Faculty of Science and Technology

MASTER'S THESIS

Study program/ Specialization: Master in Offshore Technology / Subsea Technology	Spring semester, 2010 Open / Restricted access
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Title of thesis: Model for economical analysis of oil and gas deepwater production concepts / Comparisons of Life Cycle Cost of Subsea Production Systems vs. Floating Structures with dry wellheads.	
Credits (ECTS): Thirty (30 ECTS)	
Key words: Deep Water, Dry tree, Wet tree, Concept Selection, Mexico,	Pages: 106 (Including this frontpage, abstract and acknowledgement) + enclosure: ………… Stavanger, June 14th/ 2010 Date/year

Frontpage for master thesis
Faculty of Science and Technology
Decision made by the Dean October 30th 2009

Abstract:

The scope of the work was to create a model that will allow the comparison of Life Cycle Costs (LCC) for subsea production systems and floating structures with dry wellheads for the Mexican territorial waters of the Gulf of Mexico.

To give validity to the model, an empirical comparison on the resulting recovery factor based on data of the US Gulf of Mexico was included. This comparison is intended to answer ¿Is there a significant difference in the recovery factor when is used the dry tree vs. the wet tree concept solutions?

The model proposed integrates a number of already published models done by academics, the industry and governments. Also, it was found that the activity in deep water offshore Mexico is having place in a region with an evident lack of preexisting infrastructure. Hence it is proposed in the model that new offshore structures shall have an added value for comparison purposes

Two hypothetical projects (three different concepts for each project) of field development, based in public information released by PEMEX, are assessed.

Conclusions and recommendations are made to increase the possibilities of feasible future field development and efficient depletion of the hydrocarbons located in Mexican deepwater.

Acknowledgement:

This thesis has represented a large amount of challenging work that finally has been completed. It also increased my knowledge and extended much more my curiosity about the oil and gas industry, which makes me understand in a much better way the complexity and scope of decisions that are taken when the field development projects are committed.

I hope that this work will contribute to the discussion and further analysis that increase the possibilities of oil and gas field development and ensure an efficient depletion of hydrocarbon resources located in Mexican deepwater. Most of all, is my best wish that these possibilities will be in the wellbeing of the Mexican population

This work might have not been possible without the valuable and encouraging participation of the advisor for this master thesis the professor Ove Tobias Gudmestad. The advice and commitment of the professor Jonas Odland as well as the feedback received from the professors Tore Markeset and Arnfinn Nergaard were very important.

An acknowledgement is needed also to an important sponsor for the writing of this thesis, the “Instituto de Financiamiento e Información para la Educación” from Guanajuato Mexico.

Big thanks to my parents Jose Jesus and Maria Esther and for all my brothers and sisters for their support and encouragement.

Finally and most important, this work is dedicated to my wife Olena and my daughter Elena Valentina whom represents my major motivation.

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1. Scope of the work

The scope of the work is to create a model that will allow the comparison of Life Cycle Costs (LCC) for subsea production systems and floating structures with dry wellheads for the Mexican territorial waters of the Gulf of Mexico. This model should be capable of generating a basis for economical analysis of oil and gas deepwater production systems in the early stages of the concept selection phase of a project.

The first part of this thesis (Chapters 3, 4, 5 and 6) will introduce to the theoretical background of field development in deep water. The second part (Chapters 7, 8 and 9) presents the development, conclusions and recommendations.

In Chapter 3 is shown a revision of the state of the art in production of oil and gas in deep water. The Offshore field development process before concept selection is overviewed in chapter 4. In chapter 5 is presented a deeper review of the "concept selection" and "life cycle cost". Before to close the first part, in the chapter 6 of this thesis, a brief summary of the characteristics of production concepts for offshore field development in deepwater is made.

A discussion on comparisons of the recovery factor dry vs wet tree is done in chapter 7. This discussion is intended to answer an important question. ¿Is there a significant difference in the recovery factor when is used the dry tree vs. the wet tree concept solutions?.

Chapter 8 presents the models employed in the creation of the model proposed to calculate the cost of deep water concepts either dry or wet tree.

Most of the calculations were made using the "Oil and Gas Exploration Economic Model" of the Nova Scotia Department of Energy (Nova Scotia, 2008), see annex F, and the results obtained were adjusted where necessary by the "Empirical cost models for TLP's and SPARS´s " (Jablonowsky, 2008), and the "Models of Lifetime Cost of Subsea Production Systems, prepared for Subsea JIP, System Description & FMEA" (Goldsmith, 2000).

In this work is also proposed a way to calculate the added value of an offshore structure acting as a hub, see point 8.4. Tax calculations are out of the scope of this work, consequently, the results will show just values before taxes.

In chapter 9, the proposed model was used to perform LCC analysis for a ***case study*** centered in the development of the deep water regions of Mexico. The two projects of field development considered are Lakach (Lakach Field) and Holok (Noxal, Lalail, Leek and Tabscoob fields). The names of the projects are just representing proposals for the analysis in this study and it should not be understood that they are the real denominations of the projects. For each project were evaluated three different concepts.

Subsea production concepts (tieback to shore or tieback to offshore facilities) are characterized by evident savings in capital costs, but become a more questionable selection following the considerations of the Life Cycle Costs Analysis due to the cost of their intervention and work over operations as well as the typically lower recovery factor when they are compared against floating structures with dry wellheads.

Alternative concepts using floating structures (SPAR or TLP) with dry wellheads would represent an increased recovery rate with respect to subsea tieback concepts. However they are also associated with high investments costs and a huge competence challenge for the skills in the construction, installation, and operation management of these facilities.

For the case analysis it was found that the activity in deep water offshore Mexico is having place in a region with an evident lack of preexisting infrastructure. This fact makes it important to develop a network of facilities that should increase the feasibility of development in the future.

Hence it is proposed here that additional offshore structures shall have an added value for comparison purposes. This added value will be calculated by doing an evaluation of NPV for the prospects that could be developed if the facility would be in place already.

This work closes with conclusions and recommendations that in opinion of the author might increase the possibilities of development and ensure efficient depletion of hydrocarbon resources located in Mexican deepwater.

2. Expected benefits of this work

PEMEX Exploración and Producción (PEP) is developing the field Lakach in the Mexican territorial waters of the Gulf of Mexico. The Lakach field is the first offshore field to be developed in deep water by PEMEX and is a part of an extensive effort by this National Company to fulfill the exploratory works and field development in basins that before were not considered to be commercially feasible.

A subsea tieback to shore has already been revealed by PEP as the selected concept for this development. However, there are many other prospects of development in the adjacent area that are already being included in the portfolio of exploration and that in the future could be the subject of further studies.

FIRST PART: THEORETICAL BACKGROUND

3. State of the art in production of oil and gas in deep water

3.1. Sizing the global industry of construction of subsea oil and gas facilities.

The subsea technology is not the only way that can reach deep water, as we will see along this work, also the floating structures that use dry completion can be a sound solution for field development in deep water. However, subsea systems are important because in many cases they are the only option to develop fields and alone or in conjunction with floating structures represent the most extendedly used solution for deep water.

The construction of production facilities of oil and gas using subsea technology is expected to be one of the most dynamically developed industries in the next years. According to "Infield Energy Analysts" (Offshore, 02-09-2009), the forecasted total global subsea sector´s expenditure will exceed $80 billion USD over the period 2009 through to 2013.This amount almost doubles the expenditure in subsea equipment, drilling and completion that were accounted for $46 billion USD the past five years.

The biggest operators, based upon the number of subsea valve trees expected to be started up within the next five years are:

1. Petrobras 374
2. Shell 244
3. Total 237
4. Chevron 236
5. BP 229
6. ExxonMobil 215
7. Statoil 194

In total 3,222 subsea valve trees are expected to begin their operations in this period.

3.2. Subsea deep water record.

The record in drilling and completion is hold by Shell Oil Co. This company has reached 9,356 ft (2,852 m) below the water's surface in the Silvertip field at the Perdido Development project in the Gulf of Mexico (Offshore, 12-02-2008).

- Location: Gulf of Mexico, US
- Depth: ~2,380 metres
- Interests: Shell 35% (operator), Chevron 37.5%, BP 27.5%
- Fields: Great White, Tobago, Silvertip
- Peak Production: 130 kboe/d [API: 18-40]
- Key contractors: Technip, Kiewit, FMC Technologies, Heerema, Marine Contractors.

Technology:

Perdido, moored in approximately 2,380m of water, will be the world's deepest Direct Vertical Access Spar. The spar will act as a hub that will enable the development of three fields – Great White, Tobago, and Silvertip – and it will gather process and export production capability within a 48km radius. Tobago, in 2,925m of water, will be the world's deepest subsea completion.

However, Deep water is not only good news. Petroleos Mexicanos (PEMEX) is a particular case of a national oil and gas company that is planned to start the operation of projects in deep water in the first half of the 2010's. This company has identified operative challenges and risks that will be enounced next (PEMEX, 2008).

3.3. Main operative challenges.

Among many others these can be pointed to:

Marine currents and waves: strong marine current and waves induce the movement of structures and pipeline vibrations resulting in fatigue in the components of the drilling and production equipment.

The temperature changes, due to the different degrees of temperature between the surface and the drilled sub seabed formations make the pumping of the drilling fluid to become complex. Also these low temperatures alter the properties of the cement utilized to secure the casing of the well.

Critical aspects of drilling at the start up: During the drilling across shallow formations, the water flows are at high-pressure, there are also gas flows and therefore the pressures are usually abnormal.

Remote Operation of subsea installation must be made through R.O.V s, since human beings cannot reach great depths.

High costs involved: the fields need to be developed with fewer wells than the traditionally employed in the shallow waters. The conditions usually demand highly deviated and horizontal wells to ensure the flow of oil.

Subsea facilities and equipment: the application of new technologies is required to make possible the flow assurance either to the multiphase transportation systems or for fluids separation equipment on the seabed; a high degree of automation and use of robotics is required.

Salt formations: the demand for specialized technologies for formations surveying and assessment, also the drilling of these is challenging and demand the use of new and underdevelopment technologies.

Geometry of the reservoir in deep water may be different from the familiar in shallow waters.

3.4. Risks in projects in deep water.

Geological risks: exists due to the complexity of geological structures and the difficulty of identifying reservoirs, also in some cases the presence of saline subsurface formations deteriorate and diminish the likelihood of discovering deposits in these environments.

Operative risks: the operations are considerable more difficult to solve than in shallow water, for example:

•Flows of shallow waters and flows of gas might cause blow outs during drilling.

•Underwater tides and waves threaten the drilling facilities and the production infrastructure.

•Drilling equipment is expensive and sometimes unavailable

•Installation and maintenance of facilities is carried on at distant places and offer difficulties to access, which increase costs and delay operations.

Financial Risk: nevertheless, exposure of capital due the high costs of exploration, development and operation all-together with instability of oil prices.

Although the technology, equipment, and materials required for the project execution in subsea field developments, including deep water, have high cost of acquisition and operation, in the most of the cases they are already commercially available worldwide.

Nevertheless and particularly more important for the operators, is necessary acquire skills and implement systems to minimize risks for the operator company and increase the added value of the investment.

Proper business process management trough the whole lifecycle undoubtedly will diminish risks as well as will increase expected economical value added of the project.

Components for the management of the business process that can be listed are:

- Asset Management
- Documentation and management of project architecture, standards, recommended practices and procedures.
- Human resources and competence management
- Health, Safety and Environmental management.
- Implementation and management of suitable information systems
- Life Cycle Cost Management
- Process Safety Management
- Project Management
- Reliability and maintenance methodologies
- Risk Management.
- Suppliers and contractors management.

4. Offshore field development

Along the next chapters (4 and 5) some basic assumptions and facts will be reviewed on offshore field development and the concept selection in deep water. Necessarily, only an extract of all the public and available information will be mentioned due the expectancy and requisite to develop innovative content in this thesis. Wherever necessary, is suggested and encouraged to search and consult general references on this topics, a non exclusive list of suggested references is shown below:

- **Class Notes of Offshore Field Development with Compendium (Odland, 2000-2008).**
- **Deepwater development: A reference document for the deepwater environmental assessment Gulf of Mexico OCS (1998 through 2007)(Regg, 2006).**
- **Deepwater petroleum exploration & production: A nontechnical guide, (Leffler, 2003).**
- **Handbook of Offshore Technology, Volume I, (Chakrabarti, Editor, 2005).**
    - Chapter 1, Historical Development of Offshore Structures (Chakrabarti et. al, 2005).
    - Chapter 2, Novel and Marginal Offshore Structures (Capanoglu et. al., 2005).
    - Chapter 6, Fixed Offshore Platform design (Karsan et. al, 2005).
    - Chapter 7, Floating Offshore Platform design (Halkyard et. al, 2005).
- **Petroleum Engineering Handbook (Lake, Editor in chief, 2006).**
    - Volume I General Engineering (Fanchi, Editor, 2006).
        - Petroleum Economics (Wright, 2006).
    - Volume II Drilling Engineering (Mitchell, Editor, 2006).
        - Introduction to Well Planning (Adams, 2006).
        - Offshore Drilling Units (Childers, 2006).
    - Volume III Facilities and construction engineering (Arnold, Editor, 2007).
        - Oil and gas processing (Thro, 2007).
        - Gas Treating and processing (Wichert, 2007).
        - Piping and pipelines (Stevens and May, 2007).
        - Offshore and Subsea Facilities (O'Connor et. al., 2007).
        - Project Management of Surface Facilities (Kreider, 2007).
    - Volume V Reservoir engineering and petrophysics (Holstein, Editor, 2007).
        - Estimation of primary reserves of crude oil, natural gas, and condensate (Harrel and Cronquist, 2007).
        - Valuation of oil and gas reserves (Long, 2007).
- **Oil & Gas Exploration and Production Reserves, Costs, Contracts (Babusiaux, 2004).**
- **Oil and gas production handbook, an Introduction to oil and gas production (Håvard, 2006).**

4.1 Origins of oil and gas resources

The terms "Oil and gas" encompasses all the different hydrocarbon compounds (those compounds made of Hydrogen and Carbon in a chemical configuration) that are useful either for combustible or for transformation purposes and that were formed from the transformation of organic substances through geophysical and geochemical processes along plenty millions of years.

The sedimentary basins are those geological layers that were formed by successive deposition of organic and inorganic masses. Along the pass of the time, those first depositional layers were subject to increasing temperatures and pressures, down in the earth, as new layers were deposited on the surface.

In some cases, the conditions deep in the earth were propitious for the decomposition and transformation of the organic masses along many thousands and millions of years. These sedimentary layers where the organic substances are changing its properties are known usually as ***Source Rocks.***

Once the source rocks start to produce hydrocarbon compounds, those tend to climb passing trough interconnected porous in the rock and or fractures in the rock media, the path that the substances follow is refereed frequently as the ***migration path***. ***Porosity*** is the fraction of volume of the rock that is the empty space inside of a rock formation and ***permeability*** is the ability to flow or pass trough of the fluids contained in the rocks.

The hydrocarbons substances that move from the source rock are expected to flow trough a porous and permeable media until they are stopped by a geological barrier that is above a region of porous and permeable rock that is able to store the hydrocarbon substance and make possible its economical recovery. The geological barriers are know commonly as ***traps*** and the region of porous and permeable rock where the hydrocarbon is stored is named ***Reservoir Rock***. Depending on its form and origin the traps are classified as anticline, stratigraphic, unconformity and fault. The anticline traps are by most the more exploited so far due to their relative easiness to be located and dimensioned.

Summarizing, a promising area to be drilled for exploration (prospect) of oil and/or gas field must have:

1. A source rock reservoir rich of organic matter.
2. Enough heat and pressure along millions of years to make possible the transformation of the organic matter to hydrocarbon substances.
3. A migration path.
4. A reservoir rock limited by a:
5. Trap system with a impermeable seal (anticline, stratigraphic, unconformity or fault).

4.2. Hydrocarbon products

It is know that the characteristics of the reservoir are the main driver (On the decision to develop or not, on the specification of the concept and engineering, etc.) for the field develop. Those characteristics for example, will determine the type and fractional amount of the mixture of products to extract.

Hydrocarbons are not homogeneous when they are found in the subsoil. The considerable variations of the hydrocarbons in color, gravity, aroma, sulfur content and viscosity are common in petroleum from different geographical areas and even from reservoir to reservoir.

All the hydrocarbon reservoirs will differ from any others in its contents of hydrocarbons compounds and associated substances. The hydrocarbons can range in physical state from solids to gasses with water and sand as well as other impurities such as sulfur, oxygen and nitrogen.

The classification of the hydrocarbon products is based on its chemical composition. Lighter hydrocarbons (those with molecules with a small number of atoms of carbon) are usually gasses when are extracted and stay at normal atmospheric conditions.

The definitions of Odland (Odland, 2000-2008) regarding the different products that can be processed from the reservoir mixtures are reproduced below; the figure 4.1 shows the relation of the different products with the number of atoms of carbon predominant in the hydrocarbon substance:

- ***Petroleum*** *is a collective term for hydrocarbons, whether solid, liquid or gaseous. Hydrocarbons are compounds formed from elements hydrogen (H) and carbon (C). The proportion of different compounds, from methane and ethane up to the heaviest components, in a petroleum find varies from discovery to discovery. If a reservoir primarily contains light hydrocarbons, it is described as a gas field. If heavier hydrocarbons, it is called an oil field. An oil field may feature a gas cap above the oil and contain a quantity of light hydrocarbons in solution - also called associated gas.*

- ***Crude oil*** *includes condensate and natural gas liquids. Most of the water and dissolved natural gas have been removed.*

- ***Condensates*** *means the heavier natural gas components, such as pentane, hexane, iceptane and so forth, which are liquid under atmospheric pressure - also called natural gasoline or naphtha.*

- ***Natural gas*** *means petroleum that consists principally of light hydrocarbons. It can be divided into:*

    - ***lean gas****, primarily methane but often containing some ethane and smaller quantities of heavier hydrocarbons (also called sales gas) and*
    - ***wet gas****, primarily ethane. propane and butane as well as smaller amounts of heavier hydrocarbons; partially liquid under atmospheric pressure.*

- ***LNG*** *means* ***Liquefied Natural Gas*** *lean gas – i.e. primarily methane- convened to liquid form through refrigeration to -163C under atmospheric pressures.*

- ***LPG*** *means* ***Liquefied Petroleum Gas*** *and consists primarily of propane and butane, which turn Liquid under a pressure of six to seven atmospheres. LPG is shipped in special vessels.*

- ***Naphtha*** *means an inflammable oil obtained by the dry distillation of petroleum.*

- ***NGL*** *means* ***Natural Gas Liquids*** *light hydrocarbons consisting mainly of ethane, propane and butane which are liquid under pressure at normal temperature.[Odland, P.p. II "Miscellaneous term", Hard copy compendium, 2000-2008].*

Additionally there is an alternative post processed product known as ***GTL (Gas to liquids)***. Gas to liquids refers to a refinery process to convert natural gas or other gaseous hydrocarbons into longer chained hydrocarbons such as gasoline or diesel fuel.

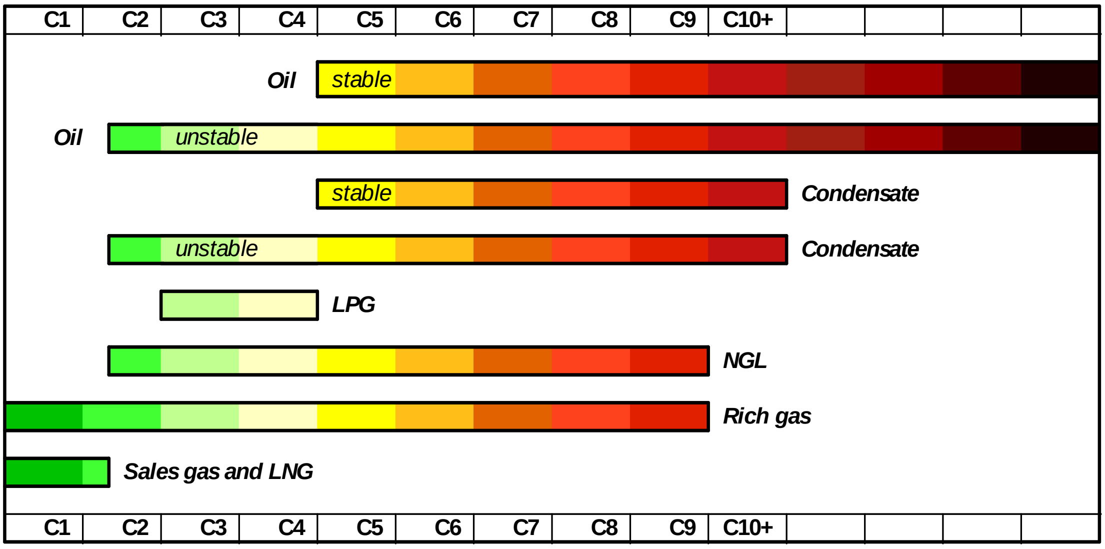

Figure 4.1: Classification chart of hydrocarbons and sales products [Odland, P.p. 12, Mod. 3 Petroleum resources and production, Class Notes…,2000-2008].

4.3 Value chain in oil and gas

The exploration and production of oil and gas has as main purpose to **"Extract (in a cost effective, efficient, safe and as environmentally friendly as reasonable) the hydrocarbons that rely in basins under the soil surface (either in land, fresh water bodies or in the seas) and transport, process and deliver the production to a market"**.

These previous facts are the basis to explain the term "value chain" that is going to be introduced in this section.

The value chain of oil and gas encompasses the chain of technological solutions that make possible to bring the hydrocarbon products from the reservoir to the final market. It is usually divided in Up-stream, Mid-stream and downstream.

Upstream in offshore, refers to the extraction and initial processing or stabilization to transportation located offshore.

Mid stream refers to the transportation and distribution networks of technologies and process that mobilize the products from offshore to onshore processing facilities or to distribution pipeline networks to market delivery.

Downstream, is mentioned to make reference to the refining and further transformation of the products received from the upstream and midstream steps.

The transportation issue is closely related to the products handled and it takes an important role determining the selection of the value chain elements that will be emplaced. The goal is to optimize the life cycle value creation along the entire value chain, from the reservoir to market

A field of oil plus an associated gas reservoir will have most of the possible products cataloged on the above list. Then, the handling options for the exploitation of these reservoirs would be as shown in the figure 4.2.

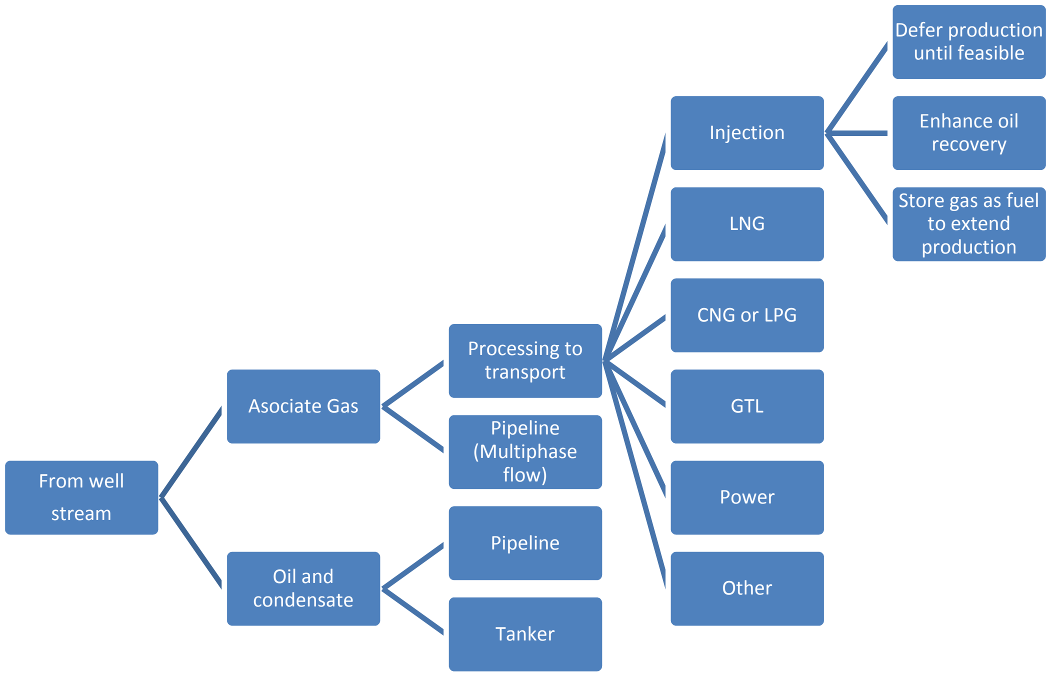

Figure 4.2: Products and handling options for a field of oil with associate gas.

The selection should in addition conciliate aspects entirely related to the production process such as type of hydrocarbons, geographic region, water depth, available existing assets and infrastructure, etc. There are also other non technical aspects, but not for that less important, that require attention.

There are many aspects not merely related to the hydrocarbon production that must be taken in consideration. One of the most important among them is the existence of different shareholders around any oil and gas project that can have many different points of view, reacting according to them instead of focusing on the value creation. In this case a careful analysis of the value chain would help to find and conciliate the shareholders interest.

4.4 Phases and decision gates planning the offshore field development

The field development is a sequential process that is carried out over several years. The figure 4.3 shows the main stages of it.

Figure 4.3: Stages of the field development.

Along each section of the field development until the start of the project execution there are several major decision gates that drive to the continuation or not of the investment. These decision gates are in place since the beginning of the pre-concession works. It is relevant for the scope of this work to extend the discussions of the first four stages:

- Pre-concession or prelease work
- Concession round
- Exploration
- Appraisal and development planning

Figure 4.4 shows the decision gates related to the pre-concession works, the concession round and the exploration of prospects.

In most of the world regions the process starts with the interest of an oil and gas company to explore a determinate region or section offshore.

Exploratory activities have as a goal to find accumulations of hydrocarbons that can be extracted in a profitable way. These activities conclude successfully after the drilling of a well that reach an accumulation of oil and gas o alternatively with a declaration of non commercial feasibility or in the worse case, failure to find hydrocarbons (a dry hole).

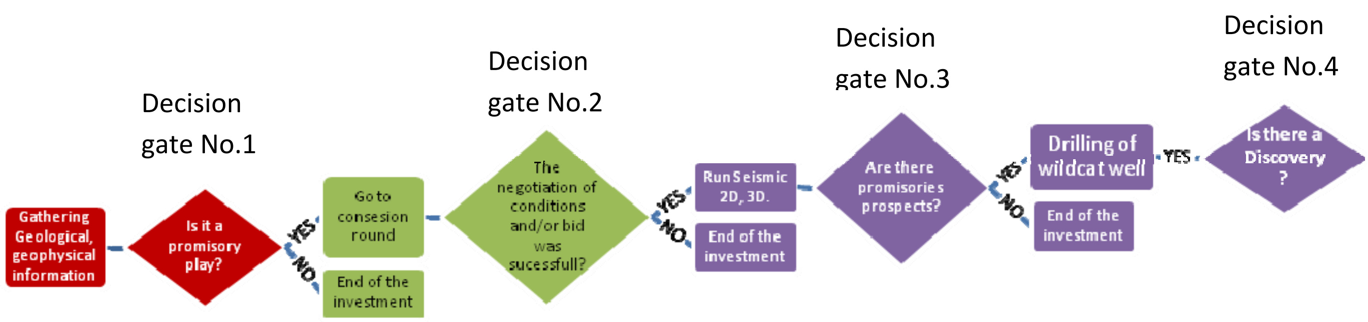

Figure 4.4: Decision gates related to the pre-concession works, the concession round and the exploration of prospects

Oil companies classify the level of maturity in the definition of areas likely to content hydrocarbon resources previous to the exploratory drilling, a set of commonly referred definitions after Magoon will be reproduced below (Magoon et al., 1999).

> ***Petroleum province**, a geographic term, is an area where petroleum occurs in commercial quantities. Basin is sometimes used geographically to mean petroleum province, such as the Williston Basin or Paris Basin. The Zagros fold belt could be a structural province or a petroleum province, not a basin.*
>
> *A map showing differential thickness of sedimentary rocks is used to determine basins (thick), uplifts (thin), and fold belts (folded). These features are properly named provinces; if they contain petroleum, they are called petroleum provinces. The use of "basin" in this context is improper; it is also inconsistent with the petroleum system concept described below, which defines "basin" as the area into which sedimentary rocks are deposited.*
>
> ***A sedimentary basin** is a depression filled with sedimentary rocks. The presence of sedimentary rocks is proof that a basin existed.*
>
> *The depression, formed by any tectonic process, is lined by basement rock, which can be igneous, metamorphic, and/or sedimentary rock. The basin fill includes the rock matter, organic matter, and water deposited in this depression. In certain cases, such as with coal and some carbonate deposits, the sedimentary material is formed in situ.*
>
> *The essential elements of a petroleum system are deposited in sedimentary basins. Frequently, one or more overlapping sedimentary basins are responsible for the essential elements of a petroleum system. Traps are formed by tectonic processes that act on sedimentary rocks. However, the moment petroleum is generated, biologically or thermally, a petroleum system is formed.*
>
> ***The petroleum system** includes the pod of active source rock, the natural distribution network, and the genetically related discovered petroleum occurrences. Presence of petroleum is proof that a system exists.*
>
> *The pod of active source rock is part of the petroleum system because it is the provenance of these related petroleum occurrences. The distribution network is the migration paths to discovered accumulations, seeps, and shows. In contrast to the play and prospect, which address undiscovered commercial accumulations, the petroleum system includes only the discovered petroleum occurrences. If an exploratory well encounters any type or amount of petroleum, that petroleum is part of a petroleum system.*
>
> *The play and prospect are used by the explorationist to present a geologic argument to justify drilling for undiscovered, commercial petroleum accumulations. **The play** consists of one or more geologically related prospects, and a **prospect** is a potential trap that must be evaluated by drilling to determine whether it contains commercial quantities of petroleum. Once drilling is complete, the term "prospect" is dropped; the site becomes either a dry hole or a producing field.*
>
> *The presence of a petroleum charge, a suitable trap, and whether the trap formed before it was charged are usually involved in this evaluation. These terms are compared in the table* 4.1. *[Magoon et al., P.p. 24-25, 1999].*

Item to be Compared	Sedimentary Basin	Petroleum System	Play	Prospect
Investigation	*Sedimentary rocks*	*Petroleum*	*Traps*	*Trap*
Economics	*None*	*None*	*Essential*	*Essential*
Geologic time	*Time of deposition*	*Critical moment*	*Present day*	*Present day*
Existence	*Absolute*	*Absolute*	*Conditional*	*Conditional*
Cost	*Very low*	*Low*	*High*	*Very high*
Analysis	*Basin*	*System*	*Play*	*Prospect*
Modeling	*Basin*	*System*	*Play*	*Prospect*

Table 4.1 Comparison of area concepts in exploration [Magoon et al., P.p. 25, 1999]

4.4.1 Pre-concession or prelease work

At the stage of the pre-concession or prelease works the oil companies should gather and evaluate geological information of the play´s area and negotiate or present an offer in a public bid considering the royalty and tax conditions that will govern the future value of the area to explore. Usually the oil companies are understood to pay the cost and assume the risk of these gathering of information.

A set of technical and economical disciplines is used for the analysis of the information gathered, it should be understood that those technical and economical disciplines are not going to be used at one single time but will be constantly updated according to the delimitation of prospects for exploration advance. Lewell shows graphically an approach of the interactions of disciplines for the Prospect de-risking that illustrate the above expressed, see figure 4.5.

The stratigraphycal analysis, structural geology and seismology correlations help to understand the geological data, including maps, cross-sections, electric logs, and seismic surveys. Furthermore, the reservoir geology deals with the relationships between paleo-environmentalg interpretations and the practical application of these interpretations to field development. All those science resources are quite sophisticated nowadays, but we must be aware of their associate’s uncertainties in geological and geophysical data/interpretation.

Reservoir characterization and modeling allow advanced interpretation and recognition of the geological data which make them easier to be presented for evaluation to the integrated asset teams in charge of the development plans.

The volumetric analysis will help to understand and realistically evaluate economically the geological data and its interpretation. Analyst also should be aware of how geological data impact decisions made during production of a field (Well planning, reservoir appraisal, field development concept, uncertainty analysis).

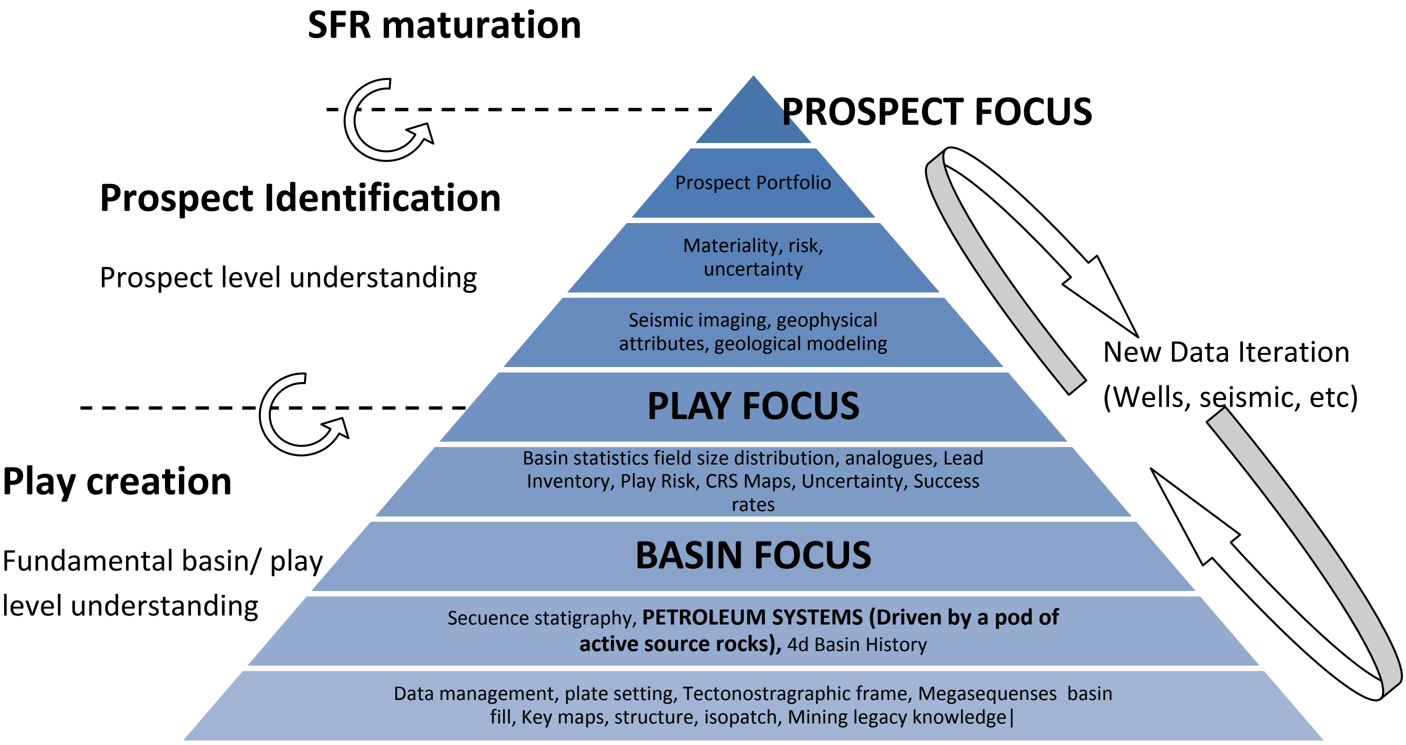

Figure 4.5 Interactions of disciplines for the Prospect de-risking *[Lewell, P.p. 11, 2009]*

After the evaluation of the prospects and the play, Oil companies should be able to identify whether or not it is interesting to engage in a exploratory commitment and even to start with a drilling exploration program and in this way to pass the first, second and third decisions gates shown in figure 4.4.

At the early stage of maturation of the projects is common that different companies get together in a coordinate association to develop a specific field. The aim of these associations is to take advantage of the particular technological, organizational, political or financial strength of the companies that will diminish the risk for the others, making possible to develop a field. Another reason can be to integrate neighbor's exploration license areas that have been proven and that where initially assigned to different companies.

In any case a conjunction of companies will be leaded operatively by one of them that will be knew as the "operator company" other companies will be then knew as the partners. The operator is not necessarily the main partner in relation to the capital invested, however is a common practice that the operator has a substantial participation to encourage the interest in good results in the project.

Another important aspect in these associations will be the decision making process that must be characterized by transparency and agreement among the parties.

4.4.2 Concession round.

The oil companies must evaluate in this stage both technical and economical aspects of the exploration ventures. Besides the geological risks the relevance of the tax systems in the profit results must be assessed because different tax systems might drive whether there is a commercially successful discovery or not.

The oil and gas resources contained in the subsoil are entitled to be property of the nation in where these accumulations of hydrocarbons rely, with some exemptions like in the USA where a particular owner of the land is also entitled to have rights over the subsoil. The exploitation of those resources however is in the hands of oil companies, either of national, private or mixed shared ownership.

Despite some countries have National Oil Companies that operate in their own countries with monopoly practices, they are more the exception than the rule. The most of the producing countries have emplaced ***Fiscal Systems*** in order to ensure the collection of cash flow from the oil and gas ventures.

A particular analysis of those systems should be emplaced for each country or even each province or state because the set of laws and codes are different according to the geographical location of the facilities and resources. Nevertheless, it can be listed four mechanisms that the States can use to get benefits from the exploitation of resources, either emplacing all of them or just partially and with or without operative participation through National oil companies (Masseron, 1990).

- **Cash Bonus:** Is a form of initial payment of the company that wants a permit to do exploration. The amount can be specified by law or can be subject to negotiation. The contracts establish an initial payment that is usually done when the concession is granted and also can include a series of further payments as the time passes. The payment is irrespective of the results of the exploration activities.
- **Annual Rental:** A yearly payment to the owner of the land and the rights of exploitation of its subsoil. This payment is also not dependant of the results of the exploration activities.
- **Royalties:** A payment in exchange of the rights of exploitation due once the first oil is extracted. It can be in cash or in petroleum products and is set according in a percentage (around 12%-15%) of the planed rate of exploitation that might be adjusted on the view of the actual production.
- **Income Tax:** The proportional taxes that all countries impose to commercial activities (around 50% in average for oil and gas activities).

The governments as a general rule might use the above elements in two main ways to tax the oil and gas extraction:

1.) Concession agreements. See figure 4.6 for a example of distribution of expenses and income along the life cycle of the field development with this tax system.

2) Production sharing agreements. See figure 4.7 for a example of distribution of expenses and income along the life cycle of the field development.

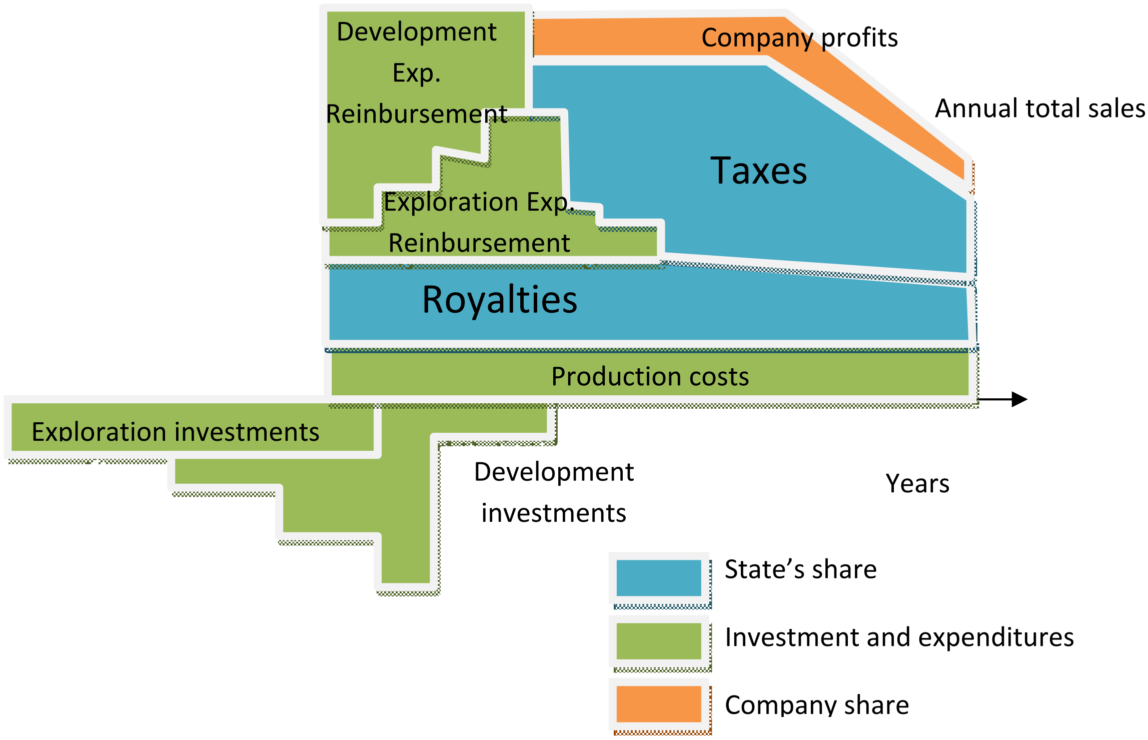

Figure 4.6 Cash flow distributions in standard concession agreements [Masseron, P.p. 137, 1990]

In this work is not intended to explore this important aspect of the economical evaluations, it is however recommended to review the following documents as a way to understand with more clarity the aspects related to tax systems for the decision making of both oil companies and governments.

- Fiscal System Analysis: Concessionary and Contractual Systems used in Offshore Petroleum Arrangements (Kaiser and Pulsipher, 2004).
- Fiscal systems for hydrocarbons : design issues (Tordo, 2007).

4.4.3 Exploration activities

The exploration activities follow an extensive process to increase the probability of success, is common that the exploration drilling is preceded of many seismic surveys and analysis previous to be approved. The most important and costly activity is drilling, which marks the success or failure of the value chain until this point, success in case that there is enough oil and gas to be commercially feasible develop, failure in case that it is found a “dry hole”, and stand by in case the finding is not commercially feasible at the moment but could be exploited in the future due to technological improvement.

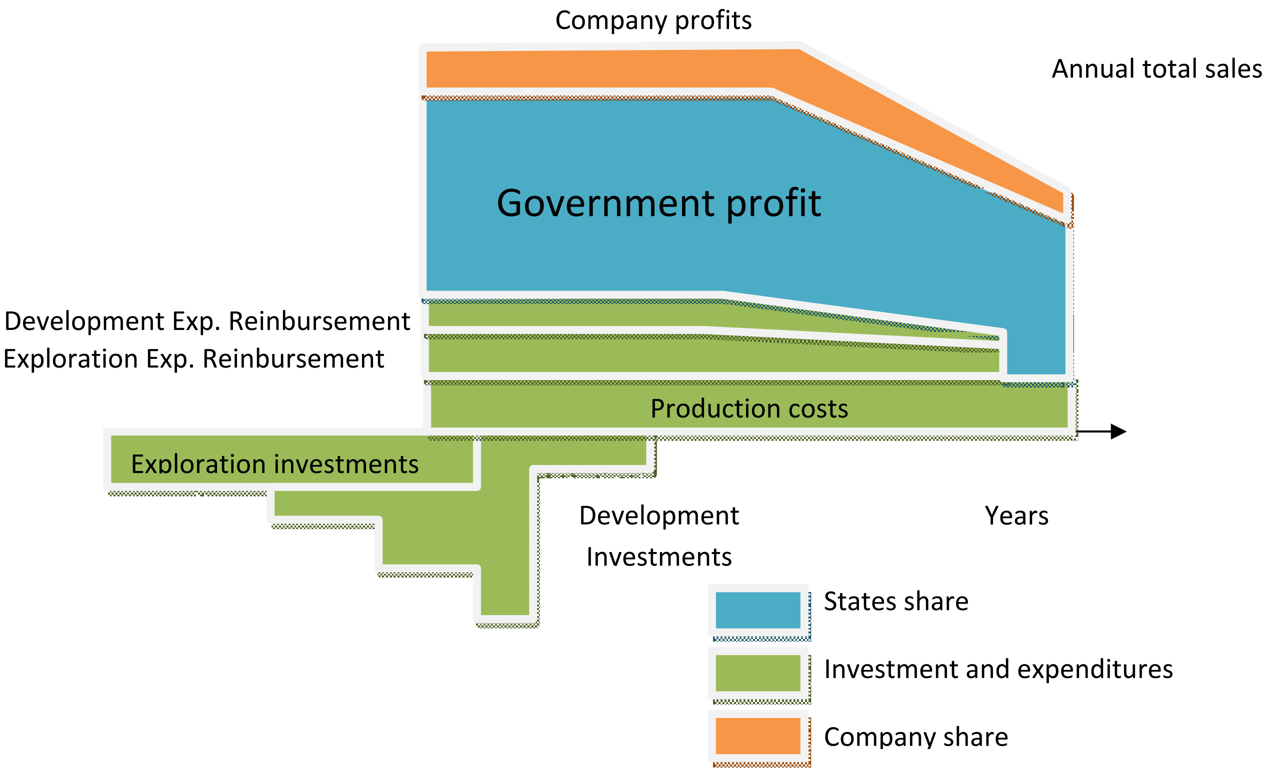

Figure 4.7 Cash flow distribution in standard production sharing agreement [Masseron, P.p. 137, 1990]

The main economical trigger of exploration drilling and consequently of the most of the investment expenditures in exploration is the price of the oil. As an example is suggested to take a look in annex D. Annex D shows an empirical study on the drivers of the investment activity in Norway.

In this annex D was intended to identify which are the factors that drive the level of petroleum investments in exploration. It was also proposed to explain how and in which magnitude those factors influence the investment decisions with basis in an econometric analysis using statistical inference on available data of the Norwegian Continental Shelf.

It was found that the exploration investments level is driven mainly by only one explanatory variable available in the originally considered data set, the oil price. It was also found the existence of a positive correlation between the level of investment in exploration and the oil price that improves as it is employed a lagged distribution of the explanatory variable.

It is inferred then that the increment in one dollar in the price of the barrel of oil induce approximately an investment of 26 Million NOK to be realized two quarters after the change in the price is effective and 11 Million NOK and 26 million NOK to be perceptible tree and four quarters after the price is adjusted.

4.4.4. Appraisal and development planning

Once it was proven a commercial discovery it is recommended to the oil company to proceed to develop an appraisal drilling program that will provide of information needed for an effective development plan. It is a bargaining situation to balance the cost-benefit of the investment in this appraisal program. Figures 4.8 and 4.9 show the decision gates related to the appraisal and early development planning for a field development.

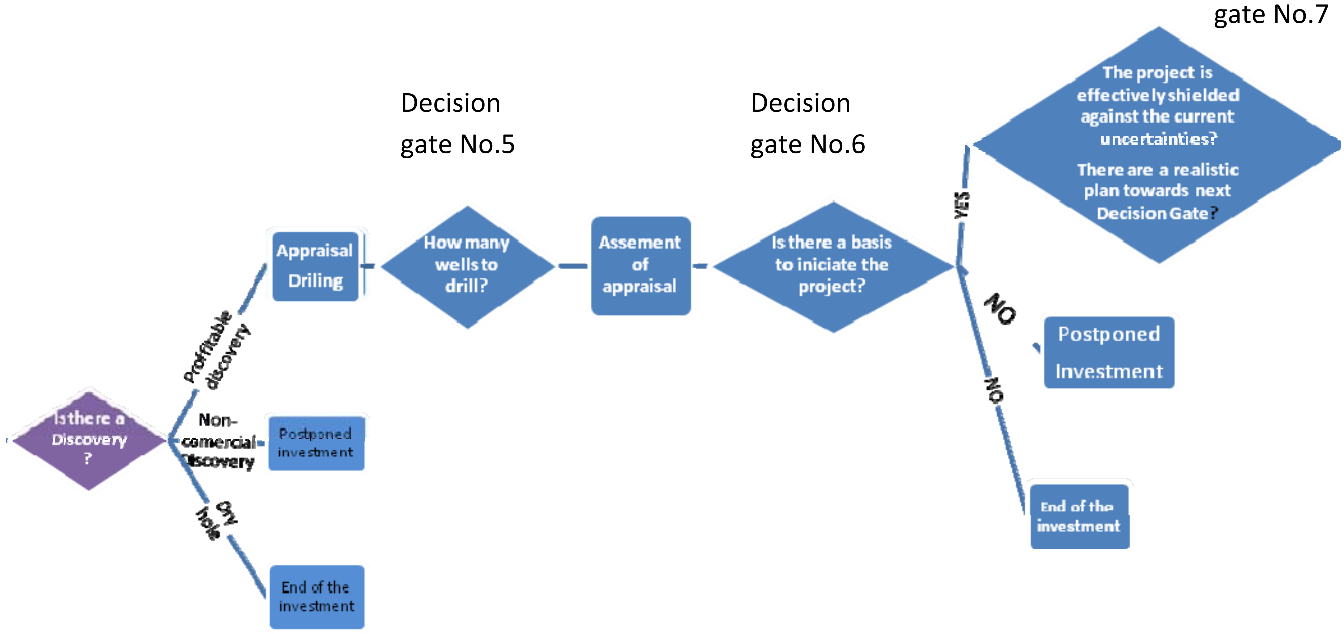

Figure 4.8: Decision gates related to appraisal and early development planning.

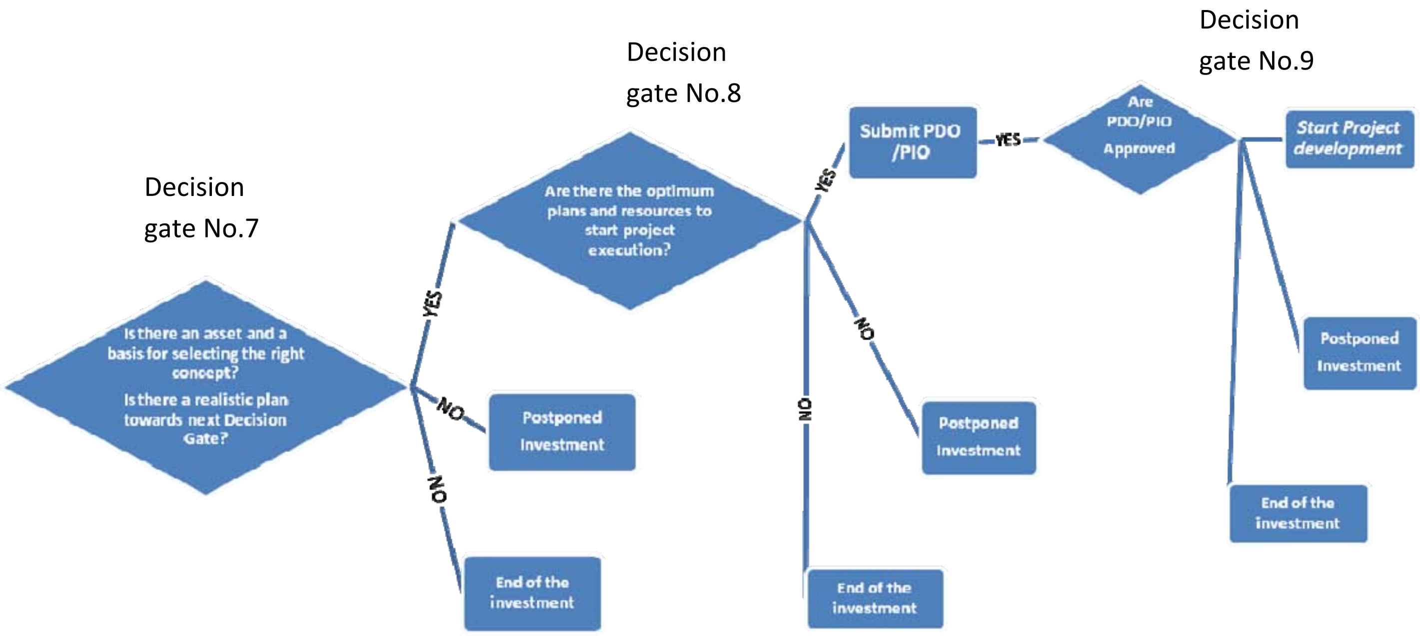

Figure 4.9: Decision gates related to early development planning.

The stage of the early development is discussed in an extraordinary clarity in the "Introduction to development of a petroleum installation" (Coker J.W.A. and Gudmestad, 2003), although it is discussed in the frame of the company Statoil and the Norwegian continental Shelf it is suitable to be reproduced below, due its high value added and correspondence whit the topic here explained. Below the excerpt from [Coker J.W.A. and Gudmestad, P.p. 11-23, 2003].

Once the exploration has proven a finding of hydrocarbons suitable for commercial exploitation the Investment projects are divided into two periods, the project planning and the project execution, see figure 4.10.

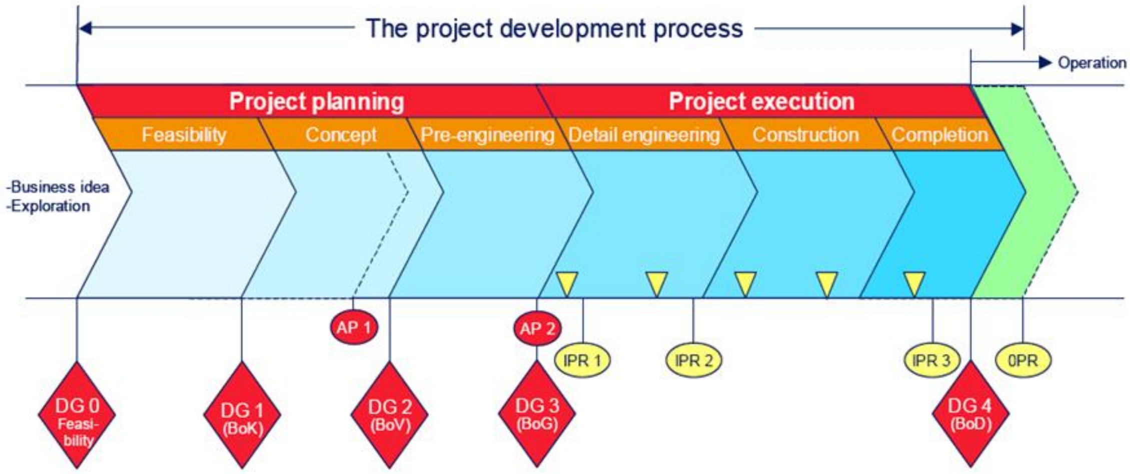

Figure 4.10. The project development model for investment projects with phases and decision gate, figure 7 in [Coker J.W.A. and Gudmestad, P.p. 12, 2003]

The outcome of the planning stage is the decision to initiate the project execution. The successful completion of the project execution conducts to the start of the production operations. Both periods are divided in phases with identifiable purpose and results.

It is proposed to define five decision gates (DG) *[for this work, it will be described only the first three of the mentioned literature]*, established at milestones to review the status of the project progress to be able either to terminate, continue the project or to implement important changes. This decision gates coincide with transition steps in the projects and also approval points (AP) are defined in order to take major decisions. The process of the project development must flow smoothly from the feasibility assessment to the start-up despite is divided in phases.

The planning period.

Is an assessment period is aimed to make clear if a business opportunity that satisfy the expectations of the oil company in profitability, HSE and technical feasibility can be development despite of the uncertainties. This assessment must be systematic and inclusive of the viable range of concepts and should deliver a selected concept to develop.

It consists of three phases:

- **Feasibility**, which conclude in DG 1 (Coker J.W.A. and Gudmestad, 2003) and in decision gate No. 6 in this work, see figure 4.9.

- **Concept,** which conclude in DG 2 (Coker J.W.A. and Gudmestad, 2003) and in decision gate No. 7 in this work, see figure 4.9.
- **Pre-engineering**, which conclude in DG 1 (Coker J.W.A. and Gudmestad, 2003) and in decision gate No. 8 in this work, see figure 4.9.

*The main purpose of the **feasibility phase** is to establish and document whether a business opportunity or a hydrocarbon find is technically feasible and has an economic potential in accordance with the corporate business plan to justify further development. The feasibility phase is initiated at DG 0 with a project agreement that defines the task, goal, framework and budget. The feasibility phase leads to decision gate DG 1, "Decision to start concept development" (BoK). [Coker J.W.A. and Gudmestad, P.p. 12, 2003].*

*The purpose of the **concept phase** is to provide a firm definition of the design (resource and product) basis and to identify all relevant and feasible technical and commercial concepts. Further to evaluate and define the selected alternative (preferably one) and confirm that the profitability and feasibility of the business opportunity will be in accordance with the corporate requirements and business plans. The concept phase leads to the selection of the concept(s) (AP1) to be further developed up to decision gate DG 2, "Provisional project sanction" (BoV). [Coker J.W.A. and Gudmestad, P.p. 15, 2003].*

*The purpose of the **pre-engineering phase** is to further develop and document the business opportunity based on the selected concept(s) to such a level that a final project sanction can be made, application to authorities can be sent and contracts can be entered into. The preengineering phase leads to approval point 2 (AP2), "Application to the authorities", and to decision gate 3 (DG 3) " Project sanction" (BoG). [Coker J.W.A. and Gudmestad, P.p. 19, 2003].*

An additional point is the submission and approval of the plan of development and the plan of installation and operations. Coker and Gudmestad (2003) explain this point as Approval point 2, here corresponding to the Decision gate No. 9. See figure 4.9.

Approval point 2 (AP 2), "Application to the authorities"

The project shall compile and prepare for submittal of the necessary application(s) for approval of the facility development in accordance with the relevant laws and regulations. It is particularly important to have undertaken an analysis to determine which requirements apply.

For projects within the jurisdiction of the Norwegian Petroleum Act, a "Plan for development and operation" (PDO) (Norwegian: PUD) or a "Plan for installation and operation" (PIO) (Norwegian: PAD) is required. The PDO / PIO shall be prepared in accordance with the document "Guidelines for PDO and PIO", issued by the Norwegian Petroleum Directorate. The PDO / PIO shall be approved by the responsible business unit, corporate management (KL), the board and the partners, before it is submitted. When the partnership submits a PDO / PIO to the authorities, this represents a commitment by the partnership to carry out the project development. For projects in this category, completion of the PDO / PIO and DG 3 (BoG) should occur at the same time. [Coker J.W.A. and Gudmestad, P.p. 21, 2003].

Annex C shows the summary of requisites, activities and products for each of the phases of the development planning.

The commitment to use specific technology and configurations, the set up of performance and cost are determined in the early stage of conceptual design, consequently as the project advance the ease of change in the concept become much more difficult and the cost incurred due change of mind increase considerably. The figure 4.11. shows the relationship with the project phases and the cost, easiness of change and technical issues for a project developed according to the model presented in figure 4.10.

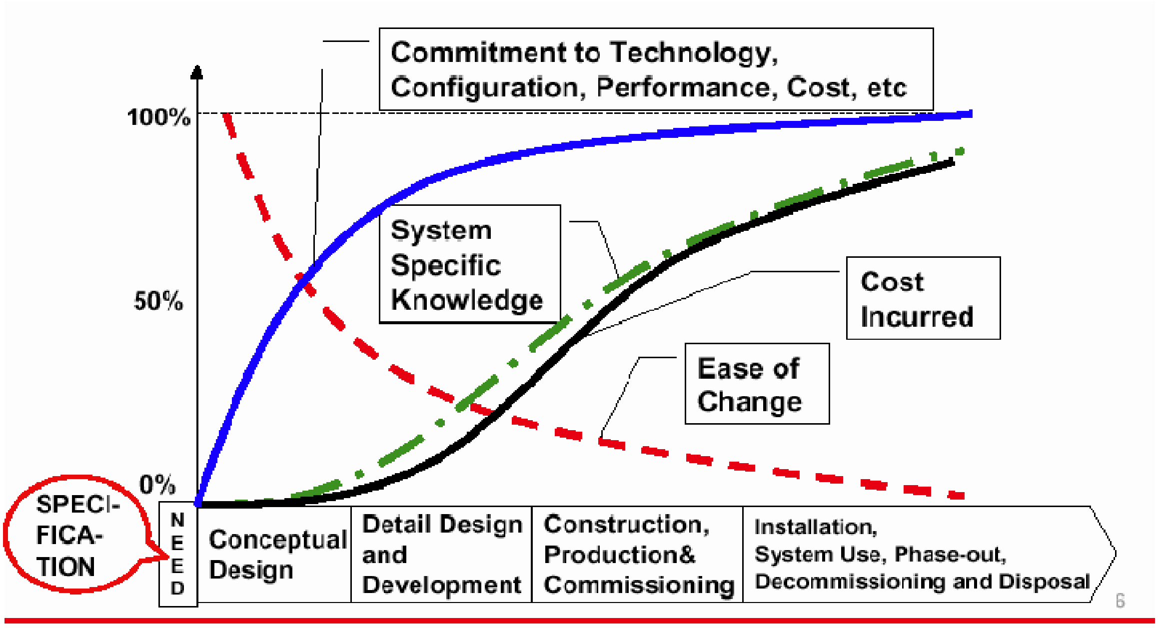

Figure 4.11 Summary of relationships between project phases and cost, change easiness and technical issues, Figure 8 in [Coker J.W.A. and Gudmestad, P.p. 23, 2003)

5. Concept Selection and Life Cycle Cost

5.1 Concept selection purpose and organization

A concept is a business case documenting an option for the development of an oil and gas field. The basis is technical information with a relatively accurate economical forecast. Odland (Odland, 2000-2008) offers the following definitions see chart 5.1.

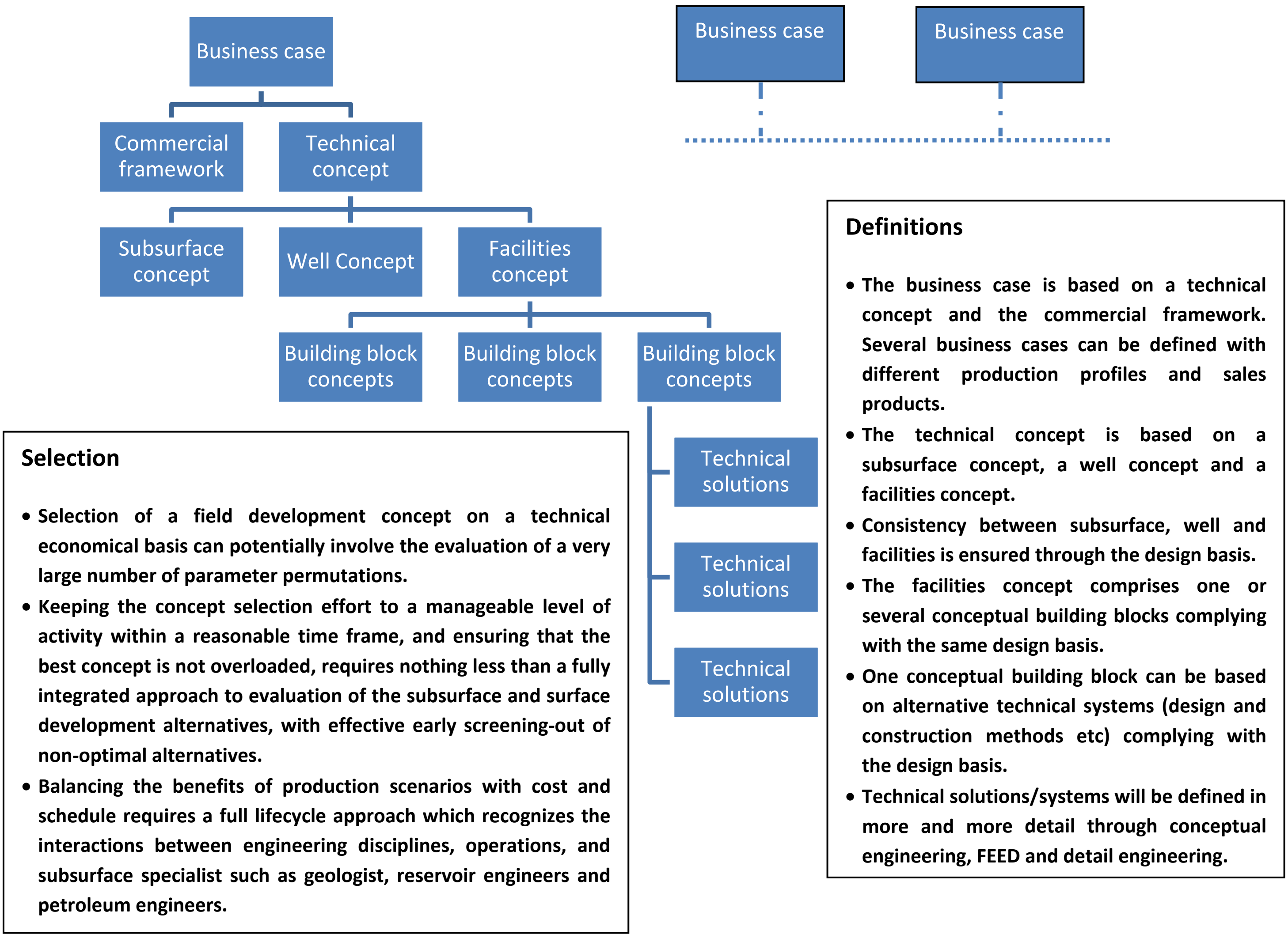

Chart 5.1. Definitions of concept selection [Odland, Chapter 7, P.p. 20, 2000-2008]

Continuing with the information shown in the Chapter 4 and Annex D, the concept stage has as purpose:

> *… provide a firm definition of the design (resource and product) basis and to identify all relevant and feasible technical and commercial concepts. Further to evaluate and define the selected alternative (preferably one) and confirm that the profitability and feasibility of the business opportunity will be in accordance with the corporate requirements and business plans. The concept phase leads to the selection of the concept(s) (AP1) to be further developed up to decision gate DG 2, "Provisional project sanction" (BoV).*

Different sources of literature, for example (Karsan, 2005) also relate the “Front End Loading (FEL)” processes, these are defined as all the activities that precede the start of the basic design phase and these should deliver:

- A well defined field development plan.
- Basis for conceptual design.
- Configuration of the field as well as conceptual drawings of major components of the development.
- Concept cost estimate +/- 40%.

Ignoring small differences it will be assumed that the ***concept stage*** is not different from the ***FEL***, along this work and hence It will not be a differentiation of both terms hereby.

The concept stage is generally by a group of multidisciplinary senior staff with expertice in both technical as well as economical issues. For the demanded flexibility and rapid response it is recommended to handle a flat and hands on organization dedicated to this task. Figure 5.1 shows a suggested organization.

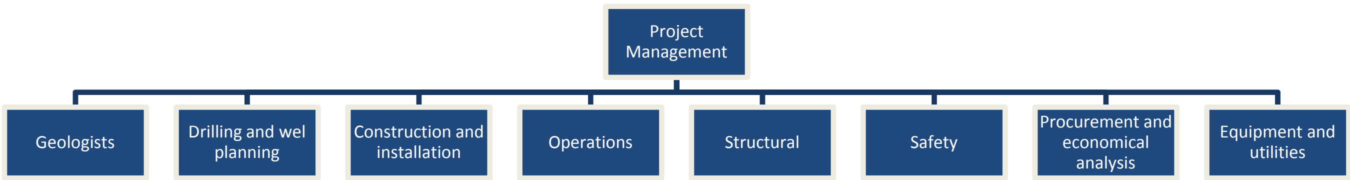

Figure 5.1. Suggested organization to develop a concept selection for a field development.

5.2 Factors influencing the concept selection.

The concept selection is developed as an spiral at the beginning with a high level of uncertainty and high requirements of flexibility that are being refined and narrowed as the process advance. Figure 5.2 and table 5.1 list some of the main issues that must be addressed when the concept of development is being chosen. (Karsan, 2005).

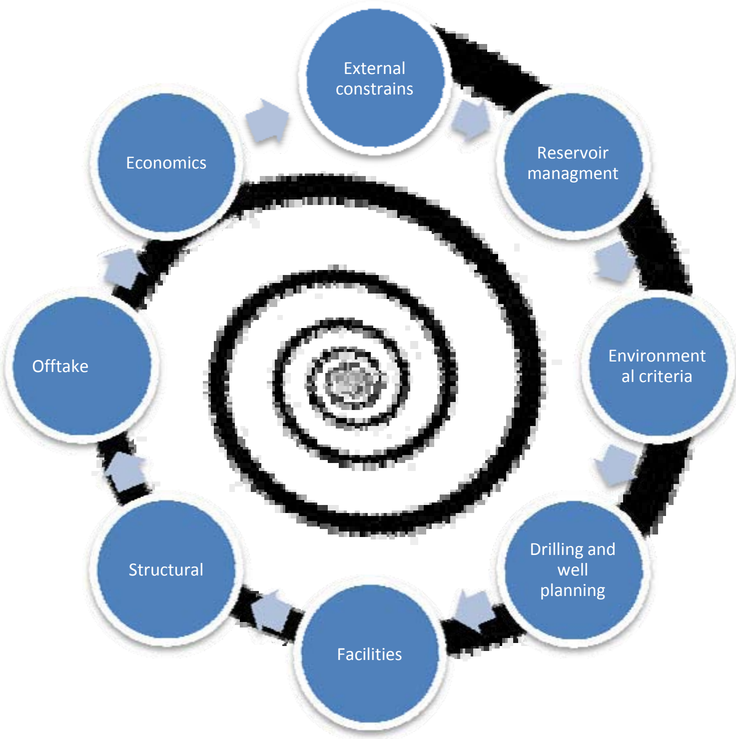

Figure 5.2. Design spiral in the offshore field development (Karsan, 2005)

External constrains	***Reservoir management***	***Environmental Criteria***	***Drilling and Wells plan***
Government regulations	*Mapping and reserves estimates*	*Meteorological*	*Casing size and sequence.*
Company and partners policies/goals	*Well tests and fluid properties*	*Oceanographic*	*Directional design*
Industrial design codes	*Modeling and development scheme*	*Geotechnical*	*Rig Selection*
	Bottom hole locations	*Biological*	*Completion and workover*
Facilities	**Structural**	**Offtake**	**Economics**
Oil/gas processing	*Floaters*	*Metering*	*Cost/Schedule*
Injection	*Subsea template*	*Pipeline*	*Risk*
Accommodation and logistics		*Tanker*	*Project strategy*
		Storage	*Operating plan*

Table 5.1 Elements of the spiral design in the offshore field development in deep water.

The elements that are in a close interaction with the production process are pointed:

1. Reservoir management (Subsurface concept).
2. Well systems features (Well concept).
3. Facilities (Facilities concept).

Cited by Karsan, Morrison (Morrison, 1997) proposes figure 5.3. That shows the drivers affecting those three elements.

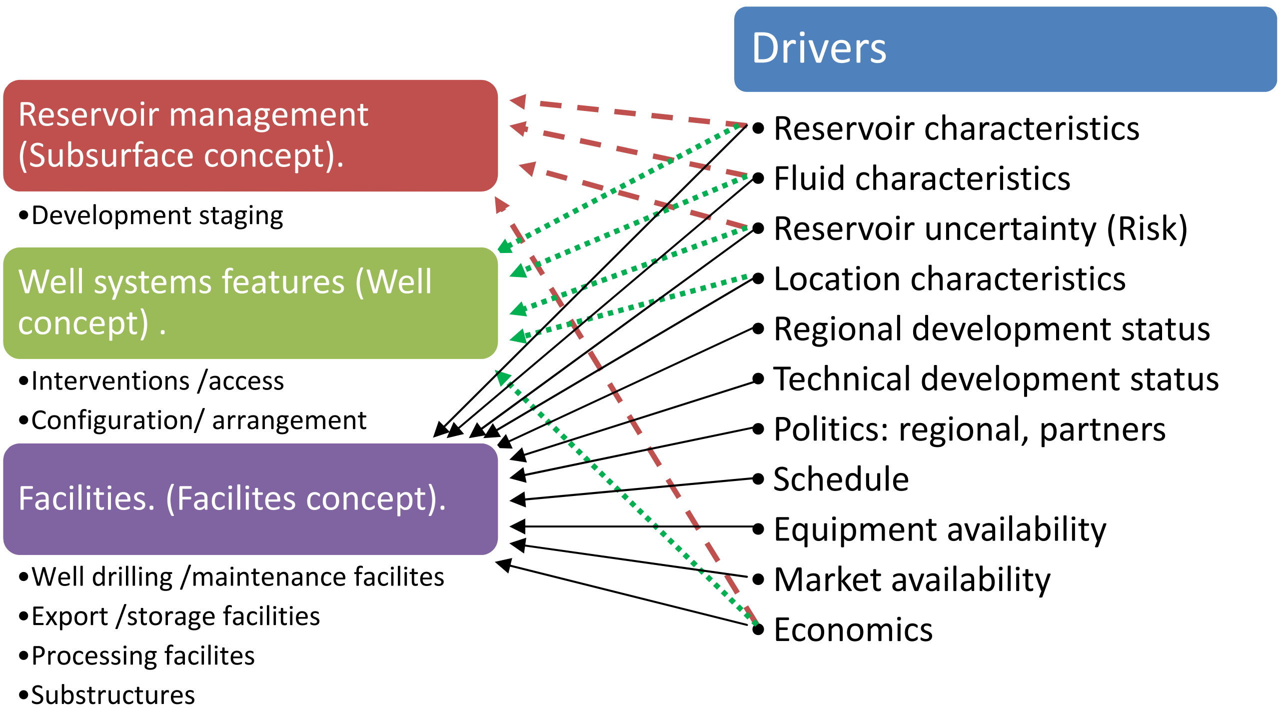

Figure 5.2. Factors that drive field development selection (Morrison, 1997)

5.2.1 Reservoir characteristics

The main driver of any field development is found down hole. Among some of the important facts that are needed it is necessary to have the most detailed picture of the following aspects:

5.2.1.1 Size of Field and complexity of the reservoir

These parameters will interact with the fluid characteristics to determine the optimal number of wells. The number of wells will increase when the reservoir becomes larger and also when is more fragmented (or complex, see also 7.2) since it will require more depletion points to keep a required recovery factor.

The drilling of those wells has a major impact on the facility selection. As more wells are required the larger the topsides should be considered. Dry tree solutions will need more load capability from the substructure than the wet tree solutions.

If the field is extremely fragmented and the depletion points are distant or have difficult access trough directional drilling, the best option becomes the subsea completion that will require straight and simpler drilling.

On the other hand, a clustered set of depletion points will be favorable for a single central structure, possibly with a rig package included, this will save the appointment of a semisubmersible rig for well maintenance and work over, particularly expensive in deep water scenarios (Stiff and Singelmann, 2004).

Odland (Odland, 2000-2008) also mentions that in case of larger fields it might be reasonable to think of the development as made up of several hub structures. More than one major structure in the field will open the possibility of increased recovery factor, more options for handling and transport of the hydrocarbons as well as risk and reliability robustness.

5.2.1.2. Expected Production Rate

As a result of a big and pressurized reservoir a high production rate can be foreseen. This will need more processing equipment leading to higher loads in the topsides. It will be necessary also larger export facilities. The concept will need consequently much more capacity for space and weight. The balance between produce at high rate or undersize the facilities must be assessed in this case. *(Stiff and Singelmann, 2004)*

5.2.1.3. Quantity of Gas and pressurization

A high pressure field with a relatively high content of gas leads to increasing need of processing equipment. Small fields might not be economical to exploit if the only solution is a large floating structure with capability to process the gas, in this case the subsea solutions become an attractive concept to study (Stiff and Singelmann, 2004).

Several options for handling of gas can be reviewed in the MMS study “Technology assessment of alternatives for handling associated gas produced from deepwater oil developments in the GOM” (Ward et. al., 2006).

5.2.1.4 Length of field life

Another aspect is the influence on the decommissioning considerations since some concepts such as SPAR’s, production semisubmersibles and FPSO’s can be reused when a field is exhausted. On the contrary, a TLP will represent a complex scenario for its relocation (Stiff and Singelmann, 2004).

Odland (Odland, 2000-2008) also points out that in small field developments it might be an option for the operator companies to establish leasing agreements instead of commit to the construction of the production assets.

5.2.2. Fluid characteristics

5.2.2.1 Type of Crude

The subsea concepts are the best solution when it is anticipated that the wells will have low workover / interventions requirements and a high-quality flow assurance (Dry gas reservoirs, free of parafins, etc.) The solution for complex flow assurance might involve the use of chemicals and other technologies, but they might be cost prohibitive (Stiff and Singelmann, 2004).

5.2.2.2. Need for Workover and Intervention.

All the types of wells will eventually require some kind of maintenance; they can be from a simple i***ntervention*** (for example a coil tubing operation) to full ***work over*** (recompletion) procedure to hit a different pay zone.

Nergaard (Nergaard, 2009) gives a definition of the two terms and explains their purposes as:

Workover: The term is used for a full overhaul of a well. It reflects the full capacity to change production equipment (tubing etc) in the well as well as the Xmas tree itself. This implies the use of a rig with fullbore BOP and marine riser. This means the we have to apply the same capacity systems as used during initial completion of the well. Full overhaul/workover might imply a full recompletion of the well. Using a full capacity drilling/completion rig offers the full capacity for redrilling, branch drilling and recompletion. In some cases we see the full capacity WOI system referred to as Category C intervention: heavy well intervention.

Well intervention: This term is used commonly for all vertical interventions that is done during the wells production life, i.e. after initial completion. The term is most commonly used for the lighter interventions; those implying that operations take place inside and through the Xmas tree and the tubing. These are:

Category B intervention: medium well intervention, with smaller bore riser.

Category A intervention: light well intervention – LWI, through water wireline operations.

The purpose of the interventions is to increase the recovery rate and also as required:

- Survey – mapping status-data gathering.
- Change status (ex open/close zones – smart wells)
- Repair
- Measures for production stimulation.

When the facility has a drilling package on board, or the capability to install one, the cost of these well interventions become lower than in the subsea developments, where for the same operations a dedicated type of vessel must be appointed (a semisubmersible with a day rate of 500,000 USD per day for example). Light intervention vessels are available at a lower rate but with lower capabilities (Stiff and Singelmann, 2004).

5.2.3. Reservoir uncertainty (Risk)

Although oil companies invest a lot of time and resources in the de risking of their investments (See 4.4.2) there is a substantial risk that might be the result of a limited appraisal of the discovery. The best option in this case is to have a flexible concept designed to be able to adapt to possible resizing of the production rate as well as ability to accommodate more wells or supplementary process capability. These options, of course, have a cost that must be evaluated.

5.2.4. Location characteristics

5.2.4.1 Water Depth

The main driver in offshore is the water depth at the proposed site, it influences overall cost of the development and also restricts the number of possibilities. Ronalds (Ronalds, 2005) explores in the paper "Applicability ranges for offshore oil and gas production facilities" some key features and constraints of the ten common fixed, floating and subsea facility options that include, of course, water depth and some other drivers here mentioned. For an updated survey consult Wilhoit and Chan (Willhoit and Chan, 2009)

Facility	***No direct vertical well access***				***Direct vertical well access***				
	FPSO	***Subsea***	***Semi***	***Minifloater***	***Semi***	***TLP***	***Comp tower***	***Spar***	***Jacket***
First application	*1977*	*1961*	*1979*	*1998*	*1975*	*1984*	*1984*	*1997*	*1947*
Present maxima									
Water depth (m)	*1993*	*2934*	*2414*	*1425*	*576*	*1450*	*531*	*2382*	*126*
Well slots capability	*120*	*63*	*51*	*36*	*51*	*46*	*58*	*26*	*61*
Oil production capability (MBOE/d)	*317*	*412*	*352*	*317*	*283*	*366*	*277*	*154*	*253*

Table 5.2 Production facilities statistics with data of Willhoit and Chan (Willhoit and Chan, 2009).

5.2.4.2 Environmental conditions

Related to the area of interest of this work it is undeniable that hurricanes and tropical storms are commonly present in the Gulf of Mexico usually in the second semester of the year.

However, the conditions on Mexican sites are usually milder than those presented in the northern Gulf of Mexico because the paths of the hurricanes, are often directed to the north and the shield effect that produces on the side of the Yucatan peninsula weakens the strength of the hurricanes as they pass on firm soil.
Motivated by the effects of the hurricane seasons in 2004-2005, the American Petroleum Institute (API) released a document reevaluating the metocean conditions due the impact of the hurricanes. In this guidance are proposed changes due to the observed conditions that occured since the API RP2A were last updated. The document is available on the API web site with the code:

API BULL 2INT-MET
Revision / Edition: 07 Chg: Date: 05/00/07
INTERIM GUIDANCE ON HURRICANE CONDITIONS IN THE GULF OF MEXICO

It is likely to expect this kind of phenomena to be strengthened in the future years due to possible climatic changes.

5.2.4.3. Geotechnical conditions

A careful study is needed for the installation and decommissioning, a soft soil could be as risky as an extreme tropical storm and the combined effects might be catastrophic.

5.2.5 Regional development status

In a region like U.S. Gulf of Mexico an enhanced possibility to develop small fields exists, due its extensive networks of pipelines. The distance to the facilities is a major restrictive element to consider for small to medium field developments because of flow assurance issues; due to this reason a major content of gas in the production fluids has a longer reach to be exported.

The development of hub´s in any case might create the feasibility for further developments in an area. Even in the case of ownership of different companies it is possible to establish agreements to allow the transportation of crude per a transfer fee (Stiff and Singelmann, 2004).

5.2.6. Technical development status.

Sometimes the companies face options to develop fields by using new technologies. However, operator companies, either national or international usually prefer a conservative approach to the development and use of new technologies. This adversity change when the technology become proven, but still it would be necessary to implement effective programs for technology acquisition.

5.2.7 Politics

The governmental, corporative and industrial polices usually have the same weight as the technical and economical considerations. The governments may ask for the fulfillment of tariffs of local contents, restrictions on particular development options, health, safety and environment regulations, and even recovery factors like the NPD in Norway, see 7.2.

Corporate politics will be evident in the selection of specific development options because of the perception to have lower risk than others based on previous experiences of the operator. Also for the preference of contractors companies that are viewed as more reliable, even though those companies can offer just a limited pool of options where the best concept is not necessarily included (Stiff and Singelmann, 2004).

5.2.8. Schedule

The drilling strategy might have a powerful impact on the schedule to get the first oil. A company might save a lot of time running a partial or total pre-drilling program while they are constructing the floating structures and/or the subsea systems. Pre drilling in deep water means the appointment of semisubmersibles or drilling ships that will represent a considerable cost against the option of some floaters that might have the possibility to drill from the same structure. This drilling strategy of course is part of the decisions that must be analyzed in the conceptual stage.

5.2.9. Equipment availability

The heavy lift vessels are examples of scarce but unavoidable tools for some concept of field development. Hence the appointment of them become a fact of major importance when the concept is defined.

5.2.10. Market availability

The gas is the most representative example of one product that must have a mature market to make it feasible to commit a field development. In contrast to the oil that might be stabilized and transported by tankers to the market, the gas production needs to be delivered at a constant basis to a market because the storage cost of large amounts of product is extremely costly if technically feasible.

5.2.11. Economics

Practically in all the past examples the economics is part of the debate between one options or another.

5.3 Life Cycle Cost in concept selection processes

The economical analysis for field development are essentially Life cycle cost analysis, the minimum requirements are already suggested initially for the oil and gas industry by the Norwegian Standards (Norsok).

- O-CR-002 Life cycle cost for production facility (Rev. 1, April 1996)
- O-CR-001 Life cycle cost for systems and equipment (Rev. 1, April 1996)

Those standards were withdrawn in 2001 when the series ISO 15663 were published:

- ISO 15663-1:2000 Petroleum and natural gas industries -- Life cycle costing -- Part 1: Methodology.
- ISO 15663-2:2001 Petroleum and natural gas industries -- Life-cycle costing -- Part 2: Guidance on application of methodology and calculation methods.
- ISO 15663-3:2001 Petroleum and natural gas industries -- Life-cycle costing -- Part 3: Implementation guidelines.

The use of the LCC in most of the concept studies is limited to the Capital Expenditures (CAPEX) and Operational Expenditures (OPEX). Goldsmith (Goldsmith et. al., 2000) propose a much more ample spectra to calculate LCC including the risk and the reliability costs associated with the field development options. Below the methodology proposed by Goldsmith to estimate the lifecycle cost of subsea production systems [Goldsmith et. al., Sections 2.1-2.3.3, 2000].

2.1 Introduction

The economics of deepwater developments are different from shelf activities. Deepwater is characterized by high capital expenditures with relatively low operational expenditures and high sustainable production rates - hence high costs for production interruption.

Field development profitability is a function of many income and expense factors such as capital expenditures (CAPEX), operating expenditures (OPEX), production rate, product price and the frequency of completion component failures. Component failures reduce the field total production rate and increase intervention expenditures.

Until recently it was quite common for the decision making process used to evaluate deepwater ventures to focus on optimizing the balance between potential revenue, CAPEX and OPEX according to the equation:

$$Profit = Max\ (Revenue - CAPEX - OPEX) \quad (2.1)$$

The shortcoming in this equation is that it does not take into account unscheduled and unplanned events that have the potential to destroy a facility, tarnish a company's reputation, pollute the environment, and/or shut down production for a long time. Major accidents, although highly unlikely, have the potential to put a facility out of business for 3, 6, 12 months or even render it totally useless.

When moving into deeper water, the economic penalty for delayed/lost production becomes greater. The uncertainty related to whether "unforeseen" events will occur is also increased as prototype and novel technology are introduced into an operating environment not encountered in shallow water platform design. Furthermore, subsea well system repairs and interventions also become more expensive and are associated with longer delays due to reduced availability and increased mobilization times for the required repair vessels. The alternative to a subsea system, a dry tree tieback concept provides the efficiency and the convenience of direct well access, but requires the surface host to support the weight of permanently attached production/intervention risers for which the load cost penalty and the likelihood of a riser leak increases with water depth.

The implications of disasters and business interruptions should be incorporated into business decision analyses that seek to evaluate the viability of alternative designs. These analyses introduce two more components to the economic "balance", namely, risk expenditures (RISKEX[1]) and reliability/availability/maintainability expenditures (RAMEX[2]). It takes a balanced, mature appraisal of the uncertainties and risks involved when considering front-end cost savings (CAPEX) that may have detrimental consequences on initial, intermediate and long-term revenue streams.

Inclusion of an "unforeseen" RISKEX and RAMEX element into equation (2.1) modifies the economic model to:

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[1] *RISK Expenditures (RISKEX) are defined as the costs associated with the risks of a blowout. It is derived by estimating the frequency of the event and multiplying the frequency by the estimated cost (clean-up cost, outrage cost, asset damage cost and business interruption cost) for that event.*

[2] *Reliability/Availability/Maintainability Expenditures (RAMEX) are defined as the cost associated with lost revenues and interventions due to component failures.*

Profit = Max (Revenue - CAPEX - OPEX – RISKEX - RAMEX) (2.2)

The methodology is developed to permit predictions of lifetime cost for a field development based on statistical and judgmental reliability data and assumed system parameters. It might be asked "Why not simply estimate the lifetime cost for a field development rather than estimating all these input parameters?" The answers are:

• The system is broken down to a level where some experience data is available and where it is possible to evaluate failure modes and their corresponding effect on system level.

• The quality of the input data (reliability of completion string components, sand control system failures, subsea equipment, risers, individual well production profiles, rig availability time, rig spread costs, etc.) is independently evaluated to minimize bias.

• The methodology and spreadsheet tool "model" show the sensitivity to changes in specific input data that is not readily apparent otherwise.

• This model is especially useful to determine which parameters most influence field development cost. The quality of data for these parameters can then be scrutinized to achieve the maximum practical quality. Likewise, time is not wasted by attempting to improve the quality of data that are of minor importance.

• Sensitivity analyses can determine the financial incentive for improving reliabilities of components.

2.2 System Boundaries

The systems that can be analyzed by using the proposed methodology are typical highrate, deepwater well completion systems and cover both subsea well tieback and dry tree tieback concepts. A subsea well intervention has longer rig availability and mobilization time, is more sensitive to weather conditions, and is associated with higher day rates for the repair resource. However, all these parameters are part of the input data specified by the user.

The methodology includes:

Subsea: Downhole completion components, casing, wellhead equipment, subsea production trees, flowline jumpers, tie-in sleds, flowlines and risers (up to the boarding valve), subsea control module, control jumpers, subsea distribution units, umbilical termination assemblies, umbilicals, topside controls and chemical injection points.

Dry Tree: Downhole completion components, casing, wellhead equipment, risers, tensioners/air cans, surface production tree and manifold up to the 1st stage separation isolation valve.

For both concepts the well intervention equipment (risers, BOPs, controls, etc.) necessary to install and workover the completion equipment are included.

Examples of sand control systems considered by this project are frac-packs and horizontal laterals with gravel pack.

2.3 Life Cycle Cost Calculations

The CAPEX, OPEX and RISKEX occur during different times in the field-life. The net present value of future costs is used to take the time value of money into account. The lifecycle cost is calculated by:

where $OPEX_k$, $RISKEX_k$, $RAMEX_k$ represent the OPEX, RISKEX and RAMEX in year k respectively, r is the discount rate and N is the field-life in years.

The various cost elements are defined as follows:

CAPEX: Includes material cost and costs associated with installation

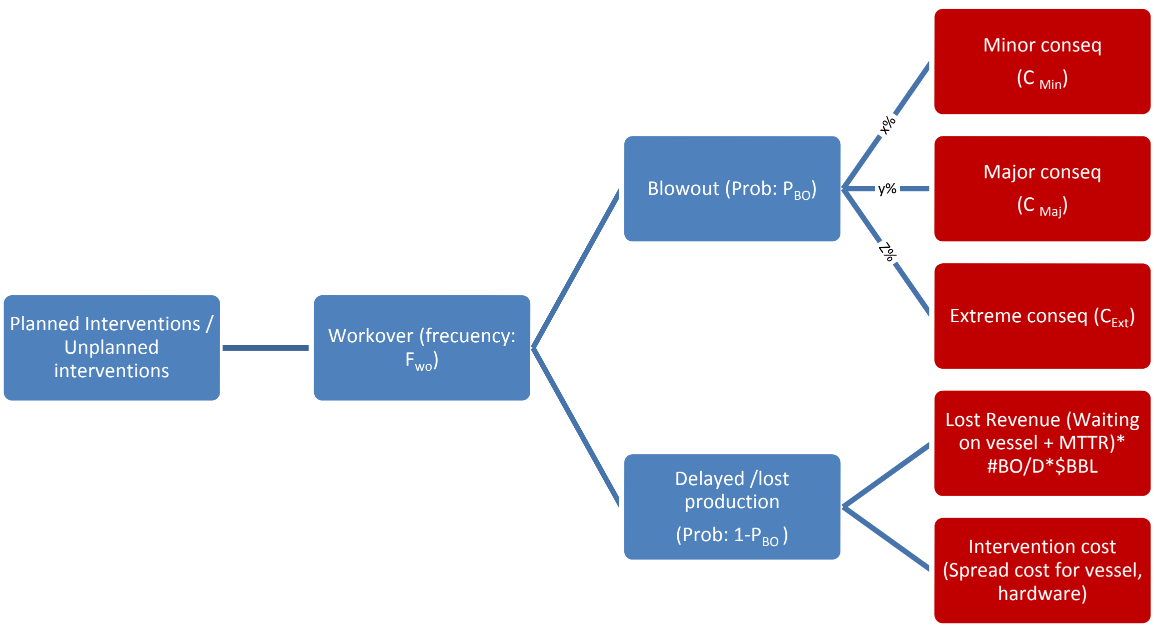
OPEX: Includes intervention costs associated with "planned" interventions, i.e. re-completions caused by depleted reservoir zones.

RISKEX: Includes risk costs associated with blowouts

RAMEX: Includes lost revenues and intervention cost associated with "unplanned" intervention, i.e. interventions caused by component failures such as sand controls system failures, tubing leaks and production tree valve failures.

The RISKEX and RAMEX element are further illustrated in figure 5.3.

The method by which these cost elements are calculated is described in the following sub-sections.



x + y+ z = 100%

Figure 5.3. RISKEX and RAMEX calculation approach adapted from figure 2.1 (Goldsmith, 2006)

2.3.1 Operating Expenditures (OPEX)

Each of the identified intervention procedures are broken into steps. The duration of each step is estimated based on a combination of historical data and expert judgment. This is further documented in Section 5. The non-discounted OPEX associated with a recompletion is estimated as:

OPEX = (Intervention Duration) x (Vessel Spread Cost)

2.3.2 Risk Expenditures (RISKEX)

The probability of failure of the well completion system is a function of the probability of failure during the various operating modes (drilling, completion, normal production, workovers and re-completions). The lifetime probability of a blowout is calculated as:

$$P(\text{BO during lifetime}) = P(\text{drilling}) + P(\text{initial compl.}) + P(\text{prod}) + \sum P(WO) + \sum P(re-compl.)$$

The cost of a blowout depends on the size of the release ("Limited, "Major" or "Extreme"). The Risk Cost (RC) associated with a certain activity (j) was calculated as:

$$RC(j) = \sum_{i \in \{\text{limited, major, extreme}\}} Probi\,(activity\ j) \cdot Ci$$

where Probi(activity j) is the probability of a blowout of size i during activity j, and Ci is the cost of leak of size, i ∈{limited, major, extreme}. This is further described in Section 7.

2.3.3 Reliability, Availability and Maintainability Expenditures (RAMEX)

The RAMEX is divided into two:
- *Cost associated with lost revenues*
- *Cost associated with interventions*

For the model developed, the consequence for the production in a given year depends on the following:

- *The production rate at the time the failure occurred*
- *Lost capacity while waiting on repair resources*
- *Availability time for the repair resources*
- *Mobilization time for the repair resources*
- *Active repair time*

An example is given below:

Example 1:

- *Failure: Workover (WO) required to repair the failure in year*
- *Resource: Rig*
- *Production loss: 50% while waiting on rig (90 days) + 30 days for WO.*
- *Production rate: 10,000 BOPD in year 3.*
- *Lost volume:*

The financial consequence of a well failure will in addition to the factors discussed above depend on:
- *Failure time*
- *Oil operating margin in year produced ($/BBL)*
- *Spread cost for intervention vessel ($/day)*

An example is given below:

Example 2:

- *WO required to repair the failure*
- *Resource: Rig*
- *Failure time: year 3*
- *Production loss: 50% while waiting on rig (90 days) + 30 days for WO*

• *Production rate: 10,000 BOPD in year 3*
• *Spread cost for Rig: $100,000 per day*
• *Oil operating margin in year produced: $10/BBL*
• *Discount rate: 15%*
• *Financial Consequence (FC):*
FC = Lost Revenues + Intervention Cost

FC = 0.5 90days 1* 30days)* 10,000BOPD*($10 per BO/(1+0.15)*^{3}*)+ ($100,000/d * 30days)/ (1 0.15) ≈ 4.9MM + 2MM = 6.9MM*

6. Production concepts for offshore field development in deepwater

Field development in deep water has a number of generic concepts associated. The production technology concepts can be divided in two branches, either if the solution employs wet or dry tree. As mentioned in the introduction the dry tree has been associated in most of cases with a low capital expenditure but a lower recovery factor per well and flexibility to use new or already emplaced offshore structures. On the other hand, the dry tree solutions are related to higher capital expenditure, more complex operation and maintenance as well as possibility to get an improved recovery factor. See figure 6.1.

Table 6.1. shows examples of fields that have employed the generic concepts as illustrated in figure 6.1. Annex C in this work give details on the particular characteristics of each one of the field development concepts listed in table 6.1.

For another reference it is recommended to review the survey of the records in deep water and its concept selection updated yearly and provided by the company Mustang Engineering, see http://www.offshore-mag.com/index/maps-posters.html and "2009 Deepwater solutions & records for concept selection" (Wilhoit and Supan, 2009).

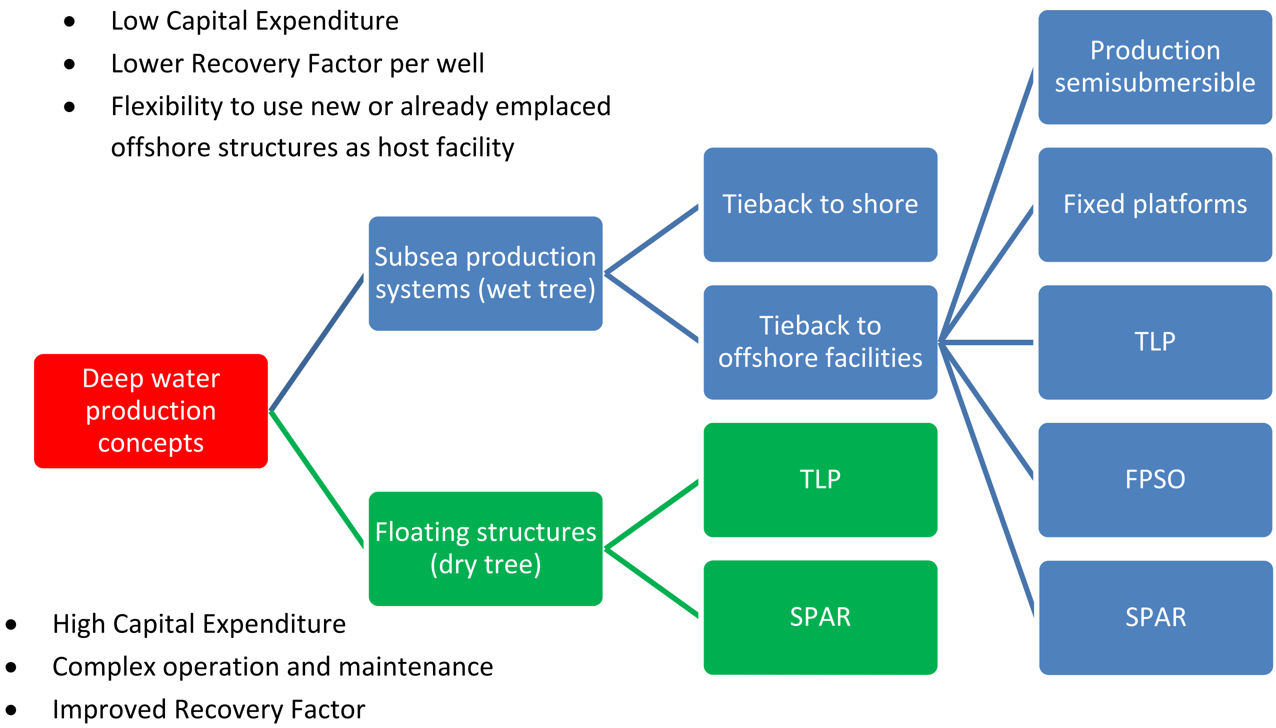


Figure 6.1 Generic classifications of technological concept solutions for deep water

Generic Concept	Field Development Example	Location
Subsea tieback to shore	*Ormen Lange*	*Norway.*
Subsea tieback to existing platform	*Canyon Express*	*Gulf of Mexico U.S.A.*
Subsea tieback to semisubmersible	*Thunder Horse*	*Gulf of Mexico U.S.A.*
Subsea tieback to FPSO	*Pazflor*	*Angola, West Africa.*
Subsea tieback to SPAR	*Boomvang*	*Gulf of Mexico, U.S.A.*
Subsea tieback to TLP	*Auger*	*Gulf of Mexico, U.S.A.*
Dry tree SPAR	*Mad Dog Field*	*Gulf of Mexico, U.S.A.*
Dry tree TLP	*Matterhorn Field*	*Gulf of Mexico, U.S.A*

Table 6.1 Examples of fields employing generic concepts of field development for deep water, see Annex C for details of the field developments.

6.1 Technological assessment of the subsea production systems (wet tree solutions)

An assessment of the Subsea Production and well systems was developed for the MMS in 2003 and lead by Scott (Scott et. al., 2004). Scott identified seven issues that are accounted as some of the most important to deal with when a subsea production system is selected:

1. *Subsea Processing*,
2. *Flow Assurance*,
3. *Well intervention*,
4. *Long term well monitoring*,
5. *Factors affecting ultimate recovery*,
6. *Safety and Environmental concerns*,
7. *Technology development and transfer.*
8. *Reliability of production and control of subsea systems.*
9. *A flexible concept. Tieback to floating or fixed offshore installations or tie back to shore.*
10. *Marine Operations.* [3]

6.1.1. Subsea Processing

The expected primary recovery factor per well, using a subsea production system are historically lower than for production systems based on a fixed or floating platforms. Subsea processing is typically mentioned to help to increase the recovery extending the productive life of the reservoir.

FMC is one of the most important suppliers of the technology and services related to this issue. FMC explains (FMC, 2009) that the subsea processing might move some of the equipment that is installed at the top of the platform to the seabed. This represents a potential cost saving instrument considering that the weight of the equipment at the top-sides is a major driver of capital costs on floating structures, see “Empirical cost models for TLP´s and Spars” (Jablanowski, 2008).

For example, the flowlines and the topsides might increase their efficiency by having subsea separation and local reinjection of produced water and/or gas to the reservoir or to any other

[3] *Points 8 and 9 and 10 were not listed by Scott but are important as previously enounced by the opinion of this author.*

disposal zone. The subsea gas/liquid separation and the liquid boosting can improve the rate of production when used in low energy reservoirs. (FMC, 2009).

Subsea processing can be configured in a outnumbered way of configurations according to the needs of the field. A classification for the configuration of subsea processing is provided by Scott in table 6.2. He signals that at the year 2004, multiphase pumping was the only commercial solution available.

For a dry gas reservoir the normal expectancy is that the reservoir pressure will drop over the life of the field and it would be necessary at some point introduce a ***Gas boosting system*** that could be either a topside system or a state of the art subsea gas compression system. Statoil is one of the operator companies with projects on development for this particular technology for its field "Ormen Lange".

Bass (Bass, 2006) points that subsea gas compression is an alternative to consider instead of the use of onshore compression technologies when it is used for short range distances and a competitor concept for the floating compression systems for longer offsets. He predicts that the subsea compression is likely to be chosen when there is a case of a large field with a moderate long distance from the reservoir to the existing infrastructure. Also in the case of a short distance, the subsea compression might be a more effective alternative than the topside compression if there is liquid holdup in the system.

Classification	***Characteristic***	***Equipment***	***Water Disposal***	***Sand Disposal***
Type 1	*Multiphase Mixture is Handled Directly*	*Multiphase Pump*	*None...Pumped with Other Produced Fluids*	*None…Pumped with Other Produced Fluids*
Type 2	*Partial Separation of the Production Stream*	*Separator and Multiphase Pump; possible use of Wet-Gas Compressor*	*Possible Re-Injection of partial water stream, i.e. "free" water*	*None..Pumped with Liquid Stream*
Type 3	*Complete Separation of the Production Stream at Subsea Conditions*	*Separator and Scrubber Stages w/ Single or Multiphase Pump; possible use of Gas Compressor*	*Re-Injection/Disposal of Majority of Water Stream*	*Must be addressed*
Type 4	*Export Pipeline Quality Oil & Gas*	*Multi-Stage Separator and Fluid Treatment; single-phase pumps and compressors*	*Re-Injection/Disposal of Entire Water Stream*	*Must be addressed*

Table 6.2 Classification of Subsea Processing Systems after Scott (Scott et. al., 2004)

Bass (Bass, 2006) also states that the Subsea gas dewpointing/dehydration (subsea separation) may be useful in several ways related to a gas field, including:

- To reduce the flow assurance costs by eliminating or minimizing the need for continuous hydrate inhibition.
- To reduce pipeline construction costs by removing water and allowing the use of cheaper carbon steel rather than a corrosion resistant alloy.

- To process close to sales quality or even reach sales quality that also addresses flow assurance needs.

6.1.2 Flow Assurance

Scott (Scott et. al., 2004) refers that flow assurance is the term related to the study of the complex phenomena involving the transportation of produced fluids trough the producing and transportation flow lines.

The produced fluids are a combination of hydrocarbon gases, crude oil/condensate and water together with hydrocarbon solids such as, hydrates, scale, wax, paraffin, asfaltenes, and other solids and gases such as sand, CO_2, H_2S.

In order to get satisfactory recoveries rates it is necessary to identify the potential and quantify the magnitude of the produced fluid to be managed in the system. The flexibility of the system is required because different parameters of the produced fluid (pressures, temperatures, production fractions) involved in the design of the system are expected to change along the life of the project, and also that mentioned flexibility will be necessary to control during the transient periods of production (shutdown and restart).

The design of a flow assurance program for a field needs to consider the requirements for all parts of the system for the entire production life. Some of those considerations are, production profiles, chemical injection & storage, produced fluids properties, host facility (pigging, fluid storage, tubulars (tubing & flowline ID's) & handling, intervention capability, Insulation (tubing, wellhead, etc.), capital and operating costs.

Flow assurance also depends to a large extent if the development is for an oil or a gas reservoir. Flow assurance is much more challenging in oil than in gas producers, both of them will have corrosion and hydrate issues but in oil's the wax, asphaltenes, scale and emulsion expectations should also be considered in the design.

The gas systems can be managed with a flow assurance strategy driven by the injection of hydrate inhibitors chemicals such as MEG (monoethylene glycol), thermal isolation is usually not as demanding as in oil production but is an important factor in low temperature environments for example in the developments on the Norwegian continental shelf (Ball, 2006).

6.1.3. Well Intervention

The cost of well interventions in subsea production systems is considerable higher compared to fixed or floating platforms with work over systems since they require the mobilization of MODU's (Mobil offshore drilling units) or drilling ships for each well location.
This issue is the main reason to select pressure boosting at the seafloor rather than artificial lift in the wellbore and has also motivated the development of Intelligent Well Technology (IWT) to increase the operative flexibility as an alternative to well intervention (Scott et. al., 2004).

6.1.4. Long term well monitoring

Scott (Scott et. al., 2004) refers to this long term well monitoring as Intelligent Well Technology (IWT), which compresses two main concepts:

1. Monitoring of measurements of down hole flow and/or reservoir conditions. The measurement is performed by electronic devices or fiber optics, parameters currently functional today are pressure, temperature and flow rate.
2. Remotely control zones through on/off control or choking. The control is achieved by electric, hydraulic or electro-hydraulic (hybrid) actuation of a valve or sleeve. Commercially available.

Control and monitoring are being accepted slowly due to concerns about complexity, reliability and cost. It does not matter how sophisticated is the installation when the system fails and workover is required.

An additional motivation for further development of IWT in the Gulf of Mexico is that in this region there has been registered a large occurrence of Sustained Casing Pressure (SCP) in producing wells. Citing Wojtanowicz (Wojtanowicz et. al., 2001) *"The Minerals Management Service (MMS) defines SCP as a pressure measurable at the casinghead of a casing annulus that rebuilds when bled down and that is not due solely to temperature fluctuations and is not a pressure that has been deliberately applied."*(Wojtanowicz et. al, P.p. 4, 2001).

SCP is identified as a cause of leakages that are dangerous for personnel near well heads located on topsides of platforms and for the environment in subsea facilities. Currently is not possible for a monitor to access the outer with a subsea wellhead a necessary improvement is to find a way to develop the ability to monitor and remediate SCP.

6.1.5. Factors affecting ultimate recovery

Scott (Scott et. al., 2004) also found that the multiphase flowlines that make possible the development of long subsea tiebacks reduce the ultimate recoveries. According to his work since the subsea wells operate with a continual high backpressure the energy that could be used to deplete more efficiently the reservoir is lost in the flow line and in the choke valves of the system.

6.1.6. Risk, safety and environmental concerns

Although each facility is different due its design, functions and operation conditions, the remoteness of the subsea systems location reduces the risks to the personnel but still, the environment risks remain for subsea production systems. It is recommended to be as strict as reasonably possible with the safety system requirements defined for subsea production systems. (Brandt, 2004).

6.1.7. Technology development and transfer.

As mentioned before, just some of the conceptually developed subsea production systems have been implemented commercially. Operator companies either national or international usually prefer a more conservative approach on the development of new technologies. This, however, is going to change when the technology become proven, but the implementation of effective programs of technology acquisition will still be necessary.

6.1.8. Reliability of production and control of subsea systems

To obtain cost effective and reliable production and control systems are also challenges of major importance, this aspect is managed in general by redundancy in design and applying reliability centered design and maintenance philosophies.

The reliability also implies a lot of work on the organization of the operators and contracting companies that are part of the subsea projects. The high amount of uncertainty due to restrictions in time and budgeting are a cause of increased risk in the design, construction, installation and operation of the systems.

On the knowledge of the importance of human and organizational factors, API has released recently a "Recommended Practice for Subsea Production System Reliability and Technical Risk Management" API 17 N (API, 2009) This document has as purpose that the users of that RP gain a better understanding of how to manage an appropriate level of reliability throughout the life cycle of their subsea projects.

The whole industry demand that the developers of subsea systems:

> *— recognize the trade off between up front reliability and engineering effort vs. operational maintenance effort,*
> *— provide better assurance of future performance of subsea systems,*
> *— effectively manage the risks from using novel equipment and standard equipment in novel applications,*
> *— schedule projects with sufficient time to address all the technical risks. [API, P.p. 1, 2009]*

On the other hand, Scott (Scott et. al., 2004) mention in their work that most of the designs have focused on increasing component reliability and extending the mean time to failure to address intervention concerns. Remarkably the redundant systems were not found to be in widespread use due to the increased capital costs these systems incurred.

6.1.9. A flexible concept. Tieback to floating or fixed offshore installations or tie back to shore.

The main benefit of the subsea production systems is that they are recognized to diminish the capital cost of the new developments since the construction expenditures of an entire new-brand offshore platform are avoided.

The subsea production systems might be quite different in form and size (ISO-13628-1,2005), they can be designed as:

- A single satellite well with a flowline linked to offshore platforms, floating or onshore processing facilities.
- Several wells located in one or more templates.
- Wells or set of wells in templates clustered around a manifold with or without subsea processing connected to facilities onshore or offshore.

The concept of a subsea production system to shore has been used already in several developments around the world i.e. Snøhvit, Ormen Lange, Patricia Baleen, BHPBP Minerva, and ONGC G-1.

As example of deep water tiebacks to fixed platforms just as example is possible to mention, the Devils Creek, Pompano, Bullwinkle and Canyon Express, all of them located in U.S. Gulf of Mexico and acting as a host for subsea tiebacks.

The subsea production systems are most often selection when a semisubmersible or a FPSO is employed, however there are recent developments that have used topside trees using a semisubmersible this are related to mild environment as West Africa. (Often, 2000).

Odland summarizes the characteristics of the semisubmersible production units (Odland, 2008):

- Large number of risers, these facilities can handle a large number of slots for production and injection risers what made them suitable for larges and multifield tie back field developments.
- Good motion characteristics, due its proven dynamic characteristic response it is possible to have a high pay load on its top sides.
- New built or conversion, it is possible to use drilling rig hulls that are still usable and otherwise would face decommissioning.
- Not offer storage capability.
- Have a spread mooring systems.

Lim and Ronalds (Lim and Ronalds, 2000) presented an historical and prospective review on the Semi submersible production systems and FPSO's. In their view the floating production systems were developed initially (1970's) for their advantages in deep water and reservoirs of short production life, at the beginning the semisubmersibles were common selected against FPSO's because the concept offered:

- Drilling and workover capability for wells located just below the semi.
- Good motion response (stability).
- Availability of drilling rigs for conversion to production semis.
- It was possible to use rigid risers before the technology of flexible risers appeared.

Later, at the end of 1980s and beginning of 1990 the semisubmersibles were recognized for their capabilities to operate in the deep water.

At the beginning of the 2000's the FPSO are more numerous than the semisubmersibles, some reasons for this are:

- Advantages of the shape of the hull of the FPSO's, more stability and maniobrability.
- Improvements in turret technology.
- Preferable when used for small and remote oil fields.

The production semisubmersibles are also popular in case of gas reservoirs and compete with the new designs of SPAR's and TLP's when there is a large reservoir to exploit and a suitable infrastructure of pipelines is available. Its evolution has been remarkable, through developing new types of risers, hulls forms and methods of construction.

Odland (Odland, 2008) also states that in deep water the principal challenge of the semisubmersible is related to the hydrodynamic effects that induce loss of position and slamming over the structure and the riser systems. A related issue with the deep water is its weight gain due both the mooring and the riser systems.

6.1.10 Marine operations.

Regarding marine technology and operations, although important is not considered to be a challenge for the subsea production systems. After its installation the subsea facilities are considerable less exposed to environmental loads than the fixed and floating offshore units.

However as stated in the Standard ISO ISO-13628-1:2005 *"All applicable loads that can affect the subsea production system during all relevant phases, such as fabrication, storing, testing, transportation, installation, drilling/completion, operation and removal, should be defined and form the basis for the design"* [ISO-13628-1,2005].

Since marine operations represent an important part of the costs of installation a summary of marine operations for both, subsea production systems as well as floating structures, is presented in Annex D.

6.2 Technological assessment of floating structures (dry tree solutions)

Any floating structure has as a purpose to extend the range of operation offshore by the provision of space to locate machinery and supplies for the exploitationn of oil and gas fields. The technical solutions are not so different from the ones that are installed onshore but the reduced weight and space capability is a major restriction for the equipment.

This topic is extensive and it is suggested for the reader to consider as a reference the ISO standard IS0 19904-1, Floating offshore structures Part 1: Monohulls, semi-submersibles and spars (ISO, 2006) which have been developed for this topic.

> *ISO 19904-1:2006 provides requirements and guidance for the structural design and/or assessment of floating offshore platforms used by the petroleum and natural gas industries to support production, storage and/or offloading, drilling and production, production, storage and offloading, and drilling, production, storage and offloading. [ISO, Abstract, 2006]*

Whilst the ISO standard IS0 19904-2, Floating offshore structures Part 2: Tension Leg Platform is still in discussion and development process, "API RP 2T- Recommended Practice for Planning, Designing, and Constructing Tension Leg Platforms" is the suggested reference to know more about TLP´s.

This Recommended Practice is a guide to the designer in organizing an efficient approach to the design of a *Tension Leg Platform (TLP). Emphasis is placed on participation of all engineering disciplines during each stage of planning, development, design, construction, and installation. Iteration of design through the design spiral…. [ANSI/API, Scope, 1997].*

6.2.1 State of the art of developed fields using SPAR.

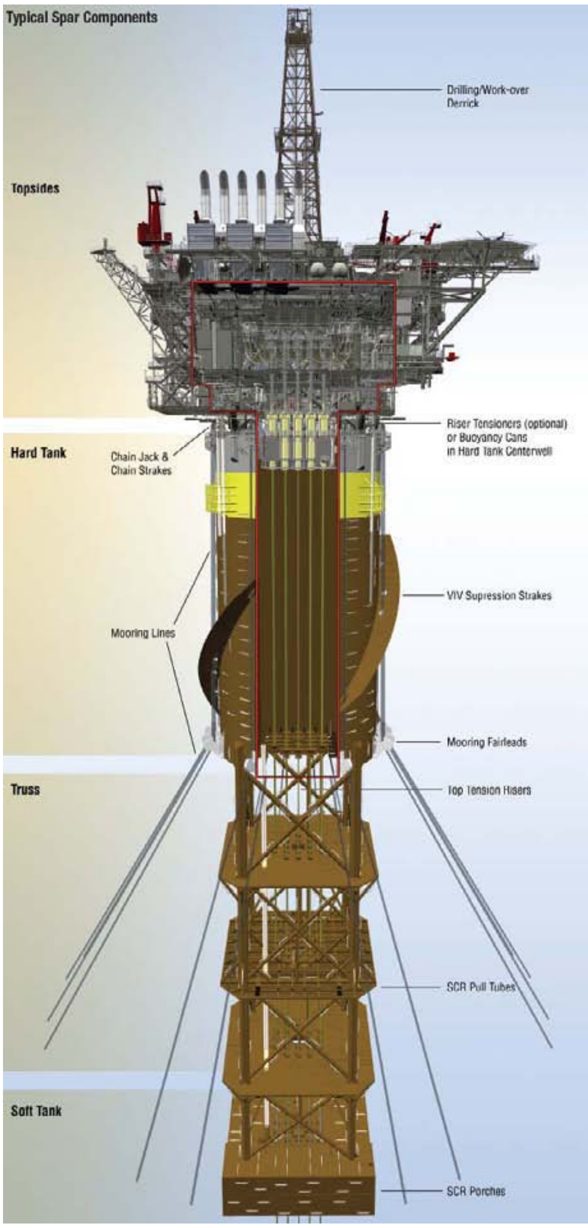


Figure 6.2. Typical Spar Components [Wilhoit, 2009]

The SPAR system is currently in use at seventeen locations (those developments are Neptune, Medusa, Genesis, Gunnison, Front Runner, Boomvang, Nansen, Mirage, Tahiti, Holstein, Kikeh, Mad Dog, Constitution, Red Hawk, Horn Mountain, Devils Tower and Perdido.) 16 of them in the GOM and 1 more in Malaysia. Although the design of each SPAR is different it is possible to say that there are broadly three different versions of Spar, classic version, truss version and cell version, (Sablok, 2009).

The Record in drilling and completion in deep water is held by Shell Oil Co. using the SPAR "Perdido". The SPAR is moored in ~2,380m of water and will be the world's deepest direct vertical access SPAR in operation. The SPAR will act as a hub for, and enable development of, three fields – Great White,Tobago, and Silvertip – and it will gather process and export production within a 48km radius. Tobago, in ~2,925m of water, will be the world's deepest subsea completion (Offshore Magazine, 2008).

6.2.2 Description of the SPAR floating system.

A SPAR is a floating system with deep-draft floating caisson that produces low motion response characteristics compared to other floating concepts.

For this document it is relevant to introduce the configuration of the Truss Spar (See figure 6.2). In this version the hull can be divided in three sections:

1) The cylindrical hard tank upper section provides buoyancy to support topsides, hull, mooring and risers. This section includes both variable ballast and void components.

2) The truss section has heave plates. The truss helps to reduce the overall hull weight, environmental loads and heave motion. The reduced hydrodynamic loads and motions also results in savings in the mooring system and facilitate the building and transportation of the hull.

3) The soft tank is also known as "keel" contains the fixed ballast and is divided in different compartments to control the buoyancy during transport. It also acts as a natural hang-off location for export pipelines and flow lines since the environmental influences from waves and currents and associated responses are less pronounced as we go deeper in the water.

6.2.3. Benefits and challenges of the SPAR's concept.

The low motion characteristics make the SPAR a structure suitable to accommodate a large diversity of combinations of production systems. Sablok and Barras (2009) announce the benefits of this hull type has for the field development:

1. The SPAR is a floating structure viable and technologically mature for application in a large range of water depths and environments.

2. Provides high hydrodynamic stability which make possible to install export risers of large diameter to connect with pipelines and in this way develop gas fields easily.

3. The high stability also allows to accommodate large and flexible options for drilling and production equipment:
    - Dry trees-subsea trees
    - Subsea production systems
    - Direct vertical access
    - Drilling from the platform, MODU, tender assistance.
    - Export risers systems
    - Disconnectable moorings and risers.
    - Sour fluids treatment.

4. They also can be designed to allow major local content. Although the adjudication of these projects must follow technical and economical evaluations there is considerable options for constructors in the Region of Gulf of México (TECHNIP) and even some of them have their construction yards installed in Mexico (FLOATEC LLC).

5. Diminish dependence of lifting equipment that could result in high cost and be scarcely available using its hull as a basis to install cranes to perform the installation of the system modules over the SPAR deck.

6. In the Gulf of Mexico region there is also considerable availability of large lifting vessels that can manage the transport and installation of SPARS.

Challenges:

The main challenge to consider is the massive structure of the SPAR´s. This massive structure can be installed as one single piece after relatively complex marine operations, see Annex D.

It is also important to consider the cost of the steel; it is suggested to make careful arrangements to ensure that the project could not be jeopardized by instability in the price of the steel along the construction process.

6.2.1 State of the art of developed fields using TLP´s.

The TLP system has been employed and planned as concept in twenty five field developments up to 2010; table 6.3 summarize the list of those field developments.

Notable facts are:

- The Hutton TLP in UK, has already been retired
- The Typhoon TLP in US GOM was converted to artificial reef after the damages caused by the hurricanes Katrina and Rita.
- World's larger TLP is Heidrun in Norway
- World´s deepest installed TLP is Magnolia in US GOM at 1425 m water depth. (Willhoit and Supan, 2010)

6.2.4. Description of the concept of the TLP´s systems.

Regg (Regg et. al., 2000) did a summary of the deepwater concepts for the MMS in 2000. bBelow a part of their work is reproduced taking advantage of its clear description of the TLP. See figure 6.3 for a visualization of a generic concept.

> *A Tension Leg Platform (TLP) is a buoyant platform held in place by a mooring system…*
>
> *The TLP's are similar to conventional fixed platforms except that the platform is maintained on location through the use of moorings held in tension by the buoyancy of the hull. The mooring system is a set of tension legs or tendons attached to the platform and connected to a template or foundation on the seafloor. The template is held in place by piles driven into the seafloor. This method dampens the vertical motions of the platform, but allows for horizontal movements. The topside facilities (processing facilities, pipelines, and surface trees) of the TLP and most of the daily operations are the same as for a conventional platform…(see figure 6.4).*

	FACILITY INDUSTRY NAME	General Location	Water Depth (M)	STATUS	TLP/TLWP (Type)	Operator/ Partner 1
1	HUTTON	UK	147	RETIRED	6 Column Conventional TLP	ConocoPhillips
2	JOLLIET	US - GOM	536	PRODUCING	4 Column Conventional TLWP	MC Offshore Petroleum
3	SNORRE A	NORWAY	335	PRODUCING	4 Column Conventional TLP	Statoil
4	AUGER	US - GOM	873	PRODUCING	4 Column Conventional TLP	Shell
5	HEIDRUN	NORWAY	345	PRODUCING	4 Column Conventional TLP	Statoil
6	MARS	US - GOM	894	PRODUCING	4 Column Conventional TLP	Shell
7	RAM/POWELL	US - GOM	980	PRODUCING	4 Column Conventional TLP	Shell
8	MORPETH	US - GOM	518	PRODUCING	1 Column New Generation TLP	Eni
9	URSA	US - GOM	1,159	PRODUCING	4 Column Conventional TLP	Shell
10	ALLEGHENY	US - GOM	1,009	PRODUCING	1 Column New Generation TLP	Eni
11	MARLIN	US - GOM	987	PRODUCING	4 Column Conventional TLP	BP
12	TYPHOON	US - GOM	639	Note[4]	1 Column New Generation TLP	Chevron
13	BRUTUS	US - GOM	910	PRODUCING	4 Column Conventional TLP	Shell
14	PRINCE	US - GOM	454	PRODUCING	4 Column New Generation TLP	Palm Energy Offshore
15	WEST SENO A	INDONESIA	1,021	PRODUCING	4 Column New Generation TLWP	Chevron
16	MATTERHORN	US – GOM	859	PRODUCING	1 Column New Generation TLP	Total
17	MARCO POLO	US - GOM	1,311	PRODUCING	4 Column New Generation TLP	Anadarko
18	KIZOMBA A	ANGOLA	1,178	PRODUCING	4 Column New Generation ETLP	ExxonMobil
19	MAGNOLIA	US - GOM	1,425	PRODUCING	4 Column New Generation ETLP	ConocoPhillips
20	KIZOMBA B	ANGOLA	1,178	PRODUCING	4 Column New Generation ETLP	ExxonMobil
21	OVENG	EQUATORI AL GUINEA	271	PRODUCING	4 Column New Generation TLWP	Amerada Hess
22	OKUME/EBANO	EQUATORI AL GUINEA	503	PRODUCING	4 Column New Generation TLWP	Amerada Hess
23	NEPTUNE	US - GOM	1,280	PRODUCING	1 Column New Generation TLP	BHP
24	SHENZI	US - GOM	1,333	PRODUCING	4 Column New Generation TLP	BHP
25	PAPA TERRA P61	BRAZIL - CAMPOS BASIN	1,180			Petrobras

Table 6.3 List of the field developments using the TLP´s concept (Willhoit and Supan, 2010)

[4] *Damaged by the hurricanes RITA and Katrina currently converted into artificial reef.*

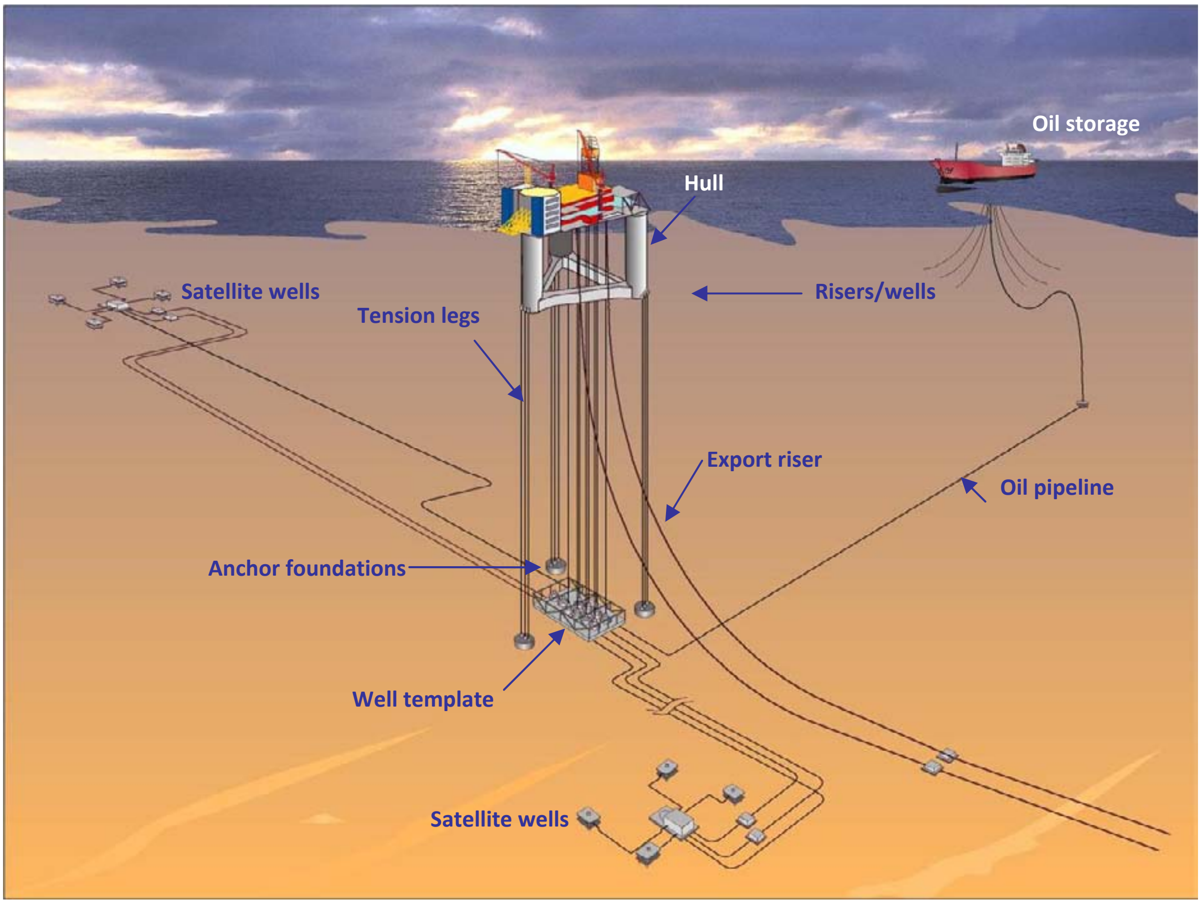


Figure 6.3. A TLP concept illustration figure from Offshore Field Development by Odland [Odland, P.p. 5 Mod. 5, 2008]

TECHNICAL DESCRIPTIONS

Foundation. *The foundation is the link between the seafloor and the TLP. Most foundations are templates laid on the seafloor, then secured by concrete or steel piles driven into the seafloor by use of a hydraulic hammer, but other designs can be used such as a gravity foundation. The foundations are built onshore and towed to the site. As many as 16 concrete piles with dimensions of 100 ft in diameter and 400 ft long are used (one for each tendon).*

Hull. *The hull is a buoyant structure that supports the deck section of the platform and its drilling and production equipment. A typical hull has four air-filled columns supported by pontoons, similar to a semisubmersible drilling vessel. The deck for the surface facilities rests on the hull. The buoyancy of the hull exceeds the weight of the platform, requiring taut moorings or "tension legs" to secure the structure to the seafloor. The columns in the hull range up to 100 ft in diameter and up to 360 ft in height; the overall hull measurements will depend on the size of the columns and the size of the platform.*

Modules. *…Modules are units that make up the surface facilities on the deck section of the platform. Early in TLP development, industry discovered that it is cost effective to build the surface facility in separate units (modules), assemble them at shallow inshore location, and then tow them to the site. The modules that are part of a typical TLP include the wellbay, power, process, quarters, and drilling; they are secured to the deck, which is attached to the hull. The typical surface facility will be 65,000 sq ft. The living quarters house up to 100 people, depending on the type and scope of activity being performed. Process capacity ranges up to*

150,000 BPD oil and 400 MMscfd gas. A typical drilling rig located on a larger TLP would have a 1.5 million-pound pull derrick, a 2,000-hp top-drive derrick, and three 2,200-hp pumps.

Template. *A template provides a frame on the seafloor in which to insert either conductors or piles. Not all TLP's use templates; if used, they are typically the first equipment installed at the site. There are several types of templates that may be used in conjunction with a TLP to support drilling foundation integrity, or the integration of the two. Drilling templates provide a guide for locating and drilling wells; they may also be a base for the tie-in of flowlines from satellite wells or for export pipelines and their risers. Foundation templates may be one single piece or separate pieces for each corner. The foundation piles are driven through the foundation template. An integrated template is a single piece that contains all drilling support, anchors the tendons, and locates and guides the foundation piles. Separate templates allow each part to be installed individually. They also use smaller pieces that weigh less and are easier to install. The drilling template can be installed and drilling can begin while the foundation template is being designed and built.*

Tension Legs (tendons). *Tension legs are tubulars that secure the hull to the foundation; this is the mooring system for the TLP. Tendons are typically steel tubes with dimensions of 2-3 ft in diameter with up to 3 inches of wall thickness, the length depending on water depth. A typical TLP would be installed with as many as 16 tendons.*

Production Risers. *A production riser conveys produced fluids from the well to the TLP surface production facilities. An example riser system for a TLP could be either a single-bore or dual-bore (concentric pipe) arrangement. The dual-bore riser would consist of a 21-inch, low pressure (e.g., 3,000 psi) marine riser that serves as an environmental barrier, and an 11 ¾-inch inner pipe (casing) that is rated for high pressures (e.g., 10,000 psi) [Regg, P.p. 28-30, 2000].*

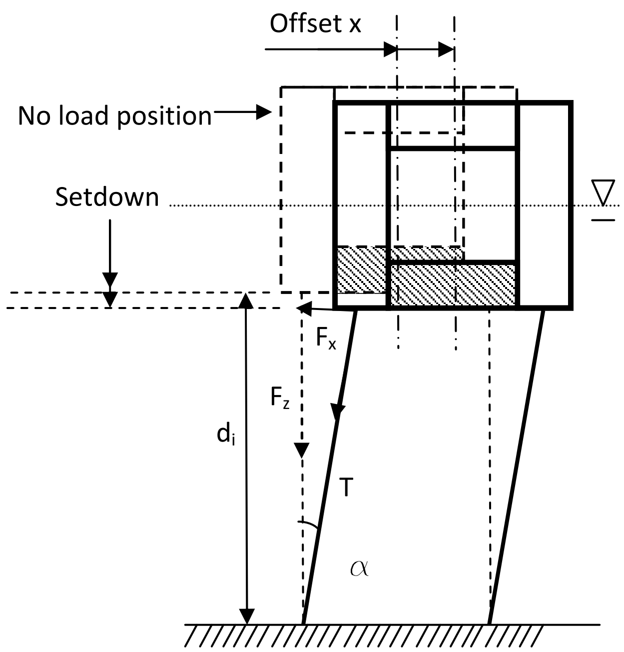


Figure 6.4. TLP in offset. When a TLP is offset by a distance x, the tendons are supposed to maintain the length d_i, and consequently the tension T. This effect will cause the TLP to keep its position.

The concept of a lighter TLP known as "mini TLP" or monocolumn is also a popular concept to develop small fields. An analysis of the concept was made by Kibbee and Snell (Kibbee and Snell, 2002), below their conclusions:

This section draws conclusions from project experience and future plans for expanding the capabilities of mono-column TLP's.

1. The successful installation and operation of SeaStar TLP's in the Morpeth, Allegheny, and Typhoon fields demonstrates that tension-leg moorings provide a reliable, cost-effective, and compact means for providing safe and stable real estate in deep water, regardless of the operator's choice of completion type (i.e., wet-tree or dry-tree). The tension-leg mooring makes it possible for smaller, less expensive hulls to be stable with favorable motion characteristics. The elimination of vertical motion not only makes dry-trees feasible, but it also expands SCR applicability, simplifies production operations, and increases personnel comfort and safety.

2. The mono-column hull has proven its versatility in all project phases:

- *Design: Mono-column hull sizes continue to increase to support increasing payloads. Between standard designs, it is possible to increase payload capacity by adding a column extension, thereby avoiding extensive hull structural redesign.*

- *Fabrication: SeaStar's modular nature allows it to be efficiently built in relatively small fabrication yards, thereby increasing competition.*

- *Installation: The monocolumn hull can be wet-towed or dry-towed. Smaller hulls, like Morpeth, Allegheny, and Typhoon can be lifted and installed much like a vertically lifted jacket. Larger hulls, like Matterhorn, can be wettowed. Major innovations are underway to reduce dependence on derrick barges.*

- *Operations: There are no holes below the waterline in a SeaStar hull, eliminating the possibility of accidental flooding due to pilot error.*

3. Like the mono-column fixed base platform, the monocolumn TLP will continue to evolve based on field experience and new requirements. The standardized nature of the monocolumn TLP product avoids the inefficiency of starting with "a blank sheet of paper" on each project, while still providing the benefit of product-focused lessons learned and execution systems. Atlantia's continuous involvement in platform performance monitoring provides a wealth of knowledge that can be used to validate design tools and improve design details. [Kibbee et. al. P.p. 4-5, 2002].

6.2.5. Benefits and challenges for the TLP concept.

Odland made a summary of the characteristics of the TLP concept during his class at the University of Stavanger [Odland, 2008]. He stated that the TLP concept is well-known, but needs a careful design of its hull and mooring configuration. It has a complex dynamic behavior but is suitable for deep water. The wells are located over the platform, which increase the capability for increased oil recovery. A challenge to manage is also the, top-tensioned (exposed) rigid risers.

Its installation and decommissioning presuppose comprehensive and complex marine operations, however, it is possible to do the installation of the topsides at shore. The concept is not suitable for oil storage. Last but not least, subject of main concern is the action of the Hurricanes in the Gulf of Mexico, the recent effects of Katrina, Lili, Ivan, etc. allowed research on the effects of the environmental loads on floating structures including the TLP.