Generic Development Concept and Costing for Marginal Field

By

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CERTIFICATION OF APPROVAL

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CERTIFICATION OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that the original work is my own except as specified in the references and acknowledgements, and that the original work contained herein have not been undertaken or done by unspecified sources or persons.

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ABSTRACT

The objectives of this study is to identify the latest approaches and technical advances associated with development of marginal offshore field and the innovations used to reduce overall field development cost. Also to develop a costing basis to evaluate quick estimation of development cost of a marginal field.

Increasing oil demand pushes oil companies to find concepts, which considerably reduce the costs of marginal field developments and consequently make these developments economically feasible.

The methodology adopted for this study is literature review. Review and analysis of actual marginal field development concepts, novel facilities, and criteria used for options selection and development strategies around the world.

A Generic development concept of marginal offshore field development were reviewed in order to identify the suitable alternative options, project management strategies and innovative technology that can be used for conceptual development phase for marginal prospects. A definition and understanding of marginal fields was established, drilling development approach conventional and innovative methods were identified, and also conventional and novel facilities development concepts were reviewed. The development basic cost estimation method is carried out. The findings showed that factors such as the reserve, environmental and regulations conditions, market conditions, field development cost and proximity to host existing process platform determine the commercial viability of marginal prospects. The success of such prospects was found to be dependent on development strategy, applied technology and project execution. Cost, schedule and existing infrastructure were identified as the main drivers influencing the strategy selection and facilities viability. Strategies involving fast track developments, tie-back to host facilities, leasing of facilities and stand alone developments were highlighted as the preferred choices. The life –cycle cost is an important method in assessing the impact of new technology on marginal field economics. A guideline for selecting a marginal field development strategy was proposed.

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ABBREVIATIONS

Bbl	Barrels
BOP	Blowout Preventor
BOPD	Barrels of oil per day
BWPD	Barrels of Water per day
CAPEX	Capital Expenditure
CT	Coiled Tubing
CTU	Coiled Tubing Unit
DC	Direct Current
EMT	Electromagnetic Telemetry
EUR	Estimated Ultimate Recovery
ETLP	Extended Tension Leg Platform
FPSO	Floating Production, Storage and Offloading Vessel.
FSO	Floating Storage and Offloading Vessel.
FWHT	Flowing Wellhead Temperature
FWP	Flowing Wellhead Pressure
GOR	Gas Oil Ratio
HWU	Hydraulic Workover Unit
ID	Inner Diameter
MLLW	Minimum Lower Level Water
MODU	Mobile Offshore Drilling Unit
MMScf/d	Million standard cubic feet per day
MT	Metric Tonne
MWD	Measurement While Drilling
NPV	Net Present Value
OD	Outer Diameter
OPEX	Operating Expenditure
PCSB	PETRONAS Carigali Sendirian Berhad
PDC	Polycrystalline Diamond Compact
UBD	Underballanced Drilling
UTC	Unit Technical Cost
ROP	Rate Of Penetration
SFD	Satellite Field Development
SSF	Suction-piled Stacked Frame
SSV	Safety Shutdown Valve
TC	Tungsten Carbide
TD	Target Depth
TFL	Through Flow Line
TLP	Tension Leg Platform
TTGP	Thru-Tubing Gravel Pack
WD	Water Depth
WOR	Water Oil Rate

CHAPTER 1

INTRODUCTION

1. 1 Background of Study

The increasing world energy demand is pushing oil prices to unprecedented heights. This is putting pressure to the industry to produce more reserves, especially those considered to be marginal reserves which in current economic climate (e.g. high oil price) become more economically attractive. The high oil price brings with it new challenges and innovations to development oil and gas fields in places otherwise considered to be marginal or inaccessible. Therefore, oil companies are trying to find concepts, which considerably reduce the costs of these marginal field developments and consequently make these developments economically feasible. The challenge for today's marginal fields is to reduce development costs/bbl to acceptable levels and to do this through working the two available levers: cost and the number of barrels. The solution for this large number of small fields can be found in the effective combination of new innovative technologies and financial solutions; horizontal drilling to accelerate the field depletion rate, reuse of equipment, multiphase pumping and transportation to lighten equipment and platform. The main area of cost reduction is in the re-usable platforms, decks and topsides and in the demanning of the platforms.

The term “Innovation” is often defined either as “developing a unique solution to overcome a problem” or “developing a unique answer to a specific need”. Many project development teams are tasked to develop novel offshore structures or component systems, which are well suited for cost-effective development of marginal oil and gas fields. Development concepts of marginal fields should be fit for purpose and cost-effective. This can be achieved through application of appropriate strategies such as leased facilities or share nearby facilities to use the benefits of economies of scale, reduce of tax rate and abolition of royalty rate for production to be able attract investors.

In this study, the generic marginal field development concepts and solutions in terms of structure types, strategies and innovations are addressed. Then the environmental constrains and basis for determine a desirable field development options are discussed. Finally, a detailed analysis of investment and cost estimation is presented.

1.2 Problem Statement

Marginal field hold the promise of future production volumes and are currently the focus of most government agencies due to high word energy demand. To develop these marginal fields, often provide great challenges to Oil and Gas Company in order to exploit their limited reserve. Therefore, operating companies are looking for more appropriate strategies and concept which help marginal reserve to be economically feasible. Thus, the main purpose of this study is to identify the generic development concept and strategies for marginal field and basis for conceptual development costs estimation

1.3 Objectives and Scope of study

The objectives of this study is to identify the latest conceptual approaches, strategies and technical advances associated with development of marginal offshore field and the innovations used to reduce overall field development costs (Capex & Opex) .This study focus on field development components, constrains and selection of suitable development approaches. Also to develop a costing basis to evaluate quick estimation of development cost of a marginal field.

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CHAPTER 2

LITERATURE REVIEW

2.1 Definition of Marginal Field

Marginal field is a term used by different oil and gas companies to describe a wide range of offshore hydrocarbon prospects. The marginal word may give a sense that the field in question is can hardly meet the minimum required return on investment which would be set by corporate philosophy of oil and gas companies.

The first stage in exploration-production cycle is of course to look for deposits of hydrocarbons, which will then be produced if techno-commercial conditions permit [1], the offshore reservoirs containing hydrocarbons will only be exploited if the estimated revenues of recoverable exceed the cost of the exploration investment and operating expenditure to such an extent that an acceptable return on investment can be achieved. Therefore the reservoir discovery classified as commercial, marginal or un-commercial [2].

A field may deem to be marginal due to a mixture of technical, commercial and political factors. It often related to the size of an individual company portfolio. The internal competition for budget funds leaves profitable opportunities on the shelf. So that there are a number of definitions of marginal field as follows:

A marginal field is a limit reserve that may not produce enough net income or a minimum required return on investment, to make it worth developing at a given time; should technical and economic conditions change, such a field may become commercial. Marginal offshore fields may contain small recoverable reserves in shallow water (i.e. up to maximum 100 meter water depth) or relatively large reserves in deep water (i.e. more than 500 meter water depth), where higher investments are necessary to exploit the field.

A marginal field may be capable of yielding an economic return to the oil company but only by using some innovative, technical and/or financial options [2].

A marginal field can be an undeveloped field, a mature field or an abandoned field. For example a giant gas field may also contain oil deposits in limited quantities and when produced along with the gas becomes a by-product but in itself is a marginal prospect in terms of the quantity of oil and for stand alone development [3].

2.2 The Marginal Field Characteristics.

a) Size and characteristics of the field (reservoir size, depth, Pressure and temperature, porosity and permeability)
b) Geographical condition (water depth, remote field, infrastructure)
c) Field development and operating costs i.e. capital and operating expenditure (CAPEX and OPEX)
d) Availability of other infrastructure for activities such as export, logistics and administration
e) Current development technology (adequate technology for CO_2 removing)
f) The legal and current fiscal regime has impact taxes, profit Sharing, cost Recovery)
g) Potential revenue from the reserve which depends on the recoverable oil, production rate and oil and gas prices

2.3 Factors for Marginal Field Evaluation

The economics of marginal field are usually so finely balanced that changes in basic economic conditions such as development cost (capital expenditure and operating cost), production levels and recoverable reserves can have a major effect on the profitability of the venture. The development costs depend on technological selection whereas production levels and recoverable reserve are sometimes derived on the scantiest of information. All of these factors that affected the marginal field economics are controlled by oil price, as the oil price raise the some marginal field become economical viable using conventional development methods.

2.4 Marginal Field Development Considerations

The elements that influence the development of a marginal field are the reservoir characteristics, the drilling requirements, recovery, site and environment as well as design rules and regulations. These topics are discussed in the following sections.

2.4.1 Reservoir Characteristics

The definition of the reservoir type, its size, real extend, depth and pressure uncertainty among others will influence the number of wells that will be required to develop the field [4]. The main objective in determining an optimal subsurface development plan (well plan, production profile and policy) is to maximize economic reserves of marginal field. The most important element is geological model(structure, lithology, stratigraphy, diagensis), volumetric (in-place volumes), reservoir behavior under production, well productivity and performance and field production profile(reserves).Consideration of these and related aspects will determine optimum well requirements in terms of type, number, and location in the reservoir. One of the most striking features of marginal field economics is the necessity for a very high production –to- reserves ratio to enable rapid depletion of the field. If the volume of reserves and the levels of production can be relied on, then the characteristic is not necessary a problem. The difficult, however, is that, at a low level of reserves, the definition of reserve size must be expected to be poor. In marginal field it is vital to have an accurate prediction of the productivity of the well and, in particular, the ability of the field to attain the required level of production in early years of its life. In order to achieve this it requires a good understanding of the reservoir drive mechanisms and the need for artificial lift and secondary recovery. For major projects, a numerical model study of reservoir, including wells, is used most often to forecast production profile and associated reserves. In the end, we must realize that the subsurface plan forms the basis for facilities design. Uncertainties and risks need to be defined properly.(technology of marginal).There is considerable uncertainty in the subsurface; this manifests itself in teams of a range of reservoir deliverability and reserve. In many projects, this subsurface uncertainty is not properly conveyed to the surface teams who are charged with selecting the best facilities design for project .Often the result of this disconnect yield suboptimal facilities followed by expensive retrofitting. The framework presented automates optimization of the concept design with rigorous reservoir and facilities modeling [5]. Probabilistic modeling is critical to properly assess risk in the development of marginal reservoirs and study the way to mitigate these uncertainties.

Well productivity should properly be established by means of a well testing and logging programme, not by drilling multitude of wells. Only if reserves changes in well productivity are expected over the relatively small area of a marginal field can drilling to establish well productivity be justified. The cost of logging, coring and production testing is always minimal when field development decisions are to be made. Thus through programmes for well data acquisition are normally undertaken as a matter of policy by operators.

There are, however particular cases where not only productivity a problem but where recovery factors are in doubt or where reservoir limits are best established by extended well testing .Thus many uncertainties associated with recovery factors and productivity could be resolved at little cost beyond the delineation well.

Laboratory tests should be performed to determine the crude characteristics and define the functional requirements that directly affect the drilling, production and export systems.

2.4.2 Drilling Requirements

Typically, the number of production and injection wells, geological complexity and depth of reservoir defines the scope of development drilling requirement.

2.4.3 Recovery

Production facilities requirements are defined in terms of system capacities for processing fluids as defined by barrels of oil per day (BOPD), standard cubic feet of gas per day (MMscfd), barrels of produced water (BWPD) and the gas and water injection. Production specifics such as hydrates directly affect the deck area and load requirements and the crude oil characteristics, such as the pour and cloud points, directly affect the selection of the export system. It should be noted that the most cost-effective field development option is to use an existing facility in adjacent to process production from a newly discovered field.

2.4.4 Site and Environmental Issues

Extreme environmental conditions (site characteristic and environment) can readily make the marginal field development not feasible due to technical and/or economic reasons. The key parameters defining the site characteristics, namely the water depth, foundation material, seismicity, ice, wind, wave and current, directly influence the selection of field development option and the magnitude of required investment.
The limits strength and flexibility of material make water depths for each of the options fall as indicated in Table 2.1 [6]:

Table 2.1: Facilities Application

Fixed platform	up to about 1500ft
Gravity platform	1000ft
CTs	3000ft
TLPs	5000ft
Spars	7500ft
FPSO	Unlimited
Subsea systems	Unlimited

The extremely hard clay soil e.g. North Sea bottom provides fine support for gravity base structures. In contrast, the under-consolidated, soupy clay soils, for example, Gulf of Maxico would have platforms slipping and sliding around if they weren't nailed down with deep driven piles.

2.4.5 Company Design Philosophy

Management philosophy may be too conservative to select a novel field development concept. The life of every oil and gas field begins with its discovery. Almost immediately, we want to know what its potential is (in terms of reserves and monetary value) and what the development options are in terms of subsurface plan and facilities.

So a systematic approach is required to evaluate the discovery, to forecast the reservoir behavior under expected producing conditions, and to design the optimum facilities to meet forecasted production.

A preliminary decision to develop a marginal field can be made after the completion of studies that define the reservoir and determine its functional requirements, evaluate the site and environmental characteristics and identify the technically feasible development concepts. Then, the capital and life cycle operating expenditures are estimated and economic studies are performed to determine the net return on investment. Since the operator will have limited capital and personnel resources and several commercial fields, only those fields with the highest return on investment are likely to be developed first.

2.4.6 Rules and Regulations

The other key variables affecting the marginal field development concepts and the cost are rules and regulations applicable to the site. The rules and regulations may substantially add to the cost of some field development concepts making them financially unattractive. Oil field is subjected to government approval and systems must conform to current regulation. Safety-related aspects of field development came under scrutiny and regulations changed. There were cost implications for both existing and planned projects.

2.4.7 Reduced Capital Investment.

Marginal fields have low oil and gas reserves which are economically viable when produced with low capital cost and overheads. Some of marginal field could utilized an existing drilling support or tanker converted to production operations. The significant impact on investment cost when the production equipment is leased. An economic analysis of marginal field developments carried out showed that time to first oil is one of significant parameters [2].

The option to lease both production and support facilities provides the operator with opportunity to delay payment significant proportion of this cost of field development from his oil revenues as they accrue. This factor greatly improves the profitability of the venture and leads to a maximization of return investment.

2.4.7 Minimize Abandonment Costs

Many projects incur significant expenditure relating to decommissioning, site clearing and it is important to consider the implications for cash flow evaluation. However abandonment costs are real and substantial and any development system which reduces them reflects positively on project profitability. For marginal field the abandonment costs tend to be minimized; the use of anchored floating production supports, crude exporting via tanker and not pipeline have low abandonment cost. Therefore, the only fixed installations are the subsea wellheads which can be abandon easily [2].

2.5 Drilling Development Approach

In this section we shall examine the various drilling technologies and methods which can use in marginal field development systems. The drilling methods can be classified as follows: (a) Conventional Drilling Methods. (b) Innovational Drilling Methods.
The conventional drilling methods can be used if the economic evaluation and analysis justify that, otherwise, operating company looking for other technology (innovation methods) that promise for improving drilling efficiency and costs.

2.5.1 Conventional Drilling Methods

For marginal field the drilling operations should be selected such as that, to reduce drilling cost and/or increase the recoverable reserve per well and both can increase the project's risked net present value (NPV). This can achieved through application of the following technologies:

2.5.1.1 Well Design

The well design is one of the most important items in any offshore development. In general the well should be designed to be simple to improve the overall project development economics; by improving project management schedule and cutting cost per well. There are many wells can be used in marginal field such as:

a) Slim-hole Drilling Technology

Slim-hole drilling technology is frequently considered as a means of reducing drilling cost. Therefore, it is used to enhance the economics of developing a marginal field by significantly reducing drilling and development costs. The term slim-hole is relative and generally referred to any drilling hole that smaller than conventional drilling wellhole. Although the technique was first used in the oil and gas industry in the 1950s, its acceptance has been hampered until recently by concerns that smaller boreholes would limit stimulation opportunities, production rates, and multiple completions. Advances in technology, coupled with a growing record of success, have dispelled these concerns, making slim-hole an increasingly attractive option for reservoir development.

Slim-hole wells demonstrably applicable for marginal field, HP/HT wells and deepening or side-tracking of existing well [7].

The improvements mentioned above have driven dramatic reductions in well costs and rig days. Drilling costs have been reduced by approximately 20%to 70%. Risks have also increased with slim-hole technology, but are within manageable levels. Initially, wells were drilled to a conventional design (13 3/8, 9 5/8", 7" casings) with water based drilling fluids, but drilling has evolved through the 1990's to a leaner slim-hole design (9 5/8", 7", 2 7/8") [8].

Improved slim-hole drilling technology brings the twin advantages of environmental protection and economical results to oil and gas exploration and production. See table 2.2 for economic and environmental advantages.

Table 2.2 economic and environmental advantages of slim-hole drilling technology

Economic Advantages	Environmental advantages
Smaller drilling crews and less drilling time .Drilling strings will be lighter, therefore smaller drilling rigs could be used.	A slim-hole rig occupies far less space than a conventional rig—the entire footprint including site access can be up to 75 percent smaller
Smaller and therefore less expensive bits are required, smaller- diameter pipe and drillcollar.	The rig requires far less drilling fluid and produces far fewer cuttings for disposal
Slim-hole is feasible in a wide range of operations and capable of reducing exploration and development costs.	Reduced volume and weight of equipment favors use in sensitive environments, such as rainforests and wetlands, particularly in helicopter-supported campaigns
Slim-hole drilling is critical for adding millions of barrels of oil to the Nation's reserves	Better wellbore control

The accompanying disadvantages of drilling smaller hole are as follow:

i. Smaller hole generally require a better quality of drilling mud throughout because of the greater danger of sticking the drillpipe.
ii. The better-quality mud tends to give a slower rate of penetration
iii. The smaller annular clearance tends to produce great pressure drops when circulating and greater pressure surge when hoisting. So that the probability to mud losses into formation is increased.

b) Advanced Wells

Recent advances in drilling and completion techniques have resulted in improved well system design and completion reliability. Extended reach wells, multi-laterals, smart wells producing from multiple pay-zones and a range of completion methods provide high well production rates and significant recoverable reserves per well.

The motivation for using this technology is to access otherwise inaccessible reserves, improve recovery factor/sweep efficiency, increase flow rates and enhance profitability per dollar invested which can be keys driver for developing a marginal offshore field. Also an intelligent well system can be used to minimize the need for intervention throughout the life of the well.

Advanced wells can bring commercial benefits and allow cost effective data acquisition to be carried out. The commercial benefits occur through one or more of the following: [9]

i. Reduced capital expenditure per barrel
ii. Reduced operating expenditure per barrel
iii. Accelerated reserve steam

2.5.1.2 Completion Design

In general, the completion strings is a critical component of production system and to be effective it must be efficiently designed, installed and maintained. Increasingly, with moves to complex reservoir and more hostile development areas, the actual capital costs of completion string has become an significant proportion of total well cost and thus worthy of greater technical consideration and optimization. In marginal field the completion design should Lower the production costs, lengthen reservoir life, and optimize hydrocarbon recovery with completions designed. The completion process can be split into several key areas which require to be defined including [9]:

a. The fluids which will be used to fill the wellbore during the completion process must be identified, and this requires that the function of the fluid and the required properties be specified.
b. The completion must consider and specify how the fluids will enter the wellbore from the formation i.e., whether in fact the well will be open or whether a casing string will be run which will need to be subsequently perforated to allow a limited number of entry points for fluid to flow from the reservoir into the wellbore.

c. The design of the completion string itself must provide the required containment capability to allow fluids to flow safely to the surface with minimal loss in pressure. In addition however, it would be crucial that the string be able to perform several other functions which may be related to safety, control, monitoring, etc. In many cases the completion must provide the capacity for reservoir management. The completion string must consider what contingencies are available in the event of changing fluid production characteristics and how minor servicing operations could be conducted for example, replacement of valves etc.

The following are some of completion design that used to improve the marginal field economics:

a) Monobore Completion Design

The monobore completion design is used for marginal field to minimize well installation times and costs. In this approach, more than one zone flows into the tubing string, e.g. two zones producing up a single tubing string. Use of this monobore technology combined with slim-hole well can achieve cost optimization and help in the successful drilling by allowing the well to be drilled to TD in a small hole interval (e.g. 6” hole). However, due to small hole size, no more contingent hole size will be available in case of any problem prior to reach TD.

The advantages of monobore completion can be summarized as follow [9]:

1. Since each well provides a drainage point in each reservoir unit, the total number of wells and the capital investment, is therefore minimized.

2. Since the amount of drilling is minimized, the production plateau for all the reservoirs should be reached as quickly as possible. i.e. production should be accelerated compared to the other optional strategies

The monobore completion design has limitations and disadvantages as same as any completion designs which can give guide line to use the technology:

1. The mixing of produced fluids in the wellbore can be disadvantageous if one or more fluids have corrosive material, produced sand, fluids have different hydrocarbon compositions and different GOR or WOR.

2. Variation in individual zone pressures and permeability can lead to a back pressure effect on the less productive or lower pressure reservoirs

3. The use of co-mingling removes the capability for continuous control of the production process, i.e. closure of one individual zone cannot necessarily be effected unless a relative configuration is used

4. Injection of fluids, e.g. stimulation fluids cannot easily be diverted into individual layers without temporary isolation using sealants (diverters) or bridge plugs

5. A change in the production characteristics of one zone e.g. water coning and a consequent increase in WOR, will influence the total production from the well but may be difficult to remedy without closing in the well

b) Horizontal Well

The objective of a horizontal well is to drain hydrocarbons from a reservoir in more cost- efficient manner than a conventional vertical or deviated well**.** Horizontal wells greatly improved production rate and also appear to slow down the water coning [10]. The most practical application of horizontal drilling is to place a well below a gas or above water zone in order to avoid gas and water coning, and to optimize the production rate and reserves recovery [11]. Productivities of horizontal wells are found to be more than three times that of conventional wells. Critical coning rate of horizontal wells is also found to be about three times that of conventional [12].

Marginal prospect that in thin, tight reservoirs, reservoirs inaccessible by vertical drilling, and reservoirs where horizontal wellbores significantly increase flow rates and recovery. These are strong reasons that justified the application of horizontal well. Further more, horizontal well reduces the number of slots at surface and maximize utilization of drilling sites and infrastructure. Therefore, it enhances the use of light structure which is a preferred type of structure used for a marginal field development in a shallow water depth. The advantages of horizontal well summarized as in the table 2.3 below:

Table 2.3 economic and environmental advantages of horizontal well

Economic Advantages	Environmental advantages
Increased recoverable hydrocarbons from a formation, often permitting revitalization of previously marginal or mature fields	Fewer wells needed to achieve desired level of reserve additions
More cost-effective drilling operations	More effective drilling means less produced water
Less produced water requiring disposal and less waste requiring disposal	Less drilling waste
Increased well productivity and ultimate recover	

c) Multilateral Well

Multilateral wells are relatively recent development. Several “branch” wellbores are drilled from primary “trunk” wellbore. This can be done for several reasons [13].

i. To place wellbore in several different reservoirs
ii. To get increased production in one reservoir
iii. Reduce the number of slots at topside

In general, multilateral well creates an interconnected network of the separate pressure-isolated, and reentry accessible horizontal or high-angle wellbores surrounding a single major wellbore, enabling drainage of multiple target zones. In many cases, this approach can be more effective than simple horizontal drilling in increasing productivity and enlarging recoverable reserves. Often multilateral drilling can restore economic life to an aging field. It also reduces drilling and waste disposal costs. Today, in a wide variety of drilling environments, both onshore and offshore, from the Middle East to the North Sea and from the North Slope to the Austin Chalk, multilateral completions are providing dramatic returns for operators. [13]

Multilateral drilling is of greatest value in reservoirs that:

i. Have small or isolated accumulations in multiple zones
ii. Accumulate oil above the highest existing perforations
iii. Have pay zones that are arranged in lens-shaped pockets
iv. Are strongly directional
v. Contain distinct sets of natural fractures
vi. Are vertically segregated, with low transmissibility

Table 2.4 economic and environmental advantages of multi-lateral well

Economic Advantages	**Environmental advantages**
Improved production per platform	Fewer drilling sites and footprints
Increased productivity per well and greater ultimate recovery efficiency	Less drilling fluids and cuttings
New life for marginally economic fields in danger of abandonment	Protection of sensitive habitats and wildlife
Reduced drilling and waste disposal costs	
Improved reservoir drainage and management	
More efficient use of platform, facility, and crew	

d) Coiled Tubing Completion

Coiled Tubing (CT) technique is mostly considered for drilling or well intervention operation rather than an effective completion tool. This technique is a surprisingly effective and suitable means for marginal field exploitation. The employment of a CT Completion technique may enhance the economics of marginal prospects; It allows costs and time reductions and rigless maintenance throughout well life.

In particular, the use of CT Concentric Completion is an effective alternative to conventional tubing string for reducing completion and workover costs. A Concentric CT Completion can be defined as a completion string installed inside another completion string [14].

The purpose of CT Concentric Completion can be

1. To provide new geometry with a single flow path as a Velocity String
2. Dual flow path equivalent to a dual completion as a Dual Zone
3. To provide a distinct second flow path as an Inverse Gas Lift String
4. To re-establish completion integrity
5. To inject chemicals or Gas Lift below the packer among the types of CT Concentric Completion we can quote.
6. New well original design to deploy & retrieve a completion under pressure
7. Integral retrofit designed to fit inside the candidate well
8. Scab string top of a string not reaching surface
9. Hang off string temporary installation thru existing x mas tree

Special application aimed at:

1) Extendeding gas lifts injection depth
2) Chemical injection
3) Sub Surface Safety Valve repair

d) Thru-Tubing Gravel Pack

An effective sand control has long been a concern within unconsolidated sandstone formation. Many of the producing wells have stopped production due to the influx of formation sand. These wells that have low rate marginal reserves cannot economically justify re-completion with conventional gravel packing techniques. Thru tubing gravel pack or TTGP completions accomplished control of the formation sand flow by placing a downhole sand filter across the perforated intervals (see appendix 2.5, 6). This filter is formed when the gravel-pack sand filters out the formation sand and the screen filters out the gravel-pack sand. Ideally, the result allows the production fluids to pass through with minimal restriction [15].

The TTGP completion was deployed using coiled tubing. Perforation pre-packing was done with the screens in place.

Some of TTGP advantages are mentioned bellow:

1. Effective – Sand production can be controlled, allowing production from unconsolidated zones.
2. Cost Efficient – The operation does not require workover rig since the coiled tubing unit is capable of performing full scale TTGP operations including foam washing and deploying the TTGP assembly.
3. Simple and reliable – No tubing manipulation is required, and sand placement across the screen is easily accomplished.
4. Reduces Possibility of Formation Damage – New VES fluid used as gravel pack carrier fluid minimizes potential damage, as retained permeability was 90%.
5. Increase Inflow Area – Re-perforation with 12 – 18 SPF, increasing the cross-sectional area, provides the well with sufficient area to flow. This allows the well to produce at less draw down pressure after the perforations are filled with the proper size of gravel.

These methods can provide an operationally efficient, remedial method for sand control, and still be able to recover production from wells that are sanded up. These capabilities are particularly attractive for wells with marginal reserves in which rig-based remedial operations would be economically unfeasible.

2.5.1.3 Production Profile

The success of the marginal field projects underscores the importance of adequate planning to ensure both optimal resource recovery and a strong economic return on investment. Thus, cost-effective single zone or commingling zone’s fluid can be used. Also the completion should be for permeable high hydrocarbon saturation zone and bypass poor, uneconomic zones. However, as experience in offshore operations grows, companies' need for measured caution lessens and firms emphasize timely activity in their approaches to project development. The goal is to accelerate development, which increases the expected net financial return by yielding an earlier economic return and reducing the carrying costs of early expenditures on leases, geology and geophysical work, and exploratory drilling. Accelerated production profile of marginal field development enhances economic attractiveness by reducing project uncertainty because adverse changes in market price for the commodity or factor costs become more of a possibility as development time lengthens. One approach to achieve revenues as soon as reasonable is the use of a fracturing technology, downhole pumps. The maximum production profile is controlled by number of wells and the capacity of surface facilities, therefore, the selection of accelerated technical must carefully studied and insures improvement of risked net present value (NPV).

Generally, self-flow period of marginal field is very short, thus, necessitating artificial lift since beginning. For successful exploitation of isolated and marginal offshore field selection of suitable lift system is very crucial and determines the viability of the total project [16].

2.5.2 Innovational Drilling Methods

Developing marginal petroleum fields becomes significantly more attractive when technology is available that can enhance cost efficiency and reduce operational and environmental risks. To support the above needs, a major oilfield equipment supplier has introduced innovative drilling methods that provide an alternative to conventional methods. The unconventional drilling methods include:

2.5.2.1 Coiled Tubing Drilling

A relatively modern drilling technique involves using coiled tubing instead of conventional drill pipe. This has the advantage of required less effort to trip in and out of the well (the coil can simply be run in and pulled out while drill string must be assembled and dismantled joint by joint while tripping in and out). Instead of rotating the drill bit by using a rotary table or top drive at the surface, it is turned by a downhole motor, powered by the motion of drilling fluid pumped from surface. Continuous coiled tubing can dramatically increase the efficiency, profitability, and productivity of drilling for oil and gas. Whereas in conventional drilling operations, the drilling pipe consists of several jointed pieces requiring multiple recommendations, a more flexible, longer coiled pipe string allows uninterrupted operations. Cost-effective alternative for drilling in reentry, underbalanced, and highly deviated wells, coiled tubing technology minimizes environmental impacts with its small footprint, reduced mud requirements, and quieter operation. Quick rig set-up, extended reach in horizontal sidetracking, one-time installation, and reduced crews cut operating costs significantly. For multilateral and slimhole recently operations, coiled tubing provides the opportunity for extremely profitable synergies [17].

In a variety of drilling applications, coiled tubing eliminates the costs of continuous jointing, reinstallation, and removal of drilling pipes. It is a key technology for slimhole drilling, where the combination can result in significantly lower drilling costs. Reduced working space— about half of what is required for a conventional unit—is an important benefit, as are reduced fuel consumption and emissions. A significant drop in noise levels is also beneficial in most locations. The noise level at a 1,300-foot radius is 45 decibels, while at the same radius a conventional rig has a 55-decibel level.

Applications of coiled tubing in both drilling and well maintenance are expanding, but the nature of the technology makes it critical that producers apply the prior lessons learned when using coiled tubing. These insights come only from those who have been out there doing it.

Downhole motors attached to the end of coiled tubing can be used to drill through cement, debris, etc. This is generally a quicker and cheaper alternative to workover rigs. For coiled tubing drilling, two major types of bits exist: diamond PDC and tungsten carbide (TC: splatter-welded). Tri-cone roller bits are generally not suitable for coiled tubing drilling because of the high rotational speed of the motors. Experience has shown that TC mills perform best when milling out tools and cement. Great care should be exercised when selecting a motor as too much power can have an adverse effect on the string, especially when drilling/milling in large tubulars where correct stabilization may be difficult. Motors with medium-stall torque are preferred over high-stall torques. Stabilizers fitted to the top of the motor are always recommended.

Table 2.5 economic and environmental advantages of coiled tubing drilling

Economic Advantages	**Environmental advantages**
Increased profits, in certain cases, from 24-hour rig set-up and faster drilling	Reduced mud volumes and drilling waste
Smaller drilling infrastructure and more stable wells	Cleaner operations, as no connections to leak mud
No interruptions necessary to make connections o to pull production tubing	Reduced operations noise
Reduced drilling and waste disposal costs	Minimized equipment footprints and easier site restoration
Reduced fuel consumption	Reduced fuel consumption and emissions
Increased life and performance from new rig designs and advanced tubulars, educing operating costs	Less visual impact at site and less disturbances, due to speedy rig set up
	Reduced risk of soil contamination, due to increased well control

2.5.2.2 Underballanced Drilling

Underballanced drilling is a procedure used to drill oil and gas wells where the pressure in the wellbore is kept lower than the fluid pressure in the formation being drilled. As the well is being drilled, formation fluid flows into the wellbore and up to the surface. This is the opposite of the usual situation, where the wellbore is kept at a pressure above the formation to prevent formation fluid entering the well. In such a conventional "overbalanced" well, the invasion of fluid is considered a kick, and if the well is not shut-in it can lead to a blowout, a dangerous situation. In underbalanced drilling, however, there is a "rotating head" at the surface - essentially a seal that diverts produced fluids to a separator while allowing the drill string to continue rotating.

Underbalanced wells have several advantages over conventional drilling including: [18]

a) Eliminated formation damage. In a conventional well, drilling mud is forced into the formation in a process called invasion, which frequently causes formation damage - a decrease in the ability of the formation to transmit oil into the wellbore at a given pressure and flow rate. It may or may not be repairable. In underbalanced drilling, if the underbalanced state is maintained until the well becomes productive, invasion does not occur and formation damage can be completely avoided.
b) Increased Rate of Penetration (ROP). With less pressure at the bottom of the wellbore, it is easier for the drill bit to cut and remove rock.
c) UBD Provides a Rapid Indication of Productive Reservoir Zones. Because the hydrostatic pressure of the circulating fluid system in a truly underbalanced operation is less than the formation pressure, a condition of net outflow of formation fluids (oil, water or gas) should occur given sufficient formation pressure and in-situ permeability. Proper flow monitoring of the produced fluids at surface can provide a good indication of productive zones of the reservoir and act as a valuable aid in the geosteering of the well (if a horizontal application). Significant production of liquid hydrocarbons (because gas is usually flared) during the drilling operation may provide some early cash netback to partially defer some of the additional costs associated with the UBD operation.
d) Logging While Drilling/MWD Through the Use of Electromagnetic Telemetry (EMT) Tools**.** A major drawback in past UBD operations was the inability to MWD/geosteer when gas-charged fluid systems are used (unless a parasite or concentric drillstring configuration is used, which allows pulsed logging up an entirely liquid filled drillstring). The development of EMT tools, which directly transmit downhole information back to the surface while drilling, even in an underbalanced mode, have proven highly useful in UBD operations. Depth and temperature limitations and some formation restrictions on these tools still

currently limit their applicability in deeper wells but it is expected that, as technology continues to advance in this area, deeper wells will be drilled with this technology. An increased use of coiled tubing drilling technology for UBD that utilizes an internal wireline for MWD purposes can also minimize problems associated with MWD operations during UBD.

e) Ability to Flow/Well Test While Drilling**.**Recently, several operators have taken advantage of the flowing condition occurring during UBD to conduct either single or multirate drawdown tests to evaluate the productive capacity of the formation and formation properties during the drilling operation (in a static mode or while drilling ahead in some situations).

f) Reduction of Lost Circulation. Lost circulation is when drilling mud flows into the formation uncontrollably. Large amounts of mud can be lost before a proper mud cake forms, or the loss can continue indefinitely. If the well is drilled underbalanced, mud will not enter the formation and the problem can be avoided.

There are a variety of limitations that should be considered before selecting UBD technology for a given reservoir. The primary reason for drilling in an underbalanced mode must be economically motivated so that an operator feels that the increased cost, and other potential downsides of UBD, is offset by a potential significant increase in well productivity or other technical or operational concerns which can be attributed to UBD. A proper understanding of some of the potential adverse phenomena that may be associated with UBD is essential before implementing any UBD program. These will be discussed now [19]:

I. **Expense.** UBD is usually more expensive than a conventional drilling program, particularly if drilling in a sour environment or in the presence of adverse operational or surface conditions (i.e. remote locations, offshore, etc.). Also, as will be discussed in greater detail in the following sections, there is little advantage to drilling a well in an underbalanced mode if the well is not completed in an underbalanced fashion. This often results in additional costs for snubbing equipment required to strip the drillstring from the hole in an underbalanced flow condition. A portion of this expense may be offset by increased ROP conditions resulting in a reduction in drilling and rig time and if the well can be drilled in a truly underbalanced fashion, limited or no completion work will be required, reducing the cost of extensive and expensive completion and stimulation treatments which may often be required in severely damaged horizontal and vertical wells. Obviously, the major objective in implementing a UBD operation in most cases is to improve well productivity over a conventional overbalanced completion. Therefore, in a properly executed operation, it is expected that the potential downside of increased drilling costs will be more than offset by increased productivity of the well.

II. **Safety Concerns.** The technology for drilling and completing wells in an underbalanced fashion continues to improve. Recent developments in surface control equipment, rotating blowout prevention equipment, and the increased usage of coiled tubing in UBD, has increased the reliability of many UBD operations. The fact that wells must be drilled and completed in a flowing mode, however, always adds safety and technical concerns in any drilling operation. The use of air, oxygen content-reduced air, or processed flue gas as the injected gas in a UBD operation, although effective at reducing the cost of the operation, can cause concerns with respect to flammability and corrosion problems.

III. **Wellbore Stability Concerns.** Wellbore consolidation issues have been a longstanding concern in UBD operations, particularly in poorly consolidated or highly depleted formations. A detailed discussion of this issue is beyond the scope of this paper, but considerable research work remains to be conducted in this area as many horizontal wells have been drilled and completed successfully in an underbalanced condition, even when conventional wisdom and failure calculations have indicated that stability issues should have resulted in formation collapse. Considerable evidence exists, therefore, that stability concerns in many UBD applications may not be as problematic as classically assumed, but a reservoir by reservoir evaluation is required to quantify stability concerns for each UBD application.

2.5.2.2 Subsea Technology [Drilling]

Recent advances in subsea technology have enabled the cost effective production of smaller and marginal fields transforming them into profitable assets.
The technologies with positive impact that were included in this part are:

i. Dual gradient drilling technology
ii. Low Cost Well Intervention

Drillers are facing entirely new challenges. Some relate to the riser and the mud. In ten times deeper waters, the length of the riser becomes ten times longer and the pressure of the mud inside the riser ten times greater. This increased mud pressure can easily fracture the well, if not managed properly. The solution to this problem is the dual gradient drilling concept. Instead of having a mud column connected all the way from the rig to the seabed, we have substituted the mud in the riser with sea water. This gives one pressure gradient from the surface down to the seabed, and another pressure gradient from the seabed down into the well. Sea water weighs less than drilling mud and the actual mud weight can be increased without increasing the overall pressure in the well. The drilled cuttings and mud will be brought up to the rig using a pump system located at the wellhead close to the seafloor, thus ensuring the necessary circulation in the well. Though oil and gas is currently being produced from a number of fields where the sea depths are far greater than 300 metres although not 3,000 metres so far new technology must be made available to reduce costs yet maintain an acceptable level of safety

2.5.2.2 Mudline Suspensions

In this system the wellhead is built up on the sea bed but the production well will be completed back to the platform or production well jacket. Thus although the well will be controlled above sea level hence requiring its completion back to that point, the weight of the suspended casing strings cannot be transmitted to the jacket or platform. Mudline suspension technology allows fabricating the facilities while drilling the wells. The two facilities required of the wellhead are therefore separated positionally in that:

a) A wellhead built up on the seabed will be used to suspend casing strings
b) In addition each casing will have an extension string from the seabed wellhead to a subsidiary wellhead at the platform where the BOP and subsequently the Xmas Tree will be attached.

If the well is to be completed then it can be done so either with a sea bed Xmas Tree or alternatively if a small jacket is used, above sea level. If the well is completed with a jacket then a single Xmas Tree can be installed. However, if the well is to be completed at sea bed, then the casing extensions can be removed using the running tools and retrieved. The Xmas Tree would then be clamped on to the extended neck of the 7" casing. Alternatively, if the well is to be suspended temporarily, it can be capped after retrieving the casing string extensions from the mudline [9].

Conducting drilling operations with the BOPs at the surface obviously requires some type of bottom-supported platform. The mobile bottom-supported platforms, such as jackup or submersible rigs, can also use conventional wellhead equipment and BOPs at the surface with the use of a mudline suspension system. When a mudline suspension system is employed, the casing is suspended at or near the mudline, but the casing strings are later tied back to the rig at the surface. Conventional BOPs and wellhead equipment may then be installed and used during the drilling operations. After the well has been drilled and tested, the BOPs, wellhead equipment, and extension casing from the mudline hangers are removed. If the well is to be completed, a cap is usually installed over the well at the mudline. When the operator is ready to re-enter the well, usually after exploration activities have been completed, the cap is removed and the well completed by either installing a tree on the ocean floor or locating a platform over the well and extending the conductor casing up to the platform. A conventional tree can then be installed at the surface.

A typical mudline suspension system consists of a series of concentric casing hangers, each having an internal profile to provide a support or seat for the subsequent hanger assembly. Two types of casing hangers are usually incorporated in a mud-line suspension program. Fluted mandrel-type, or boll weevil-type, hangers are generally used for larger size casing suspension, where casing ID and bit OD clearance is sufficient to allow a support shoulder to be provided in the outer hanger. The fluted hanger incorporates a replaceable fluted hanger ring that provides flexibility in the event of a last-minute change in casing program. Expanding-type hangers are used for the smaller casing strings where bit sizes closely approach casing ID, precluding sufficient clearance for a support shoulder inside the outer hanger. Expanding-type hangers use spring-loaded steel segments that lock the mating downhole hanger. Both types of hangers provide fluid passage for circulation and cementing returns. Generally, all assemblies may be furnished with circulating ports for washing and displacing cement from around the landing/tieback thread area. As with conventional mandrel hangers, the hanger body is made up on the casing to suspend it. Most hangers are designed with coarse threads for landing sub and tieback sub connections. Exact landing and tieback procedures vary by manufacturer.

Conventional wellheads may be used with mudline suspension systems. Since casing weight available for the surface casing hanger is limited, some form of packoff in the top bowl of the casing head or spool is common.

If the well operations are suspended for possible future reentry, a plug is placed inside the last casing string. The casing extensions are then removed to the last casing size that it is desired to cap. A cap is then placed, sealing this casing string and all subsequent strings. Any remaining casing extensions are then removed, and the location is marked with a buoy or other locating device [20].

2.5.2.3 Split Well Technology

Split well technology can enable more than one independent well to be drilled, cased and completed from one shared single conductor and thus reduce the number of slots per platform for the same number of well to be drilled. It uses standard compact internal wellhead compartment and only its external shape is different from the conventional wellhead. The drilling and completion procedures remain as per the standard procedures respectively. The triple splitter wellhead technology (figure 2.1) also allows flexibility for batch drilling and completion. Based on a comparison conducted by PCSB between conventional wellheads and triple splitter wellhead technology applications for a revisit campaign in their Bokor field in 1999, the findings indicated that triple splitter wellhead technology was almost 10% cheaper than using 3 independent conventional wellheads, thus yielded better net present value (NPV) and unit technical cost (UTC@USD/barrel) for the campaign [21].

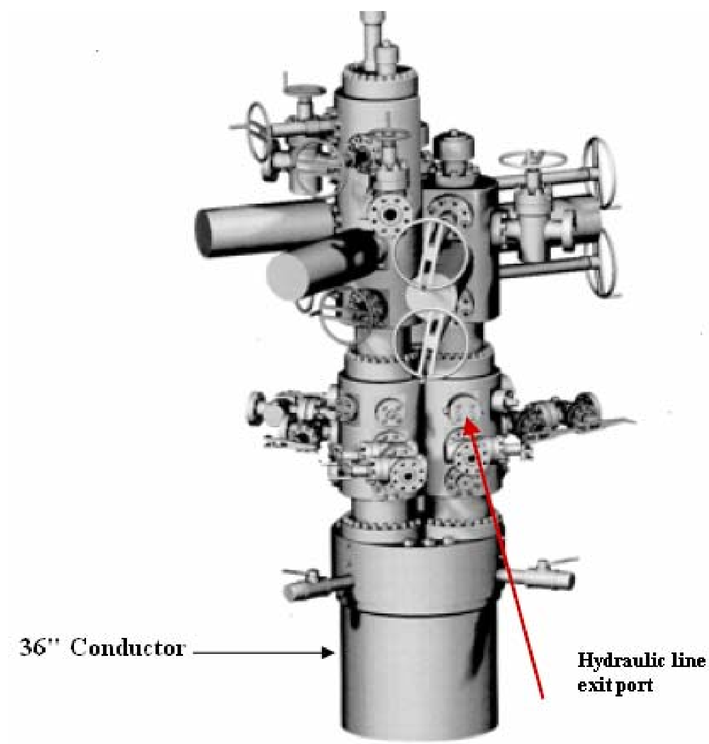


Figure 2.1 Splitter& triple wellhead technology in PCSB- Sarawak operations

2.5.3 Type of Facilities Related to Drilling Methods

The fixed production platform and well head platform (WHP) can be used with the conventional drilling methods, while the innovative methods can be use with light weight structure platform. The coiled tubing drilling (CTU) is a rigless and therefore saving cost.

2.6 Facilities Development Concepts

In this section we shall examine the various marginal field development concepts that used a worldwide and can give an overview on how an innovative structure idea creates a marginal field to be economically viable. The production supports can be classified as follows(1) Bottom-Supported Fixed Structures, (2) Floating Production Facilities (3) Subsea Development Systems.

2.6.1 Bottom-Supported Fixed Structures

In general there five basic bottom support structure concept suitable for offshore marginal field: (1) Unmanned minimal facilities platforms. (2) Conventional Fixed Platforms. (3) Jack-up production Systems. (4) The Compliant Tower.

2.6.1.1 Unmanned minimal facilities platforms

Reducing the capital cost of facilities is a key factor that allows economic development of marginal fields. For the marginal field development in shallow water; the fixed wellhead platforms with a small deck are often used. These installations (sometimes called toadstools), are small platforms, consisting of little more than a well bay, helipad and emergency shelter. They are designed for operate remotely under normal operations, only to be visited occasionally for routine maintenance or well work. These structures may support the following [22]: (1) a few wells typically less than ten wells;(2) a small deck with enough space to handle a coil tubing or wireline unit; (3) a test separator and a well header; (4) a small crane, (5) a boat landing; (6)a minimum helideck.

The unmanned minimum platform (light structure platform) can be classified to:

a. Caissons and Braced Caissons:

A Caisson platform utilizes a relatively large-diameter cylindrical shell (caisson) that supports a small deck and this type of a structure is applicable to relatively shallow water depth sites. The deck is capable of supporting limited production and control equipment and navigational aids.). When limitations of water depth and deck loading do not exist, the simple caisson is the most cost effective solution that is quickly sized, fabricated and installed. Caisson platform completions are limited to water depths of less than 100 feet or less. The Caisson structures installed in deeper water are provided with a bracing system to resist lateral loading. A Caisson that may be subjected to hurricane loading is typically limited to water depth sites of about 50 m (165 ft) while the Braced Caisson makes it cost-effective to utilize these Caissons to sites with water depths of 80-100 m (260-330 ft).Four different Caisson structures are listed in table 2.1 [22].

Table -2.6 Novel Fixed Structure

Type	Name Unit	Company Name	Production MMscfd BOPD	Steel Weight	Water Depth M (ft)
Caisson and Braced Caisson	Caisson	Atlantia	25	300	27.4
					(90)
	Caisson	Petro-Marine	35	300	49
			3000		(161)
	Sea pony	Atlantia	25	520	61
	Braced Caisson				(200)
	Braced Caisson	Worley	50	620	73
			20,000		(240)

An innovative braced caisson structure has significantly reduced costs and has allowed the development of the Kartini field in the northeastern flank of the Sunda Basin along the boundary of the Southeast Sumatra and Northwest Java Production Sharing Contract areas. The current technology allows up to eight wells with workover barge capability (Figure 2.2). This enhanced design accommodates eight development wells from one braced caisson structure rather than requiring a large, expensive, 4-pile platform. Kartini field utilized the 7- well braced caisson structure with a deck to accommodate workover barge and the cost saving in facilities [11].

Figure 2.2 KARTINI – Braced Caisson Concept

Also use of these minimum-cost platform and caisson designs would enable development of marginal fields in Cook Inlet, in 80 ft WD Alaska (figure 2.3), that heretofore could not be developed because the high cost of mobilizing and demobilizing heavy lifting equipment to and from Cook Inlet would make development uneconomic. The caisson would be set on location by upending prior to the arrival of the jack-up drilling unit. No lifting equipment is needed for the upending, only tugs or workboats. Upon completion of successful drilling, the piles are installed with the jack-up drilling unit. A small deck with crane and heliport can be installed using the jack-up drilling unit (see figure 2.6, 7) or with a small derrick barge available from the Seattle region. The deck would be large enough to enable well workovers using a coiled drilling unit. Use of a workover drilling unit would require a somewhat larger deck which could be self-erecting as was done for the Osprey cantilevered extensions. The structure would not have any living quarters [23].

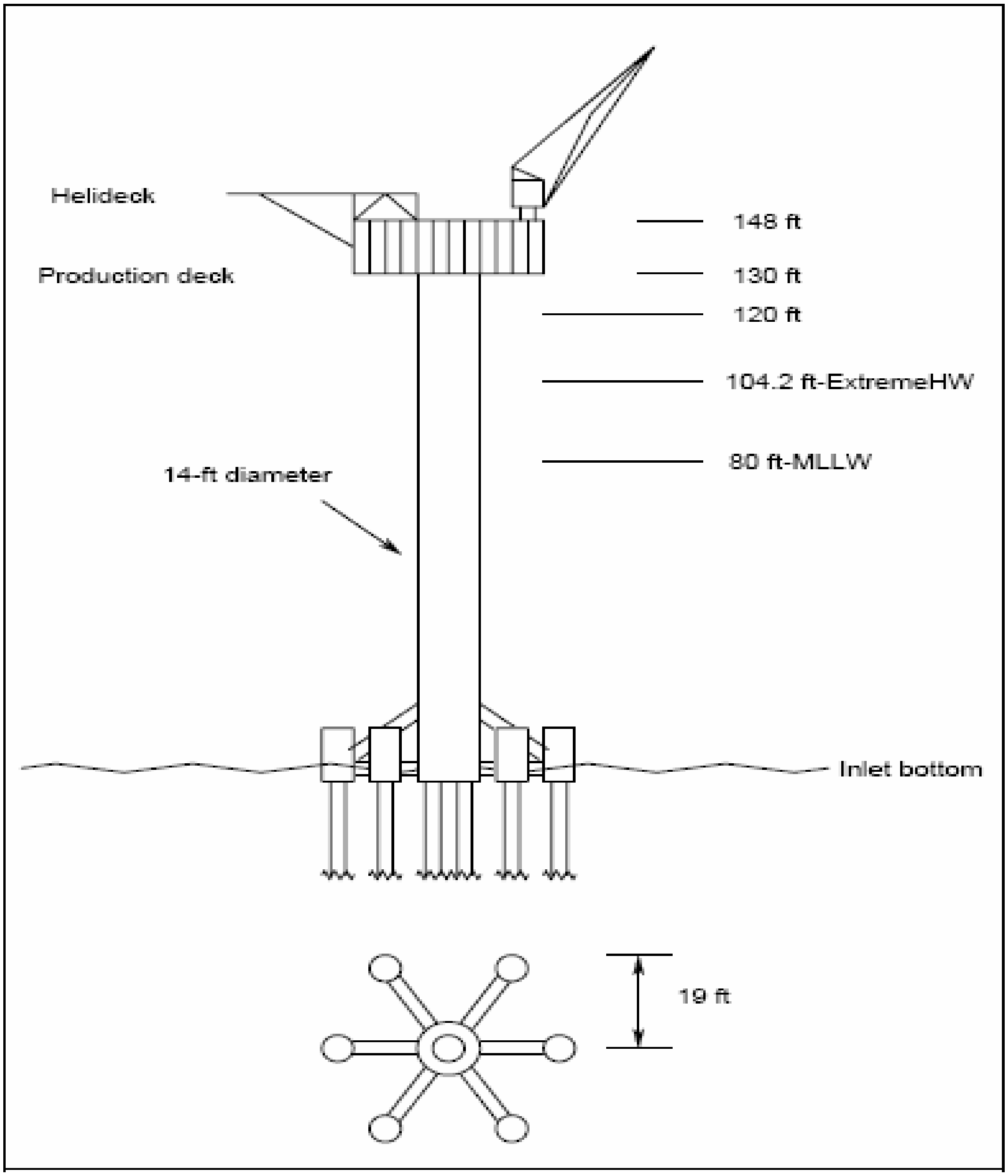
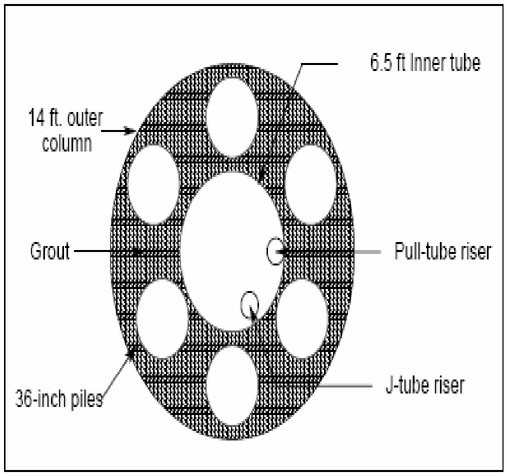


Figure 2.3 Caisson platform concepts for six wells in 80ft water depth MLLW



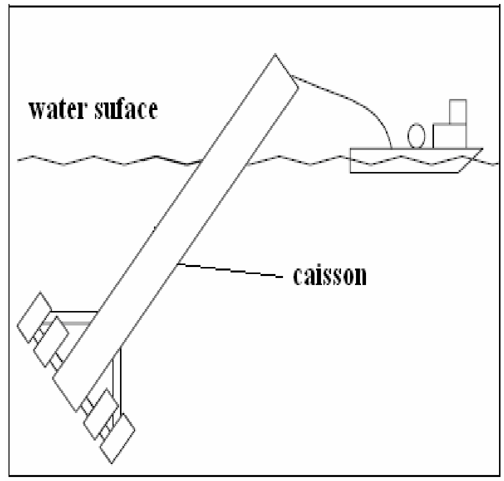
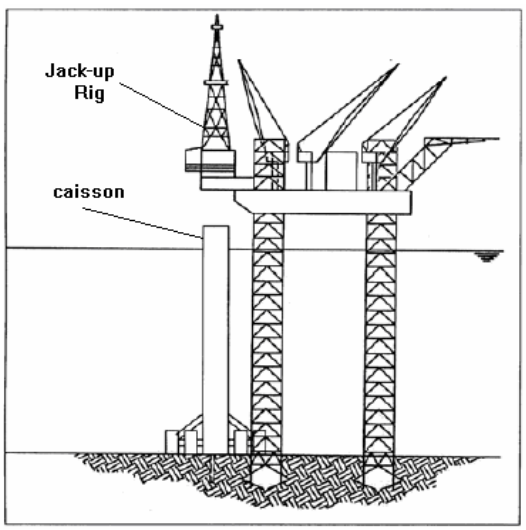


Figure 2.4 Cross-section of caisson Platform

Figure 2.5 Caisson being upended



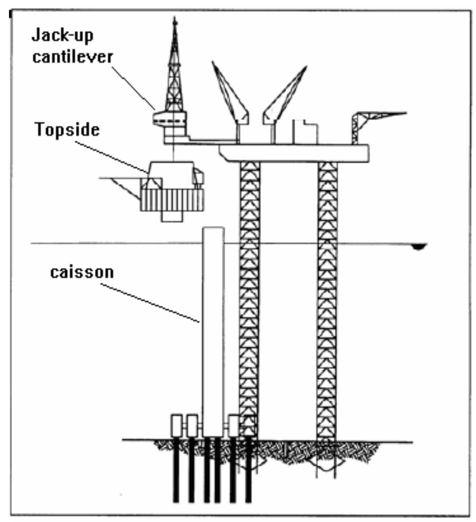


Figure 2.6 Caisson in position at jack-up drilling unit

Figure 2.7 The deck is lifted in place on caisson structure with the jack-up unit

Figure 2.8 shows an example of the structure design for a central North Sea site in 60m water depth with a 5,000kN topsides operational weight, 9 well slots and an export riser. The platform is unmanned and requires only limited access during normal operation. The platform comprises a superstructure supported above the wave crest level on a guyed caisson founded on a shallow spud-can on the sea floor. Six of the conductors are supported on the outside surface of the caisson through guides; the

export riser and other conductors are inside the caisson. The caisson is 2500mm-diameter fabricated from high strength steel plate with maximum thickness 50mm. Three pairs of wire rope guy lines are attached to the caisson. One end of each line is attached to the caisson near the top, above the water surface with the other end attached to an anchorage at the sea floor. Anchorages may be vertical load plate anchors, suction anchors, piles or anchor blocks, depending on the soil conditions and the loads to be resisted. Three arrays of flexible fender lines are attached to the guy lines near the water surface to prevent accidental boat impact damage. The impact forces are absorbed by strain energy in the fender lines and guy lines, before the boat can collide with the platform. The structure is designed to be installed by jack-up drilling rig. (Figure 2.9) shows a typical installation sequence using a Marathon Le Tourneau Class 116-C rig.
The platform structure shown in the Figures 2.8 can be constructed and installed for less than one quarter the cost of a conventional lightweight jacket for the same function, excluding topsides and basing the comparison on European construction costs [24].

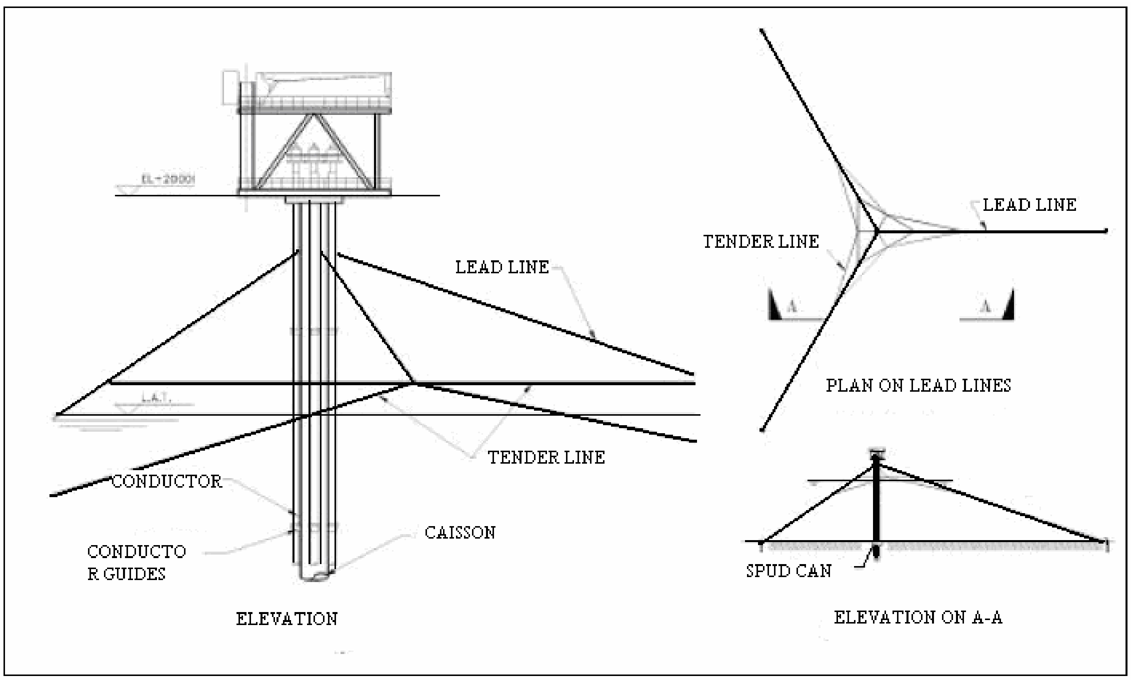
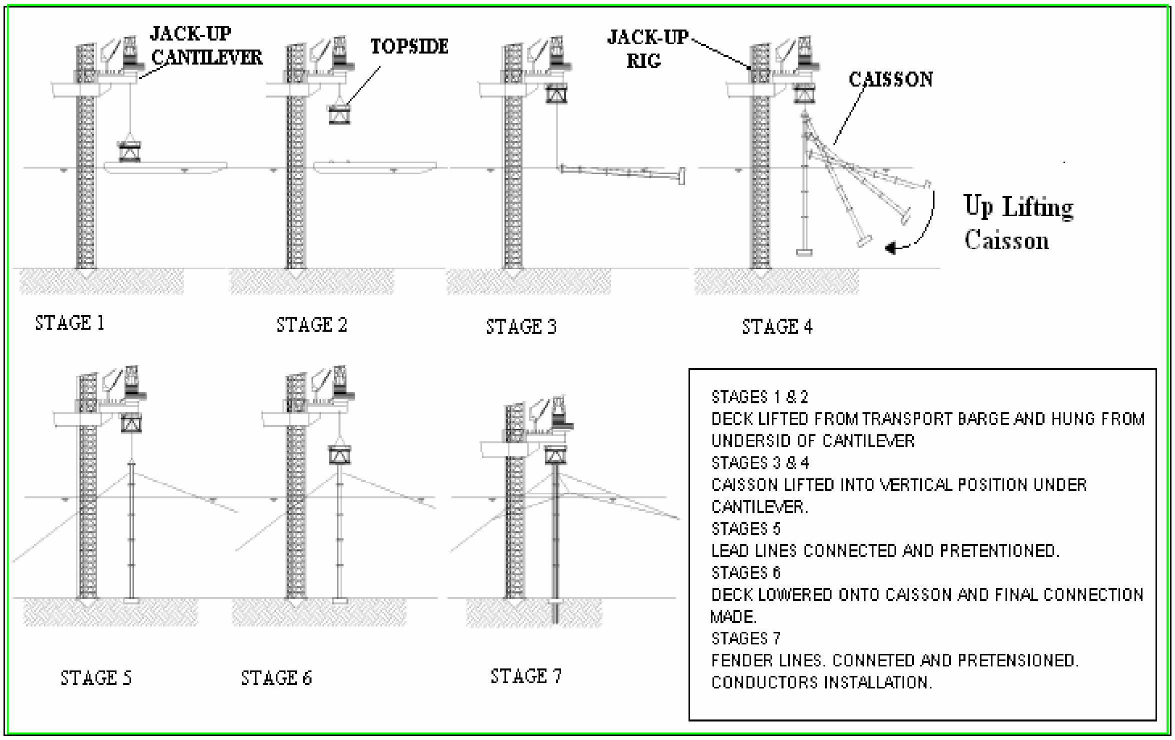


Figure 2.8 Caisson platform general arrangements.

Figure 2.9 Caisson platform installation sequence.



b. The Suction-piled Stacked Frame (SSF) Platform.

The Suction-piled Stacked Frame (SSF) platform is satellite wellhead platform (see Figure 2.10). The attractiveness of the SSF platform is essentially based on its cost-effectiveness compared with existing marginal platform concepts, whereby the main cost differentiators are the efficient use of materials and the installation method. The SSF platform consists of 3 conductors that support the small deck, the export riser and a ladder arrangement for safe access from a boat. The base of the structure comprises a frame, which incorporates suction cans and conductor guides. The conductors are simultaneously used as jacket legs and they are positioned approximately 7 meters from each other. They are braced by three frames that are positioned at the appropriate elevation to give adequate structural strength. The frames are being fixed to the conductors by means of grouting. The SSF platform is designed in such a way that it can cope with the installation limitations of the jack-up. Suction cans are positioned outside the working envelope of the jack-up rig, but since they do not require vertical access by the drawworks for installation, this is not a problem. In addition, no problems concerning lifting height or lifting capacity will occur, since the stacked frames can be installed separately should this be required [25].

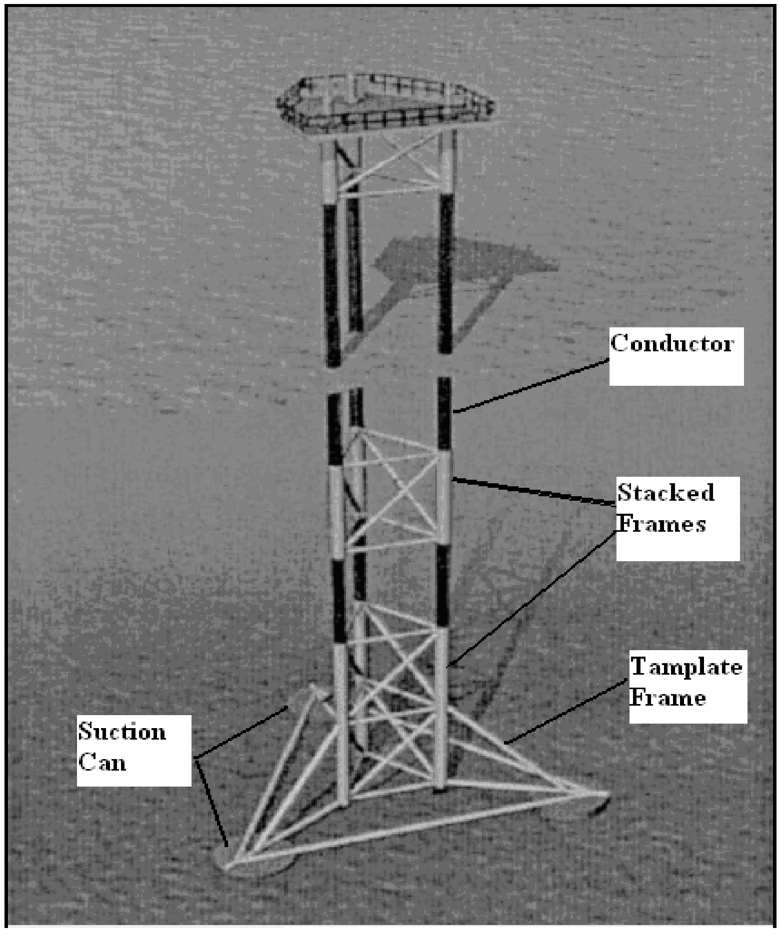


Figure 2.10: SSF platform concept

The advantages of the SSF platform can more explicitly be summarized as follows: The conductors are used in a multi-functional way. Apart from using the conductors for drilling activities, they are simultaneously used for foundation purposes and also serve as jacket legs The platform can be installed by a jack-up drilling rig (whilst retaining the crane barge installation as an option). Suction cans are used for foundation purposes, thus forming a hybrid foundation with the conductors. The benefit of using suction cans is that they do not require vertical access by a crane. Consequently they can be positioned outside the working envelope of the jack-up rig, resulting in a larger (and thus) favorable footprint for the platform. In addition it provides flexibility to adapt the platform to a range of water depths. The frames act as installation guides for the conductor. No helideck will be positioned on the platform. Any unscheduled access will be provided by a workboat, while a jack-up may make regular maintenance visits. This is quite uncommon in the North Sea, but it is considered legitimate for marginal field developments (Shell has successfully applied the idea to its Skiff and Brigantine field developments in the Southern North Sea).A large number of platform concepts are available in the industry and it has been found that many of these have similar characteristics so that they can be grouped together in eight generic groups of concepts. Figure 2.11 and 2.12 provides a more detailed overview of the platform dimensions in general and the various element sizes in specific.

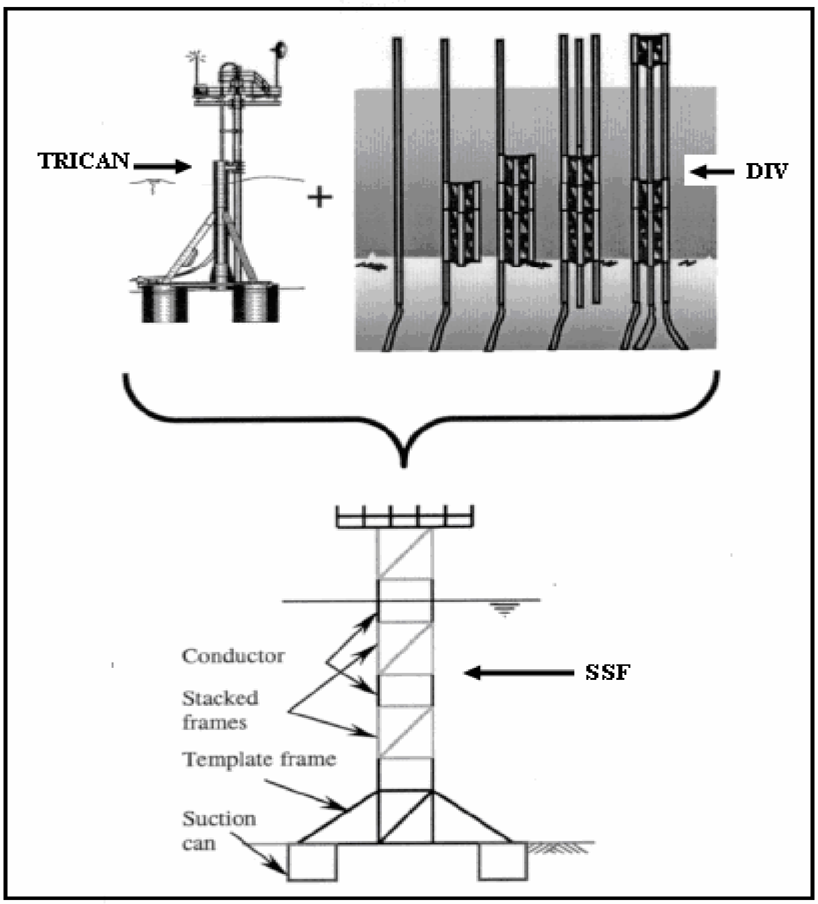


Figure 2.11: Combining the TRICAN concept and the DIV concept to the new SSF platform concept.

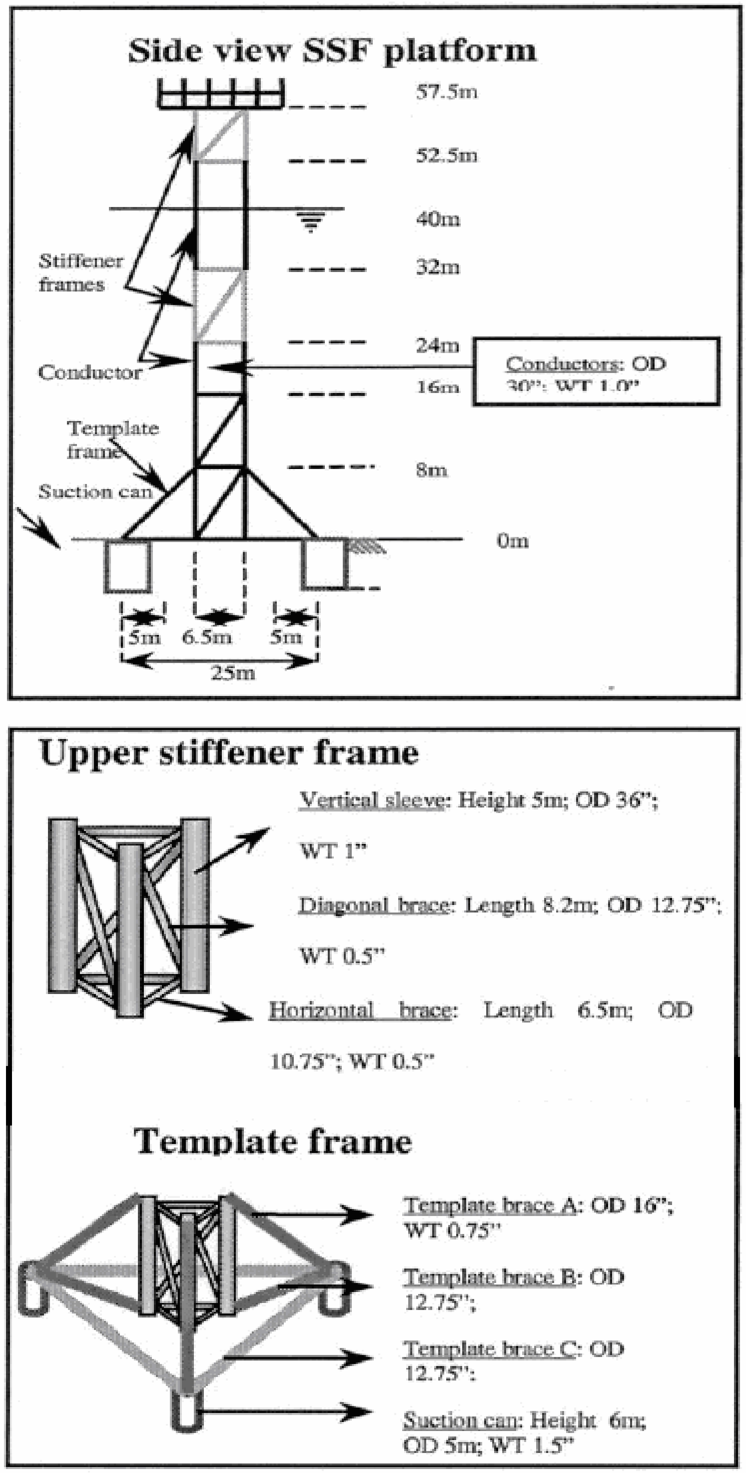


Figure 2.12: Configuration and dimensions of the SSF platform

c. Monopod Tower (one leg platform)

Single load carrying member more robust and bigger for larger topside weight but braced at the sea floor by a spread base, piled legs or braced columns.

A typical mono-tower is a large-diameter cylindrical shell supporting a deck structure and it transfers the functional and environmental loads to the foundation through the framing system and the piles. Typically, a monotower is supported by four piles at four corners of the framing system. The size of the monotower and the restraining system (i.e. framing system and piles) depend on the deck payload and the environmental condition. It is not possible to state that one structure type is superior to others. Whether an oil company selects a Tripod-, Caisson- or a Monotower-type structure depends on many factors including site water depth, foundation material and environmental characteristics, construction and installation considerations, decommissioning and removal cost, and most importantly, the management philosophy on field development option [22].

d. Tripod (3-Leged Platform)

In general, tripod is designed with several deck levels in order to provide minimum production equipment for multiple well completions. As the name indicates, it consisting of three legged platform, secured to the seafloor could be conventional, skirt piled extended base or suction piled. Platforms may be manned with living and support capabilities or unmanned with emergency quarters only. When possible the use of a Tripod provides a measurable cost savings over a traditional four legged jacket and deck

An innovative feature of Satellite Fields Development (SFD) project being undertaken by Esso Production Malaysia Inc. (EPMI) used a reusable tripod jacket designs will be reviewed. The SFD project, used consists of 6 small oil fields (Figure 2.13). These 6 fields, namely : North Seligi, Irong Barat, Lawang, Langat, Serudon and South Raya in water depth ranging between 65 – 75 m, with EUR reserves ranging from 9 to 28 MMstb oil per field (see Table 2.7). The crudes have pour points of minus 6 to +9

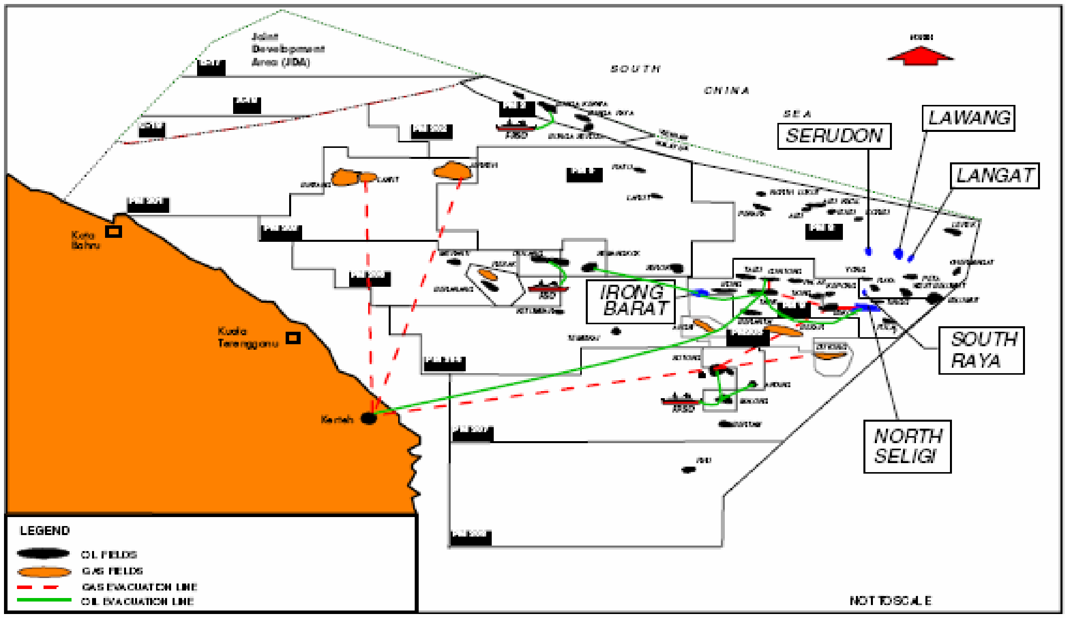


Figure 2.13: Fields locations offshore Peninsular Malaysia

Table 2.7: satellite fields development platforms development summary

DESCRIPTION	SELIGI-H	IRONG BARAT-B	LAWANG-A	SERUDON-A	RAYA-B
RECOVERABLE RESERVES (MMSTB)	16	14	39	11	9
WATER DEPTH (METER)	73	65	65	65	70
NO. OF WELLS	8	5	9	4	4
PEAK LIQUID RATE (KBPD)	10.1	4.3	25	9.6	10.1
PEAK GAS RATE (MMSCFD)	28	3.5	19	16.4	7.6
TRIPOD APPROX. WEIGHT (MT)	540	440	540	440	440
TOPSIDES APPROX. WEIGHT (MT)	480	430	480	430	430

degree Celcius. Their carbon dioxide (CO_2) level is below 4 mol% except for Irong Barat B which contains CO_2 level in the region of 22 mol%. There is no hydrogen sulphide present. Flowing wellhead pressures (FWP) and flowing wellhead temperatures (FWHT) range from 500 to 300 psig and from 30 to 100 degree Celcius respectively. Based on prudent reservoir management and field development plans (FDPs), the maximum production from these fields ranges from 4 to 25 thousand barrels per day (kbpd) liquid and from 4 to 28 million standard cubic feet per day (MMscfd) gas from 4 - 9 wells per field. The amount of gas is a sum of produced gas and gaslift gas.

To develop the 6 small oil fields concurrently, the engineering challenges for EPMI can be summarized as:

i. To conceive a cost-effective development concept for economic small scale production
ii. To provide stable offshore platforms that would be both practical and cost effective
iii. To adopt cost-effective technology for facilities and well completion
iv. To maximize synergy of concurrent development.

The system designed for the 6 fields comprises the following:

i. Fixed minimum facilities tripod platforms.
ii. Pipeline systems for Full Well Stream (FWS) production evacuation to host platforms and gaslift gas supply pipelines from the host platforms with subsea lateral tie-ins / hot taps to satellite fields (Figure 2.14).

The platforms will be standard tripod jackets with unmanned minimum facilities topsides with either 6 or 12-conductor slots (see Figure 2.15) and designed to accommodate the varying water depths. The topsides shall have a main deck, mezzanine deck and a production deck. A combination of solar modules and thermoelectric generators will be provided at each satellite for DC power generation. The multiphase meter technology will be adopted, therefore a test separator will not be provided. The

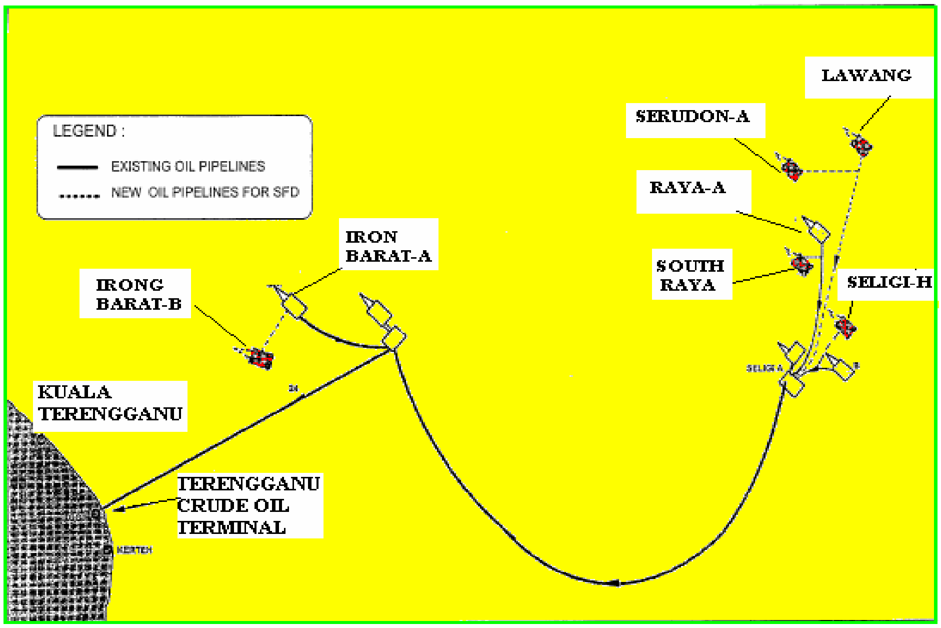


Figure 2.14: Satellite field development platforms and pipelines

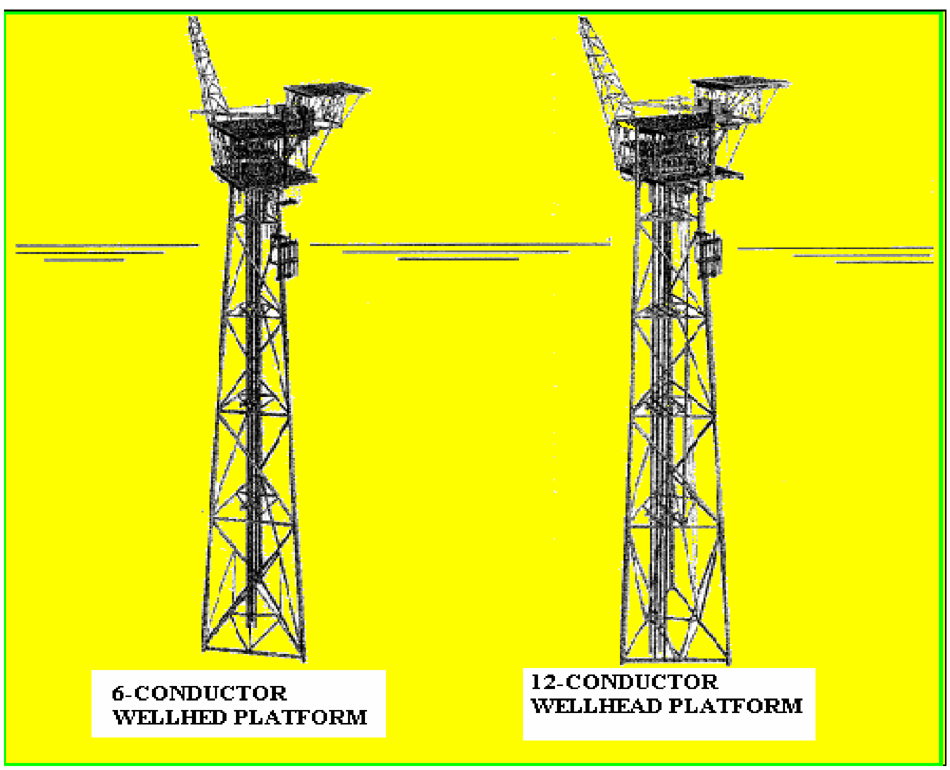


Figure 2.15: Two Tripod jacket designed based on bottom structure braces adjustment

flowlines and the multiphase flowmeters shall be sized to accommodate the maximum gas and liquid production rates ofeach platform.

The main deck is designed for wireline, coiled tubing unit (CTU) and hydraulic workover unit (HWU) workover capability. A pedestal crane with 13 metric tonnes (MT) lifting capacity will be provided. On the production deck, a closed drain vessel will be provided to facilitate initial well flowing equalisation and also for well unloading during workover operations. A shell and tube heat exchanger, a gas filter separator and an air-cooled heat exchanger will make up the gas treating system for the gaslift gas for the instrumentation system.

The platforms will be visited during daytime, and under weather conditions that allows safe access by helicopter or boat. A fusible loop system for fire detection will be installed at strategic locations on the platforms and monitored from the host platform. Manual shutdown, portable dry chemical fire extinguishers and gas detectors will also be provided for fire protection. Firewater pump, deluge system or hosereels will not be provided. A process control system for remote well testing, opening and closing of individual wells safety shutdown valves (SSVs) and remote resetting of certain shutdown valve will be provided for control and monitoring of the platforms from the host platform. Seligi-A will act as themhost platform for Lawang A, Serudon A, Raya B and Seligi-H. Irong Barat-A will be the host platform for Irong Barat-B. Produced hydrocarbons will be evacuated FWS to the host platforms. Both Seligi-A and Irong Barat-A provide the crude processing facilities and gaslift gas supply for the satellites. The stabilized crude and gas are then distributed to the crude and gas handling system of the offshore Peninsular Malaysia [21].

2.6.1.2 Conventional Fixed Platform:

Due to small recoverable reserve from marginal field, the conventional fixed platform sometimes may not be cost-effective method to development a marginal field; it require huge investment cost, therefore the use of conventional cannot be use unless justified by economic analysis. The 4-legged or 6-legged platform provide additional topside weight and space which can support drilling unit, well workover unit and installing secondary recovery equipment and pumps if required in future to increase the recovery factor and the overall project life.

2.6.1.3 Jack-up production Systems

Jack-up are normally used in drilling operations but may be used as a production support where topside weight and water depth are not limitations. Jack-up consists of a deck section, somewhat like a barge, and several truss or tubular telescopic legs. It is normally towed to the location with legs raised. On site, the legs are lowered to the sea bed and the platform is then jacked up to safe level above the sea. One of prerequisite for the use of this type of support is the suitability of the sea bed soil conditions and likely penetration of legs (Figure 2.16).

Figure 2.16 Jack up production platform (Ridgewood Energy)

The advantages of using a jack-up as a production support are as follows [2]:

a. The jack-ups are lease able and
b. They have all advantages of affixed platform in shallow water, no moorings required.
c. The have low abandonment cost and can be returned to drilling.
d. Wells and riser can be of conventional type.

The disadvantages of the jack-up are:

a. Limitations on topside weight and water depth operating range.
b. Limited to areas where soil conditions permit satisfactory support of the legs.
c. Fatigued problems could limit the utilization to several years unless costly alterations are made to structure.
d. No storage capability.

The basic production system consists, typically, of converted drilling jack-up unit which houses the production facilities with wellheads situated on the jack-up unit. Oil flows to the processing system and thence to a storage facility aboard an adjacent tanker.

2.6.1.4 The Compliant Tower:

These platforms consist of narrow, flexible towers and a piled foundation supporting a conventional deck for drilling and production operations. Compliant towers are designed to sustain significant lateral deflections and forces, and are typically used in water depths ranging from 1,500 and 3,000 feet (450 and 900 m).

The guyed tower is anther form of compliant structure. This structure is designed particularly for deep water field. The tower is supported by a piled foundation and its stability is maintained by a series of guyed wires radiating from the steel tower and termination on piled or gravity anchors on the sea bed. Weight three-fifths of the way down the guy wires will allow the structure to tilt without seriously affecting the tension of wires.

The guyed tower has the following advantages [2]: (a) In similar water depth it is much cheaper than conventional platforms; (b) It is easy to build because of design joints.

The disadvantages: (a) Unproved technology; (b) Limited payload. (c) No storage.
(d) Installation and maintenance costs of guy wires unknown [2].

A guyed tower is a slender structure made up of truss members, which rests on the ocean floor and is held in place by a symmetric array of catenary guylines. A guyed tower may be applicable in deep hostile waters where the loads on the gravity base or jacket-type structures from the environment are prohibitively high. The guylines typically have several segments. The upper part is a lead cable, which acts as a stiff spring in moderate seas. The lower portion is a heavy chain with clump weights, which are lifted off the bottom during heavy seas and behaves as a soft spring making the tower more compliant. It resembles a jacket structure, but is compliant and is moored over 360" by catenary anchor lines [22]:

2.6.2 Floating Production Facilities

The marginal fields, as mentioned earlier, could found in beyond practical fixed platform limits. Thus floating production systems (plus in many case the subsea completion) now provide the viable options in deepwater.
Floating systems have four common elements [6]:

a) **Hull:** The steel enclosure that provides water displacement. Floating systems come in shipshape, pontoons and caissons, or a large tubular structure called spar.
b) **Topside:** The deck or decks have all the production equipment used to teat the incoming well streams plus pumps and compressor needed to transfer the oil and gas to their next destinations. Some have drilling and workover for maintaining wells. Since almost all deepwater sites are somewhat remote, their topsides include living accommodations for the crew. In some cases, export lines connected at the deck also.

c) **Mooring**: The connection to sea bed that keeps the floating systems in place. Some combined steel wire or synthetic rope with chain, some use steel tendons. In some cases, they make a huge footprint on the seabed floor.

d) **Riser**: Steel tubes that rise from the sea floor to the hull. A riser transports the well production from the sea floor up to the deck. The line that moves oil or gas in the other direction, from the deck down to pipeline on the sea floor, uses the oxymoron export risers.

2.6.2.1 FPSO/FSO

Most floating production units are neutrally buoyant structures (which allow six-degrees of freedom) which are intended to cost-effectively produce and export oil and gas. Since these structures have appreciable motions, the wells are typically subsea-completed and connected to the floating unit with flexible risers that are either a composite material or a rigid steel with flexible configuration (i.e. Compliant Vertical Access Risers). While the production unit can be provided with a drilling unit, typically the wells are pre-drilled with a MODU and the production unit brought in to carry only a workover drilling system. The FPSO generally refers to ship-shaped structures with several different mooring systems. Early FPSOs in shallow waters and in mild environment had spread mooring systems. As more FPSOs were designed and constructed or converted (from a tanker) for deepwater and harsh environments, new more effective mooring systems were developed including internal and external turrets. Some turrets were also designed to be disconnectable so that the FPSO could be moved to a protective environment in the event of a hurricane or typhoon [22].

The DP-FPSO provides a flexible and highly mobile floating production solution, suitable for a range of applications. In a remote deepwater area the floating facility allows for a stand-alone field development [26].

2.6.2.2 Tension-leg platform (TLP)

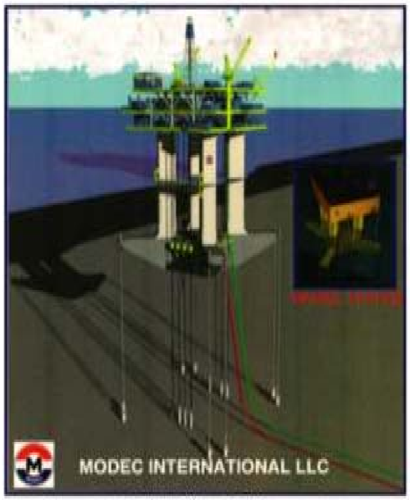
In parallel with the beginning of exploration for oil and gas reserves in deep water, major oil companies began developing platform concepts to exploit deepwater discoveries. Tension-Leg Platform (TLP) technology emerged as a cost-effective means for providing stable deepwater real estate for drilling and production operations [27]. A Tension Leg Platform (TLP) is a vertically moored compliant platform. The floating platform with its excess buoyancy is vertically moored by taut mooring lines called tendons (or tethers). The structure is vertically restrained precluding motions vertically (heave) and rotationally (pitch and roll). It is compliant in the horizontal direction permitting lateral motions (surge and sway).

A challenge for TLP designers is to keep the natural periods in heave and pitch below the range of significant wave energy. Heave period may be controlled by increasing the pipe wall thickness of the tendons. Pitch period may be reduced by placing the tendons on a wide spacing to increase stiffness. However, it makes the support of the deck with large spans expensive. The Extended Leg TLP or ETLP was introduced by ExxonMobil . This concept has four columns on a closer spacing than normal, ring pontoons and pontoon extensions cantilevered to support the tendons on a wide moment arm. Tension Leg Platform technology preserves many of the operational advantages of a fixed platform while reducing the cost of production in water depths up to about 4900 ft or 1500 m. Its production and maintenance operations are similar to those of fixed platforms. However, TLPs are weight sensitive and may have limitations on accommodating heavy payloads. There are two cost-effective types of miniTLP used in marginal field [22]:

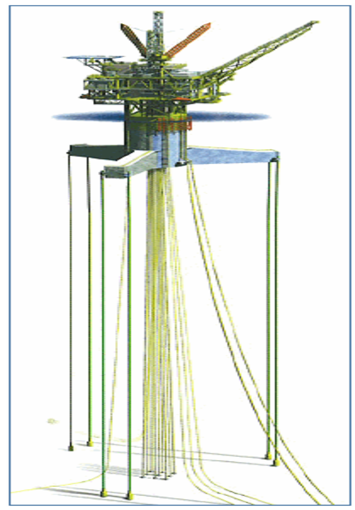
(a) **SeaStar TLP.** SeaStar is a deepwater production and utility mini-platform (see Figure 2.17(a)). It borrows from the concept of the tension leg platform and provides a cost-effective marginal field application. SeaStar is a small TLP with a single surface-piercing column. The column is necked down near the sea surface to reduce surface loads on the structure. The submerged hull spreads into three structural members at the bottom in a triangular fashion, which are used to support and separate taut tubular steel tendons. The hull provides sufficient buoyancy to support the deck, facilities and flexible risers. The excess buoyancy provides tendon pretension. SeaStar is generally towed or barged to site in a vertical position. But due to small waterplane area of its single column hull and low centre of buoyancy, it cannot carry the deck with it. Generally, the deck is mated on site similar to Spar once the tendons are connected and tensioned. The deck structure of SeaStar is supported by a single column with three pontoons converging at the keel of the column. At the end of each pontoon, two symmetrical porches are built-in to attach the six tethers, two at each pontoon. The hull is dry towed to the installation site, ballasted and connected to the tethers. Then, the deck is lift installed on a stable platform In developing the SeaStar platform, emphasis was placed on applying platform concepts developed in the evolution of the SeaHorse platform, wherever possible. While the SeaStar's hull is unique, the deck's support structure was created by incorporating the SeaHarvester's spider deck into the lower deck's framing, to create an under-deck truss. This truss allowed for a reduction in the diagonal framing between the deck levels, providing a more effective utilization of space for the equipment. For fixed platforms, from project award to loadout, including installation of the production facilities, onshore hookup and commissioning are often completed in less than sixteen weeks.

(b) Moses TLP. Moses MiniTLP appears to be a miniaturized TLP as the deck structure is supported by four columns and the columns are connected by pontoons(see Figure 2.17(b)). Motion characteristics of Moses is similar to that of SeaStar and, unlike the standard TLPs, miniTLPs need to dedicate a large percentage of their displacement (3545%) for pretension [22]. The deck structure of Moses is supported by four closely spaced columns connected with pontoons at the keel. Tethers are connected to pontoon extensions to increase the lever arm and reduce tether pretension requirements. Eight tethers, two at each pontoon extensions, connect the unit to the seafloor. A

TLP has 3-degrees of freedom and the restriction of pitch and roll results in large tendon tension variations. Thus, high initial tendon pretensions are required to prevent the tendons from buckling under compression.



(a)



(b)

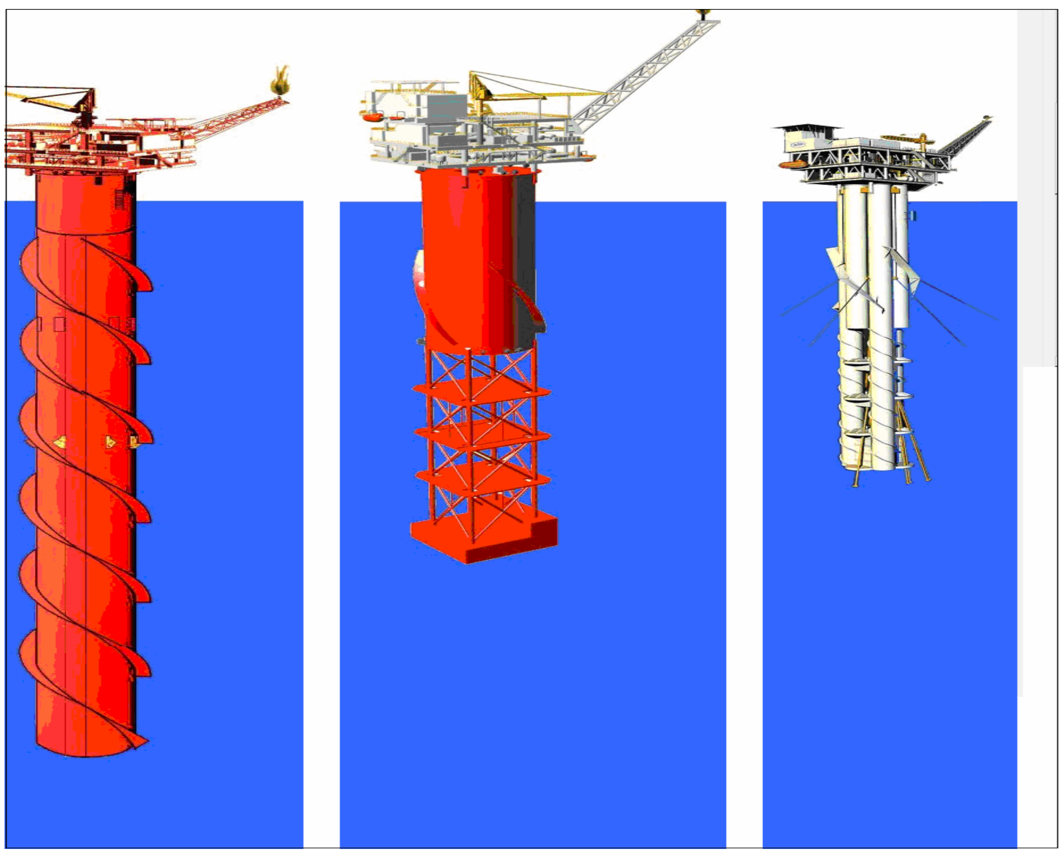
Figure 2.17: (a) Moses TLP (Source www.intecengineering.com/images/journals/moses.jpg)
(b) Seastar TLP (Source www.rigzone.com/news/image_detail.asp?img_id=2149)
[Matterhorn SeaStar]

2.6.2.3 SPAR

The Spar concept (figure 2.18) is a large deep draft, cylindrical floating Caisson designed to support drilling and production operations. Its buoyancy is used to support facilities above the water surface. It is, generally, anchored to the seafloor with multiple taut mooring lines the lower section consisted of "soft tanks" which were only used to allow horizontal flotation of the Spar during installation, and for holding fixed ballast, if necessary. Subsequent Spars replaced the middle section with a truss structure to reduce weight and cost, and to reduce current drag. Horizontal plates were included between the truss bays to trap mass in the vertical direction to minimize heave motions. Figure 1.18 shows these two types of Spars, the "classic" and the "truss" Spars.
A third generation "cell" Spar was introduced in 2004. It performs similar to the other Spars, but it is constructed differently. The hull consists of multiple ring-stiffened tubes, or "cells", which are connected by horizontal and vertical plates. This method of

construction is cheaper than the traditional plate and frame methods. Because of the length of a Spar, the Spar hull cannot be towed upright. Therefore, it is towed offshore on its side, ballasted to a vertical attitude and then anchored in place. The topside is not taken with the hull and is mated offshore once the Spar is in place at its site. The mooring cables are connected with pre-deployed moorings [22].

A Spar has 6-degrees of freedom and its keel has to be far below the water surface to minimize the dynamic heave motions in order to achieve acceptable operating motions. Consequently, a large hull displacement is required yielding a high displacement-to-deck payload ratio.



Classic SPAR **Truss SPAR** **Cell SPAR**

Figure 2.18 Spar structure concept. (Source www.globalsecurity.org**)**

2.6.2.4 Semi-Submersible Production Systems

Semi-submersibles are multi-legged floating structures with a large deck. These legs are interconnected at the bottom underwater with horizontal buoyant members called pontoons. Some of the earlier semi-submersibles resemble the ship form with twin pontoons having a bow and a stern. This configuration was considered desirable for relocating the unit from drilling one well to another either under its own power or being towed by tugs. Early semi-submersibles also included significant diagonal cross bracing to resist the prying and racking loads induced by waves.

The introduction of heavy transport vessels that permit dry tow of MODUS, the need for much larger units to operate in deep water, and the need to have permanently stationed units to produce from anoil and a gas field resulted in the further development of the semi-submersible concept. The next generation semi-submersibles typically appear to be a square with four columns and the box- or cylinder-shaped pontoons connecting the columns. The box-shaped pontoons are often streamlined eliminating [21].

The basic production systems consist of a conventionally moored semi-submersible housing the production facilities, which is linked to a subsea system by a riser. The subsea system consists typically of a template with a number of satellite wells feeding to a riser base which may incorporate a subsea manifold. Oil flows to the processing facilities on the semi-submersible and return to the sea bed when it is pumped to an offshore storage or loading system

The concept has several inherent advantages:

(1) Accelerated production from the reservoir, since the well can be pre-drilled in advance of production installation being taken offshore.

(2) Onshore and inshore construction the semi-submersible production installation is less costly than offshore construction and hook-up of conventional structures.

(3) The production semi-sub can be re-used once the reservoir has been depleted. Thus the production semi-sub can be leased for production period.

However the concept has a number of significant drawbacks. These principally related to the deck load capacity of semi-sub, the disposal of associate gas, the reliability of the riser system and the operational down time attributable to offloading system [2].

2.6.3 Subsea Development Systems

A sub-sea development option, (that is, a development without a permanent surface platform) was evaluated. In this scenario, individual wells would be drilled, and once completed; a control system of valves and pipelines would be placed on the seafloor. The drilling rig would be moved off the location and shifted to its next work location. The oil and gas would come to these facilities on the seafloor, be transported in pipelines along the seafloor to a central gathering location and then piped to the Onshore Processing Facility (see figure 2.19).

For a no-platform option, methods would need to be developed to ensure the continuous and safe functioning of the seabed facilities under conditions of ice. For example, the lack of access to the wells during winter, when they would be under ice is a factor to consider. Since there are no major projects in the world producing gas from sub-sea completions under seasonal ice.

Subsea production is not a new approach to economic offshore development, but at a time when many of the world's major offshore oil & gas fields are reaching maturity and new discoveries tend to be smaller, it's crucial for companies to exploit in the most cost effective manner available. Recent advances in subsea technology have enabled the cost effective production of smaller and marginal fields transforming them into profitable assets. Companies already use subsea systems to tap oil and gas into two ways. First, they connect smaller fields to existing infrastructure, obviating the killer cost of brand new platform. Second, subsea systems also have a place where no infrastructure exists. A combination of smaller fields, close to each other but not reachable by directional drilling and each not large enough to support its own platform, can be developed with asubsea system. Subsea production equipments become a feature of marginal field development schemes. There are five basic elements in a subsea production system i.e. template, wells, manifold and control system. The specific configurations of these elements are defined by the reservoir characteristic and the other components of the development scheme, particularly the riser [2].

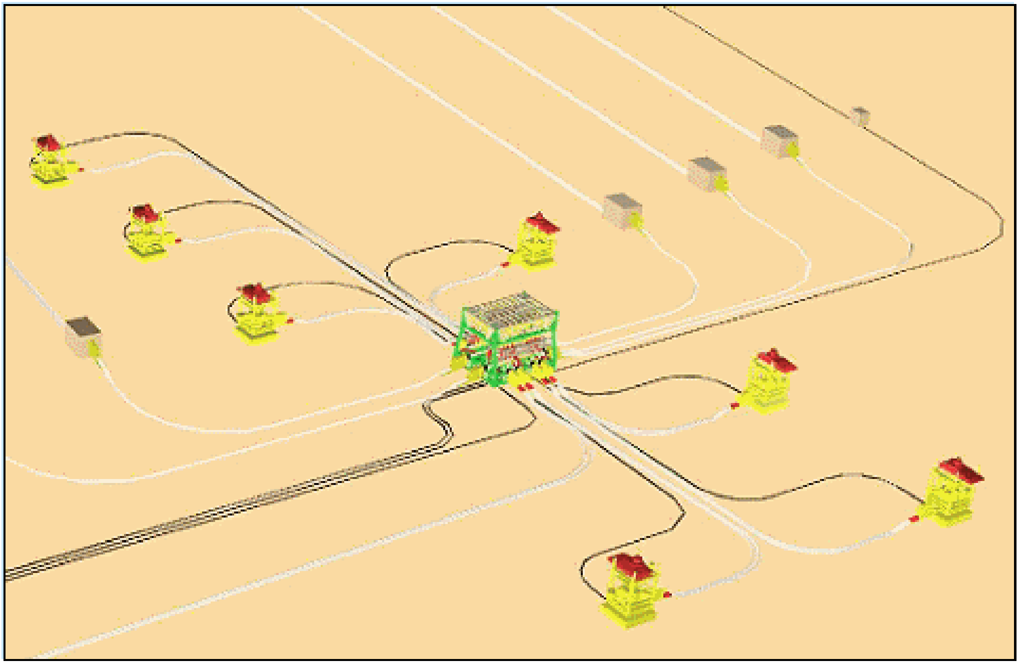


Figure 2.19 Subsea Development (Source: www.verderg.com/index_files/image2482.jpg)

a. **Subsea template.** Subsea template is a large tubular steel structure designed to accommodate a number of wellhead assemblies and Christmas trees for wells which may be either production or injection well. The purpose of the template is to provide a base through which the subsea wells are drilled; it also spaces and aligns wellhead equipment. Templates may be either of unitized construction for six or more wells have to be drilled or modular construction consists of several interlocking modules, and is used where greater flexibility in the drilling programme is required. The template is normally piled to the sea bed.

b. **The wells.** The fist general classification of wells, wellhead equipment and Christmas trees is whether they are subsea or surface. For the purpose of this section we will consider only subsea configurations**.** The second general classification is between wet and dry subsea wells. Wet wells are those in which the Christmas tree and associated equipment is open to the marine environment while dry subsea tree wells are normally encased in a habitat which is at atmospheric pressure. The latest development is insert tree concept is attempt to lower the substantially the profile of the tree by putting as much of the tree equipment as is possible downhole.

c. **The subsea Manifold.** The subsea manifold is the interface between the subsea production equipment and the production riser system. The manifold acts as the subsea point at which the production/injection flowlines and transport/export pipeline are gathered. The factors which affect the manifold design are riser type, the nature of fluid, the number and location of the wells, the maximum allowable pressure drop, the maximum flowrate , the maintenance employed (TFL or non TFL) and the need for pipeline pigging/scraping from the floating unit. This element of manifold is extremely important for marginal field systems employing floating production supports.

d. **Umbilical.** It provide the connecting media for electrical, hydraulic, chemical injection, and fiber optic connection between the topsides facilities on the host platform and various subsea items – the manifold, sleds, termination structures, subsea trees, and control. The number and the character of this umbilical vary according to specific system needs and development plans [6].

e. **Subsea Control systems** There are two basic methods for controlling wellhead equipment- hydraulic and electrical control. Hydraulic Control systems, include direct, piloted and sequenced hydraulic, have the advantage that they are simplest, most reliable and lowest cost type of control system depending, as they do, on the flow of hydraulic fluid to actuate the command. However, the significant disadvantage of hydraulic control systems for oil and gas operations is the slow respond time. Therefore, in the case of subsea wells being controlled from a production support up to 8 km away these respond times tend to be unacceptable for what may be emergency operation. Also hydraulic bundles tend to be bulky items and should be avoided if possible. Electrical control systems has the advantage of very short respond times but the proven unreliable in practice because of inherent weakness in each control method a hybrid system (electro-hydraulic) has been devised which utilizes the strength of each individual method.

The use of an intelligent completion coupled with a subsea technology can turn a potentially uneconomic prospect into a feasible one. Use of intelligent completion technology both saved slickline time and potentially additional time if coiled tubing had been required. Typically, the application of intelligent completions to subsea wells is associated with large scale, high rate production in deepwater development fields [28].

2.7 Marginal Field Development Costs

The review of generic development concept for marginal field would be incomplete without some discussion of the costs of various options. The accuracy of cost estimates tend to vary dependent on information available and the purpose [29].

2.7.1 Types of Costs

There are three types of costs involved in a project in upstream petroleum industry. This comprises [1]:

1) The exploration costs incurred mainly before the discovery of a hydrocarbon deposit. This includes the seismic geophysics, the geological and geophysical interpretation, and exploration drilling including the well tests.
2) Development investment, which include:
    a. Investment cost incurred in the delineation and appraisal phase, necessary to gain knowledge of the reservoir;
    b. Drilling and The production wells and, if appropriate, the injection wells;
    c. Construction of the surface installations such as the collection network, separation and treatment plant, storage tanks, pumping and metering units;
    d. Construction of transport facilities such as pipeline and loading terminals;
3) Operating costs including transportation costs.

2.7.2 Key parameters of development cost:

The capital cost of development an oil or gas field may amount to several billion dollars. It is crucial that the key parameters are identified and evaluated so that the project can be properly defined and its viability assessed, because some of these parameters strongly influence the costs.

I. Situation of the field water depth which may be conventional, deep or ultra-deep
II. Mete-Oceanic conditions. Production oil and gas in hostile environmental means costly production installation.
III. Reservoir type and behavior. These reservoir parameters determine the number of wells required, and whether water or gas injection will be needed during the lifetime of the field.
IV. Composition, pressure and temperature of the effluent

2.7.3 Drilling and Associated Cost:

Cost of drilling and completion offshore wells vary in proportion to number days required to drill each well. This in turn is dependent on the depth of reservoir and the amount of deviation requires [2]. Before a drilling programme is approved it must contain an estimate of the overall costs involved. When drilling in a completely new area with no previous drilling data available the well cost can only be a rough approximation. In most cases however, some previous well data is available and a reasonable approximation can be made.
Well costs can be divided into several categories [13] refer to appendix 4.1:

2.7.3.1 Fixed costs.

Fixed costs are the same no matter how long the well takes to drill or how deep it is drilled. Typical costs related to moving the rig on location, mob/demobilization and surveying the well location.

2.7.3.2 Time-related costs.

Costs are related to time (e.g. drilling contract, transport, and accommodation). A large proportion of the total cost of the well comes from the time it takes to drill the well. The larger time –related cost will be the rig itself. Other time-related costs will include equipment on daily rental, personnel, vessels, helicopters, fuel, water, shore base, and dock fees.

2.7.3.3 Depth-related costs.

Depth related cost increase as the well deepens. Typical depth dependent cost relates to casings, cement, completion tubings, drilling fluid, and drill bits

2.7.3.4 Support costs.

Overhead are the costs that are incurred by the office and the other off-rig activities.

2.7.3.5 Contingency costs.

There are some problems that can be expected to occur, with small or large probability that any particular problem will actually occur.

2.7.4 Facilities Costs:

There are two costs for purpose-built of new production systems costs or converted cost of existing drilling unit to production and drilling units. The costs include the engineering cost, martial procurement, fabrication cost, installation and hook-up commissioning cost. The basis cost estimation for 3 legged WHP is carried out in appendix 4.2.

2.7.5 Decommissioning and Abandonment Costs.

Many projects incur significant expenditure relating to decommissioning , site clearance, and it is important to consider the implication for cash flow evaluation [30] Decommissioning and abandonment costs are still relatively unknown and any estimate of costs involved is necessary very tentative at this stage as national and international regulations, governing the requirement for field abandonment.

A marginal field abandonment operation includes abandon and decommissioning each well, topside, jacket, riser systems, flowline, umbilical and template etc. The experience shows that the abandonment cost about 40% of total project capital expenditure exclude intangible drilling costs.

2.7.6 Operating Cost Estimation:

Operating expenses are divided into two croups direct and indirect operating cost. The direct operating cost generally must be developed from historical records for property or from nearby similar operations. And indirect cost, recent study determines that as a fraction would be 9% of capital and 11% of direct operating cost [31].

CHAPTER 3

METHODOLOGY

3.1 Study Approach and Methodology

The methodology adopted for this study is literature review. Review and analysis of actual marginal field development concepts, novel marginal field, and criteria used for options selection and development strategies around the world .Review of technical innovations which make marginal field economically viable.

3.2 The Work Phases

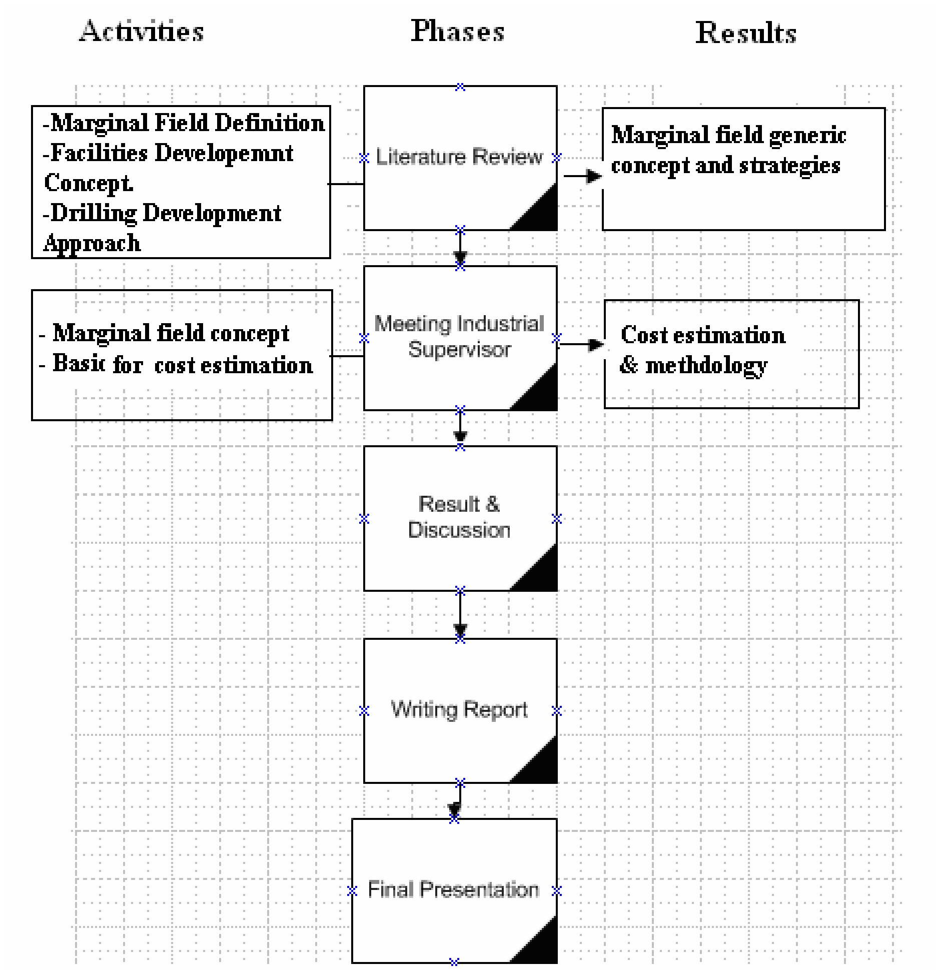


Figure 3.1 Study Flowchart

CHAPTER 4

RESULTS & DISCUSSION

Development progamme of marginal field should reduce the total project commitment cost (capex and opex), applying appropriate technology and increasing the production rate in order the improve and enhance the rate of return on investment. The key issue required here to successful develop a marginal field is to reduce development costs/bbl. Thus, the reduction in development costs while maintaining the reserve or increase the production rate while maintaining the costs must be the main task for project teams. The major cost components for developing a marginal field are drilling development costs, facilities costs, operating cost and abandonment cost. From the research findings the following results can be important for marginal field which fulfill the requirements mentioned above:

4.1 Reduce Development Costs

4.1.1 Reducing drilling costs

Drilling cost can be reduced by using slim-hole (see Appendix 2.1) well combined with coiled tubing drilling, therefore, slime-hole drilling provide smaller drilling crews, less drilling time and drilling strings will be lighter, therefore smaller drilling rigs could be used. Further, Use of this slime-hole well combined with monobore technology (see Appendix 2.2) can achieve cost optimization and help in the successful drilling by allowing the well to be drilled to TD in a small-hole interval and 32 % drilling cost reduction as shown in table 4.1. The split well technology can enable more than one independent well to be drilled, cased and completed from one shared single conductor and thus reduce the number of slots per platform for the same number of well to be drilled . The wellheads applied in SF 30 in Malaysia offshore and reduce from 12 to 3 conductors and cost saved$ 2 Million US (year 2000). Thus the cost of conductors is minimized.

Also, use of intervention-less production packer setting technique (Appendix 2.3, 2.4) reduces the completion costs. If a marginal reserve is found in unconsolidated sand an effective sand control method should be used. Therefore, the use of cost-effective thru tubing gravel pack or TTGP (see Appendix 2.5, 2.6) will be more attractive because the operation does not require workover rig since the coiled tubing unit is capable of performing full scale TTGP operations.

Table 4.1: Conventional well vs Slim-Hole well drilling costs

Wells Cost	Conventional Wells	Slim Hole Well	Cost Reduction
Time -Related cost	2,670,000	1,620,000	39%
Depth -Related cost	910,000	546,000	40%
Fixed Cost	1,237,000	989,000	20%
Support Costs	876,858	745,000	15%
Total Cost	**5,693,858**	**3,900,000**	**32%**

4.1.2 Reducing Facilities costs

The marginal field is needed to be developed by cost-effective and fit-for-purpose production support unit to reduce the capital cost of facilities that allow economic development. In shallow water depth, the unmanned light structure platform will be the attractive option for small reserve due to high reduction in investment cost by such as short project schedule, reduce material required for construction (see Table 4.2).

The offshore installation costs are the key cost driver for a marginal platform. These costs can in many cases amount to about 50% of the total platform costs; especially if the installation is taking place using scarce, purpose-built and high-cost heavy lift installation vessels. The issue drive to use innovative platform structure such as caisson and monopod it is principal feature that it can installed by jack-up drilling rig as part of drilling program. Depend on 3-legged platform concept, in Malaysia Offshore, the development cost have been improved from 120M$ to 26 M$ per platform (year1990)

Table 4.2: Facilities development costs

Water Depth	Reserve mmbbl	Number of well	Type of facilities	Topside Weigt tonne	A proximate Development Costs US $M
From Existing Platform.	1.00	1.00	ERW		NA
0-100	4.00	up to 6.00	Monopod	0-150	Up to 12
0-100	10.00	8.00	Jack-up	0-150	Leasable
0-100	20.00	6.00	3-leg WHP	450	Up to 30

4.1.3 Optimizing the operating cost

The operating success of the marginal project can be attributed to identifying, selecting, and implementing the most economical operating strategy. The primary reason for evaluating operating strategies is because of the marginal aspect. Therefore, it is essential that the operating plan must be economical and practical. Leverage operating expenditure (OPEX) through sharing and maintaining operational control; this will provide further opportunities, which can be leveraged with other operators in the area.

4.1.4 Reducing abandonment cost

For marginal field the abandonment costs could be minimized which would reflect positively on project profitability. In general the use of mobile facilities such as floating vessel, crude export via tanker will reduce the decommissioning cost. Therefore, the only fixed installations are the subsea wellheads which need be abandoned using especial facilities.

4.2 Increase and accelerate the production rate

Increase the production rate can improve the project NPV, this can achieved by using of a horizontal well which improve the production rate and educe the number of wells required. Also use of multilateral well can increase the recoverable reserve per well and reduce the overall number of wells required.

4.2.1 Marginal field development strategies

From the review of developed marginal field and novel field the Marginal field should be developing by use of suitable strategies that reduce the development costs and maximize the recoverable reserve. And therefore, improve the project economics. These strategies include:

4.2.2 Earlier production strategy

Early production systems (EPS) is used to maximize data acquisition while minimizing development costs and generating cash flow. They allow commercial production and evaluation using dynamic data to be carried out simultaneously.

4.2.3 Fast-track schedule strategy

The minimal platform concept fit well with their development philosophy by decreasing capital expenditures and reducing the time required to bring new production on stream.
A fast-track schedule is a way to reduce capital expenditures. Can be done by standardization and optimization of the structural design, through the reduction of complex joint framing details and design of easy-to-fabricate box sections for the jacket, helped to reduce fabrication time requirements

4.2.4 Sharing nearby processing platform

The basic sharing existing platform concept is to improve the project economics by use of existing nearby infrastructure such as processing platforms and pipelines as opposed to building or buying a new facility. This strategy enables utilizing the benefit of economies of scale.

4.2.5 Lease of equipment strategy:

Leasing Production Facilities will reduce the capital costs and reduce the risks; this will influence the project cash flow. The suitable equipments for leasing strategy are FPSO, Jack-up production system and semi-submersible production unit.

4.3 Guide line to select the development options and strategies

To select the development options and ensure chosen of better and optimal alternatives for economic evaluation the following factors must be considered and analyzed:

a. **Water depth.** The marginal fields that located in shallow waters are produced using platform structures while deeper water would require floaters. In shallow waters surface completions are favoured due to low cost of well intervention and with the use of minimal unmanned facilities may provide a lower cost over the field life as opposed to a subsea completion. But in deeper waters the normal concept is subsea completions and tie-backs to FPSO or existing processing platform.

b. **A proximity to infrastructure.** The proximity of nearby infrastructure is critical to selection of development strategy and also the technology to be applied. The presence of this other structures will make for sharing existing Host platform strategies as well as Shared Production facilities. The lower initial CAPEX, CAPEX conversation to OPEX through leasing and other previously identified advantages will impact significantly the viability of such marginal prospects. Absence of these will necessitate stand alone solutions which involve greater commitment and risk on the part of the marginal operator.

c. **Reserve and prudent reservoir management.** The reservoir development plan and the type of recovery mechanism have significant influence to type of facilities to be selected. For example use of water injection to increase the oil recovery and maintain reservoir pressure requires drilling water injection well and injection equipment which take space and weigh on the platform.

d. **Field life.** The field life is an important factor which influence to the selection of concepts and strategies.In general, field life influences the choice between strategies that involve leasing of facilities and installation of new structures. The short field life developments have higher profitability with the options low CAPEX investments. As the field life gets longer the advantage may be lost and a higher CAPEX investment in permanent facilities may be more beneficial.

CHAPTER 5

CONCLUSION AND RECOMMENDATION

5.1 Conclusion

(1) Marginal field is a limited reserve that may not produce enough net income; a minimum required return on investment, to make it worth developing at a given. However, as oil price raise and advanced technology emerge this marginal field may become economical attractive.

(2) To develop a marginal field it is important to substantially reduce both operating and development costs. Reserves of marginal fields provide an even greater challenge in finding ways to develop these resources. Successful planning of the development of marginal fields should focus on increase profitability by reducing development costs, these can be achieved through reduce drilling cost; by increasing drilling efficiency and drilling time and evaluate use of such a slim-hole drilling result in 32 % cost reduction, underballanced drilling, coiled tubing drilling, monobore completion method which tend to save costs , drill a horizontal well which expected to optimize production rates and increase reserves recovery in the thin oil column reservoirs, and will enhance the rate of return on the project.

(3) Light structure platforms such as monopod, tripod, caisson and braced caisson are often good concept for small reserve in shallow water which significant reduce the costs and allowed many marginal field to be brought on steam. The installation of this light structure may do using jack-up drilling unit which daily rate is lower than huge barge. Depend on 3-legged platform concept the development cost could be educed from 120M$ to 26 M$ per platform (year1990) in Malaysia Offshore.

(4) In marginal field development should considering in re-useable equipment for future applications whereby considerable number of small fields may need to be developed. A subsea completion concept with a tie-back to a host platform was economically feasible if development costs were minimized. An intelligent well system was used to minimize the need for intervention throughout the life of the well.

(5) The marginal field that found in deepwater the technologies such mini-TLP, DP-FPSO, and Spar are important aspect to make this small reserve economical feasible. The Seastar and Moses TLP is found cost-effective means for providing stable deepwater real estate for drilling and production operations. DP-FPSO concept combined with subsea technology is a very good application for standalone remote marginal field. Reduce project uncertainty by deep evaluation on development feasibility and reduce risks in geology as much as possible is an important measure for assessing the possibility to develop a marginal oil field.

(6) Integrated 3-D seismic attributes and geologic models are powerful tools to aid mapping the distribution of a reservoir.

(7) Also an effective development of marginal reservoirs requires multidiscipline teamwork from the planning stage through execution. Probabilistic modeling is found to be critical to properly assess risk in the development of marginal to economic evaluation.

(8) Marginal field should be developing by select of suitable strategies that reduce the development costs and maximize the recoverable reserve. And therefore, improve the project economics. These strategies include EPS, Sharing existing processing platform, leasing production equipment

(9) Finally, there are several elements that require deep study and evaluation to select the suitable and optimum development strategy and options these criteria

include; Reservoir Characteristics and modeling, drilling, production and export requirements, site and Environmental Characteristics, design philosophy, rules and regulations, reduced capital investment and minimum abandonment costs

5.2 Recommendation:

The project work could not cover a wide range of scope as intended due to time constraints, confidant to get relevant cost data and permission to visit fabrication yard. Hence, the following aspects have been recommended for further work in the area of marginal field development costs:

(1) A detailed steel weight for jacket of monopod, tripod and 4-legged platform versus water depth and topside weight is required as basis for jacket cost estimation.

(2) A detailed study of weight of topside steel and determine main equipments and their costs as required to specific production profile and number of wells..

(3) Detailed costs estimation and analysis for vertical, deviated, horizontal wells drilling which gives quick drilling costs estimate. Also cost of injection well if needed to increase the reservoir pressure and enhancement of recovery factor.

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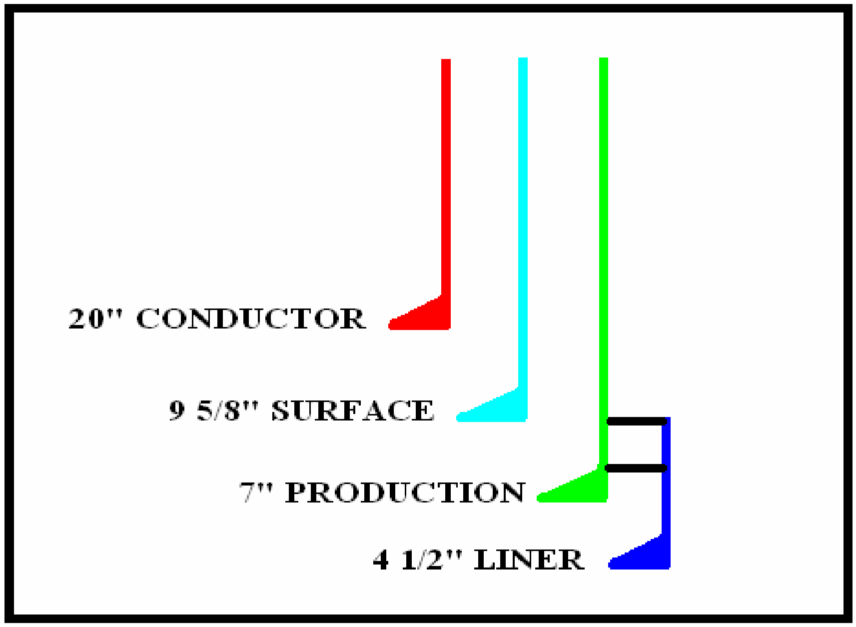
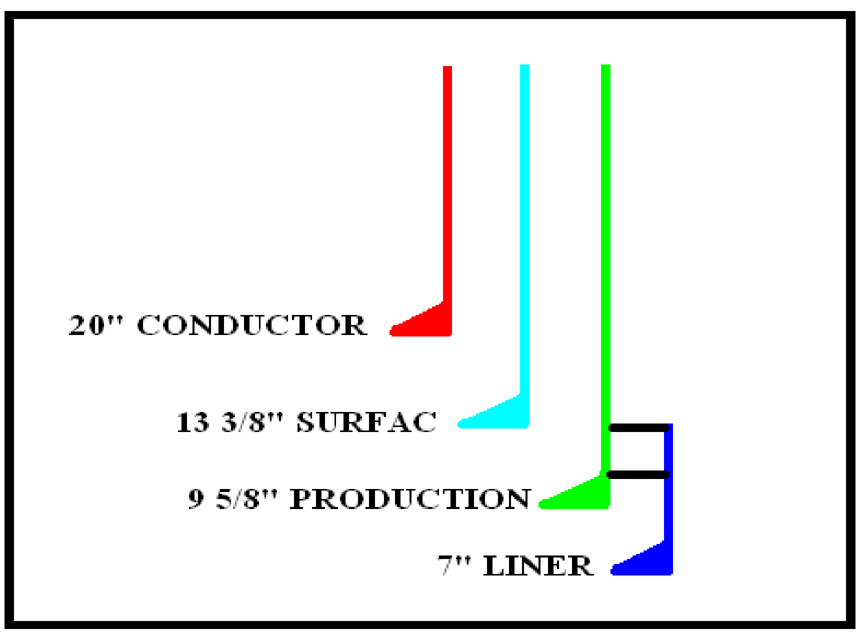
Apendix 2.1 : Slim Well Completiom

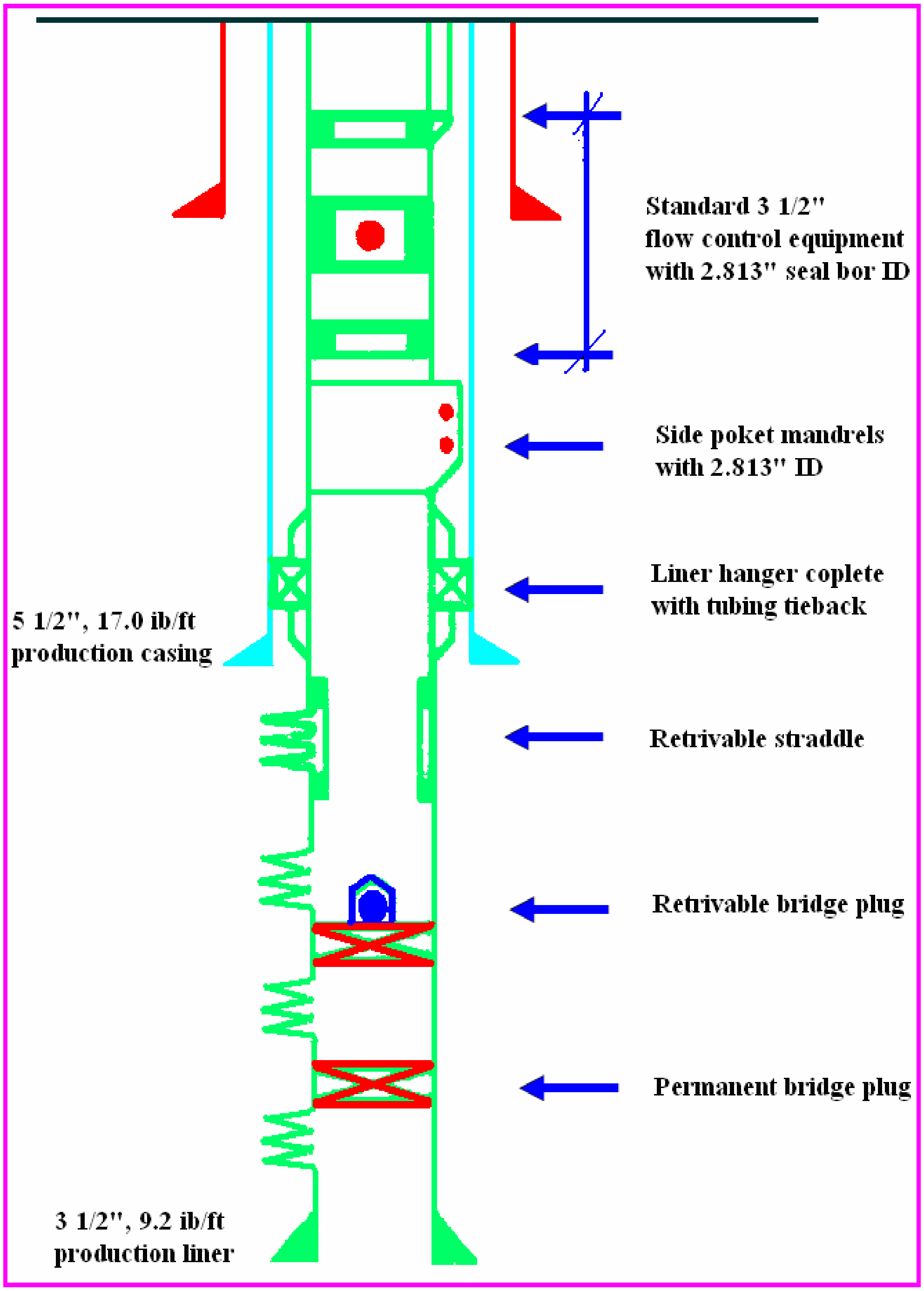


Slim-hole (single) completing

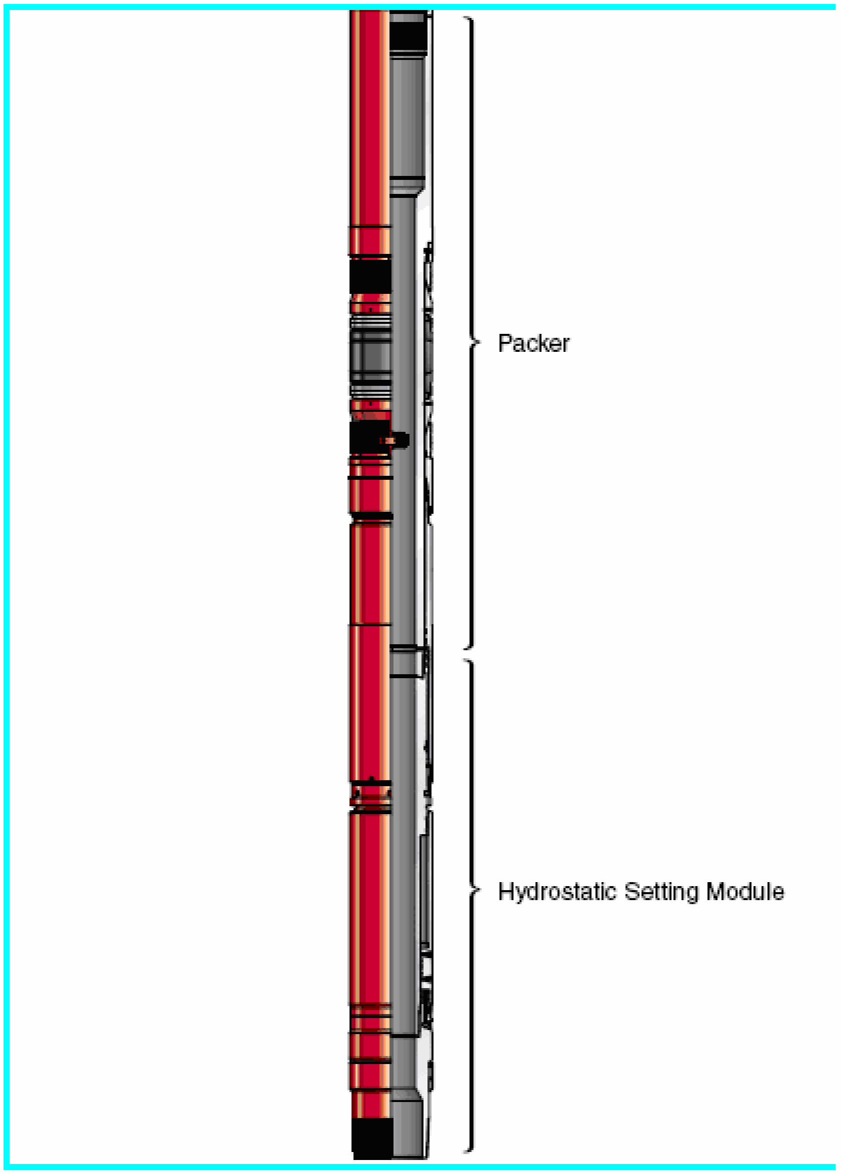


Slim-hole (dual) completion

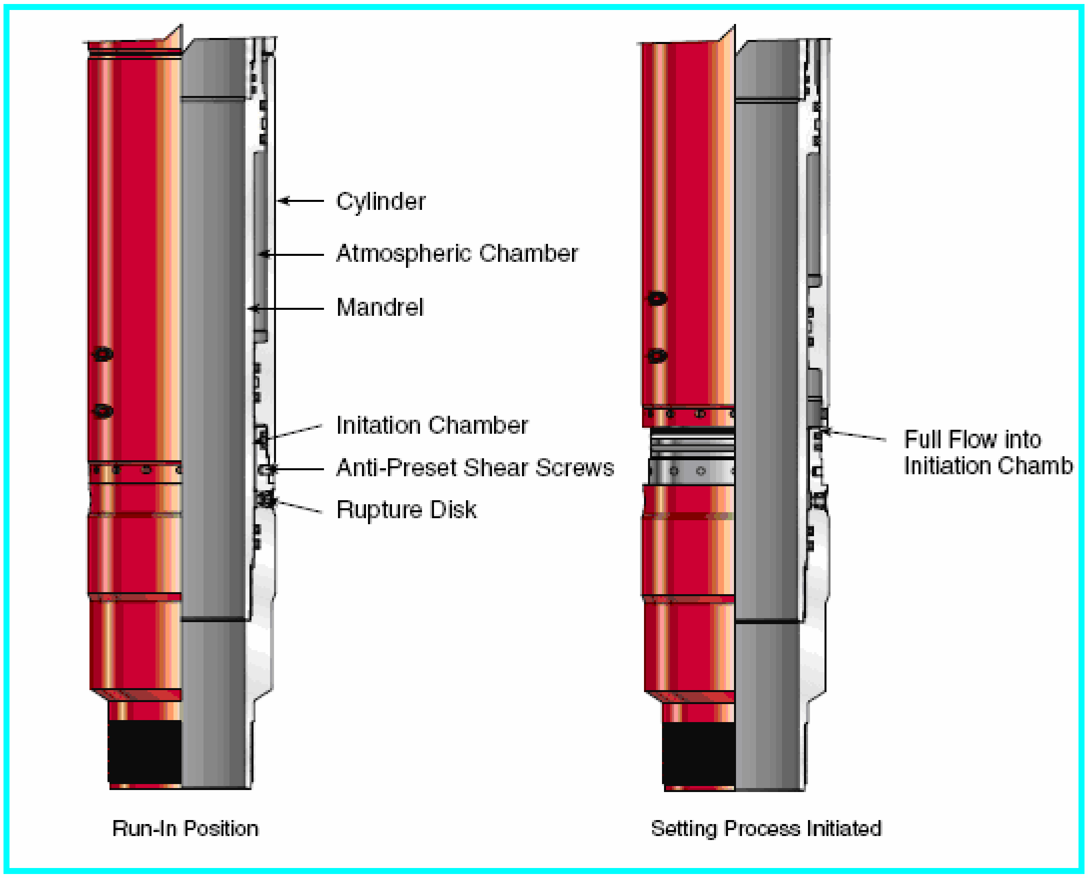
Appendix 2.2: Typical 3 ½” Monobore Completion



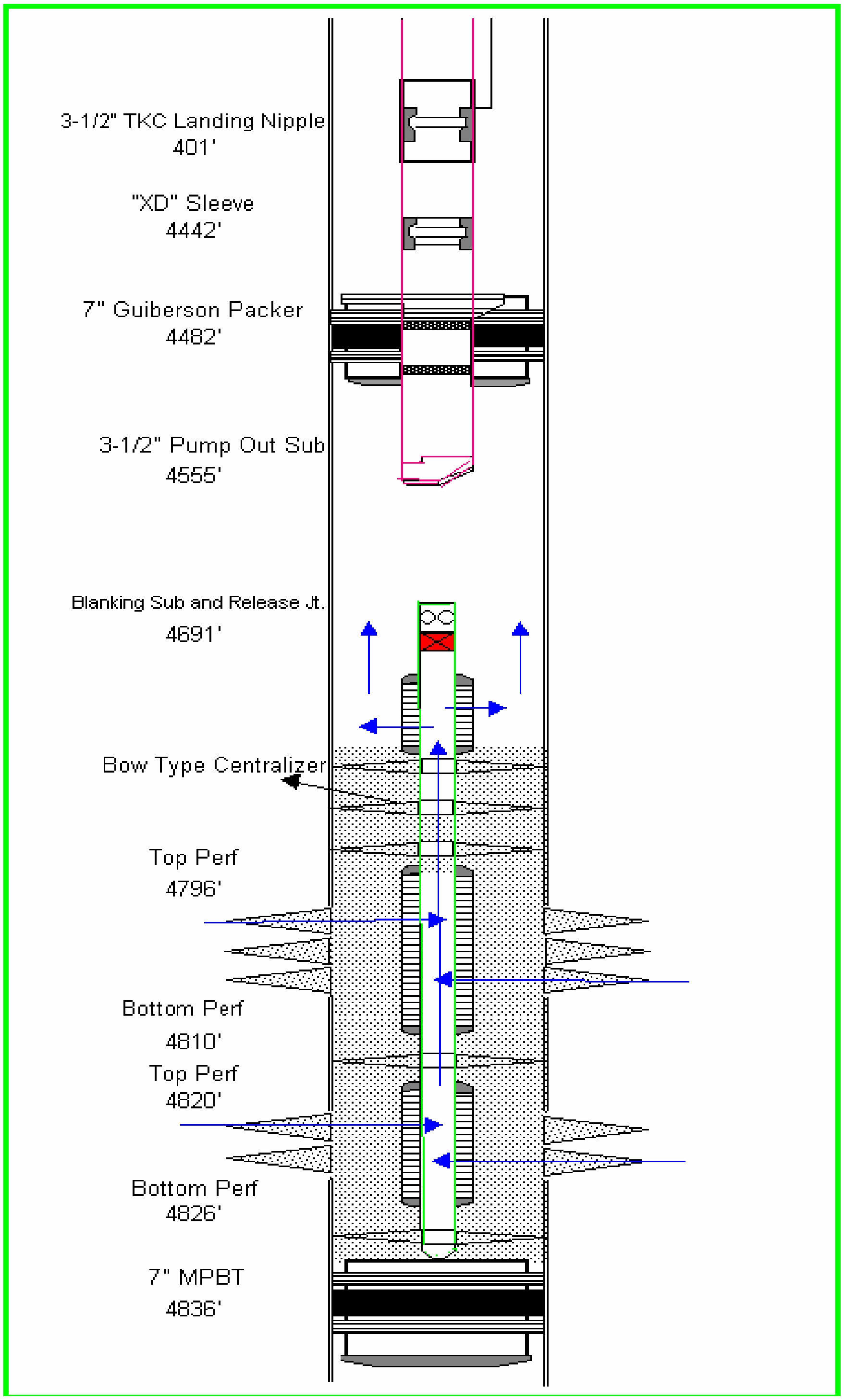
Appendix 2.3: Hydrostatic-Set Permanent Packer Comprised of Standard Hydraulic-Set Packer and Hydrostatic Setting Module



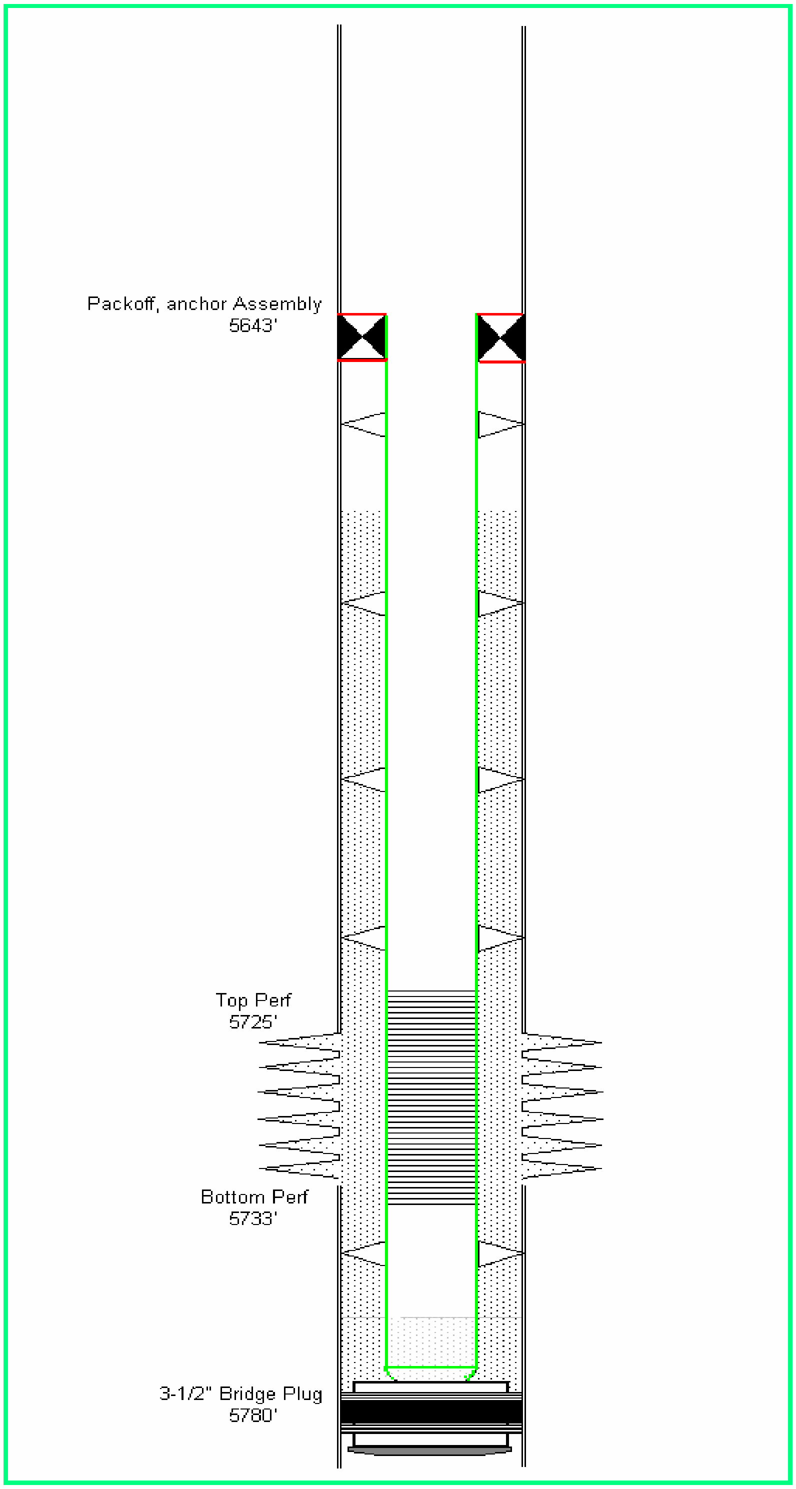
Appendix 2.4: Hydrostatic Setting Module with Biased Piston and Full flow upon Initiation



Appendix 2.5: Vent Screen Method TTGP Well Completion Schematic



Appendix 2.6: Packoff Method for TTGP Well Completion Schematic



Appendix 4.1: Basis Drilling Cost Estimation

Estimate flat time

Casing Size	Running& Cementing Days	NU (days)	Total Days
20”	1	1.5	2.5
9 5/8”	1	1	2
7”	1	1	2
4 1/2"	2	1.5	3.5
Total			10

Calculate of planning drilling time

Hole Size	Meters To Drill A	Offset ROP m/hr B	Planned Hours A/B	Planned Drilling Days
26"	45	8.5	5.3	0.22
12 1/4"	72	8.5	8.5	0.35
8 1/2"	513	5	102.6	4.28
5 1/2"	777	4	194.3	8.09

Time-depth calculation

Operations Description	Depth MD ft BRT	Days	
		Activity	Cum.
Rig up to drill		1.0	1.00
Run / cmt 20" conductor / NU diverter	45	2.5	3.50
Drill 12 1/4" hole to 122m	117	0.22	3.72
Run / cmt 9 5/8" csg / NU wellhead		2	5.72
Drill 8 1/2”hole to 685m	630	0.35	6.07
Log hole		1.0	7.07
Run / cmt 7"liner csg / NU		2	9.07
Drill 5 1/2" hole to 777m	1407	4.28	13.35
Log 5 1/2" hole		0.5	13.85
Run / cmt 4 1/2” liner , run CBL/VDL		3.5	17.35
Displace hole to completion fluids, prepare well for testing		1.5	18.85
Total Days			18.85

Well cost estimate

well Location

reporter Date

Description	Cost rates $ Rig Move	Drill/ Suspd	Comp/ Test	Cost Estimate $ Rig Move 3.0 days	Drill/Suspd 10.0 days 1400 m	Comp/Test 9.0 days 1400	Total 22.0 days
Time Related Cost							
Rig rate	30,000	130,000	130,000	90000	1300000	1170000	2560000
Vessels	2000	2000	2000	6000	20000	18000	44000
Additional (catering..etc)		50	50		500	450	950
Mud logging		200			2000		2000
Conductor driver equipment	0	500	0	0	5000	0	5000
Dock fees& base Overhead	500	500	500	1500	5000	0	6500
Rental tools	0	800	0	0	8000	0	8000
Consultant on rig	1800	1800	1800	5400	18000	0	23400
Underdrift Survey tools	0	200	0	0	2000	0	2000
ROV Mov	200	200	200	600	2000	0	2600
Water	5	5	5	15	50	45	110
Fuel	600	600	600	1800	6000	5400	13200
Total	0	136,855	0	105315	1368550	1193895	2667760
Depth Related Cost							
Deviation Survey	0	7	0	0	9800	0	9800
Mud and Chemical		8		0	11200	0	11200
Solid Control Consumable		2		0	2800	0	2800
Cement and Chemical		8		0	11200	0	11200
Bits				0	0	0	0
Casing and accessories	600			840000	0	0	840000
Completion			25	0	0	35000	35000
Total							910000
Fixed Cost							
Site Survey	25,000			25,000			25,000
Rig Positioning	25,000			25,000			25,000
Rig Mob/Demob	300,000			300,000			300,000
Boats Mob/Demob	60,000			60,000			60,000
Casing Crews& equipment		24000			24000		24000
Electric Logging		500000			500000		500000
Cased hole logging & Perf.		20000	80000		20000	80000	100000
Well Testing			100000			100000	100000
Wellhead		60000			60000		60000
Insurance	10000			10000			10000
Fishing& Abandon Services		13000			13000		13000
Well Planning		20000			20000		20000
Total							1,237,000

Support Costs							
Drilling Office Overhead	1000	3000	3000	3000	30000	27000	60000
Office Sup't Consultant	1500	1500	1500	4500	15000	13500	33000
Other Drilling Expenses	50	50	50	150	500	450	1100
Air Transpotation	4000	6000	6000	12000	60000	54000	126000
Total							220100
Total							2922860
Contingency 30%							876858
TOTAL WELL COST							**3,799,718**

Appendix 4.1: WHP Basis Cost Estimation

Assumpsion: 5 produced wells
50m WD
5000 BOPD
20 MMBBL Reserve.
10 Years Field Life

TOTAL BASE ESTIMATE US$	27888	x10^3
CONTINGENCY ADDED 15% US$	4183	x10^3
TOTAL US$	**32,071**	**x10^3**

CALCULATION OF ESTIMATED OPERATING WEIGHT			
System	**Dry Weight**	**Factor**	**Estimated Operating Weight**
Wellheads	43	2.4	102
MPFM	1	1.68	1
Gas Lift	6	1.1	7
Gas Injection	0	1.1	0
Water Injection	0	1.76	0
Power Generation	67	1.02	68
Power Distribution	29	1	29
Pro/Pers Support	84	1.6	134
Safety/FF System	9	1.37	12
Matl.Handling	34	1.06	36
Drilling(TAD)	0	2.82	0
Living Quarters	0		0
Helideck	100		100
Structure Steel	120		120
TOTALS	Dry		Operating
	493		611

CALCULATION OF ESTIMATED COSTS ALL PRICE IN US$x10^3			
A) MATERIALS PROCUREMENT			
System	**Tonnes or Power Driver/Output**	**US$x10^3 per kw of toone**	**COST US$x10^3**
Wellheads	5	0	600
MPFM	3	0	60
Gas Injection	0	58	0
Water Injection	0	45	0
Power Generation MW	3	500	1265
Power Distribution	14	30	432
Pro/Pers Support	30	34	1020
Safety/FF System	4	30	131
Matl.Handling	34	22	756
Drilling(excl,TAD)	0	21	0
Living Quarters	0	12	0
Control/ESD/F&G			14200
Telecom/Telemet			4700
Helideck	100	2	200
Bulks Steel	120	2	240
Bulks Piping	50	10	495
Bulks Electrical	10	15	152
Bulks Instrument	10	30	293
Bulks Other	19	10	190
PROCUREMENT COST TOTAL			**24734**

B)FABRICATION, LOAD-OUT AND SEA FASTENING				
System	**Quantity**	**Manhours/tonne**	**US$ / manhour**	**COST US$x10^3**
Equipment	185	70	20	259
Bulk Steel	120	190	20	456
Bulks Piping	50	640	20	634
Bulks Electrical	10	1300	20	264
Bulks Instrument	10	1400	20	274
Bulks Other	19	600	20	228
Living Quarters	500	360		0
Onshore precomm	0	20	20	0
Subtotal(A)				2114
L-out /seafastin(A)			0	106
FABRICATION COST TOTAL				**2220**

C) TRANSPORT AND INSTALLATION				
OPERATION	**Unit**	**Quantity**	**Unit Rate**	**COST US$X10^3**
Topside weight	493			
Number of lift	Nos	0		
Installation (Cat I rate include transportation cost)	Days	5	150	0.75
TRANSPORT AND INSTALLATION TOTAL				**0.75**

D) HOOK-UP AND COMMISSIONING				
Facilities	**Weight**	**Mhrs/ tonne**	**Direct Manhr rate.US$**	**COST US$x10^3**
Integrated Deck	611	29	35	620
HUC Cost Total I				620
HUC Cost Total II				620
HOOK-UP AND COMMISSIONING COST TOTAL				**620**
MATERIAL, FABRICATION, TRANSPOTATION, INSTALLATION, HOOK-UP, AND COMMISSIONNG, SUBTOTAL US$ x10^3				**27575**

E) DETAILED DESIGN, PROJECT MANAGEMENT, CERTIFICATION				
Description	**Unit**	**Total Qty**	**Unit Rate US$**	**COST US$X10^3**
Conceptual Design	yes			
Detailed Design	Mhrs	125	38	5
Fab'n yard inspection team		14	20000	280
Certific'n & warranty (based on 1% of total cost exclud'ng subtotal cost E)			0	28
DETAILED DESIGN,Etc				**312**

PROJECT TITLE :		GELAMA MERAH
DATE :		
FIXED SUB-STRUCTURE -OFFSHORE		
Platform type		
Water Depth		
Tops.oper.wt		
Type of Jecket Steel		
Type of Pile Steel		
Number of Piles		
Number of Conductors		
TOTAL BASE ESTIMATE		13056
CONTINGENCY (15%)		1958
TOTALUS$x10^3		15,014

System	Tonnes	Applied Factors	Drived Wt.
Jecket structure.	300		
Conductors	250		
Piles steel	200	0	
Anodes-Drilling Platform	27	0	
Boat fender ect	12		
Total tonnes			789

CALCULATION OF ESTIMATED COSTS ALL PRICE IN RMx10^3			
A) MATERIALS PROCUREMENT			
System	**Quantity**	**US$/tonne**	**COST US$x10^3**
Jacket Steel	300	3000	900
Piles Steel	250	2500	625
Anodes	200	20	4
Boat fender ect	12	2500	30
PROCUREMENT COST TOTAL			**1559**

B)FABRICATION, LOAD-OUT AND SEA FASTENING			
System	**Quantity tonnes**	**Fab.rate US$/te**	**COST US$x10^3**
Jacket Steel	300	7000	2100
Piles Steel	250	2000	500
Anodes	200	1000	200
Boat fender ect	12	5000	60
Subtotal			2860
Loud-out/Seafastening			143
Barge hire	0	147000	0
FABRICATION COST TOTAL			**3003**

C) TRANSPORT AND INSTALLATION				
OPERATION	**Quantity**		**Rate US$/Day**	**Equipment hire cost RMX10^3**
Fabricated Jacket wt.				
Fabricated Piles wt.				
No of piles				
No of Conductors				
Installation (days)	23		300000	6840
Mob/Demob(days)	2		300000	600
TRANSPORT AND INSTALLATION TOTAL				**7440**
MATERIAL, FABRICATION, TRANSPORTATION, INSTALLATION, SUBTOTAL US$ x 10^3				**12002**

E) DETAILED DESIGN, PROJECT MANAGEMENT, CERTIFICATION.				
Description	**Unit**	**Qty**	**Unit Rate US$**	**COST US$X10^3**
Soil Inves.	No	1	400000	400
Detailed Design	Mhrs	3000	38	114
Fab'n yard inspection team		14	30000	420
Certific'n & warranty (based on 1% of total cost exclud'ng subtotal cost E)			0	120
DETAILED DESIGN,Etc				**1054**