this type is higher than the previous one and therefore the final choice must take into account the depth, location and risks in the defined layouts. (BAI; BAI, 2010) (CRUMPTON, 2018) (SOTOODEH, 2021)

Just to clarify, the BOP is not part of the production system but a safety system, with the function of predicting and controlling the kick, which is the entry of unwanted fluid present in the rock formations inside the well, and subsequently the blowout, which is the evolution of the kick if it is not contained. Despite not being part of the production system, it plays an important role in protecting it and is therefore covered in this chapter. (FANG; DUAN, 2014)

Manifold, PLEM and PLET

The manifold is an equipment comprising an arrangement of piping and valves with the aim of combining, controlling, distributing and frequently monitoring the fluid flow, in addition to simplifying the submarine system, reducing the use of pipelines and risers. This equipment is installed at the bottom of the sea, covering a series of wells, which can be producers, injectors or, in the most modern ones, a combination of both, grouping them together. This solution is designed to bring more efficiency and reliability to subsea operations, optimizing technique and likely lowering costs. (BAI; BAI, 2010) (SOTOODEH, 2021)

This equipment can have two, four, six or eight slots, according to the number of wells that will be connected to the manifold. When the manifold is used to connect rigid pipeline with other subsea structures, such as a manifold or tree, it is called Pipeline End Manifold (PLEM). Also known is the Pipeline End Termination (PLET) which, as the name says, is used in the terminations of rigid pipelines so that the original direction is changed. (SOTOODEH, 2021)

Pipeline

Pipelines are responsible for transporting production (oil and/or gas) and injections (water and/or gas) and their influence on the designs of a subsea production layout is caused by the different types, materials, laying and maintenance that can optimize the production in a field. (BAI; BAI, 2010)

Pipelines are separated according to the function they perform and can be called flowlines, when the line connects a well to a manifold or to a platform; gathering/interfield lines, in case the connection is between a multiwell platform with another platform; trunk likes, which combine flows from one or more platforms to shore; and finally the loadings/unloadings lines, responsible for connecting the production platform and the loading facility or a manifold and a loading facility. (SUKUMAR, 2018)

The first aspect that is considered during the choice of the layout is the laying, that is, how these lines are accommodated on the bottom of the sea. This factor is important and must be taken into account, as crossing between pipelines must be avoided in order to avoid risks of rupture or pressure drop due to overlapping (SUKUMAR, 2018). Furthermore, Hong et al. (HONG; WANG; ESTEFEN, 2023) evaluates the importance of knowing the topography of the seabed and the physical obstacles that may exist, which can puncture, rupture or corrode the lines.

The second factor is that the flow must be guaranteed, i.e., the hydrocarbon must leave the reservoir to the point of sale (shore) without the flow being interrupted. However, due to environmental and transport conditions, unwanted solids can be deposited in the lines, such as waxes and hydrates. One of the ways to control flow guarantee is the use of pigs, which are pipeline inspection devices responsible for maintenance operations in pipelines without interrupting the flow. (SUKUMAR, 2018)

In addition, a factor that can affect the optimization of production in this part of the pipelines is corrosion, which is the transformation of a material or metal alloy through its chemical or electrochemical interaction in a given exposure medium, in this case the sea water. This process results in the formation of corrosion products and in the release of energy. In the case of internal corrosion, which occurs on the inside of the pipeline, the deposition of corrosive material reduces the diameter of the pipe, causing the production flow to decrease. (SUKUMAR, 2018)

To avoid the aforementioned problems, it is necessary that the type of pipeline, rigid or flexible, is chosen according to the production system environment. Some of the factors to be considered in the decision are the type of product to be transported, the presence of corrosive gases, depth, the distance between the wells and the floating unit, the diameter required to meet production, the total length, the temperature of the location, among others. (BAI; BAI, 2010)

Riser System

The riser is nothing more than the portion of the flowline that resides between the platform and the seabed adjacent to that platform. This structure is part of a larger system, having its own buoyancy system and moves independently of the movement of the platform's hull. The riser is composed of a pipe-in-pipe model, in which the outer tube acts as a conductor and what separates the two is an annular space filled with seawater. (SPEIGHT, 2014)

They can be installed in several different configurations according to the production layout and environmental conditions of the site and consideration must be given to geometry, structural integrity, rigidity and continuity, cross-section properties, means of support, type of material and costs. The configuration depends on the depth of the water and it can be completely vertical or wave-shaped, with variations in the angles and shapes formed betweetn the seabed and the platform.(BAI; BAI, 2010) (SPEIGHT, 2014)

Distribution System

The distribution system is a set of equipment and accessories that provide the necessary communication from the subsea controls to the topside, in terms of hydraulic, electrical, chemical injection and communication power distribution.

The first subsystem to be discussed is called ssubsea umbilical system and it is used to transmit hydraulic or electrical energy and to inject fluids for well control. The system composed of umbilicals, ducts that couple tubes, hoses, electrical cables and fiber optics within their diameter, with the aim of simplifying interfaces and reducing installation and production delivery time. These cables can directly connect underwater structures to floating structures or even shore installations. However, in the case of very extensive production fields where the wellheads are far from each other, equipment called UTA (Umbilical Termination Assembly) is installed, which acts as a distributor of the umbilical system, connected only by a cable to the platform and spreading cables to structures such as manifold, wellhead, trees, among others. This fully enclosed unit incorporates electrical junction boxes for the electrical power and communication cables, as well as tube work, gauges, and block and bleed valves for the appropriate hydraulic and chemical supplies. (BAI; BAI, 2010) (AJAYI; ARIBIKE, 2015)

For even larger reservoirs, there is the possibility of installing more than one UTA, which are connected using cables called flying leads, which are typically flexible pipes capable of transporting chemical fluids, water and energy between underwater structures, which also classify them as part of the distribution system. This type of pipe has a much smaller diameter compared to umbilicals and is also cheaper, which is why it is often chosen for this type of connection that requires reduced flows. (BAI; BAI, 2010)

In addition to these two systems, there is also a logic cap system consisting of stab plate mounted hydraulic couplers connected to HFL (Hydraulic Flying Leads) tubing and plumbed accordingly to suit the application, responsible for hydraulic and chemical distribution in case of failure in the two previous systems or changes in system requirements. (BAI; BAI, 2010)

Finally, the Subsea Accumulator Module (SAM) is composed of subsea units that store the hydraulic fluid so that adequate pressure is always available to the subsea system, even when other valves are operated. This system is used to improve the hydraulic performance of the subsea control system mainly in Christmas trees and manifolds. (BAI; BAI, 2010)

The distribution system is even much larger than described here, with many more subsystems and equipment. However, in the case studies discussed later in this work, only UTAs and, if necessary, flying leads will be considered.

ROV

The ROV (Remotely Operated Vehicle) is basically an underwater robot that, as the name suggests, is remotely controlled and equipped with cameras and equipment necessary for the installation and maintenance of other underwater structures, used in deep waters where these types of services cannot be carried out by divers. This equipment does not carry any human on board and that is why the camera is necessary to transmit the condition in real time. It is connected to the vessel, normally, through cables that transport electrical energy, video and other data between the robot and the operator located on the platform. (SUKUMAR, 2018) (TURGEON; MORSE, 2022)

The movement of this vehicle is done through propellers and thrusters, which have speed controllability and reversibility. The ROV's first job is to collect data, through its camera, from the environment and the equipment that needs maintenance. Also there are sensors that provide informations about the depth, temperature, currents and its orientation. All these data are sent to a computer on board the vessel controlled by a specialist, after which the data is filtered, processed and used as input for software capable of generating control signals for the robot to perform the necessary maneuvers. (SUKUMAR, 2018) (AID, 2019)

Storage and offloading

After production is completed and sent to the platform, the oil and gas produced and treated must be stored in order to meet the variation in demand and production, as well as demand in emergency situations. After storing a certain amount a little less than the total capacity of the platform, the products need to be transported to shore to be sold. (SUKUMAR, 2018)

For oil storage there are several types of system, which can be in tanks or even underground storage. Currently, most of it is stored in tanks, whose structure is made of welded steel, protected against leaks. (SUKUMAR, 2018)

About the gas storage, it is usually done in cylindrical pressure vessels, with or without refrigeration and insulation. Another option is bullet storage, cylindrical, long and generally horizontal tanks that allow storage of natural gas at room temperature, but due to the horizontal arrangement a large storage surface area is required. (SUKUMAR, 2018)

Currently, more sustainable natural gas storage is also being applied, such as underground storage, in which the excess gas produced, which will not be immediately commercialized, is stored to be later supplied in periods of scarcity, supplying market demand and maintaining the production flow of oil by reinjecting gas into the producing well. (MACULAN; CONFORT, 2007)

After being stored for a certain time, this oil or gas needs to be sent to consumers. There are different types of transport modes that can be used for this type of movement, but the most common are tankers and pipelines due to their advantages. (SUKUMAR, 2018)

For transport through pipelines there are three different types that were explained some sections above, which are flowlines, collector lines and trunk lines, each one connecting different equipment and facilities. Once the pipeline starts operating for transport, it is necessary to maintain it constantly, in order to avoid the formation of incrustations, remove obstructions and monitor the flow. (SUKUMAR, 2018)

Meanwhile, to transport oil, takers are normally used, which are ships built or adapted specifically for the transport of hydrocarbons, which can be in the crude state or products (gasoline, kerosene) and also the transport of chemicals. In this type of transport, great care must be taken with the risk of leaks when feeding the ship with the fluid stored on the platform. This feeding, as well as product unloading, is done by a high-pressure pumping system, which transfers the oil from the platform to the ship or from the ship to barrels in the port. (LEFFLER; PATTAROZZI; STERLING, 2011)

3.3 Economic Analysis

In addition to considering the technical aspects regarding the use of the facilities described in the previous sections, the economic aspect will also be considered in this work. In oil production projects, cost management and economic analysis are two important pillars because they involve controlling project costs through quantitative estimation techniques, which requires relevant data necessary for the project. (BADIRU; OSISANYA,

2013)

These costs are generated by the sum of two factors. The first is capital expenditures (CAPEX), which refers to the project's investment costs, such as purchasing equipment, design, management, testing, commissioning and facilities installations, umbilicals and pipelines, where the largest percentage is concentrated in the costs of equipment and their installation, which is precisely the focus of this project. The other factor is operation expenditures (OPEX), which are the costs of operating and maintaining the production phase, which are generally platform rental costs, well interventions, transportation, chemicals and employee expenses. (BAI; BAI, 2010)

According to Bai (BAI; BAI, 2010), the best cost estimate representation of a subsea project is obtained by combining two estimation methods: factored estimation and WBS (Work Breakdown Structure) estimation. The first is the sum of an initial basic cost with a cost that takes into account factors that are related to each specific piece of equipment, such as its sales condition on the market, temperature and depth of the installation location, characteristics of the reservoirs, among others. which will be detailed in specific sections later. Meanwhile, WBS estimation is a tree divided into levels that presents all phases of work on a subsea project. This organization allows project costs to be divided according to tasks, making the estimate clearer and easier to carry out.

Next, each section will detail the cost estimate for each of the most typical equipment in subsea projects, which are covered by the bibliography. For the others, averages based on historical data will be used and will vary for each case, depending on the specific characteristics of each one.

3.3.1 Subsea Trees

As previously described, Christmas trees, or subsea trees, are present on all well tops and that is why cost estimation is so important. Its cost is calculated based on an initial base cost, a cost called miscellaneous, which is influenced by factors such as temperature and characteristics of the reservoir, and variables relating to the type of tree, bore size and pressure rating. This function is expressed in the Formula 3.1. (BAI; BAI, 2010)

$$C = f_s.f_t.f_p.C_0 + C_{misc} \tag{3.1}$$

The specification of what each variable refers to and the range of values that can be used are present in the Table 2.

Variable		Description	Cost (USD)
C_0	Inicial cost		2,75E+06
f_t	Tree type	Horizontal	1,30
		Vertical	1,00
f_s	Bore size	3 in	0,85
		5 in	1,00
		7 in	1,15
f_p	Pressure rating	5 ksi	0,90
		10 ksi	1,00
		15 ksi	1,15
C_{misc}	Miscellaneous cost		2,50E+05

Tabela 2: Cost estimation of variables present in the subsea trees cost estimation function (BAI; BAI, 2010)

For each case study, and in each layout, the characteristics of the trees to be used will be defined and based on this, the average cost presented in the Table 2 above will be used in the Formula 3.1 to obtain the total cost of a Christmas tree.

3.3.2 Subsea Manifolds

Regarding manifolds, depending on the type and size of the field and layout, the cost of this equipment can reach 70% of the total equipment cost, which is why its accurate estimate is so important. In addition to conventional manifolds, which connect wells together to collect and redirect the flow, PLEM/PLETs also fall into this category. (BAI; BAI, 2010)

For this estimate, in addition to the base initial cost and the miscellaneous cost, the estimate is mainly dependent on the type of equipment, that is, whether it is a PLEM/PLET or cluster type. If it is the first type, only the external diameter of the pipe is considered as an additional factor. If the equipment is of the cluster type, in addition to the pipe dimensions, the number of slots must be considered. (BAI; BAI, 2010)

The estimating equation and costs according to types and descriptions are present in the Formula 3.2 and Table, respectively.

$$C = f_s . f_N . f_t . C_0 + C_{misc} \tag{3.2}$$

Variable		Description	Cost (USD)
C0	Inicial cost		3,00E+06
f_t	Manifold type	PLEM/PLET	0,6
		Cluster	1,00
f_N	Number of slots*	2	0,70
		4	1,00
		6	1,10
		8	1,30
		10	1,70
f_s	Pipe outer diameter	8 in	0,93
		10 in	1,00
		12 in	1,05
		16 in	1,15
		20 in	1,25
C_{misc}	Miscellaneous cost		2,50E+05

Tabela 3: Cost estimation of variables present in the manifold cost estimation function (BAI; BAI, 2010)

In this case, the average cost values were used for each variable, as there is a minimum and maximum cost.

3.3.3 Flowlines

As already seen in this work, flowlines are used to connect equipment to each other or from a well or equipment to the surface. The main factors considered when estimating flow are the type, whether it is rigid or flexible, the diameter, which is defined based on the pressure rating and the temperature of the location, the material class, the coating and obviously the length. The Formula 3.3 presents the way to calculate the final cost of flowline. (BAI; BAI, 2010)

$$C = f_s.C_0.L + C_{misc} \tag{3.3}$$

where f_s is the diameter size factor and L is the total length of the flowline in meters. In this case, C_0 varies according the type of flowline. The Table 4 shows how costs vary according to the variation in equipment characteristics.

Variable		Description	Cost (USD/meter)
C_0	Inicial cost	Rigid	\$230,00
		Flexible	\$2.300,00
f_s	Rigid diameter	4 in	\$0,25
		10 in	\$1,00
		12 in	\$1,30
		16 in	\$1,80
		20 in	\$2,60
	Flexible diameter	4 in	\$0,65
		6,625 in	\$1,00
		8 in	\$1,25
		10 in	\$1,90
C_{misc}	Miscellaneous (coating)	4 in	\$180,00
		10 in	\$460,00
		12 in	\$500,00
		16 in	\$600,00
		20 in	\$720,00

Tabela 4: Cost estimation of variables present in the manifold cost estimation function (BAI; BAI, 2010)

It is possible to note that the initial cost of a flexible flowline is 10 times the cost of a rigid one, leaving doubts regarding the choice of this type. In addition to the technical characteristics that allow this choice, the installation cost of the flexible type is much lower than the rigid type.

3.3.4 Installation Costs

In addition to the costs of purchasing and manufacturing the equipment, there is also the cost of installing each of them. These operations usually take days or a few weeks and therefore the cost is measured per day and the availability of operators, the weight and size of the equipment, the weather window and the method to be used must be considered, as all of this affects the final installation cost, which can reach 30% of the total cost of developing the subsea system. (BAI; BAI, 2010)

The Table 5 presents the installation cost for the main equipment. This cost is obtained by multiplying the cost of renting installers per day by the number of days in which the service is performed.

Equipment	**Cost (USD)**
Subsea tree	$300.000,00
Manifold	$250.000,00
PLEM/PLET	$150.000,00

Tabela 5: Installation costs of some equipments (BAI; BAI, 2010)

For the installation of pipelines and umbilicals, differences in time and costs must be considered based on the type of vessel used. These differences can be seen in Table 1.

Pipelaying vessel type	**S-Lay**	**J-Lay**
Length laid per day [m]	8640	4600
Daily cost [USD]	700	700

Tabela 6: Comparison of installation time and cost for S-Lay and J-Lay methods (MANESCHY, 2014)

Regard to platforms, the installation cost changes a lot depending on the type and depth it reaches, ranging from 350 to 950 thousand dollars per day. (BAI; BAI, 2010)

4 RESULTS

This chapter presents an analysis of the hypothetical subsea system configuration for a field in the Barents Sea, based on three possible design configurations. By employing this model, it was possible to systematically quantify and calculate the necessary components for the system, following with a deeper examination of the technical and economic implications of each configuration, and highlighting the factors that influence the selection and cost of the system components.

4.1 Barents Basin - Norway

The case presents a hypothetical scenario involving three reservoirs situated in the Barents Basin, located off the northern coast of Norway and Russia. This region is significant and extensive, renowned for its abundant hydrocarbon resources. It is important to note that the harsh climate in this area imposes unique challenges on oil exploration and production activities, impacting equipment choices, production methods, and transportation logistics. (ZONN; KOSTIANOY; SEMENOV, 2017)

The distance between the block and the nearest refinery facility is 240 km, in an environment with a prevalence of polar lows, sea spray icing, sub-cooled rain and fog. In addition, it is known that the primary mechanism of the reservoirs is the gas cap and that a total of 12 injection wells will be included, 8 for water and 4 for gas. Other important information is highlighted in the Table.

Characteristics	**Value**	**Unit of Measurement**
Original Oil in Place (OOIP)	111.102.224,55	bbl
1A-Reservoir Area	101,29	km^2
1B-Reservoir Area	38,98	km^2
1C-Reservoir Area	4,35	km^2
ºAPI	31	[º]
Daily production (q0)	3500,00	bbl/day
Production Plateau (Qp)	23.133.460,71	bbl/year
Recovery Factor (FR)	50	%

Tabela 7: Characteristics of the Barents Basin Oilfields

The study case block is situated at a water depth ranging from 360 to 390 meters, which is considered relatively shallow for offshore oil exploration. This depth allows for the use of fixed or floating platforms, making drilling and production operations more feasible and cost-effective compared to deeper waters. While there are still challenges, such as environmental management and logistical considerations, this depth generally provides a favorable environment for the exploration and development of oil fields, enhancing the potential for successful extraction and economic viability.

It is important to highlight that all the results obtained can be accessed in the file 'BarentSea.3dm', available in the Appendix B.

4.1.1 Number of wells

Based on some of the information provided, it is possible to calculate the estimated number of wells needed to extract all the oil in the reservoir, which is defined according to Equation 4.1. (BAI; BAI, 2010)

$$\mu_w = \frac{\frac{Q_P}{q_0}}{t} \tag{4.1}$$

where μ_w is the number of well, t is the time in days of the year that the reservoir will be in production and Q_P and q_0 are the Production Plateau and Daily Production, respectively. It is important to highlight that this equation is a simplified model that considers equal production for all wells.

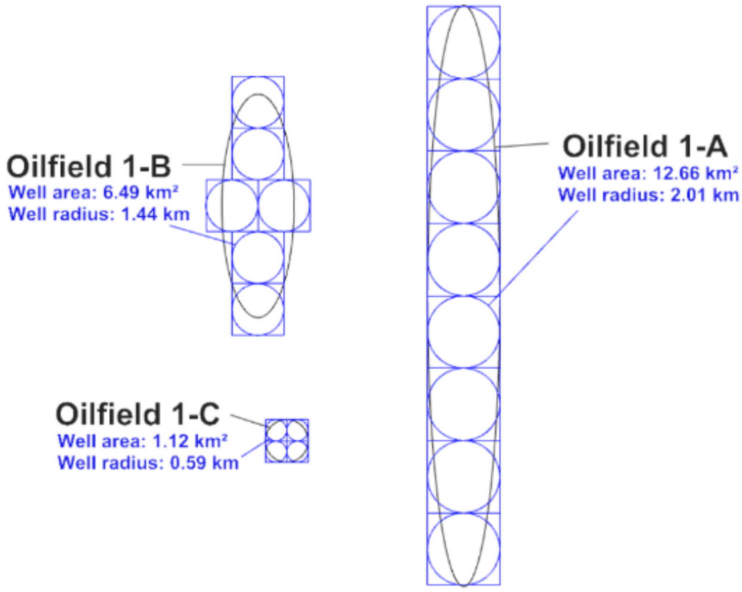
As a result, using the known values and the fact that production is active 365 days a year, the total number of wells is 18. This number was distributed arbitrarily among the

3 reservoirs, considering their areas. Therefore, the number of wells that will be drilled in reservoirs 1A, 1B and 1C are, respectively, 8, 6 and 4. With these values and knowing the areas of each reservoir from the Table 7, it is possible to calculate the area of each well according to the Equation 4.2.

$$A_w = \frac{A_r}{\mu_w} \tag{4.2}$$

The well areas for each reservoir, as well as the radius of each one and its position are shown in the Figure.

Figura 10: Distribution of wells in the oilfields in Barents Basin



Source: Author

4.1.2 Drilling and Completion

For this case study, it will be assumed that there is already evidence of the existence of oil in the reservoir, that is, the exploratory phase has already been completed and, therefore, only producing (or injector) wells will be drilled. As previously stated, it is necessary to evaluate and consider which drilling configuration will be used, as each one is capable of producing different amounts of oil at different costs. As a result, three cases were analyzed with different configurations, as illustrated in the Figures 11, 12 and 13.

Figura 11: Configuration of well drilling designs for Oilfield 1-B

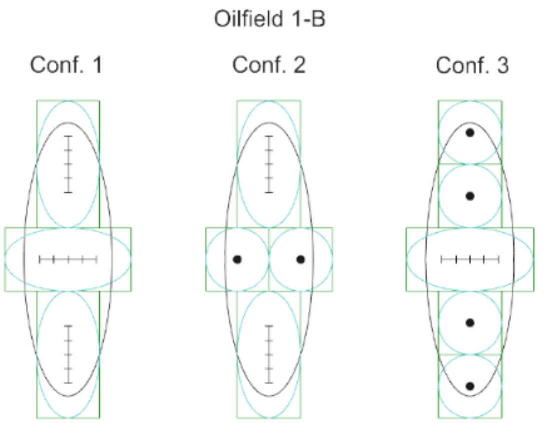


Figura 12: Configuration of well drilling designs for Oilfield 1-C

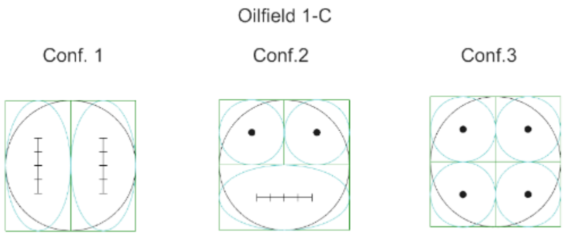
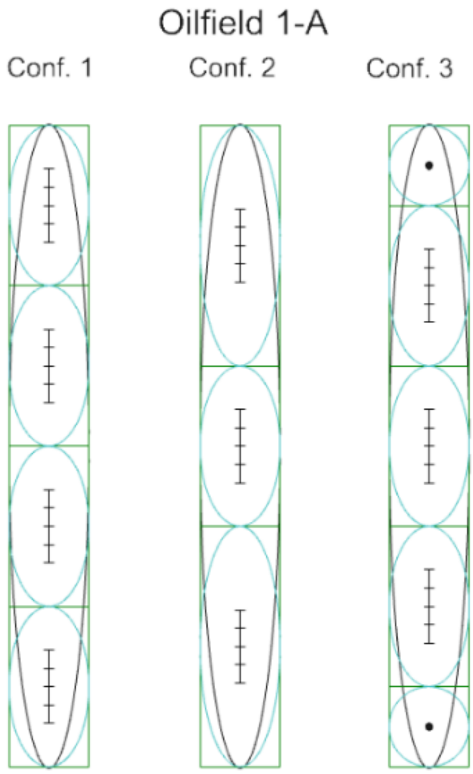


Figura 13: Configuration of well drilling designs for Oilfield 1-A



Source: Author

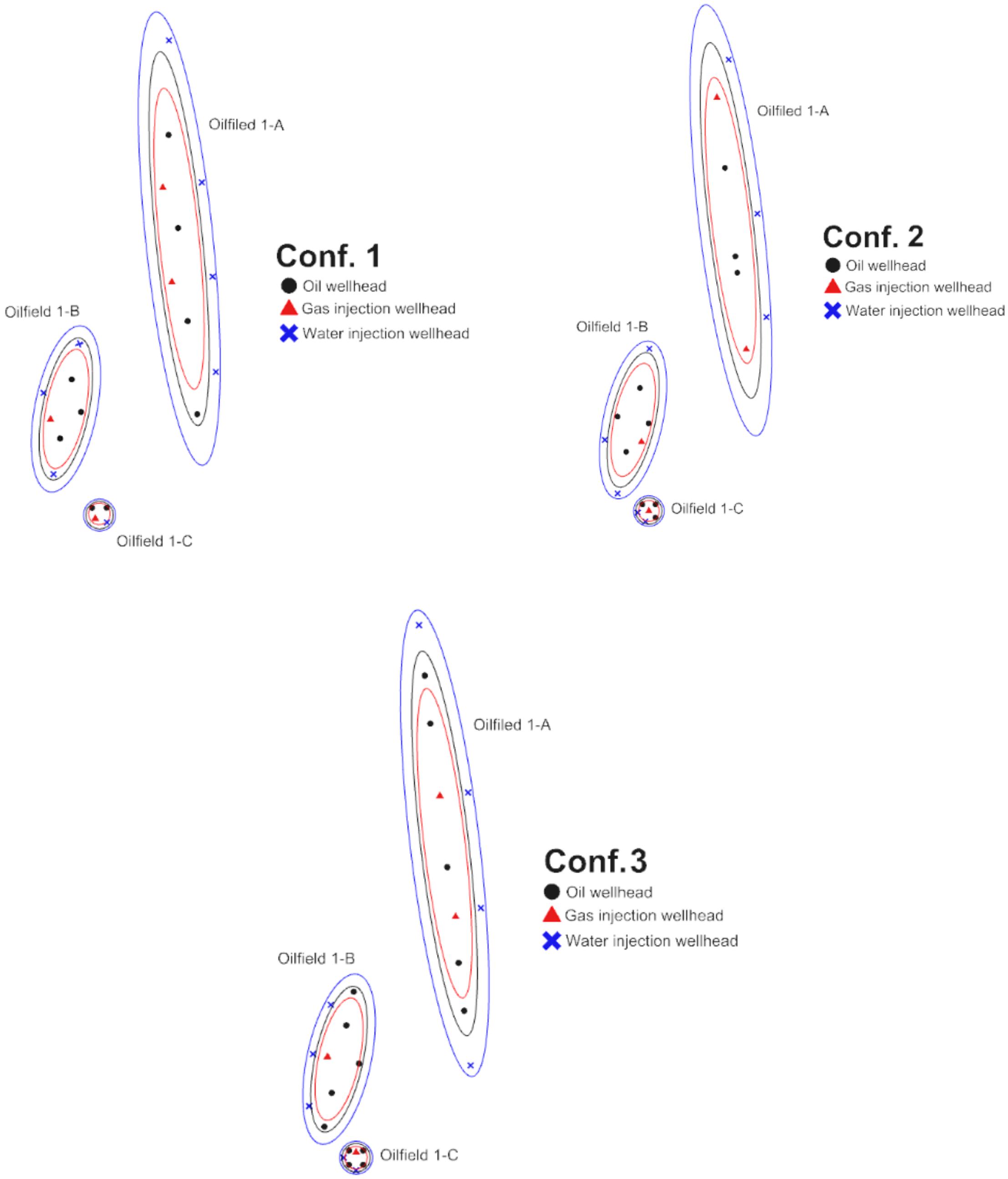
In the first configuration, only horizontal wells were chosen, to maximize the produced area and allow a better organization of the space for the future installation of manifolds. In addition, horizontal drilling has the advantage of covering a larger area of the reservoir, being considered equivalent to two vertical wells, so that this configuration not only maximizes the use of space, but also enhances the extraction efficiency and the economic return of the project. (SUKUMAR, 2018) (BAI; BAI, 2010)

In the second, some wells will be drilled vertically to reduce costs, and some of the horizontal wells will occupy 3 vertical spaces instead of 2, as in the previous configuration. The simplicity of the vertical type of drilling allows for more agile planning and execution, reducing operating time and operating costs. In addition, the approach also aligns with the minimization of technical complications and a lower environmental impact, occupying a reduced area of the seabed. (SUKUMAR, 2018)

The last configuration again considers both types of drilling, but allocating the verticals in the top.

After organizing the different drilling configurations, it is possible to establish the well layouts, specifically the locations of the wellheads. For vertical wells, the wellhead will be positioned directly at the center, while for horizontal wells, it will be located at one of the ends. Additionally, the location of the water injection wellhead is strategically chosen to maintain an adequate distance from the producing wells. This distance is crucial to ensure that water can efficiently move from the reservoir to the wells, while also directing the water flow toward areas with higher oil concentration, thereby aiding in pushing the oil toward the producing wells. The final configurations are shown in Figures 14. (NIKRAVESH *et al.*, 2024)

Figura 14: Wellhead placements for the three type of configurations



Source: Author

4.1.3 Wells Layout Configurations

When choosing possible well layout configurations, the characteristics of the reservoir and its surrounding environment must be considered. The Norwegian Sea region is an area characterized by complex geological processes and an environment that promotes the migration of subterranean fluids and the release of gas, creating extensive fields of pockmarks on the seabed. In addition, the relatively shallow depth and temperature conditions make these regions vulnerable to hydrate dissociation, with the potential to affect both gas dynamics and slope stability. (COOK *et al.*, 2023)

In addition to hydrates, the extremely low temperature conditions cause the formation of colloids known as wax when saturated compounds of crude oil solidify. After formation, if there is no maintenance of the pipelines, wax deposition occurs, contributing to obstruction in wells and pipelines and causing losses such as reduced fluid pressure, contamination of facilities such as separators and tankers, and increased energy consumption in pumps to lift the fluid. (KIYINGI *et al.*, 2022)

Therefore, if the formation and deposition of these two components cannot be avoided, subsequent treatment is required to remove them from the pipelines. This removal is mainly carried out through pigging, a process in which a device called a pig moves along the inside of the pipeline in order to clear obstructions caused by waxes and hydrates. To facilitate pig movement, the daisy chain configuration is considered the best option because it connects the wells in series through two pipelines, where one is used for the pigging process when necessary, while the other can maintain production, which would be interrupted in other configuration models. Therefore, in Configurations 1 and 2 of the first case study, the daisy chain model is applied in some wells, as can be seen in the Figures 15 and 16. (QUARINI; SHIRE, 2007)

Figura 15: Daisy Chain in Configuration 1

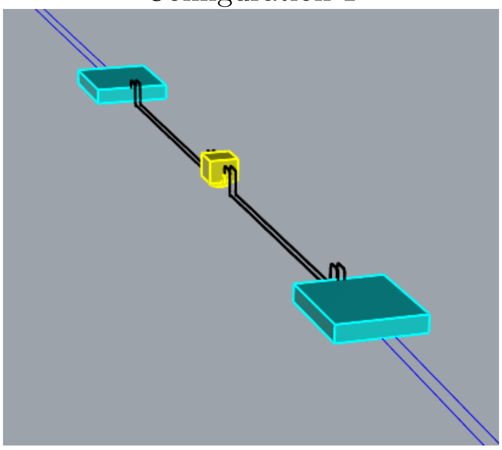
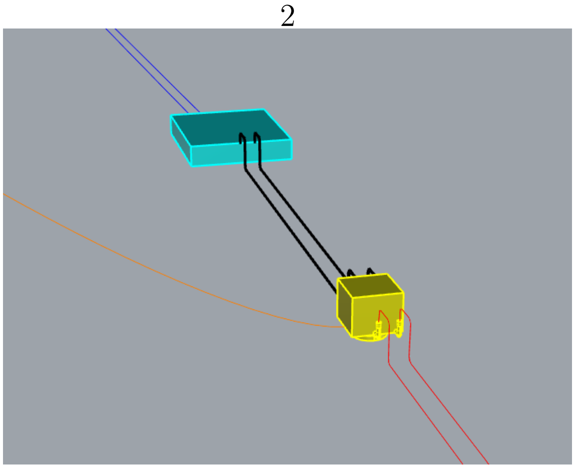


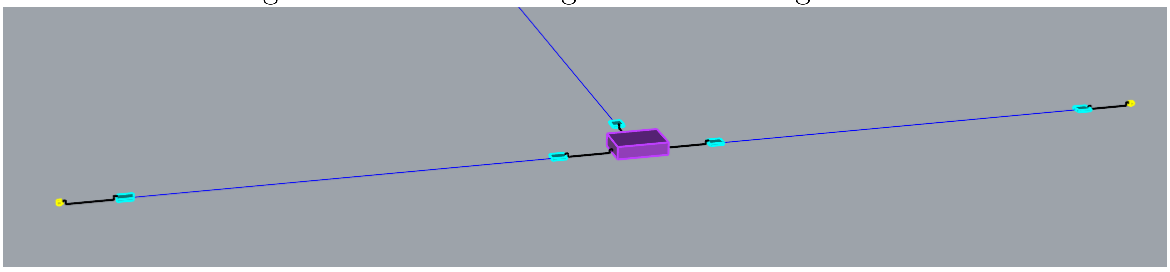
Figura 16: Daisy Chain in Configuration 2



Source: Author

In addition to this type of well configuration, there are also configurations that group two or more wells to reduce the use of flowlines and better control production, joining them through manifolds, called template or cluster. For the template configuration, it is necessary for the wells to be geographically very close, since they would in fact be within a structural weldment. Since in this case the wells are at least 1 km apart, the best grouping is the cluster, which connects up to 6 wells in a single manifold. This type was used in Configurations 1, 2 and 3 and one example is shown in Figure 17. (SA'U; ROSYID, 2018)

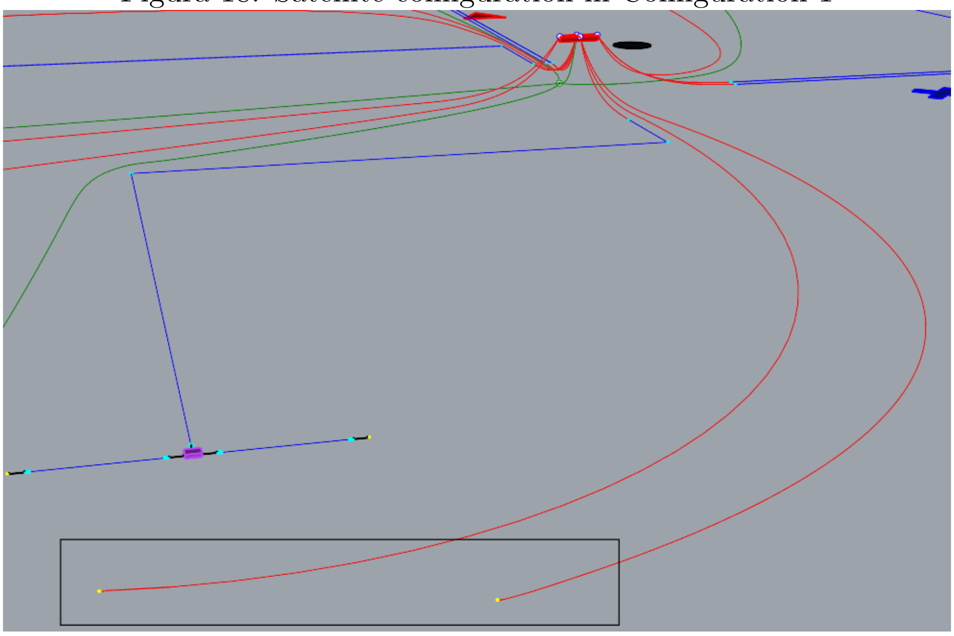
Figura 17: Cluster configuration in Configuration 1



Source: Author

The other possible configuration is the satellite, which directly connects the wellhead to the platform. However, the use of this configuration was minimized in the three options in order to reduce the use of flowlines and, consequently, lower costs. This is illustrated in Figure 18.

Figura 18: Satellite configuration in Configuration 1

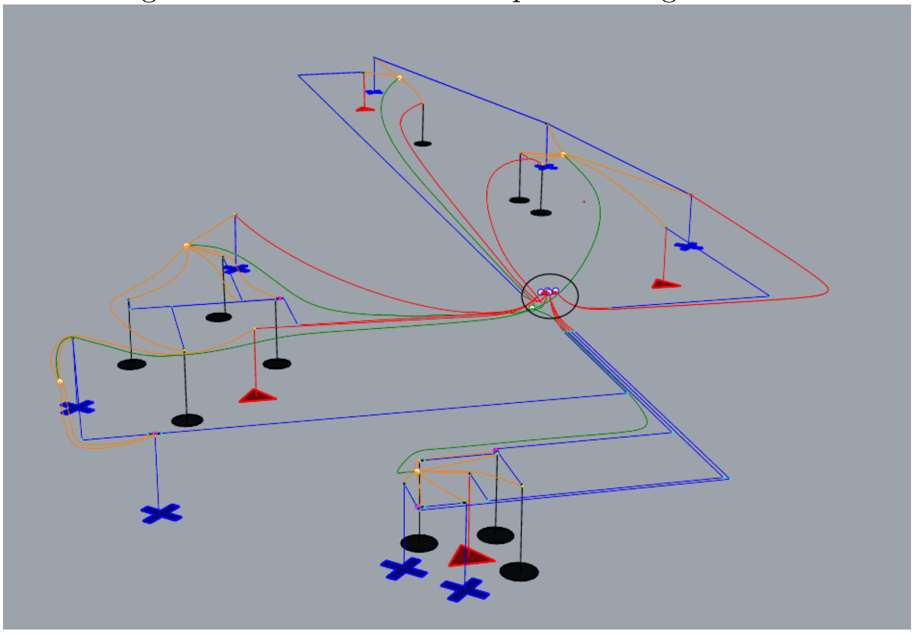


Source: Author

4.1.4 Development Concept

It was considered that the three reservoirs started producing together and there was no existing production infrastructure in the surrounding area, so the only possible concept for all configurations is stand-alone, which is the direct connection of the reservoir to a new facility. In the Figure 19, it is possible to observe the installation of a single platform in a region that serves the three reservoirs at once for the Configuration 2.

Figura 19: Stand-alone concept in Configuration 2



Source: Author

4.1.5 Subsea Facilities and Equipments

4.1.5.1 Platform

The selection of a production platform is influenced by several factors, including the maximum depth the facility can accommodate, its daily production capacity, and overall storage capacity. Additionally, if a subsea production system is chosen, the platform must be compatible with such a system.

Based on the case study data, the maximum depth of the reservoir is 390 meters, and the daily production rate is 3,500 barrels. Despite the relatively shallow depth and low production, the FPSO was selected due to the distance from shore. The FPSO offers substantial storage capacity, which enhances the logistics of transporting production to the coast.

For Configurations 1 and 2, a single FPSO was strategically positioned to serve all three reservoirs, minimizing the use of flowlines. In both configurations, the FPSO Helang was selected, with its general specifications provided in Table 8.

Information	Value	Unit of measurement
Name	Helang	
Crude Oil Production Capacity	12.000	bbl/day
Crude Oil Storage Capacity	550.000	bbl
Cost	578	$ Million

Tabela 8: Informations of FPSO Helang, used in Configuration 3 (MAYBANK, 2019) (YINSON..., s.d.)

For Configuration 3, in order to reduce the size of the flowlines, two FPSOs with slightly smaller capacities than the FPSO Helang were installed: Petrojarl I and PTSC Lam Son. This configuration minimizes the distance between the wells at the ends of the reservoirs and the platforms, thereby reducing the required length and size of the flowlines, which in turn lowers the overall costs. Informations on both facilities are in Table 9.

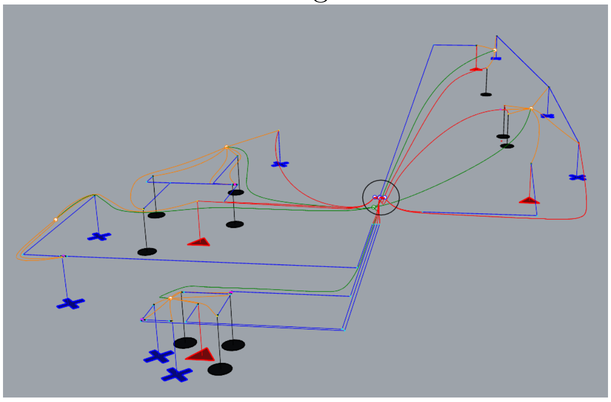
Information	Value	Unit of measurement
Name	Petrojarl I	
Crude Oil Production Capacity	10000	bbl/day
Crude Oil Storage Capacity	180000	bbl
Cost	297	$ Million
Name	PTSC Lam Son	
Crude Oil Production Capacity	18000	bbl/day
Crude Oil Storage Capacity	350000	bbl
Cost	360[1]	$ Million

Tabela 9: Information of FPSO Petrojarl I and PTSC Lam Son, used in Configuration 3 (YINSON..., s.d.) (ENAUTA..., 2023) (UGAL, 2022)

Therefore, the allocation of platforms in both Configurations 1 and 2, as well as in Configuration 3, which has two different facilities, are shown in Figure 20 and 21.

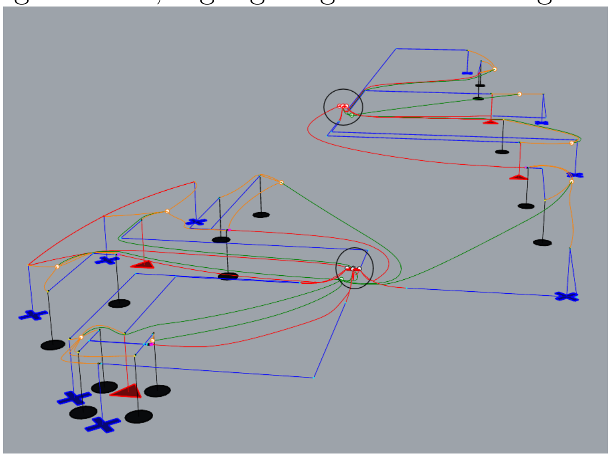
[1] The annual contract value for this FPSO is $18 million. Based on a production period of 20 years, the approximate total purchase value has been calculated

Figura 20: Location of FPSO Helang in Configurations 1 and 2, highlighting its surrounding features



Source:Author

Figura 21: Location of FPSO Petrojarl I (upper) and PTSC Lam Son (lower) in Configuration 2, highlighting its surrounding features



Source:Author

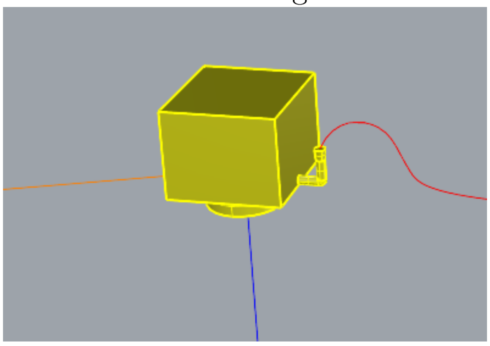
4.1.5.2 Christmas tree

In the case study of the Barents Sea, all configurations utilize vertical monobore subsea Christmas trees due to several key advantages in this specific case. One of the primary benefits is the large through-bore, which allows for the installation of larger tubing sizes when needed, providing flexibility for future production requirements. Additionally, these trees do not require a dedicated riser system, simplifying the overall infrastructure and reducing costs. (CRUMPTON, 2018)

Another significant advantage is the ability to configure well control barriers in a way that allows the tree to be installed after the rig has departed. This feature has the potential to save a substantial amount of rig time, contributing to more efficient operations. Finally, with a vertical monobore design, there is no need to recover internal "crown"plugs when reentering the well for interventions, streamlining future workovers and further reducing operational downtime. (CRUMPTON, 2018)

Furthermore, as previously stated, horizontal Christmas trees are beneficial when wells in a given reservoir have a higher probability of failure during completion and require intervention, since the tubing can be pulled without the need to remove the tree, which will not be applied in this hypothetical study. In the created model, this structure is represented by the yellow square shown in Figure 22. (WANG *et al.*, 2020)

Figura 22: Vertical Christmas Tree configurations for all studied scenarios



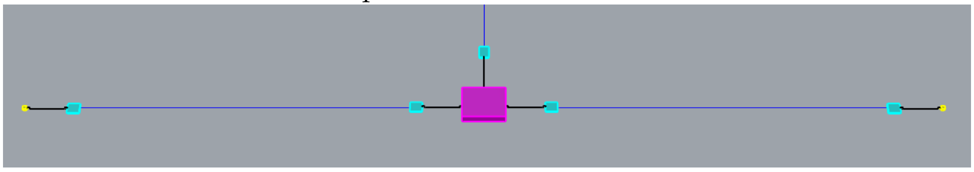
Source:Author

4.1.5.3 Manifold, PLEM and PLET

Regarding manifolds, these are utilized in cluster-type well configurations, which are present in all layouts for this case study. The main advantages of using manifolds, as previously discussed, include reducing the likelihood of fluid leaks, streamlining and shortening flow paths, minimizing temperature and pressure differences, and lowering overall costs. (SOTOODEH, 2021)

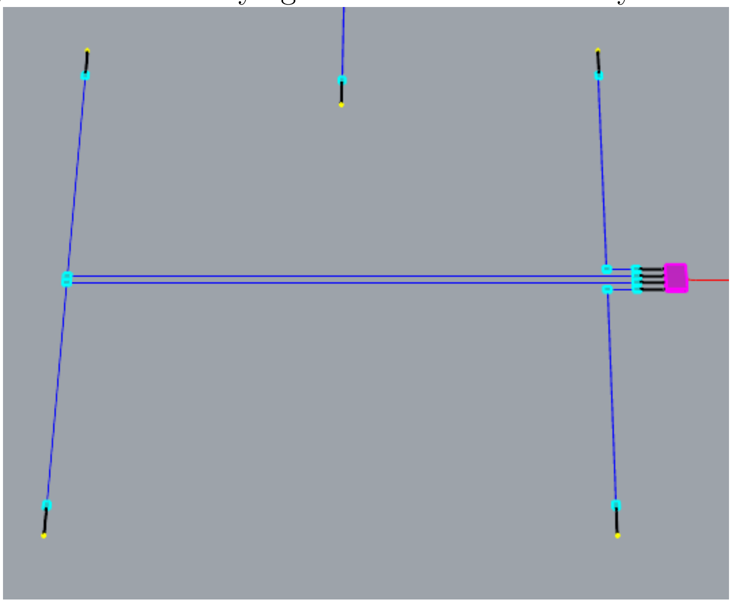
As for the types of production manifolds, they can be categorized by the number of slots, which corresponds to the maximum number of wells that can be connected to the equipment. In this study, a 2-slot and a 4-slot manifold were used in Configuration 1, while two 4-slot manifolds were employed in each of Configurations 2 and 3. Figures 23 and 25 show a 2-slot and 4-slot manifold, respectively.

Figura 23: 2-slot manifold with direct connection to the platform. The manifold is configured to support up to two wells, with the production line directly connected to the platform structure



Source:Author

Figura 24: 4-slot manifold. The manifold is not centralized to reduce the use of flowlines, umbilicals and flying leads connected directly to the platform

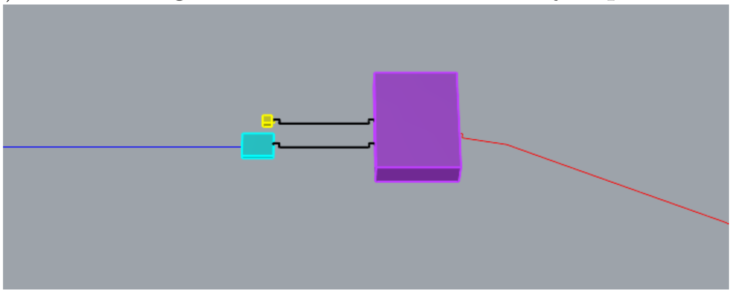


Source:Author

In relation to other types of manifolds, there are Pipeline End Manifold (PLEM) and Pipeline End Termination (PLET) structures, which play crucial roles in the subsea system, although with different purposes. The PLEM serves as an interface between the pipeline and the production infrastructure, such as platforms or floating storage units, and its main function is to distribute and control the flow of oil or gas between the different connected systems. (BAI; BAI, 2010)

On the other hand, the PLET is a simpler structure and its function is to physically terminate the pipeline, tying it to another, and anchoring it to the seabed, ensuring the stability of the flowline. Unlike the PLEM, which has flow control and distribution systems, the PLET is not involved in production management, but rather in terminating the pipeline and its connection to anchor points or platforms. In Figure 3, a PLEM (in purple) is shown, connecting two flow sources into a single line, while the PLET (in blue) represents the connection between a jumper and a rigid pipeline. (BAI; BAI, 2010)

Figura 25: A PLEM (in purple) connecting two flow sources into a single line, and a PLET (in blue) establishing the connection between a jumper and a rigid pipeline



Source:Author

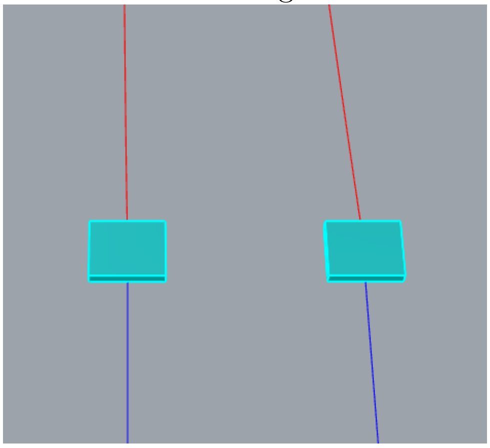
4.1.5.4 Flowlines

In oil production environments with ice and low temperatures, rigid flowlines are generally the most suitable choice due to their strength and durability. Rigid flowlines, usually made of steel or steel alloys, are designed to withstand the impact of sea ice and freezing water without compromising their structural integrity, with additional protective layers that act as coatings and insulators, preventing the formation of hydrates, for example. (OHAERI; SZPUNAR, 2022)

In contrast, flexible flowlines, although advantageous in dynamic environments such as deep water, have significant disadvantages in regions with ice and low temperatures. The composite materials that make up flexible flowlines, such as rubber and steel, can be more vulnerable to freezing and wear caused by interaction with sea ice. Flexibility, although useful in other contexts, can make them more susceptible to damage and rupture due to ice movement or pressure variations, increasing the risk of failure. (OHAERI; SZPUNAR, 2022)

Therefore, considering the Barents Sea environment, Configuration 1 was modeled only with rigid pipes, creating an ideal model in this case. However, for Configurations 2 and 3, flexible flowlines sections were included taking into account the dynamic needs of an environment with two production units and the probability of irregularities in the seabed. In Figure 26 it is possible to observe the two types of flowlines: the rigid one in blue and the flexible one in red.

Figura 26: Illustration showing two types of flowlines: rigid in blue and flexible in red, connected through a PLET



Source:Author

4.1.5.5 Installation Vessel

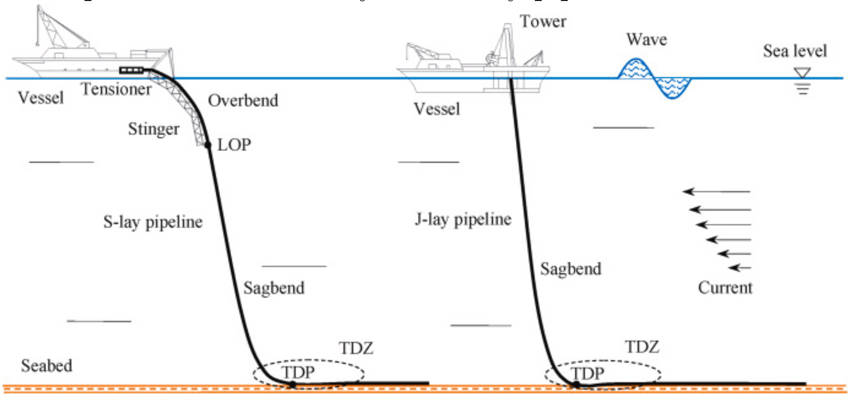
In order to initiate drilling operations, a complex structure is required to extract oil, water, and gas from reservoirs located at great depths. This structure is known as the platform, which can either be fixed or floating, depending on the environmental conditions discussed in Chapter 3. For the reservoir in question, a jack-up rig was selected, offering several advantages, such as ease of transport between different drilling sites and relatively low construction and rental costs. (SPEIGHT, 2014)

Moreover, these platforms provide excellent stability during drilling operations. Once positioned at the desired location, the large legs (jackets) are extended to the seabed, raising the platform above the water level and ensuring safe positioning. This setup minimizes movement, even in harsh weather conditions. The jack-up rig chosen for this operation is the Discovery I, which is currently operated by Jindal Drilling & Industries under a daily charter rate of USD $46.907. This rig is capable of operating at depths of up to 400 meters and drilling wells up to 30.000 meters deep. (SPEIGHT, 2014) (UGAL, n.d) (MARKET, 2022)

In addition to the drilling vessel, one or more vessels are also required for the installation of flowlines. There are some key differences in the laying mechanisms used for this type of installation, which were discussed earlier in Chapter **??**.

For this case study, only two installation techniques were considered: S-Lay and J-Lay. While the S-Lay method involves the fast installation of the pipeline with an "S-shaped curve, typically used for flexible pipelines in shallow waters, the J-Lay method employs a more slow and vertical approach, creating a ”J-shaped curve as the pipeline touches the seabed. The J-Lay technique is particularly suitable for the installation of rigid flowlines in both shallow and deep waters, as it helps avoid large curvatures in the pipeline, preserving its structural integrity. For illustration purposes, both techniques are illustrated in Figure 5. (XU *et al.*, 2021)

Figura 27: Representation of S-Lay and J-Lay pipeline installation techniques



Source: (XU et al.*, 2021)*

In this study, Configuration 1 considers the use of a J-Lay vessel exclusively for pipeline installation, while S-Lay vessels are used for installing umbilicals and flying leads. In contrast, Configurations 2 and 3 involve both rigid and flexible pipelines, requiring two vessels to carry out the installation of these pipelines.

4.1.5.6 Riser

One of the essential components of the subsea system is the riser, which serves as the connection between the pipelines and the floating production system, as discussed in Chapter 1. The riser can be installed in various configurations, depending on environmental conditions. One such configuration is the Steel Catenary Riser (SCR), which consists of a steel pipe that forms a natural catenary curve due to its weight and flexibility. This curve, similar to the shape of a chain suspended between two points, helps distribute tension forces along the riser and effectively absorb the dynamic movements induced by sea waves, offering increased flexibility and resistance to fatigue over time. (BAI; BAI, 2010)

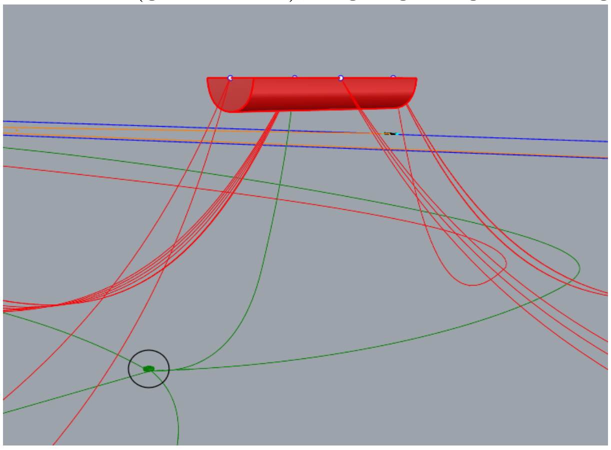
To install this type of riser, it is deployed using pipelaying vessels used for installing flowlines. Since the SCR is flexible, the S-Lay method will be used for its installation. The total installation time for all risers in the system is estimated to be 20 days. (BAI;

BAI, 2010)

4.1.5.7 Distribution System

Regarding the distribution system, the field contains a significant amount of equipment that requires both hydraulic and electrical connections to the platform, such as manifolds and wellheads. As a result, optimizing the distribution of UTAs (Umbilical Termination Assemblies) is essential. In all configurations, an UTA was placed near the platform to efficiently distribute to the required equipment via umbilicals. This arrangement is illustrated in Figure 28.

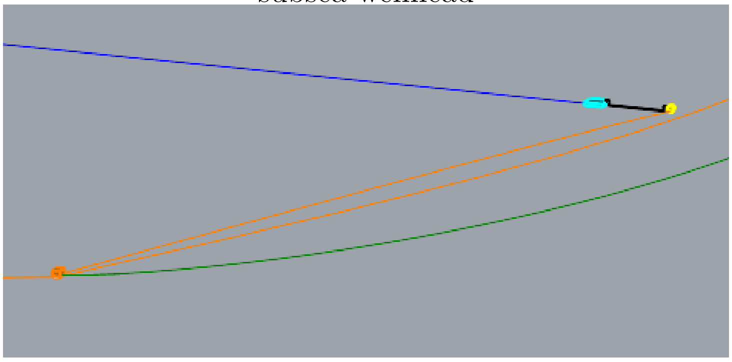
Figura 28: Overview of the main UTA (green square) connected to the platform and secondary UTAs via umbilicals (green lines), highlighting the integrated support system.



Source:Author

The energy from the umbilicals is transmitted to the secondary UTAs, which are responsible for redistributing it to the equipment via flying leads. This configuration is designed to minimize the use of umbilicals, opting instead for flying leads, which are more cost-effective and easier to install. Figure 29 illustrates this distribution.

Figura 29: Illustration of a secondary UTA (orange) receiving power from the main UTA via an umbilical (green) and distributing it through flying leads (orange) to a subsea wellhead



Source:Author

The installation of umbilicals and flying leads will also be carried out by a vessel in the S-Lay model, as they behave like flexible ducts.

4.1.5.8 ROV

For this project, two ROVs were selected to ensure continuous operation, with one providing backup coverage in case the other requires maintenance or faces a failure. This redundancy enhances operational reliability and minimizes downtime.

4.1.5.9 Storage and Offloading

In terms of storage, the facilities of the three configurations built have approximately 550,000 barrels of oil in storage, which corresponds to more than 150 consecutive days of production. Since the storage is large and sufficient for many days, there is no need to worry about additional storage.

As for the transportation of the fluid, the shuttle tanker was chosen over the pipeline mainly due to the climatic conditions of the environment, which involve snow and ice formation, and the relative distance from the field to the nearest receiving unit on land. In the case of this study, a handysize tanker was chosen as the shuttle tanker, that is, a tanker with a capacity of approximately 10,000 to 40,000 DWT, capable of transporting up to 400,000 barrels of crude oil. (HANDYSIZE. . . , n.d)

The chosen vessel is a Handysize Tanker, featuring a Double Hull and Double Bottom design, with a 2000 DWT capacity and a maximum draft of 4.2 meters. Built in 2010 and registered in China, it is classed by CCS (China Classification Society), with the class notation A1 A2, ensuring it meets high standards for safety and operation. The vessel features a 1928 cubic meter holding tank capacity, making it well-suited for the transportation of liquid cargo such as petroleum or chemicals. Regarding the operating price, this will be considered USD 11,000 per day. (FOR. . . , n.d) (SHIP. . . , 2024)

4.1.6 Economic Analysis

Based on the three potential configuration models for the Barents Sea field, a simplified economic analysis of the subsea system can be conducted. Using this framework, the quantity and type of each component required were quantified, forming the foundation for the subsequent cost estimation and economic evaluation of the subsea infrastructure. This analysis provides valuable insights into the financial implications of each configuration. Table 10 shows the quantity of each element and also the size in meters of each type of line used.

Number of Elements			
	Conf. 1	Conf. 2	Conf. 3
PLET	43	51	57
UTA	5	6	11
Jumper	40	34	32
XMAS prod	9	10	14
XMAs inj	12	12	12
PLEM prod	1	1	3
PLEM inj	0	2	0
Manifold prod 2 slots	1	0	0
Manifold prod 4slots	1	2	2
Manifold inj 4slots	0	0	0
Platform	1	1	2
Flowline rigid 4”[m]	90.380,2	97.162,5	129.711,5
Flowline rigid 8”[m]	118.959,8	49.974,6	0,0
Flowline flexible 4”[m]	70.290,2	42.633,8	27.093,7
Flowline flexible 8”[m]	9.939,6	36.243,4	62.803,8
Umbilical [m]	59.827,8	74.262,8	94.049,5
Flying Leads [m]	85.585,9	84.356,2	73.386,5
Flexible Jumper [m]	0	0	0
Rigid Jumper (Horizontal) [m]	2200	1870	1760

Tabela 10: Quantification of subsea system elements for the three modeled configurations for the Barents Sea field

With the quantities of each one and the purchase and installation values of each piece of equipment, it was possible to calculate the initial cost of each configuration for different groups of operations and equipment, such as pipelines, drilling and FPSO, and also the total cost, which is obtained by the simple sum of all the calculated costs.

	Configuration 1	**Configuration 2**	**Configuration 3**
Total Costs Equipments	$199.766.500	$221.493.000	$259.260.000
Total Costs Umbilical/Flying Leads	$260.760.033	$310.546.159	$373.218.261
Total Costs Pipeline	$166.384.393	$185.156.327	$228.653.835
Total Costs Drilling (Vertical)	$29.640.000	$40.500.000	$56.700.000
Total Costs Drilling (Horizontal)	$324.840.000	$324.216.000	$179.052.000
Installation Cost	$700.000	$700.000	$400.000
FPSO cost	$578.000.000	$578.000.000	$657.000.000
Total	$1.560.090.927	$1.660.611.486	$1.754.284.096

Tabela 11: Estimation of total costs for subsea equipment and operations in three different configurations for the Barents Sea field. The values include costs for equipment, umbilicals, pipelines, drilling (horizontal and vertical), installation and FPSO

The economic analysis presented in Table 11 provides a detailed overview of the total costs associated with each of the three configurations modeled for the Barents Sea field. The data reveal significant cost variations between the configurations, reflecting differences in equipment choices, drilling methods and subsea infrastructure. Configuration 3, for example, presents the highest costs, primarily due to increased FPSO and pipeline expenses, while Configuration 1, despite its lower initial cost, results in higher costs for pipeline installation and horizontal drilling. Configuration 2, on the other hand, falls in between, with more balanced costs across the various system components.

Additionally, it is evident that the FPSO category represents a significant portion of the costs, particularly in Configurations 2 and 3, while pipeline installation and vertical drilling costs also have considerable impact in configurations with greater depth and operational complexity. The analysis also highlights that subsea installation costs, although lower compared to equipment and operational expenses, still constitute an important part of the project's overall economic feasibility.

All calculations used to generate these estimates are detailed and can be reviewed in the attached Excel file, where the formulas, inputs and assumptions behind the analysis are clearly documented.

5 DISCUSSION

The analysis of drilling and installation operations in the Barents Sea field requires the consideration of several key components, such as drilling rigs, pipeline systems, risers, Umbilical Termination Assemblies (UTAs), ROVs, and storage and offloading systems. The selection of the drilling rig is crucial for the success of subsequent operations. For this specific case, a jack-up rig, the Discovery I, was chosen due to its ease of transport between different drilling locations and its relatively low construction and rental costs. This rig provides excellent stability during drilling operations, with a high operational capacity at depths of up to 400 meters and the ability to drill wells up to 30,000 meters deep. The platform is stabilized by large legs (jackets) that extend to the seabed, reducing movement and ensuring a safe position even in harsh weather conditions.

In addition to the drilling rig, vessels are required for the installation of pipelines. For this study, two installation techniques were considered: S-Lay and J-Lay. The S-Lay technique is typically used for the fast installation of flexible pipelines in shallow waters, forming an "S-shaped curve, whereas the J-Lay method, which forms a vertical "J-shaped curve, is better suited for the installation of rigid pipelines in both shallow and deep waters, as it minimizes large curvatures and preserves the structural integrity of the pipeline. Configuration 1 involves the use of a J-Lay vessel exclusively for pipeline installation, while S-Lay vessels are used for installing umbilicals and flying leads. Configurations 2 and 3, on the other hand, require both rigid and flexible pipelines, necessitating two vessels for installation.

Risers, which connect the pipelines to the floating production system, are another essential component of the subsea system. In this case, a Steel Catenary Riser (SCR) was selected due to its flexibility and ability to absorb dynamic movements induced by sea waves, offering increased resistance to fatigue over time. The installation of the SCR will be carried out using the S-Lay method. The estimated installation time for all risers is around 20 days.

The distribution system is critical for ensuring that energy and control signals are efficiently distributed to the subsea equipment, such as manifolds and wellheads. In all configurations, a main UTA was placed near the platform to effectively distribute power to secondary UTAs, which then distribute energy via flying leads. This arrangement optimizes the use of umbilicals and flying leads, which are cost-effective and easier to install. The S-Lay method will be employed for the installation of umbilicals and flying leads, as these components behave similarly to flexible ducts.

Furthermore, the selection of two ROVs for the project ensures redundancy and continuous operations, minimizing downtime in case of failure or maintenance needs.

Regarding storage and offloading, the analysis indicates that the facilities in all three configurations are adequate, with approximately 550,000 barrels of oil in storage, enough for over 150 consecutive days of production. A Handysize tanker was chosen for fluid transportation due to the challenging environmental conditions, including snow and ice formation, and the relative distance from the field to the nearest receiving unit on land. This tanker, with a capacity of up to 40,000 DWT, features a double hull design for added safety and has a holding capacity of 1,928 cubic meters, making it suitable for transporting petroleum.

The economic analysis of the three configurations reveals significant cost variations, which are primarily driven by equipment selection, drilling methods, and subsea infrastructure. Table 11 summarizes the total costs for each configuration, highlighting differences across equipment, umbilicals, pipelines, drilling (both horizontal and vertical), installation, and FPSO.

Configuration 1 has the lowest total cost, primarily due to its smaller expenditure on equipment and umbilicals. However, the costs for pipeline installation and horizontal drilling are notably higher compared to the other configurations. The configuration is less complex in terms of subsea infrastructure, yet the higher costs for pipeline installation suggest that simpler designs may lead to higher overall costs in certain components. The cost of FPSO in this configuration is \$578,000,000, which is lower than in Configurations 2 and 3. Additionally, horizontal drilling costs in Configuration 1 (\$324,840,000) are significantly higher than in Configuration 3, suggesting a trade-off between the initial lower costs and increased drilling expenses.

Configuration 2 has total costs of \$1,660,611,486, representing a balance between equipment, installation and operational costs. The FPSO cost is identical to Configuration 1 (\$578,000,000), but this configuration has a higher cost for subsea equipment compared to Configuration 1 and it also involves higher costs for umbilicals and flying leads installation. This configuration presents a more balanced approach in terms of subsea infrastructure and pipeline installation, resulting in moderate costs for both vertical and horizontal drilling. The total costs for drilling in this configuration are \$364,716,000, with vertical drilling at \$40,500,000 and horizontal drilling at \$324,216,000.

Configuration 3, with total costs of \$1,754,284,096, is the most expensive due to the inclusion of more complex subsea systems and higher FPSO costs (\$657,000,000), since it includes two platforms instead of just one. The costs for subsea equipment and umbilicals/flying leads are the highest among all three configurations. The significant increase in FPSO and subsea system costs pushes the overall expenditure to its highest level. The higher costs for installation and horizontal drilling (\$179,052,000) suggest that the complexity of Configuration 3 contributes to a considerable increase in total project costs. Additionally, it requires more extensive pipeline installation, which includes 129.7 km of rigid flowlines, compared to 90.38 km in Configuration 1, further increasing the costs.

The economic implications suggest that while Configuration 1 offers the lowest initial expenditure, its higher costs in pipeline installation and drilling (particularly horizontal drilling) highlight the trade-off between upfront savings and operational expenses. Configuration 2, being a balanced solution, offers a middle ground in terms of overall costs, while Configuration 3, while offering the most comprehensive subsea infrastructure, results in significantly higher costs. Therefore, the choice of configuration depends on the project's priorities: whether it is minimizing initial investment or ensuring a more robust and flexible subsea infrastructure at a higher operational cost.

6 CONCLUSIONS

6.1 Achievements

The study underscores the critical role that a detailed technical-economic analysis plays in the design and development of subsea production systems. By analyzing three different configurations for the hypothetical Barents Sea field, the research highlights how equipment choices, drilling methods, and subsea infrastructure can significantly impact the total project costs.

One of the key insights from the analysis is the importance of understanding the physical and geological characteristics of the field when selecting and installing subsea equipment. The depth of the water, reservoir pressure, and geological formations such as sedimentary rock or shale directly influence the choice of drilling techniques and the design of subsea infrastructure. This knowledge ensures that equipment is not only technically suitable but also cost-efficient, preventing unnecessary expenditures associated with over-engineering or the use of inappropriate technologies for the field conditions.

The study also reveals that there is potential for further optimization of subsea system designs. For instance, it is possible to combine the more cost-effective equipment and pipeline choices of Configuration 1 with the drilling methods of Configuration 3, which demonstrate lower drilling costs. This hybrid approach could offer a more balanced and cost-efficient solution while maintaining the technical performance required by the field's specific characteristics.

In addition to equipment and drilling decisions, the analysis highlights that subsea installation costs—though lower than equipment and operational expenses—still play an important role in the overall economic feasibility of the project. Thus, reducing installation costs without compromising operational efficiency could lead to substantial savings.

Overall, the research contributes to the optimization of conceptual design processes for subsea production systems, offering a methodology that can be adapted to various fields. By taking into account the physical and geological conditions of each site, this approach ensures that the subsea design not only meets technical requirements but is also economically viable.

6.2 Future Work

Building on the findings of this study, future work could explore the inclusion of additional economic factors that are critical to the long-term feasibility of subsea production systems. One important avenue for further research would be the integration of methods that take into account inflation, the value of reserves and the price of oil over the life of the field. These factors can significantly influence the economic viability of a subsea project, as a configuration that appears cost-effective initially may not yield a worthwhile return over the field's lifetime. It is essential to assess the project's profitability in the context of market dynamics, especially with respect to fluctuating oil prices and the financial returns expected from the extracted reserves.

Additionally, the incorporation of maintenance costs into the economic evaluation would offer a more complete picture of the long-term financial sustainability of subsea systems. Maintenance, operation and decommissioning costs can accumulate over time and have a substantial impact on the overall profitability of a subsea project. A more comprehensive analysis that includes these costs would provide deeper insights into the trade-offs between initial investment and long-term expenses, leading to better-informed decision-making.

Another promising direction for future work is the development of optimization models, potentially through the use of software tools or mathematical models, to more efficiently allocate subsea equipment and resources. These models could consider multiple variables—such as equipment costs, operational complexity, environmental conditions and drilling depth—to determine the most cost-effective allocation of resources across different configurations. Such optimization would allow for the creation of a more dynamic and adaptable subsea systems that can be fine-tuned throughout the field's operational life, ensuring maximum efficiency and cost-effectiveness.

By incorporating these factors, future studies could provide more robust and comprehensive models for subsea production systems, enabling stakeholders to make decisions that account not only for upfront costs but also for long-term profitability, sustainability, and operational efficiency. This would ultimately lead to more resilient and financially viable subsea projects.

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APÊNDICE A – EXCEL

All the calculations related to the design configurations and cost estimates for the subsea production system, as discussed in the main body of the thesis, are detailed in the attached Excel file. This file includes the formulas, inputs, and assumptions used to generate the cost data for each configuration. It provides a transparent and comprehensive view of the calculations behind the economic analysis, which can be reviewed in full for greater clarity and verification. Click here to open the Excel file

APÊNDICE B – 3D MODEL

The 3D model of the subsea production system, used to visualize the design configurations and layout, is provided in the attached file. This model offers a detailed representation of the subsea infrastructure, including equipment placement and system components, aiding in the understanding of spatial arrangements and operational setup. The file can be reviewed for a clearer perspective on how each configuration is structured in a real-world context. Click here to open the Rhinocerus file

Universidade de São Paulo

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Conceptual Engineering Design of Subsea Production System

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Abstract

This study conducts a technical-economic feasibility analysis for the development of a subsea production system, focusing on supporting decision-making during the conceptual design phase. The applied methodology follows the principles of Systems Engineering, aiming to optimize the decision-making process by breaking the problem down into smaller, more manageable components.

Three design configurations for a hypothetical field in the Barents Sea are analyzed, considering different subsea equipment and facilities. The technical analysis evaluates the number of wells, drilling methods, layout, and required equipment for each alternative, while the economic assessment considers the costs of equipment, drilling, installation, and FPSO.

The results show that the choice of the optimal configuration depends on the specific characteristics of the field and the costs associated with each system component. The proposed integrated technical-economic analysis provides a clearer understanding of the financial implications and helps make more informed decisions, contributing to the efficient development of subsea production systems.

Resumo

Este estudo realiza uma análise de viabilidade técnico-econômica para o desenvolvimento de um sistema de produção submarina, com foco no apoio à tomada de decisões na fase de *desgin* conceitual. A metodologia aplicada segue os princípios da Engenharia de Sistemas, buscando otimizar o processo de decisão ao dividir o problema em componentes menores e mais gerenciáveis.

São analisadas três configurações de *desgin* para um campo hipotético no Mar de Barents, considerando diferentes equipamentos e instalações submarinas. A análise técnica avalia o número de poços, métodos de perfuração, *layout* e equipamentos necessários para cada alternativa, enquanto a avaliação econômica considera os custos de equipamentos, plataformas, perfuração e instalação.

Os resultados mostram que a escolha da configuração ideal depende das características específicas do campo e dos custos associados a cada componente do sistema. A análise integrada técnico-econômica proposta proporciona uma visão mais clara das implicações financeiras e ajuda a tomar decisões mais criteriosas, contribuindo para o desenvolvimento eficiente de sistemas de produção submarina.

1 Introduction

The offshore oil and gas industry has faced increasing challenges as hydrocarbon exploration moves into deeper and more complex marine environments. For millions of years, organic matter from plants, algae, and animals has transformed into hydrocarbons through geological processes like diagenesis and catagenesis. As temperatures and pressures rise, oil and gas are formed, with oil first being commercially produced in the 19th century. By the late 1800s, offshore oil drilling began in shallow waters, and the industry soon expanded to deeper reservoirs. Today, technological advancements allow for the production of hydrocarbons from depths exceeding 3,500 meters. However, these advancements also introduce new difficulties, as harsher conditions at greater depths—such as higher pressures, colder temperatures, and more unstable reservoirs—complicate the planning and development of offshore fields. (Turgeon & Morse, 2022) (Vandenbroucke & Largeau, 2007) (Porto et al., 2019) (Sukumar, 2018) (Seyyedattar et al., 2020) (Bai & Bai, 2010) (González, 2020)

These challenges, combined with volatile oil and gas prices, have led to the development of subsea production systems, an engineering solution designed to address the complexities of offshore operations. The subsea production system begins with evaluating the economic viability of a field through exploration techniques like geological and geophysical assessments. Following this, the critical phase of conceptual design aims to identify the most viable technical and economic solutions. In this phase, thousands of design configurations are considered, requiring careful decision-making to ensure that the final design optimally combines technical feasibility and cost-effectiveness. This decision-making process involves evaluating the positive and negative aspects of various equipment configurations and layouts, as well as assessing economic factors such as production profiles, oil prices, and infrastructure costs. (Silva & Soares, 2023) (González, 2020) (Bai & Bai, 2010); González (2020)

In light of these challenges, the demand for subsea production systems has grown significantly, particularly as deep and ultra-deepwater fields have become increasingly vital to global energy supply. Since 2019, deepwater exploration has dominated the industry, representing a significant portion of global growth projections. This shift has also been influenced by economic factors, as offshore projects tend to offer shorter payback periods compared to onshore alternatives. Moreover, with the ongoing energy transition and the rising importance of natural gas as a cleaner alternative to oil, the need for efficient and sustainable subsea production technologies has never been more urgent. As such, optimizing subsea systems not only addresses technical and economic challenges but also plays a crucial role in supporting global energy goals. The development of subsea production systems is deeply connected to Ocean Engineering, which encompasses the design, construction, and installation of offshore systems, linking it to broader fields such as Petroleum, Naval and Ocean Engineering. Mercado Subsea Production and Processing system - Crescimento, Tendências, Impacto COVID-19 e Previsões (2022-2027) (n.d.); Pereta et al. (2022) Engenharia Naval, Engenharia Oceânica ou Engenharia Costeira (n.d.); Mestrado (n.d.)

2 Objectives

The present work attempts to develop a techno-economic feasibility study, describing the advantages, disadvantages and limitations of the different subsea layout concepts, aiming o improve the decision-making process during the conceptual design phase to define the most viable subsea production system.

The objective of this work is to enhances the design planning of a subsea production system in the most efficient and expeditious manner at the early stage of an oilfield development contributing t an informed decision-making process.

In this way, this work will deliver different layouts for the same field, considering different equipment and facilities according to the technical and economic aspects. In the end, it will serve as a basis for generating layouts for other fields, as the document compiles all the technical and economic information necessary for the application.

3 Literature Review

The methodology used to develop the present work was explored by Yasseri (2014) and focuses on applying Systems Engineering (SE) principles to address the complexity of subsea production systems. SE is particularly effective in managing large-scale projects by breaking them down into smaller, more manageable components. The methodology for subsea design integrates various system inputs, including field data, production capacity, technical limitations, client needs, and constraints such as budget, time, and environmental conditions. These inputs guide the development of subsea layouts that optimize the arrangement of equipment and facilities while considering key factors like depth, climate, and the physical characteristics of the area. Yasseri (2014) emphasizes that an SE approach should define system outputs, manage risks early on, and ensure proper validation and verification at each stage to ensure that the proposed system performs as expected. Yasseri (2014)

The technical feasibility of subsea production systems has been a subject of many studies, addressing the unique challenges posed by factors such as ice presence, geological conditions, and reservoir modeling. Ivanova and Shabalov (2021) explored subsea production in regions affected by ice, focusing on the challenges it introduces to the development of oil and gas fields. They developed software to assess the technical and logistical factors influencing subsea layout, including ice season duration, distance from shore, and transport infrastructure. By inputting values for these factors, the software generates optimal layout configurations that minimize risks and reduce material and time waste in the early stages of planning. Ivanova & Shabalov (2021)

Further technical challenges are discussed by Pribytkov (2013), who examined field development in the Arctic, where ice complicates logistics, supplies, personnel transfer and emergency response. His study highlights the importance of both technical analysis and risk management in the decision-making process for subsea system development. Pribytkov discuss that selecting the optimal subsea configuration in challenging regions requires thorough consideration of both technical solutions and economic factors, particularly the high costs and logistical difficulties involved in remote Arctic locations. The author emphasizes the need to assess similar past projects and apply relevant lessons learned to new developments. Pribytkov et al. (2013)

In addition to technical feasibility, the economic aspects of subsea system design are essential for optimizing production systems. Sánchez et al. (2012) studied the impact of economic viability on subsea production systems and demonstrated that methods like Net Present Value (NPV) and Multiattribute Decision Models (MDM) can yield different results. They concluded that integrating economic feasibility with technical considerations—such as real-world application and risk assessment—is critical to selecting the best subsea layout. The authors propose a combined approach, where NPV optimization is considered alongside practical feasibility, thereby ensuring a balance between financial viability and operational risk reduction. Sanchez et al. (2012)

The integration of technical and economic analyses is further exemplified by Silva and Guedes Soares (2019), who proposed a mathematical model to optimize subsea production systems, considering factors such as the number and location of wells and production capacity. The model focuses on minimizing investment costs by evaluating different configurations and optimizing the placement of equipment. Similarly, González et al. (2020) employed numerical optimization techniques to refine subsea production models, emphasizing the need for efficient field performance while factoring in uncertainties and maximizing NPV. As offshore production systems become more complex, the integration of mathematical models, optimization algorithms and economic analysis helps ensure that subsea systems are designed for maximum efficiency, minimizing risks, costs and environmental impact. Silva & Soares (2019) González (2020)

In the context of pipeline design, Hong et al. (2018) explored the influence of pipeline location on subsea system optimization, particularly concerning the wellhead-manifold-FPSO configuration. Their model aimed to minimize pipeline length, considering seabed topography and obstacles to reduce installation complexity and costs. Similarly, Liu et al. (2022) applied the MINLP (Mixed Integer Nonlinear Programming) model to optimize subsea layouts and minimize installation costs. Their work emphasizes the importance of efficient layout planning to reduce financial losses associated with poorly planned subsea infrastructure, particularly in relation to flow assurance and transportation systems. Additionally, Liu's later work on using 3D Dubins Curves and Binary Linear Programming (BLP) for drilling site allocation further refines the optimization process by minimizing overall development costs through better allocation of resources and facilities. Hong et al. (2018) Liu et al. (2022)

These studies highlight the need for an integrated approach to subsea production system design that balances technical and economic considerations. The combination of mathematical models, risk analysis, and optimization techniques provides engineers with the tools needed to develop systems that are both technically feasible and economically viable. Furthermore, as subsea production moves into deeper and more challenging environments, the need for more sophisticated methods of evaluating and refining subsea layouts becomes increasingly important.

4 Materials and Methods

This work utilized Rhinoceros 8 (Rhino 8) for 3D modeling of subsea production systems, chosen for its flexibility and precision in engineering and design. Rhino 8 allowed for the creation of detailed and accurate representations of subsea components, such as platforms, pipelines, and risers, adapting well to their complex shapes. Its advanced modeling features, including manipulation of surfaces, curves, and solids, facilitated the visualization and optimization of subsea layouts, essential for the development of the project.

For economic analysis, Microsoft Excel was used to organize data and perform cost evaluations, making it ideal for comparing different subsea layouts. The economic analysis focused on the direct costs of equipment, such as pipelines and platforms, using unit cost estimates. Data for the project came from real-world subsea operations in the

Barents Sea, including field characteristics, environmental conditions, and operational costs, sourced from company reports, case studies and public data from Equinor, Statoil, and the Norwegian Petroleum Agency.

5 Results

A hypothetical subsea system configuration for a field in the Barents Sea is analyzed based on three possible design configurations. Using this model, the necessary system components were systematically quantified and calculated, followed by an in-depth examination of the technical and economic implications of each configuration. The analysis focuses on the factors influencing the selection and cost of system components.

The configuration of the subsea production system in the Barents Sea is assessed by considering key factors such as water depth, climatic conditions, reservoir characteristics, and economic feasibility. With a depth range of 360 to 390 meters, which is relatively shallow, the use of fixed or floating platforms is viable. The reservoirs in this region are primarily driven by gas cap mechanisms, and the system includes 12 injection wells, 8 for water and 4 for gas. The system's performance is evaluated based on factors like Original Oil in Place (OOIP), recovery factor and production rates, while also accounting for other parameters such as API gravity, reservoir area and daily production capacity. The calculation for the number of wells is done using Production Plateau (Q_P), Daily Production (q_0) and time of production (t) and its explicit in Equation 1.

$$\mu_w = \frac{\frac{Q_P}{q_0}}{t} \tag{1}$$

Using the known values and assuming year-round production, a total of 18 wells are distributed among the three reservoirs based on their areas, with 8 wells in 1A, 6 in 1B, and 4 in 1C. The area per well is calculated by dividing the total area of each reservoir by the number of wells assigned to it. Figure 2 shows the reservoirs with the well distributions.

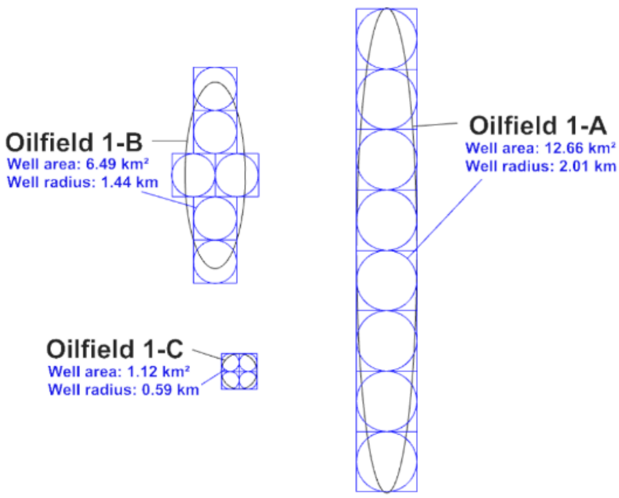

Figure 1 – Distribution of wells in the oilfields in Barents Basin
Source: Author

Three different well drilling configurations were analyzed, each offering varying production capacities and costs. The first configuration uses only horizontal wells, maximizing the produced area and improving extraction efficiency by covering more of the reservoir. The second configuration combines both vertical and horizontal wells, with vertical wells reducing costs and simplifying planning, while horizontal wells cover larger areas. The third configuration places the vertical wells at the top, balancing the advantages of both types of drilling. Wellhead locations are strategically chosen to optimize oil recovery, with water injection wells placed at an adequate distance from production wells to efficiently move water through the reservoir and enhance oil displacement. The final result of the allocations is presented in Figure 2.

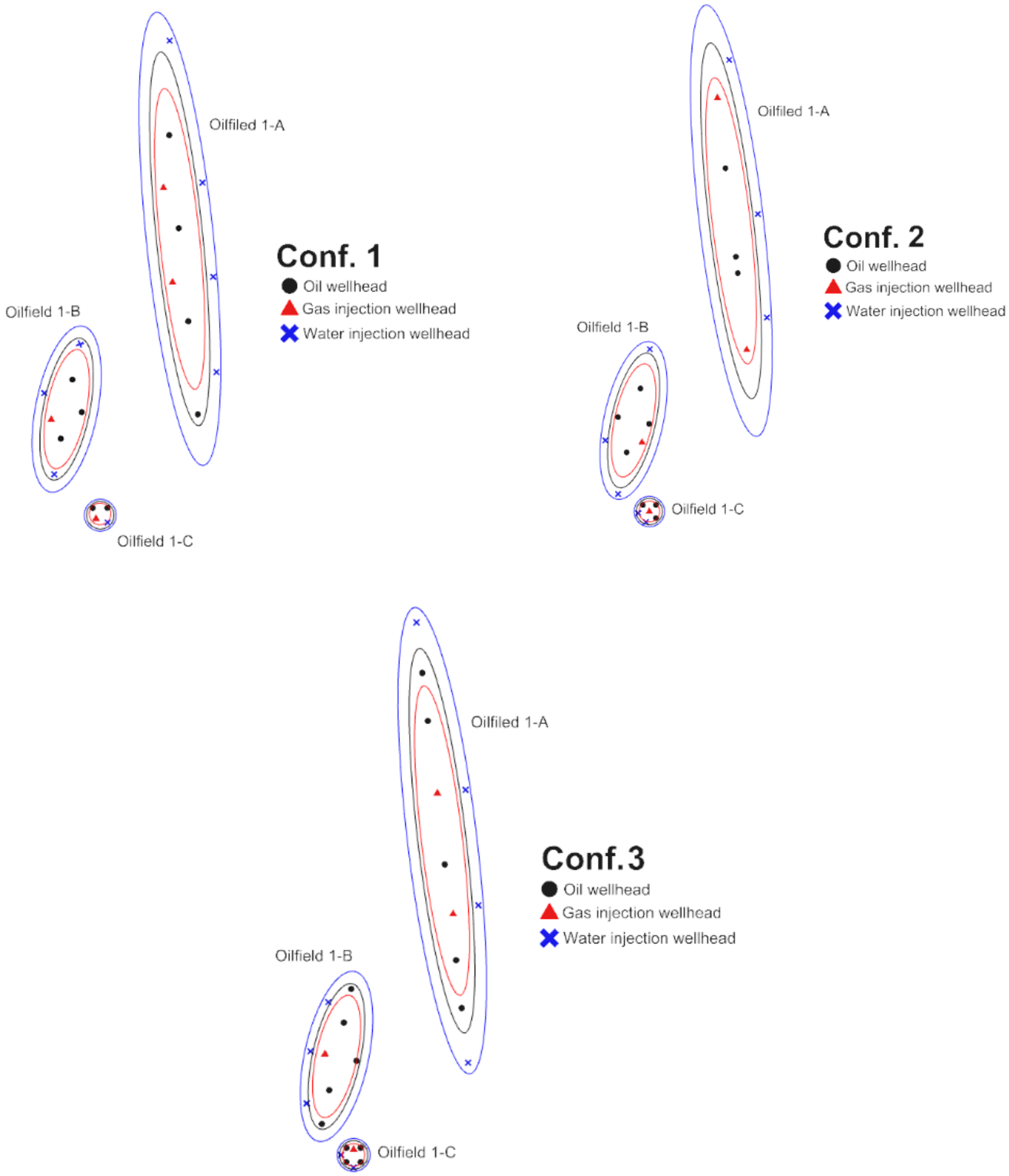

Figure 2 – Wellhead placements for the three type of configurations

Source: Author

Based on these drilling configurations, equipments, facilities and pipelines were selected to meet the technical requirements of an environment with extremely low temperatures. Each configuration was carefully analyzed to ensure that the chosen components would function effectively under the harsh conditions typical of the Barents Sea. The final models for each configuration are presented in Figure 3.

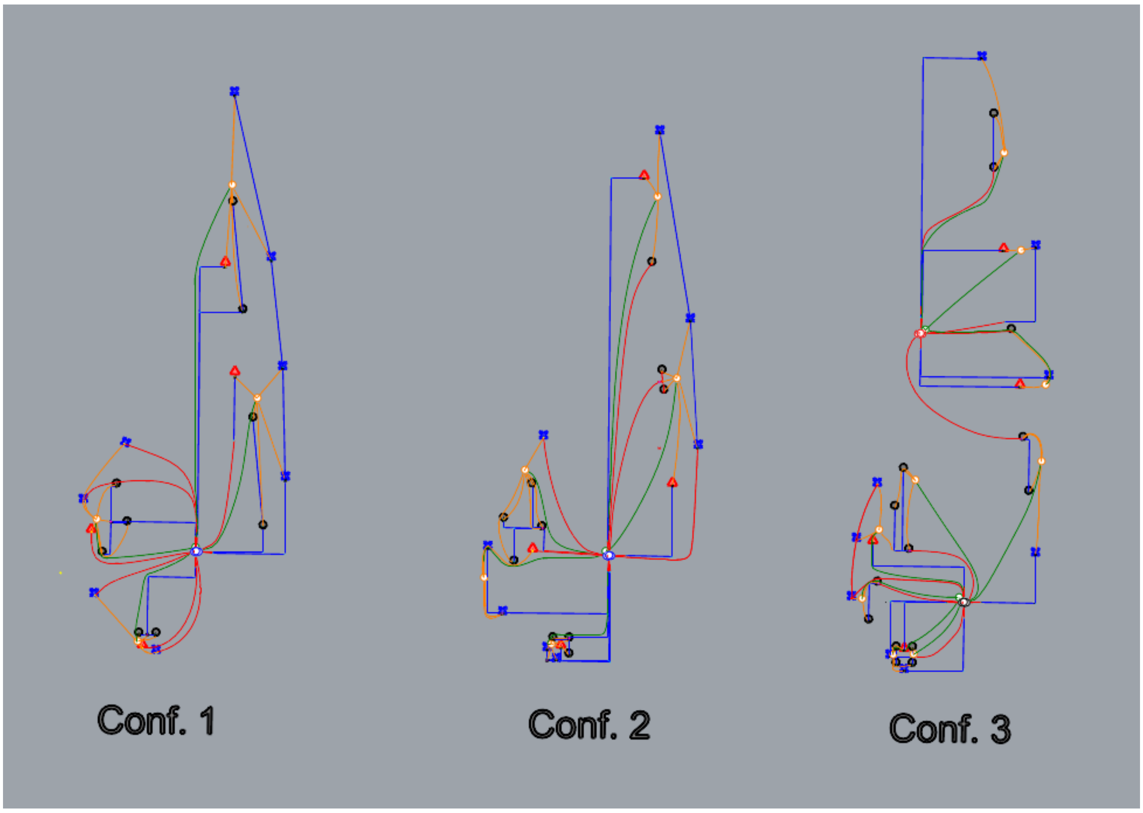

Figure 3 – Final models of the subsea production system configurations, including selected equipment, facilities and pipelines

Source: Author

Following the selection of equipments for each subsea configuration, an economic analysis was conducted to estimate the costs associated with each model. The quantity and type of components required for each configuration were determined, allowing for cost estimation across different operational categories, including equipment, pipelines, drilling (horizontal and vertical), FPSO and installation. The analysis revealed significant cost differences between the configurations, with Configuration 3 incurring the highest total cost due to increased FPSO and pipeline expenses, while Configuration 1 showed lower initial costs but higher installation and drilling expenses. Configuration 2 offered a more balanced cost structure. The total costs and detailed breakdown for each configuration are shown in Table 11.

	Configuration 1	Configuration 2	Configuration 3
Total Costs Equipments	$199.766.500	$221.493.000	$259.260.000
Total Costs Umbilical/Flying Leads	$260.760.033	$310.546.159	$373.218.261
Total Costs Pipeline	$166.384.393	$185.156.327	$228.653.835
Total Costs Drilling (Horizontal)	$36.450.000	$40.500.000	$56.700.000
Total Costs Drilling (Vertical)	$324.840.000	$324.216.000	$179.052.000
Installation Cost	$700.000	$700.000	$400.000
FPSO cost	$578.000.000	$578.000.000	$657.000.000
Total	$1.566.900.927	$1.660.611.486	$1.754.284.096

Table 1 – Estimation of total costs for subsea equipment and operations in three different configurations for the Barents Sea field. The values include costs for equipment, umbilicals, pipelines, drilling (horizontal and vertical), installation and FPSO

6 Conclusion

This study highlights the importance of a detailed technical-economic analysis in designing and developing subsea production systems. By examining three configurations for the Barents Sea field, it demonstrates how equipment choices, drilling methods and subsea infrastructure can significantly impact project costs. Key findings emphasize the need to tailor equipment and drilling techniques to the physical and geological characteristics of the field to optimize both technical performance and cost-efficiency. Furthermore, the analysis reveals potential for further optimization by combining the most cost-effective elements of different configurations, such as using more affordable equipment from Configuration 1 with the drilling methods from Configuration 3. This hybrid approach could offer a more balanced solution, improving both cost-efficiency and performance. The study also underscores the importance of subsea installation costs, which, although lower than operational expenses, are a critical factor in the overall economic feasibility of the project.

Future research could extend these findings by incorporating additional economic factors, such as inflation, oil price fluctuations and the value of reserves over the life of the field. Including maintenance, operation and decommissioning costs would offer a more comprehensive picture of long-term financial sustainability. Moreover, the development of optimization models, using advanced software or mathematical techniques, could further refine the allocation of subsea equipment and resources, ensuring that systems remain adaptable and cost-effective throughout the field's lifecycle. Such advancements would enable better-informed decision-making, helping to achieve more resilient, sustainable and profitable subsea production systems in the future.

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