SPE 147875

A Review on Offshore Concepts and Feasbility Study Considerations

Maryam MADDAHI, Curtin University, Seyed Javad MORTAZAVI, Talisman Energy

This paper was prepared for presentation at the SPE Asia Pacific Oil and Gas Conference and Exhibition held in Jakarta, Indonesia, 20–22 September 2011.

Abstract

There is no doubt that choosing the excellent technology and operation is one of the keys to achieve sustainable global energy. With the quick advancement in the subsea technology and offshore industry and its influence on the global oil and gas production through the past three decades, an update working knowledge of engaged offshore facilities around the world seems to be essential for a successful petroleum field development. Selection of the most appropriate equipment and process through the early exploitation study stages of developing an offshore petroleum reservoir can determine the right facilities for delivering the greatest value.

The current paper gives an overview of characteristics, and features of offshore production facilities, their advantages and disadvantages according to the most common offshore system selection and feasibility studies considerations. It has been tried to point out the most important criteria of the related Issues and concerns during a process and facilities selection for a potential case of installing the subsea completion as well as proposing processes to help in selection of the right concept.

Major considerations in the process and facility selection for a petroleum field, such as shore distance, drilling and well intervention, topside weight, utilities, accessibility, regional influences, financial and HSE considerations, and particularly water depth and well count, as well as their influences on the final decision have also been explored.

The review also introduces common components of a subsea completion system such as wellheads, manifolds, flowlines and risers, connection systems, control systems and umbilicals, installation tooling, and then it makes a comparison between different types of Xmas trees as well as various well arrangements. Finally, the paper summarizes the subsea development phases for establishing the right concept.

Introduction

Subsea technology has been advanced very quickly through the past three decades, as the offshore industry milestones has been improving from the installation of the first offshore platform in 20 ft of water in 1947 to Perdido spar installation in7,820 ft of water in 2010. Subsea completion is an interesting petroleum field development option as it avoids surface platform facilities by using subsea tieback to a remote host or to shore.

According to International Energy Agency, the global oil production in 2009 was 86.2 MMbopd, 27.8 MMbopd of which was produced from the offshore.

Some of the features and key constraints of the most common subsea floating and fixed production facilities and their different selection drivers for various applications have been summarized in Table 1. Although many attributes interact with determining the optimal production system, the selection process has a key impact on the field development.

Common Offshore Platform Configurations

Common Facilities Supporting Dry Tree

Fixed Steel Structure and Jack Up over a Platform

It consists of weld steel tubular framework or jacket to support the topside facilities. The jacket will be secured by the driven piles into the seafloor. The fixed steel structures are restricted to shallow water developments in water depth of about 460 m. Jack ups consist of a triangular or rectangular shaped box section barge fitted with three to four mobile legs enabling the vessel to stand to the seabed water deep about 120 m. Their advantages include handling significant topside weights, good motion characteristics and suitable for drilling/workover operations. These structures also have some limitations such as mating of jacket structures, the deeper the water, the heaviest the weight, large derrick barge may be required and considerable offshore hook-up may be required.

Compliant Tower

Similar to fixed platforms, compliant towers are secured to the seafloor with piles using a steel tubular jacket to support the topside facilities, but like floating structures, they yield to the water and wind movements. Comparing to the fixed platforms, the jacket of a compliant tower has smaller dimensions. Compliant towers are the tallest man made structures and they are used in water depths about 460 to 915 m but they are more cost effective in ranges of 300 to 670 m and can sustain significant lateral deflections and forces. The first compliant tower was installed by Baldpate and the world's deepest one belongs to Petronius in 531 m of water depth in the Golf of Mexico. Well access (dry tree), robust relative to payload changes, less steel tonnage required in the water depth range they are used in, simple conventional fabrication, and installation flexibility are some of their advantages. Similar limitations to fixed platforms apply to compliant towers as well.

Gravity Base Structures (GBS)

They are constructed using a reinforced concrete base. The design of base includes void spaces or caissons providing natural buoyancy to the structure to be floated to field development location. The void spaces will be flooded at the location seabed whilst the topside modules arrive. The void spaces will be used as storage compartments for crude oil, or filled with permanent iron ore ballast.

Tension Leg Platform

Unlike the conventional fixed platforms, TLPs are held in location by moorings in tension through the buoyancy of the hull. The mooring system is a set of tension legs or tendons attached to the platform and connected to a template or foundation on the seafloor. The driven piles into the seafloor hold the template in place. Therefore, the vertical motions of the platform will be limited, while it allows for horizontal movements. Although, TLPs are more cost effective in600 to 1200 m of water depths, they are used in ranges between 460 to 2130 m. The "conventional" TLP which look similar to a semisubmersible, are relatively low cost and suitable for water depths about 200 to 1300 m. Although, TLPs support dry trees and quayside topside integration as well as having good motion characteristics and low maintenance cost, they have some disadvantages such as sensitivity to payload change, active hull system, not friendly to offshore drilling and tendon fatigue and tendon diameter increase with water depth.

Spar

Spar as a deep draft floating caisson, is a hollow cylindrical structure similar to a very large buoy with four major systems; hull, moorings, topsides, and risers. This design produces very favorable motion characteristics compared to other floating concepts. About 90% of its structure is underwater. Also, its protected center well provides an excellent configuration for deepwater operations from 550 to 3050 m. Although, spars were used as marker buoys, for gathering oceanographic data, and for oil storage, they now are used for drilling and production. The upper section containing different types of risers provides spar's buoyancy. Similar to the upper section, the middle section is flooded with the difference that it can be economically configured for oil storage. Finally, the bottom section provides buoyancy during transport and contains any field-installed or fixed ballast.
Some of the advantages of spars are:

- Superior stability and very good floating characteristics.
- Its air cans allows supporting dry trees
- Accommodating payload changes/ability of handling significant topsides weights
- Offshore drilling/ workover friendly
- Passive hull system
- Low maintenance cost

Whereas some of the disadvantages are topside lift at installation site, large derrick barge required for topsides installation and may be heavier than semis and TLPs depending on water depth.

Common Facilities Supporting Wet Tree

Semisubmersible

Semis are vertical columns supporting topsides and supported on large pontoons, anchored to the sea floor with spread mooring lines. They have twin hulls of sufficient buoyancy letting the structure to float, as well as sufficient weight to keep the structure upright. Semisubmersibles can be moved from place to place; can be ballasted up or down by altering the amount of flooding in buoyancy tanks. They are generally anchored by combinations of chain, wire rope and/or polyester rope during drilling or production operations, though they can also be kept in place by the use of dynamic positioning. They are used in water deep from 60 to 3050 m and are more cost effective in 80 to 2500 m water depth range. Handling a significant topside weight with good motion characteristics, make them a good solution for wet trees. A deep draft semi can be a good choice for marginal water depth fields.

Semis can support large number of flexible risers as well as quayside topside hull integration. Some of their disadvantages include supporting wet trees only, high maintenance cost, hull motions can cause steel catenary riser (SCR) fatigue issues, deck payload sensitivity and need to address motions if drilling operations are required.

Floating Production, Storage and Offloading System

FPSO (floating production, storage, and offloading) vessel is converted from liquid cargo vessel. Inputs to the FPSO versus non-FPSO decision can be access to pipeline grid or shore, political or economical factors of the export site,life time of the filed, dry versus wet tree, reservoir development plan and tolerance to production down time. Basically, Floating Production Systems are ideal solution when the field is small and marginal, isolated and an established pipeline infrastructure does not exist and located in very deep water with no possibility of installing any fixed platform.
A major advantage of FPSO lies in the fact that they can simply lift anchors and depart to pastures new when oil production reaches a commercially unprofitable level. In summary the most important factors in choosing between the non-FPSO solutions are water depth, environmental conditions, initial vs. future topside weight, number of risers, drilling program, and well access (dry vs. wet trees), installation capabilities and initial versus total life cycle cost. In some cases it is economical to employ a hybrid solution to obtain the benefits of both types of facilities.

Common Considerations In Offshore System Selection

Key technical drivers in offshore system selection include shore distance, water depth and metocean criteria, regional influences, field layout, drilling/ installation plan, and drilling centre locations, reservoir characteristics, flow assurance, dry or wet trees, riser operations, topsides payload, and facility motion, market condition, contracting strategies, CAPEX / OPEX costs and risk issues and mitigating measures. Some of the most important of these key drivers will be investigated in the coming subheadings;

Shore Distance

Taking a closer look at the technical challenges for many long distanced subsea developments and solutions related to this challenge, reveals the following areas as the most important fields required to be examined:

Multiphase Flow Regime

The main area of application for multiphase flow concept is for gas and gas/condensate developments which can be managed over long distances, using hydrate inhibitors such as mono-ethylene glycol (MEG). The pressure drop typically ranges from 0.4 to 0.9 bar/km irrespective of pipeline diameter. It creates a back pressure hampering the reservoir recovery factor, a quicker fall off plateau and a loss of production. Also, in case of gas velocity in the pipeline falling below the minimum sweep velocity (typically 1.5 to 2.5 m/s), flow conditions become unstable and serious slugging may occur [1].

Hydraulic System

It is evident that an increased shore distance will increase the required response time. Related issues to consider include the long recharging time, the fluid compressibility and umbilical tubing expansion.
However, careful analysis and modeling work has demonstrated that these problems can be managed by use of subsea accumulators on the wells, assisted by the accumulation effect provided by the umbilical itself [1].

Communication System and Data Transmission

The fibre optic technology has proven to be capable of handling massive data rates over long distances. This technology is developing quickly, not least due to the rapid developments taking place within the telecom sector, and the subsea industry is well positioned to benefit from these advances. It is therefore not likely that the communication systems will be a limiting factor for ultra long step outs [1].

Umbilical System

Considering umbilical issues, is essential in any long distanced development, both in terms of cost and technical complexity. Manufacturing the umbilical in several sections, and then splicing them together into one continuous length during installation, can mitigate the issue and offer a natural opportunity to insert optical amplifiers or repeaters into the umbilical, and so improves signal fidelity [1].

Electrical Signals and Electric Power Supply

The power transmission losses limit the maximum distances to about 250 km where use of a lower supply AC frequency can be helpful. The technology that holds most promise for solving the power dilemma will be based on the use of High Voltage Direct Current (HVDC) which is independent of transmission distance, and can handle extremely high power levels [1].
Maximum subsea oil tieback lengths have increased over time by additional placement of equipment on the seabed such as subsea or down hole multiphase flow metering (MFM) and subsea pig launchers, using water driven from the host, and multiphase pumping. It provides a single rather than dual export flowlines. Gas dominated flowlines are less problematic as

they are basically exploited by natural depletion and so can have simpler and longer tiebacks. In particular, gas dominated subsea tiebacks of up to 160 km are under development, whereas most oil dominated tiebacks are less than 30 m in length. Longer tieback lengths are thus possible, although there are ongoing hardware challenges associated with the delivery of utilities to the subsea wellheads [2].

Table1. Production facility key features, constraints, and selection drivers [2]

Platform Configuration	*JU*	*CGS*	*Jacket*	*CT*	*MF*	*FPSO*	*Semi***	*Semi*	*Subsea*	*TLP*	*Spar*
Water Depth (m)*	109	303	412	535	1615	1853	1890	2438	2740	1450	1710
	S***	S/M		M	V					D	UD
DVWA	Y				N		Y	N		Y	
Well Pattern	Clustered				Distributed		Clustered	Distributed		Clustered	
Tieback Length	V	L	V			L	V	M		V	
Well Count	M	M /H	H	Low		V	M / H	V	Low	M /H	M
Steel Catenary Riser	No Constraint			Needs Evaluation						No Constraint	
Top Tension Riser[3]				N							
Service Life	V	M / L		M		V				M / L	
Derrick	Platform / Jack up		Platform	MODU						Platform	
Tree	Dry/Wet			Wet			Dry/Wet	Wet		Dry/Wet	
Structure Weight Sensitivity To Topside	SW			Least			SW		Least	More	SW
Export Mode	P / T	T	P / T			T	P / T		P	P / T	
Drilling	C		Y	N			C	N		C	
Just MODU Drilling			N	Y			N	Y			
Unmanned	C	N	C	N					Y	N	
Inshore Integration	Y	N				Y			-	C	N
Reuse / Conversion	C								N		
Early Production System	C					C			C	N	
Contracting Flexibility	Good			Better		Best	Better		-	Good	
Storage	N			-		Y	N				

Abbreviations of Table 1 Contents

C	Common	JU	Jack up	S	Shallow	*Data is valid for the maximum water depth (meter) in which facility have been employed till the year 2003[2].
CGS	concrete gravity structures	L	Long	SW	Somewhat	
CT	Compliant tower	M	Moderate	T	Tanker	** Semi-submersibles are categorized into tow groups; with and without direct vertical well access[2].
D	Deep	MF	Mini floater	TLP	Tension leg platform	
DVWA	Direct vertical well access	MODU	Mobile offshore drilling unit	UD	Ultra deep	***Production facility types have been categorized into shallow and deep water with the division at 300 m here.
FPSO	floating production, storage, off-loading vessel	N	No	V	Various	
H	High	P	Pipeline	Y	Yes	

Water Depth

Shallow Water

Figure 1 (a) shows the distributions of jackets and remote subsea tiebacks installed in the North Sea since 1980 as well as accessibility of them (See Fig 1 (a) and (b)) [2]. It is obvious that for lower well counts and deeper water, subsea tiebacks are more employed than platforms as a result of dramatic cost increase of jackets with water depth while the cost of subsea satellite mostly depends on the well count.

Deep Water

Figure 2 [2] shows some worldwide deepwater facilities such as dry tree platforms, floaters, as well as subsea satellites according to well counts (w) and water depth (d). As it can be seen in Table 2, that fixed platforms are use in shallow water and k<20 m (k=d/w) as well as with compliant towers in moderate water depths and very high well counts (w>20). Well conductors may be used for these platforms. (see Xmas Trees).

Structures handling dry trees:

A MODU is adapted to pre drill wells before the platform is installed, whereas, after jackets in shallow water or spars in deep or very deepwater are in place, it can be used few dry tree platforms in moderate *w* and *d*. However, employing the small TLPs brings cost effective pre drilling in moderate *d* and moderately low *w*, it is not recommended for high *w* cases due to its greater upfront cost and first oil delay, while, for low *w* in deep water, dry tree platforms have been shown higher cost efficiency.

Fig 1.[2] (a) distributions of jackets and subsea tiebacks in relation with the water depth and well count in North Sea. Those with a cross mark usually operate in an unattended mode, (b) distributions of fixed and floating platforms in relation with the water depth and well count in North Sea. The platforms which support drilling rig are marked with a cross, and (c) distributions of fixed, floating platforms and subsea satellites in relation with the water depth and well count in Australia. In the region upper the line with slope of *k*=20m, subsea tiebacks are commonly employed. Jackets are sometimes used in the region between the two boundaries, whereas CGSs are employed rather than jackets in higher *w* and *d*. Floaters are in favour of *d*>70m. Drilling philosophy of the platforms can be recognized in Figure (b) and (c) [2]

Fig 1: Jackets and subsea tie-back dristribution

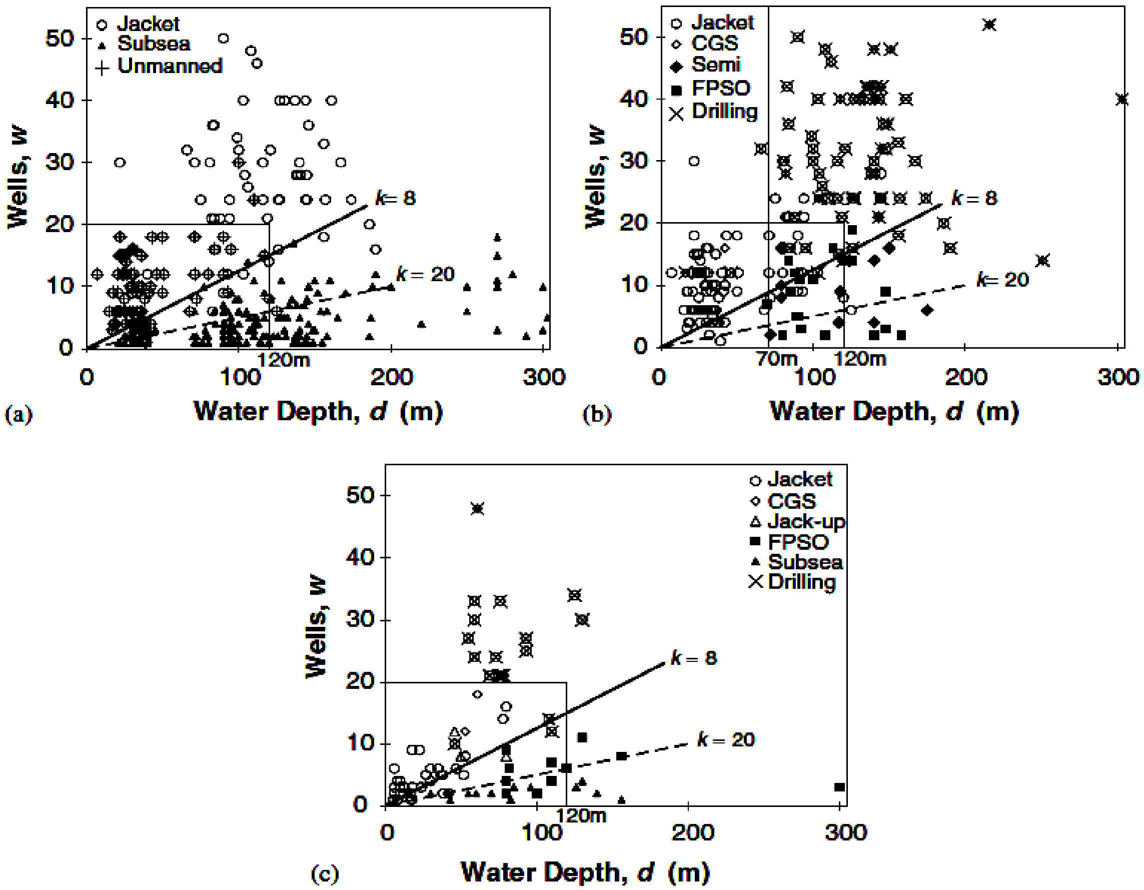
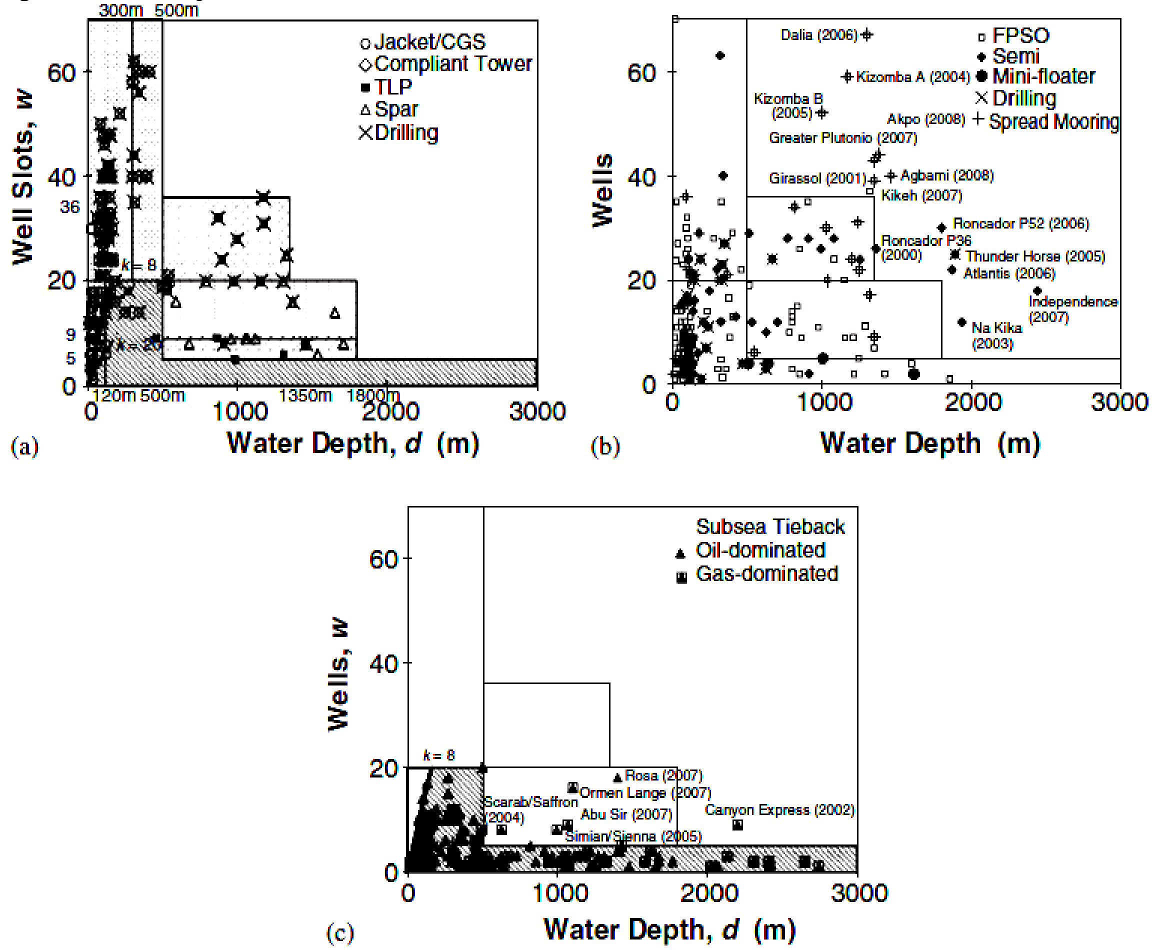


Fig. 2. Worldwide deepwater facilities: (a) dry tree platforms, (b) floaters, and (c) subsea satellites. The drilling philosophy of the platforms can be recognized in Figure (a) and (b) [2]

Fig 2: Worldwide deepwater facilities



Large TLPs are employed as dry tree platforms in deep water (500m<*d*<1350m) and high well counts (20<*w*<36). Although they provide inshore topside integration, the number of risers would be then limited by the required spacing for accommodating the top tensioning equipments as well as avoid harmful clashes in deep water. Use of these dry tree platforms also result in greater tendon tensions as the water depth increases [2, 4].
Spars are considered in deep to very deep water (500<*d*<1800 m) and low to moderate well counts (5<*w*<20) as a result of their taut catenary mooring being relatively independent from water depth. Therefore, risers are basically supported by large air cans. Last but not least, small TLPs with a lighter hull than the spar are dominantly used for 5 to 9 well slots [2, 5, 6]

Structures handling wet trees

Floaters (semisubmersibles and FPSOs) and mini floaters: in contrast to deep water dry tree platforms, floaters show versatility in a wide range of d and w (Figure 3(b)), while to our knowledge there is no dry platform to be able to perform in high d and w. Semis are favored for high w rather than FPSOs, as they do not require tensioning for risers to hang off the deck edge or pontoon in catenaries, as well as more suitable features for applying manifolds to reduce the number of risers, while spread moored FPSOs can only support high w in benign environments. The later alternative is preferred in deep to ultra deep water large fields. Application of FPSOs in shallow water is limited to vey benign environment. Floaters are also deployed across a very wide range of service lives and field sizes. Mono column TLPs, cell spars, and some other hull forms which support low w and small topsides, are categorized as mini floaters. These light weight cost effective alternatives are suitable for hub development and for small deep water fields with flow assurance issues.
Subsea tiebacks to beach: these tie backs flow well fluids direct to shore. With the help of this option, we can produce reservoir areas in extreme depths. Satellites and well clusters may be used and control buoys are used for long step-outs. Subsea satellites are the choice of solution in low to intermediate w over the complete spectrum of d. details can be seen in Tables 1 and 2.

Table 2. Facility selection according to water depth and well count

Water Depth	**Well Count** *Very High >36*	*High 20–36*	*Moderate c_2–20*	*Moderate Low 5-9*	*Low < c_1*
Shallow <120m			Jacket (can be unmanned) CGS (remote) Jack-up (remote)		Subsea
Moderate Shallow 70–300m	**Jacket** **CGS** **(remote/harsh)**	**Jacket**	**Jacket (Gulf of Mexico)**		Subsea
Moderate Deep 300–500m	**Compliant Tower**				
Deep 500 –1350m		Large TLP	Spar	Small TLP Spar	Subsea Mini Floater
Very Deep 1350-1800m					
Ultra deep >1800m					

Legend		
FPSO (benign metocean)	d	Water Depth (meter)
FPSO/Semi	If d > 500m	$c_1 = 5$ and $c_2 = 9$
Platform drilling rig for dry trees	If d < 500m	$c_1 = c_2 = (d/k) < 20$
$8m < (k = d/w) < 20m$		Well Count

Drilling philosophy of dry tree platforms according to well count and water depth				
w	*w* <20			*w* >20
***d*(m)**	*d*<120	500<*d*<1800		*d*<1350
Drilling Philosophy	Jack Up (rig through platform)	Floating (rig translate platform)	(rig pre drilling)	Platform mounted rig
Platform Type	Jacket	Spar	Small TLP	Various Dry Trees

Drilling and Well Intervention

Although, one third of semis support drilling, FPSOs do not yet have the drilling capability. In the case of well direct access requirement, this option makes semis a competitor to dry tree platforms in deep water. Also FPSOs can support optimal well distribution across fields, completion and work over operations performed by MODU. In the absence of the drilling system, the field GOR will determine the use of either FPSOs or semis. In the other word, FPSOs are more suitable for large oil export rates due to their oil storage, where as semis are widely employed for gas dominated fields as a result of FPSOs' challenges regarding to processing and exporting gas in harsh environments.

Topside Weight

Some of the world examples of offshore facility selection according to topside weight and water depth as well as well direct access capability can be seen in Fig. 3.

Accessibility; Fabrication, Transport, Installation, and Maintenance

Although accessibility for equipment operations, delivery of utilities and assisting flow assurance, have been receiving considerable attention from industry, it still is a major challenge for subsea completions which limits their use in many cases. A comparison between the minimum platform and subsea completion applicability can be seen in Table 3. Table 1 as well as Figures 2 (a) and (b) are showing some data on the platforms accessibility. Normally, platforms with w< 20 do the first stage separation prior to export to shore or to a central processing unit. The accessibility of these platforms is usually though subsea satellites as a result of their straightforward support intervention equipments. Platforms with w≥20, are very likely to have larger production rates with drilling facilities, work over equipments, as well as full production/processing capabilities and are mostly manned to provide economical returns with greater productivity, reliability, and recovery, while Table 3 shows that a remote subsea satellite needs a MODU, subsea work over equipment, and specialist intervention vessel [2, 5-7].

Fig. 3. facility selection according to topside weight and water depth as well as well direct access capability

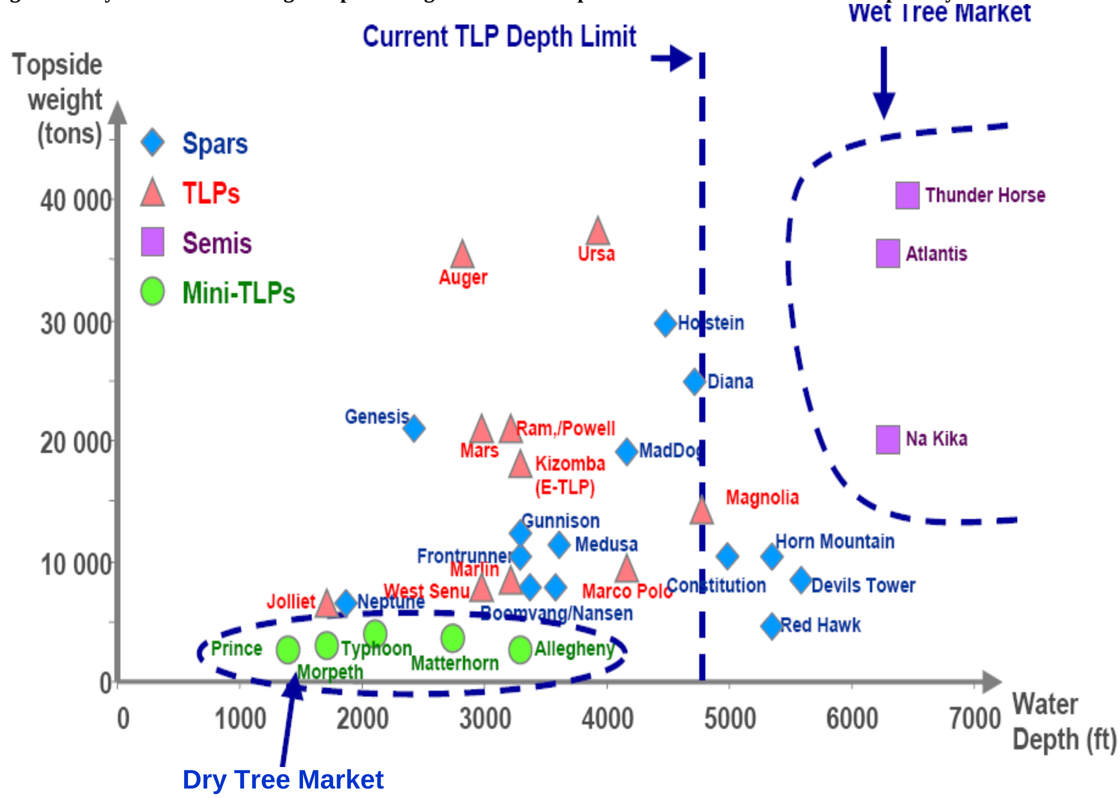


Table 3. Surface and subsea satellite applicability comparison

Satellite	Access		Utility			Flow Assurance				
	Drilling	*Intervention*	*Remote control*	*Power*	*Metering*	*Separation*	*Boosting*	*Water/gas injection*	*Chemical injection*	*Pigging*
Subsea	MODU	Specialist vessel	Umbilical		Test line	Host			Umbilical	Round-trip
Surface	MODU Satellite	Satellite boat	Line of sight Satellite Cable	Diesel Cable	Satellite MFM	Host/satellite			Flowline boat	Satellite launcher

In the case of the lower *w*, little drilling and intervention, and a lower acceptable recovery factor, subsea tiebacks are used. Jack-up is employed as the drilling system in lower *w* as it requires relocation around the platform for reaching wells in high *w* cases. MODUs, over a fixed platform in cantilever mode, and subsea satellites would be the system of choice for low *w* in $d \leq 120$m and $d > 120$m respectively, whereas, a dry tree platform should support a derrick in deeper water and higher *w* (see Figure 1). Floaters are a solution for low to intermediate *w* in moderately shallow waters, where very expensive cantilevered jack up MODUs are not feasible. A jacket may enable help in the safety benefits as it usually offers an unmanned facility, whereas it is not a possible option for floaters as a result of their operational complexity Therefore, jackets are preferred over floaters or subsea tiebacks in moderate *d* and for low to intermediate *w* [8].
In general, lower w, shorter field life, lower production rate, and greater uncertainty, are the typical profile of each subsea completion which offers shorter cycle time, lower CAPEX, and greater OPEX of intervention after flowing the revenue [2].

Regional Influences

Multiple small platforms are more preferred over the extended reach wells from a single drilling centre in a large field in shallow waters[2, 9]. Floaters are not suitable in harsh environments in very shallow waters due to insufficient riser stability.
CGSs are preferred rather than jackets in higher *w* and *d*, due to jackets' fatigue challenges in similar conditions, as well as large CGSs' capability of having oil storage, allowing less expertise and specialized equipments, as well as topside and substructure inshore integration which addresses the problematic offshore lifts, extensive hook up and commissioning for large topsides. Global CGSs, jack ups, FPSOs, and jackets in different regions show very similar trends to the North Sea facilities indicated in Fig. 1(a) and (b).

Utilities

Preference of a minimum platform over a subsea tieback can be because of simplifying or avoiding the expensive umbilical from the host, in the case of long gas tiebacks or when the satellite functionality is a real concern. Communications and control can be performed by employing line of sight, space satellite, injection chemicals boat transporting, and generating power onboard, while a control buoy would fulfill this aim in deeper water. When $d>kw$, floaters and particularly FPSOs are preferred over the subsea tiebacks as they avoid the oil export line, while for $d<kw$, either a floater or a fixed platform can be chosen [2]. When the wells are dispersed or the service life is short FPSO and semi submersible are mostly the solution of choice, while frequent well intervention favors jackets [10].

Hazard Identification, Risk Management, and Integrity Assessment

The offshore oil and gas industry can be dangerous. As engineers and designers have a huge impact on others safety and environment, considering safety and environment in their design and decisions is very important.

A fundamental factor to achieve a safe system design and operation of a process plant and its facilities is identifying hazards. Hazardous situations can be identified by a variety of techniques, which are performed thoroughly, rigorously, and systematically applied by an expert team. Success depends on early identification, possible accidents scenarios analyzing with various severity degrees. Therefore, a structured identification system is crucial to prevent and manage possible risks, hazards, and so losses [11].

Different hazard types can be considered, studied, and prevented prior and through a field's life, such as jacking, trawl, blowout, collapse, capsize, subsidence, landslide, earthquakes, fire, explosion, lightning, heavy weather, winds and storms, tsunamis, workmanship, mechanical failure, pipe laying, piling operations, trenching, stuck drill stem, collision, corrosion [12].

The purpose of integrity assessment is to ensure that the material, practices, and inspection tools used to maintain a safe operation are state of the art. An assessment process usually includes developing a facility integrity assessment management plan, gathering information, conducting risk assessment and prioritizing utilizing risk-ranking software. Using a proper inspection is the key to safe and reliable operations [12]. Some inspecting methods are smart pigging, long range guided wave inspection, mapping tools, hydrostatic testing and pipeline corrosion assessment methods such as external and internal corrosion direct assessments (ECDA and ICDA) [13-18].

Environmental Issues

The offshore oil and gas operations, should receive more attention as a result of its environment being highly sensitive. All offshore operations with the environmental impacts can be systematically managed by employing the environmental management system, one of key factors of which is environmental policies with clear guidance, identifying significant environmental issue with more negative impacts [19, 20].

Most of the potential environmental issues in offshore oil and gas industry are resulted from oil spill into the marine habitat, interaction between released oil and the coastal area, and loss of oil and gas, which usually ends to really highly cost consuming impacts. The total cost of oil spill highly depends on the spill size, as it dramatically increases when the oil spill size increases. In comparison, the oil recovery ratio will significantly increase with the size of spill as a result of easier dispersion of small spills by winds and currents [21, 22]. Some of these costs as well as the related calculations can be seen in Table 4 [21, 23].

Table 4. Cost calculation of some of the potential damages caused by oil spill in the offshore industry [23-26]

Damage Cost Type	Cost Source	Aftermath	Cost Calculation Related Equations
Environmental	Degradation of natural resources	Decrease of natural resources' services	$L=\sum_{t=0}^{b}(1-f(t))(1/\ 1+d)^{t}$
			$V=Q.M.L$
			$T\sum_{i=1}^{n}V_i=\sum_{i=1}^{n}Q_i.M_i.L_i$
Socioeconomic	Property damages	Economical users' claim in an admissible compensation scheme	$E=\sum_{i=1}^{n}yr_i\sum_{t=0}^{P_i}(1-f_i(a)(\frac{1}{1+d})^{t}$
	Profit and income reduction in various economic sectors		
Cleaning up	Response equipments and crews	Removal of oil from the coastal waters	$C=\sum_{j=1}^{n}uP_j.du_j$

Abbreviations of Table 4 Contents

a	Year a	*L*	Lost services (a time integrated area)
b	Years of loss until the injured resource is completely restored	*M*	Monetary value per unit resource and year
C	Clean up cost	*n*	Number of damaged resources
d	Yearly discount rate (today costs> future costs)	P_i	Required years for the full recovery
du_j	Facilitating combat vessel j duration	Q	Amount of injured resources units
E	Economic losses (sum of forgone income of economic sectors during recovery time)	*t*	Time
		T	Total value lost
i	Economic sector *i*	uP_j	Unit price for combat vessel *j* and its crew
$f_i(a)$	Relative service provided by the affected sector (*i*) at year (*a*)	*V*	Lost value of a specific affected habitat
f (t)	Fraction of intact services (a time dependent recovery function)	yr_i	Yearly revenue of economic sector *i*

Flow Assurance Issues

The challenge of delivering multiphase reservoir fluids to the host with high availability is now commonly known as flow assurance [2]. Flow Assurance addresses all issues of importance which ensure transfer of production fluids from the reservoir to the point of sale. It facilitates operability by the development and implementation of strategies to manage key areas of concern, such as hydraulic performance, hydrate formation and wax deposition, and other production chemistry related issues.

Several subsea gas field developments to shore or a platform via a long distance flowline or pipeline have already been on production such as Mensa [37, 38], and Canyon Express [39] in the Gulf of Mexico, Scarab/Saffron in Mediterranean Sea [40-42], Troll-Oseberg gas injection [43], Snohvit, and Ormen Lange [44] in the North Sea. Oil and gas dominated tiebacks are considerably different. In particular gas dominated tiebacks are easier to handle regarding to technical and economical flow assurance issues through the longer distances than oil dominated subsea tiebacks. Key flow assurance issues include: hydraulic performance, hydrate formation, wax / paraffin deposition, asphaltene deposition, emulsion & foam, sand production, erosion / corrosion, scale precipitation and well testing, clean up & workover.

Most common flow assurance issues, their source, as well as the most common treatments used for them have been summarized in Table 5. These treatments usually require additional import flowlines, various complex configurations, and materials to the satellite field, which are extremely expensive and bring more difficulties over longer distances. Therefore, selecting the optimal option is very important, and in some circumstances, performing the required functions at the field location is more feasible by choosing a surface facility. Here we expand tow major issues and the suggested treatments for them as examples.

One of the subsea gas development flow assurance key issues is hydrates management.

Hydrates are ice like crystals formed from water and light hydrocarbons (~85 mol% water, ~15 mol% hydrocarbon), which when agglomerated can block the flow path, contain as much as 180 volumes (STP) of gas per volume of hydrate, can form at >18°C (>65°F) when the pressure is >170 bar (>2,500psi), can form in wellbore, flowline, valves and meter discharges, and have been found in wet gases, condensates & black oils. They most often encountered on restart and would make safety issues associated with depressurization.

The most common three different hydrate structures are;

- Structure sI: usually formed by smaller molecules like methane, ethane, and carbon dioxide
- Structure sII: formed by larger molecules such as propane and isobutene
- Structure H: formed by large molecules such as methylcyclo-hexane, only in the presence of a smaller molecule

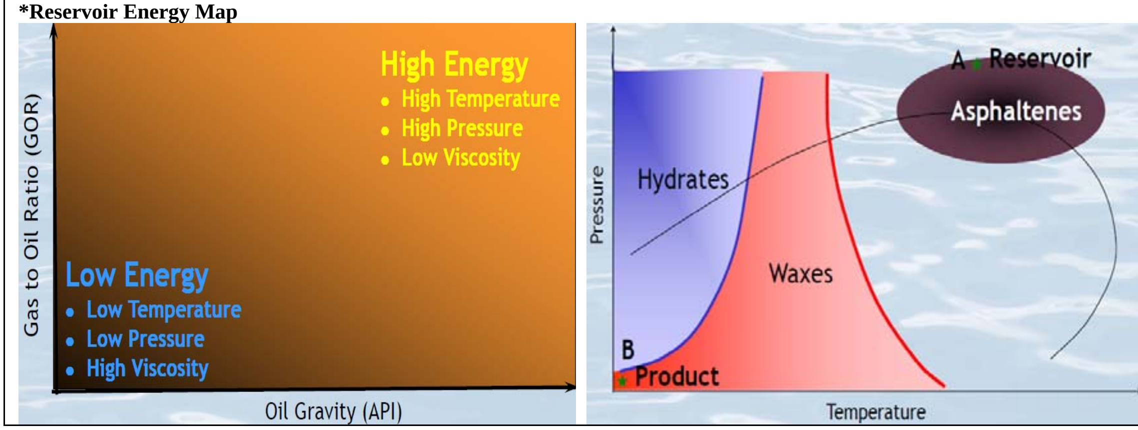
Hydrates form when the pressure and temperature conditions fall into the hydrate region for the liquid hold up in a pipeline consists of some H_2O. In that case we need to seek help from inhibitors or pipeline depressurization to prevent hydrate formation. Most of the hydrate inhibitors act thermodynamically to shift the equilibrium condition towards lower temperature or higher pressure than the similar uninhibited case such as methanol, methyl-ethylene-glycol (MEG), whereas low dosage hydrate inhibitors (LDHI) such as kinetic hydrate inhibitor (KHI) which consists of water soluble polymers and delays hydrate crystal nucleation and initial crystal growth processes [45, 46], and Anti-Agglomerants (AA) which allows hydrate crystals to disperse into a liquid hydrocarbon phase and keeps them in a slurry form. Therefore, AA is applicable to wet gas which fulfills the liquid hydrocarbon phase as the suspension matrix.

Second key flow assurance issue in subsea to shore gas development, is managing the liquid holdup through the long distance and relatively large diameter multiphase pipelines. This is trickier for transient operations such as turndown and ramp up. It is because of the increasing in the liquid hold up during turndown, as a result of the lower gas velocity liquid sweeping efficiency. The increased hold up liquid will be swept out of the pipeline as a result of increased gas velocity through ramp-up causing the arrival of liquid surges to onshore which could exceed the slug catcher capacity and so operational difficulties causing plant shutdown and production loss [27, 36].

Table 5. Major flow assurance issues, their source, and most common treatments

Issue source	Issue to handle	Most common treatment
Low reservoir energy*	Limited distance that fluid at a practical pressure and production rate can flow	Boosting
	Low production rate	Enhanced oil recovery (EOR) mechanisms such as water or gas injection and gas lift
The temperature drop down**	Formation of solids such as hydrates and paraffins through a long multiphase export flowline	Insulation Pipe-in-pipe construction Active heating Chemical injection Pigging Free water removal
Corrosive fluid	Material loss leading to leaks / rupture Replacement of facility particularly pipeline	Monitor material loss / wall thickness Examine solids produced from pipelines&present in vessels Model anticipated corrosion rate Select appropriate materials of construction Minimize dips / pockets / deadlegs in system design Chemical inhibitors: -Try to ensure good distribution to combat segregated flows -Dosage rate to consider both liquid and gas phases -Corrosion inhibitors / MeOH / Glycols

***Reservoir Energy Map**



**** Flow assurance is about How to get from A (Reservoir) to B (Product) cost effectively**

Therefore, managing liquid hold up at each phase of operation is very important especially because we cannot monitor the liquid holdup as a common operating parameter directly during operations and is usually estimated during the design phase for different operating conditions by a numerical simulator according to input data namely pressures, fluid rates, temperatures, and fluid physical properties applied to a geometrical model. Based on multiphase transient simulators, managing pipeline liquid holdup in long distance and large diameter gas pipelines [39-41, 47-50] as well as the actual data comparison [39, 47, 51] have been discussed in the literature. An effective flow assurance management program should cover: prediction, prevention, monitoring, intervention, improvement.

Flow assurance scenarios are valid over the whole of the field life including normal operation, start-up, planned and unplanned shutdowns, and restart and depending o various issue we may choose different tactics such as total avoidance, management, or even ignore it (reactive intervention). Flow assurance strategy development approach consists of:

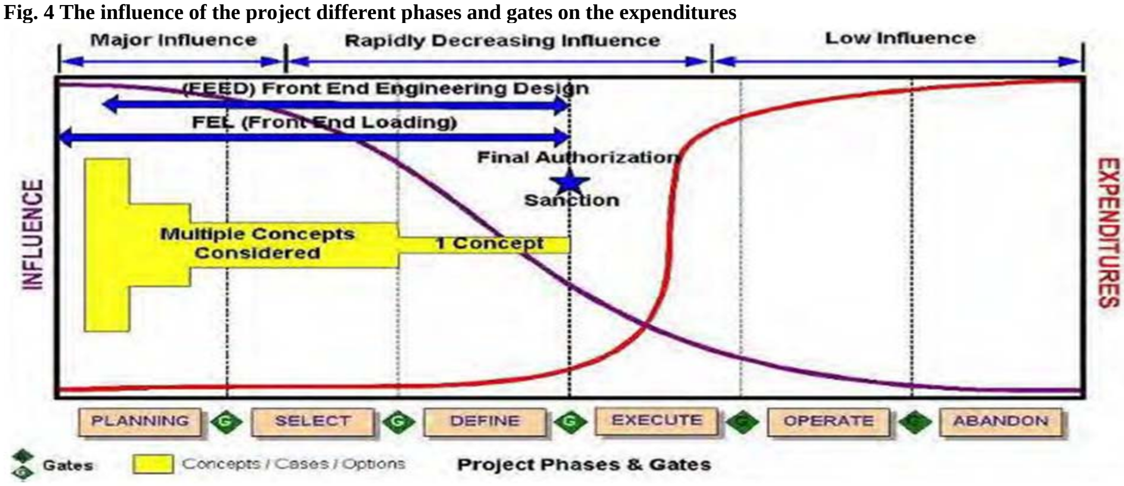
- Integrate flow assurance strategies in to project design
- Good representation of all interested groups in design team, especially production operations
- Understand fluid behavior, requires proper laboratory characterization

- Used for property prediction in computer modelling of operating range
- Look at life cycle costs for flow assurance program
- Qualification programs for chemical treatments. Good correlation of laboratory tests with field performance data minimizes unnecessary field trials
- Proactive prevention is better than reactive intervention
- For systems prone to solids deposition, regular intervention e.g. periodic pigging should be included with other preventative programs
- Proper monitoring of flow assurance programs ensures effectiveness
- Review existing production systems for potential process optimization to enhance flow assurance
- Innovative technologies should be seriously considered and incorporated

Financial Considerations

A successful offshore project very much lies down on clearly quantified and defined cost knowledge in order to a cost effective and feasible subsea technology. Some of the considerable principal cost areas include initial capital cost, cost of pre investment, in service maintenance costs, abandonment costs, and residual capital value [27-31].
In order to lower the CAPEX, a relatively appropriate, and safe design and good engineering, use of instrument alternatives with higher failure preventability, and applying more intelligent risk and safety policies such as using diverless maintained cluster can be really useful. Combining the installation and hardware costs, shows a significant cost benefit for diverless systems over diver based approaches [32].
Relative total cost for deepwater development solutions is dramatically increasing with depth for compliant towers especially in ranges of more than 1600 ft, whereas TLPs and even more economically spars and semis follow a smother trend of the total cost relative to the depth [33-36]. (See Fig. 4)

Fig. 4 The influence of the project different phases and gates on the expenditures



Why Choosing Subsea Completion?

Economics

If in a case studies suggests that production may not justify the CAPEX for a platform, field reservoir areas may not be reached by deviated drilling from surface wells, the water depth may be too great to use a surface well platform, or a fast-track development is required, then subsea completions offer a better economical solution.

Advantages

- Eliminate CAPEX of platform
- Cost burden transferred from CAPEX to OPEX
- Construction cycle is conducive to fast-track projects
- Suitable to phased projects – future expansion
- No visual impact
- Under ice in Arctic conditions

Disadvantages

- Complex hardware
- Inaccessible for maintenance and repair
- Intervention is expensive and complex
-

Common Components of Subsea Systems

Wellheads

Wellhead is the access point to the well foundation and connection point for Xmas tree or B.O.P. It usually supports the subsurface equipment production tubing and completion and is designed to take riser bending loads during drilling and workover operations and pressure and temperature loads.

Xmas Trees

It is an assembly of valves mounted on wellhead which controls of flow to and from well during normal production, provides safe access to well during well interventions (“workovers”). Most important Xmas tree’s features are dual barrier philosophy, gas lift, annulus monitoring / pressure relief, chemical injection and mounting location for other equipment.
Dry trees:

- Potentially higher recovery
- Less flow assurance risks
- Minimize well intervention costs and downtime
- Simpler hardware
- Lower OPEX and life cycle costs for medium and large developments
- Single drill centre

Wet trees:

- More complex flow assurance issues
- Maximizing development plane flexibility
- Minimizing project schedule
- Maximizing project economics for small developments
- Multiple drilling centers and minimizing drilling costs and risks for large area extent reservoirs
- Lower CAPEX but potentially higher OPEX

Subsea Well Arrangements

Satellite: individual wells are tied directly to a host facility and tiebacks can be single or multiple wells. Hosts can also be shallow water platform, TLP, SPAR, FPS, FPSO, etc.
Cluster: wells are drilled in close proximity to manifold and produce through a common manifold. This kind of arrangement can accommodate batch drilling and completion and the components are small easily deployed modular units.
Template: wells are drilled and completed through template manifold and central drilling center, however the well can be targets reached via directional drilling. The arrangement may have satellite wells tied back to manifold.
Daisy-chain: they are simple tie-in method with less complex structures. The loss of a well as a result of dropped object or problems during drilling or completion program would be less catastrophic.

Templates and Manifolds

There are the collection point of valves and piping which collect flow from multiple wells into a single transportation system, provide an economic alternative to individual flowlines, and allow for isolation of one Xmas Tree from others and pigging of flowline and well testing. It also is a distribution point for chemicals, gas for gas lift etc. to Xmas trees which have been designed to take expansion loads etc. from flowlines and provide protection from various impacts such as dropped objects, as well as snags like fishing.

Flowlines and Risers

Rigid or flexible pipes used to transport product, inject gas and chemicals. Selection of various types is based on product service (temperature / composition), water depth, economics, installation vessels, insulation requirements, etc.
According to water depth and type of facilities we can use flexible flowlines or steel catenary risers.

Tie-In and Connection Systems

Subsea connectors’ types either diver or diverless are flange, collet, mandrel and clamp which fall in to the following alignment and connection methods category horizontal stab type connectors, vertical stab type connectors, vessels, Risers and moorings and vertical stab and hinge over type connector.

Control Systems and Umbilicals

Purpose of applying control systems is to control and monitor valves and chokes, hydraulic power, remote flow measuring, and signal transmission for pressure, temperature, and erosion.
Umbilical are configurations lines to transport hydraulic fluid, injection chemicals, and transport electrical power and signal cores.

Installation Tooling

Installation tooling includes a wide range of workover control system, tubing hanger tooling, wellhead tooling, ROV tooling package, lifting equipments, Onshore / Offshore test equipment and workover riser / EDP / LRP / landing string.

Subsea Development Phases

System Design and Subsea System Design Options

According to the result of studying the actual concept, Front End Engineering (FEED), detail reservoir engineering and flow assurance, subsea system development, project's CAPEX, OPEX, as well as risk, reliability and availability, various subsea system design options could be considered such as host facility, tie-backs, well arrangements, diver vs. diverless, control system options, horizontal vs. vertical Xmas trees, steel vs. thermoplastic umbilical, vs. Control Buoy, infield flowlines - flexible vs. rigid (carbon steel vs. CRA), riser options, materials and corrosion inhibition and manifold configurations and pigging.

Fabrication and Testing

This phase covers the component, qualification, Factory Acceptance Testing (FAT), and System Integration Testing (SIT).
Weight and size limits selection of fabrication shops, road transport constraints and selection of installation vessels. Also welding procedure requires qualifications and weld testing particularly in the case of corrosive environment. The complexity in the joint design, assembly, and access may be critical.

- Component testing: ensures the component functions reliably within specified limits, i.e. is fit for purpose
- Qualification testing: proves a component or assembly is fit for the intended application.
- Factory acceptance testing (FAT): demonstrates correct functionality and integrity of an assembly.
- System integration testing (SIT): verifies the correct and operation of the overall system.

Installation and Operation

After finalizing the field development option (See Common Offshore Platform Configurations), installation and operation requires regular inspection, maintenance and repair. Some of the subsea system operational considerations include system commissioning, start-up, operation, shutdown, reliability of subsea equipment, failures, maintenance and well Intervention.
In this regard tasks include but not limited to monitoring of equipment condition, retrieval of modules such as chokes and control pods, and monitoring the operation of valves. To complete these tasks we can seek help from divers either saturation or hard suits, remotely operated vehicles (ROV), and remotely operated tools (ROT).

Developing the Right Concept

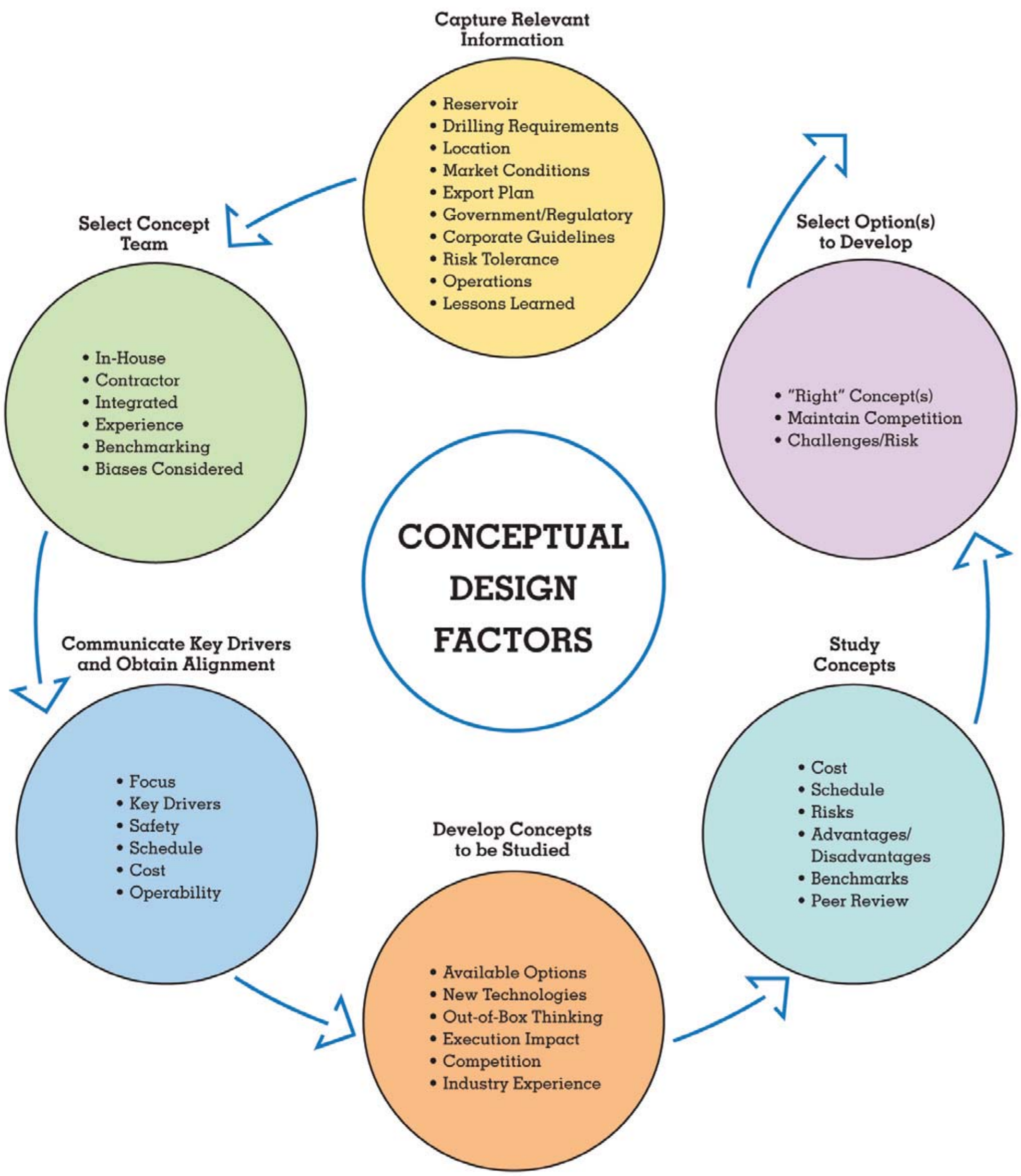
A project's conceptual phase is series of phases that eventually lead to the best possible solution to fit the project parameters. This process is not just about numbers and can take long time depending on the nature and complexity of the project as well as the client's requirements. There are many issues that need to be addressed and they will be studied in various steps of the process such as capturing relevant information, selecting the most appropriate concept team, communicating key drivers, obtaining alignment of purpose, identifying concepts to study, studying those options, and finally selecting the best option for the project (See Fig 5) [50] .

Conclusions

The key drivers for facility selection outlined as water depth, well count, drilling and well intervention, utilities, accessibility, regional influence and metocean criteria, reservoir characteristics and flow assurance, facility motions, field layout and drilling centre locations, market conditions and financial and HSE considerations.
For many long distanced subsea developments, high voltage power distribution is required to provide sufficient power to support subsea gas compression schemes. The feasibility of such field development concepts will necessitate development and implementation of technological solutions to meet this challenge. The remoteness of many of these locations, combined with the harsh environment, means that subsea to shore development solutions with the subsea wells tied back directly to an onshore facility in many cases can offer significant benefits over platform or floater based development concepts. In some cases, subsea to shore development solutions may even be a strict necessity for the feasibility of the development. The industry-wide efforts to meet the associated technical requirements such as management of multiphase flow and provision of remote control over long distances represents a frontier area within the current subsea technology development [1].
In general FPSOs and semi's are found in most combinations of well count and water depth. Other production systems have much more specific applications, as itemized in the table, and there are number of zones where no dry-tree platform is suitable. Nonetheless, the discussion should be of use in the preliminary stages of the facility selection process for a particular field, in rapidly pin-pointing the likely optimal production system or highlighting any challenges where the limits of current experience are being approached. It also indicates gaps in the current suite of options where future innovation might be of particular benefit. The water depth and the well count are seen to be very important drivers of concept selection.

Both are variables: the well count is an output of the chosen production plan, while in some situations the water depth may be adjusted by moving the platform location. This suggests the value of integrating facilities and subsurface considerations in the system selection process.

Fig.5. flow diagram of developing the right concept for the project [50]



References

1. Witting, F., Snohvit and Beyond - Setting New Standards For Subsea to Shore Developments, in SPE Russian Oil and Gas Technical Conference and Exhibition. 2006, Society of Petroleum Engineers: Moscow, Russia.
2. Ronalds, B.F., Applicability ranges for offshore oil and gas production facilities. Marine Structures, 2005. 18(3): p. 251-263.
3. Walters, D., Thomas, David., Hatton, Stephen., , Design and Optimization of Top Tension Risers for Ultra Deep Water, in Floating Production Systems 2004 Conference. 2004.
4. Jenkins, R.W., et al., Drilling the First Ultra Deepwater Wells Offshore Malaysia, in SPE/IADC Drilling Conference. 2003, SPE/IADC Drilling Conference: Amsterdam, Netherlands.
5. Bass, R.M., Subsea Processing and Boosting-Technical Challenges and Opportunities. 2006.
6. Hammett, D.S., Semi-Submersible Used as Floating Production Facility, in International Meeting on Petroleum Engineering. 1986, 1986: Beijing, China.
7. Forbord, P.K., et al., The Challenges Associated With the Installation of Long-Distance Tiebacks. 2007.
8. Hannegan, D.M. and G. Wanzer, Well Control Considerations - Offshore Applications of Underbalanced Drilling Technology, in SPE/IADC Drilling Conference. 2003, SPE/IADC Drilling Conference: Amsterdam, Netherlands.
9. The North Sea Field Development Guide, 8, Editor. 2001, Oilfield Publications.
10. Frank Busby, R., Underwater inspection/testing/ monitoring of offshore structures. Ocean Engineering, 1979. 6(4): p. 355-491.
11. Dunjó, J., et al., Hazard and operability (HAZOP) analysis. A literature review. Journal of Hazardous Materials, 2010. 173(1-3): p. 19-32.
12. Kishawy, H.A. and H.A. Gabbar, Review of pipeline integrity management practices. International Journal of Pressure Vessels and Piping, 2010. 87(7): p. 373-380.
13. Henry, L., Pipeline engineering. 2003: Lewis Publishers
14. Manian, L. and A.M. Hodgdon, Pipeline integrity assessment and management. Materials Performance 2005: p. 18–22.
15. Larry G. Rankin, Pipeline integrity information integration. Materials Performance, 2004: p. 43–46.
16. Ernest W. Klechka, Pipeline integrity management and corrosion control. Materials Performance, 2002: p. 24–27.
17. Menno T Van Os, v.M.P., Francis A., An external corrosion direct assessment module for a pipeline integrity management system, in 6th International Pipeline Conference. 2006: Calgary, Alberta, Canada.
18. Menno T. Van and P. Van Mastrigt, A direct assessment module for pipeline integrity management at Gasunie, in 23rd World Gas Conference. 2006: Amsterdam.
19. Curran, K.J., P.G. Wells, and A.J. Potter, Proposing a coordinated environmental effects monitoring (EEM) program structure for the offshore petroleum industry, Nova Scotia, Canada. Marine Policy, 2006. 30(4): p. 400-411.
20. Yang, M., F.I. Khan, and R. Sadiq, Prioritization of environmental issues in offshore oil and gas operations: A hybrid approach using fuzzy inference system and fuzzy analytic hierarchy process. Process Safety and Environmental Protection. In Press, Corrected Proof.
21. Purnell, K.J., Comparative costs of low technology shoreline cleaning methods, in International Oil Spill Conference. 1999: Seattle, USA.
22. Grey, C. The cost of oil spills from tankers: an analysis of IOPC fund incidents. in Proceedings of the International Oil Spill Conference. 1999. Seattle, USA: The International Tanker Owners Pollution Federation Limited (ITOPF).
23. Liu, X. and K.W. Wirtz, The economy of oil spills: Direct and indirect costs as a function of spill size. Journal of Hazardous Materials, 2009. 171(1-3): p. 471-477.
24. Penn, T., Tomasi, T., Environmental assessment: calculating resource restoration for an oil discharge in lake Barre, Louisiana, USA. Environmental Management 2002. 29: p. 691–702.
25. Dunford, R.W., Ginn, T.C. , Desvousges, W.H., The use of habitat equivalency analysis in natural resource damage assessments. Ecological Economics 2004. 48 p. 49–70.
26. French McCay, D.P., Rowe,J.J. , Marine Ecology Progress Series Habitat restoration as mitigation for lost production at multiple trophic levels. Marine Ecology Progress Series 2003. 264 p. 233–247.
27. Capanoglu, C., Novel and Marginal Field Offshore Structures, in Handbook of Offshore Engineering, K.C. Subrata, Editor. 2005, Elsevier: London. p. 39-77.
28. Chakrabarti, S., Preface, in Handbook of Offshore Engineering, K.C. Subrata, Editor. 2005, Elsevier: London. p. v-viii.
29. Chakrabarti, S., J. Halkyard, and C. Capanoglu, Historical Development of Offshore Structures, in Handbook of Offshore Engineering, K.C. Subrata, Editor. 2005, Elsevier: London. p. 1-38.
30. Halkyard, J., Floating Offshore Platform Design, in Handbook of Offshore Engineering, K.C. Subrata, Editor. 2005, Elsevier: London. p. 419-661.
31. Karsan, D.I., Fixed Offshore Platform Design, in Handbook of Offshore Engineering, K.C. Subrata, Editor. 2005, Elsevier: London. p. 279-417.

32. White, J., S.M. Adamson, and P.E. Hadfield, Cost-Reduction Achieved By Convergence Of Subsea Technology In Both Shallow And Deep Water. 1993.
33. Mansour, A.E. and R.C. Ertekin, Design Principles and Criteria, in ISSC 2003 - 15th International Ship and Offshore Structures Congress, A.E. Mansour and R.C. Ertekin, Editors. 2003, Elsevier Science: Oxford. p. 393-445.
34. Mansour, A.E. and R.C. Ertekin, Loads, in ISSC 2003 - 15th International Ship and Offshore Structures Congress, A.E. Mansour and R.C. Ertekin, Editors. 2003, Elsevier Science: Oxford. p. 17-38.
35. Naess, A. and T. Moan, Probabilistic Design of Offshore Structures, in Handbook of Offshore Engineering, K.C. Subrata, Editor. 2005, Elsevier: London. p. 197-277.
36. Pratt, J.A., T. Priest, and C.J. Castaneda, Wading into Deepwater, in Offshore Pioneers. 1997, Gulf Professional Publishing: Burlington. p. 70-94.
37. Lamey, M.F.a.W., F.K., Dynamic simulation model aids Mensa development. Oil and Gas Journal, 1998. 96(32).
38. Gilchrist, R.T.a.K., F.A., Mensa Project: Flowlines, in Offshore Technology Conference. 1998 Houston, Texas.
39. Cooley, C., Wallace, B.K., and Gudimetla, R. , Liquid Management on Canyon Express, in SPE Annual Technical Conference and Exhibition. 2003 Denver.
40. Cochran, S.W.a.H., A.F., Development of Operating Envelope for Long Distance Gas Tieback, in Offshore Technology Conference. 2002 Houston, Texas.
41. Harun, A.F., Choate, T.G.A., and Cochran, S.W., Liquid Inventory Management Issues in a Dual Large Diameter Long-Distance Subsea Wet Gas Pipeline System, in SPE Annual Technical Conference and Exhibition. 2003 Denver.
42. Katamish, H.E., Steel, N., Smith, A., Thompson, P., WDDM, The Jewel of the Nile, in SPE Europe/EAGE Annual Conference. 2005 Madrid, Spain.
43. Lingelem, M.N., Braseth, A.O., Holm, H., Experience from Multiphase Flow Operations and Pipeline Operation on TOGI, in Norwegian Petroleum Society Conference on Multiphase Transport. 1992 Roros, Norway.
44. Wilson, A., Overaa, S.J., Holm, H., Ormen Lange – Flow Assurance Challenges, in Offshore Technology Conference. 2004 Houston, Texas.
45. Klomp, U.C., Kruka, V., and Reinjhart, R., Low Dosage Inhibitors: (How) Do They Work?, in 2nd International Conference on Controlling Hydrates, Waxes, and Asphaltenes. 1997 Aberdeen.
46. Clark, L.W., Frostman, L.M., Anderson, J.: "." IPTC Paper no. 10562 presented at the , , Low-Dosage Hydrate Inhibitors (LDHI): Advances in Flow Assurance Technology for Offshore Gas Production Systems, in International Petroleum Technology Conference. 2005
47. Hagesaether, L., Bruvold, R.S., Postvoll, W., and Albrechtsen, R., Rich Gas Pipeline Operations during Tail-End Production, in PSIG Annual Meeting. 2004 Palm Springs, California.
48. Hagesaether, L., et al., Flow-Assurance Modeling: Reality Check and Aspects of Transient Operations of Gas/Condensate Pipelines. SPE Projects, Facilities & Construction, 2007. 2(1): p. pp. 1-17.
49. Harun, A.F., Cochran, S.W., Choate, T.G.A., Optimization of Ramp-up Operations in a Dual Large Diameter Long-Distance Subsea Wet Gas Pipeline System, in SPE Annual Technical Conference and Exhibition. 2002 San Antonio.
50. Daryl, B.R., Developing the 'right' concept for offshore developments. offshore, 2007.
51. Hagesaether, L., Lunde, K, Nygard, F., and Eidsmoen, H., Flow-Assurance Modeling: Reality Check and Aspects of Transient Operations of Gas/Condensate Pipelines. SPEPF, 2007.

Bibliography

1. Choe, J., Analysis of Riserless Drilling and Well-Control Hydraulics. SPE Drilling & Completion, 1999. 14(1): p. 71-81.
2. Ronalds, B.F., Applicability ranges for offshore oil and gas production facilities. Marine Structures, 2005. 18(3): p. 251-263.
3. Gouldson, A., A. Morton, and S.J.T. Pollard, Better environmental regulation -- contributions from risk-based decision-making. Science of The Total Environment, 2009. 407(19): p. 5283-5288.
4. Juiniti, R., J. Salies, and A. Polillo, Campos Basin: Lessons Learned and Critical Issues To Be Overcome in Drilling and Completion Operations. 2003.
5. Forbord, P.K., et al., The Challenges Associated With the Installation of Long-Distance Tiebacks. 2007.
6. Jahn, F., M. Cook, and M. Graham, Chapter 10 Well Dynamic Behaviour, in Developments in Petroleum Science, M.C. Frank Jahn and G. Mark, Editors. 2008, Elsevier. p. 229-264.
7. Purnell, K.J., Comparative costs of low technology shoreline cleaning methods, in International Oil Spill Conference. 1999: Seattle, USA.
8. García Negro, M.C., C.S. Villasante, and A. Carballo Penela, Compensating system for damages caused by oil spill pollution: Background for the Prestige assessment damage in Galicia, Spain. Ocean & Coastal Management, 2007. 50(1-2): p. 57-66.

9. Wheeler, M.F. and M. Peszynska, Computational engineering and science methodologies for modeling and simulation of subsurface applications. Advances in Water Resources. 25(8-12): p. 1147-1173.
10. Grey, C. The cost of oil spills from tankers: an analysis of IOPC fund incidents. in Proceedings of the International Oil Spill Conference. 1999. Seattle, USA: The International Tanker Owners Pollution Federation Limited (ITOPF).
11. White, J., S.M. Adamson, and P.E. Hadfield, Cost-Reduction Achieved By Convergence Of Subsea Technology In Both Shallow And Deep Water. 1993.
12. Hartell, W.D. and J.R. Greenwald, Deepwater Development Production and Export Options, in Asia Pacific Oil and Gas Conference & Exhibition. 2009, Society of Petroleum Engineers: Jakarta, Indonesia.
13. Cochran, S.W.a.H., A.F., Development of Operating Envelope for Long Distance Gas Tieback, in Offshore Technology Conference. 2002 Houston, Texas.
14. Menno T. Van and P. Van Mastrigt, A direct assessment module for pipeline integrity management at Gasunie, in 23rd World Gas Conference. 2006: Amsterdam.
15. Jenkins, R.W., et al., Drilling the First Ultra Deepwater Wells Offshore Malaysia, in SPE/IADC Drilling Conference. 2003, SPE/IADC Drilling Conference: Amsterdam, Netherlands.
16. Lamey, M.F.a.W., F.K., Dynamic simulation model aids Mensa development. Oil and Gas Journal, 1998. 96(32).
17. Bendiksen, K.H., Malnes, D., Moe, R., Nuland, S., The Dynamic Two-Fluid Model OLGA: Theory and Application. SPEPE, 1991: p. 171-180.
18. le Leuch, H. and J. Masseron, Economic aspects of offshore hydrocarbon exploration and production. Ocean Management, 1973. 1: p. 287-325.
19. Liu, X. and K.W. Wirtz, The economy of oil spills: Direct and indirect costs as a function of spill size. Journal of Hazardous Materials, 2009. 171(1-3): p. 471-477.
20. Penn, T., Tomasi, T., Environmental assessment: calculating resource restoration for an oil discharge in lake Barre, Louisiana, USA. Environmental Management 2002. 29: p. 691–702.
21. Vinnem, J.E., Evaluation of offshore emergency preparedness in view of rare accidents. Safety Science, 2011. 49(2): p. 178-191.
22. Hansen, R.L. and W.P. Rickey, Evolution of Subsea Production Systems: A Worldwide Overview. SPE Journal of Petroleum Technology, 1995. 47(8): p. 675-680.
23. Lingelem, M.N., Braseth, A.O., Holm, H., Experience from Multiphase Flow Operations and Pipeline Operation on TOGI, in Norwegian Petroleum Society Conference on Multiphase Transport. 1992 Roros, Norway.
24. Menno T Van Os, v.M.P., Francis A., An external corrosion direct assessment module for a pipeline integrity management system, in 6th International Pipeline Conference. 2006: Calgary, Alberta, Canada.
25. Ronalds, B.F., Features, challenges and opportunities in Australian gas and oil technology. Journal of Constructional Steel Research, 2006. 62(11): p. 1184-1191.
26. Karsan, D.I., Fixed Offshore Platform Design, in Handbook of Offshore Engineering, K.C. Subrata, Editor. 2005, Elsevier: London. p. 279-417.
27. Hagesaether, L., et al., Flow-Assurance Modeling: Reality Check and Aspects of Transient Operations of Gas/Condensate Pipelines. SPE Projects, Facilities & Construction, 2007. 2(1): p. pp. 1-17.
28. French McCay, D.P., Rowe,J.J. , Marine Ecology Progress Series Habitat restoration as mitigation for lost production at multiple trophic levels. Marine Ecology Progress Series 2003. 264 p. 233–247.
29. Dunjó, J., et al., Hazard and operability (HAZOP) analysis. A literature review. Journal of Hazardous Materials, 2010. 173(1-3): p. 19-32.
30. Henzell, S.T. and A.D. Glucina, Henry Subsea Development - Challenges and Solutions, in SPE Asia Pacific Oil and Gas Conference and Exhibition. 2010, Society of Petroleum Engineers: Brisbane, Queensland, Australia.
31. Chakrabarti, S., J. Halkyard, and C. Capanoglu, Historical Development of Offshore Structures, in Handbook of Offshore Engineering, K.C. Subrata, Editor. 2005, Elsevier: London. p. 1-38.
32. Lorenzo, M.D., et al., Hydrate Formation Characteristics of Natural Gas During Transient Operation of a Flow Line, in SPE Asia Pacific Oil and Gas Conference and Exhibition. 2010, Society of Petroleum Engineers: Brisbane, Queensland, Australia.
33. SETLIFF, S.R., G.M. PARFITT, and T.S. CHILTON, HYDRATE MITIGATION IN A DEEPWATER PRODUCTION SYSTEM, in Offshore Europe. 1989, 1989 Copyright 1989, Society of Petroleum Engineers: Aberdeen, United Kingdom.
34. Nihoul, C. and J.-P. Ducrotoy, Impact of oil on the marine environment: Policy of the Paris commission on operational discharges from the offshore industry. Marine Pollution Bulletin, 1994. 29(6-12): p. 323-329.
35. Henry, W.C., A.M. Hyden, and S.L. Williams, Innovations in Subsea Development & Operation, in SPE Asia Pacific Oil and Gas Conference and Exhibition. 2000, Copyright 2000, Society of Petroleum Engineers Inc.: Brisbane, Australia.

36. Vralstad, T., et al., Leak Detection Technologies for Continuous Monitoring of Subsea Production Templates, in Middle East Health, Safety, Security, and Environment Conference and Exhibition. 2010, Society of Petroleum Engineers: Manama, Bahrain.
37. Su, C., Rydahl, A., and Shea, R.H., Liquid Inventory Management in Wet Gas Pipelines, in SPE Latin American and Caribbean Petroleum Engineering Conference. 2003 Port of Spain, Trinidad, West Indies.
38. Harun, A.F., Choate, T.G.A., and Cochran, S.W., Liquid Inventory Management Issues in a Dual Large Diameter Long-Distance Subsea Wet Gas Pipeline System, in SPE Annual Technical Conference and Exhibition. 2003 Denver.
39. Cooley, C., Wallace, B.K., and Gudimetla, R. , Liquid Management on Canyon Express, in SPE Annual Technical Conference and Exhibition. 2003 Denver.
40. Klomp, U.C., Kruka, V., and Reinjhart, R., Low Dosage Inhibitors: (How) Do They Work?, in 2nd International Conference on Controlling Hydrates, Waxes, and Asphaltenes. 1997 Aberdeen.
41. Clark, L.W., Frostman, L.M., Anderson, J.: "." IPTC Paper no. 10562 presented at the , , Low-Dosage Hydrate Inhibitors (LDHI): Advances in Flow Assurance Technology for Offshore Gas Production Systems, in International Petroleum Technology Conference. 2005
42. Castanier, B. and M. Rausand, Maintenance optimization for subsea oil pipelines. International Journal of Pressure Vessels and Piping, 2006. 83(4): p. 236-243.
43. Salleh, N.M. and M.R. Sainal, Malaysia Deepwater Project Execution Strategy and Challenges, in Abu Dhabi International Petroleum Exhibition and Conference. 2010, Society of Petroleum Engineers: Abu Dhabi, UAE.
44. Alberty, M.W., et al., Mechanisms of Shallow Waterflows and Drilling Practices for Intervention. SPE Drilling & Completion, 1999. 14(2): p. 123-129.
45. Gilchrist, R.T.a.K., F.A., Mensa Project: Flowlines, in Offshore Technology Conference. 1998 Houston, Texas.
46. Demirbas, A., Methane hydrates as potential energy resource: Part 1 - Importance, resource and recovery facilities. Energy Conversion and Management, 2010. 51(7): p. 1547-1561.
47. Mobil extends North Sea activities. Filtration Industry Analyst, 1999. 1999(27): p. 2-2.
48. Nossen, J., Shea, R.H., Rasmussen, J., New Developments in Flow Modeling and Field Data Verification. Multiphase Technology, 2000 p. 209-222.
49. The North Sea Field Development Guide, 8, Editor. 2001, Oilfield Publications.
50. Arthur, J.C.R., Offshore Drilling and Safety: the Role of Digital High Resolution Site Surveys, in Oceanology '88: Proceedings of an international conference. 1988, The Society for Underwater Technology: Brighton, UK.
51. Taylor, B.G.S., Offshore oil and gas. Ocean and Shoreline Management, 1991. 16(3-4): p. 259-273.
52. Hughes, H., Offshore oil and gas : The UK's second most valuable resource. Marine Policy, 1994. 18(6): p. 464-471.
53. Buryakovsky, L.A., G.V. Chilingar, and F. Aminzadeh, Offshore Oil and Gas Fields, in Petroleum Geology of the South Caspian Basin. 2001, Gulf Professional Publishing: Burlington. p. 52-112.
54. Pinder, D., Offshore oil and gas: global resource knowledge and technological change. Ocean & Coastal Management, 2001. 44(9-10): p. 579-600.
55. Siddayao, C.M., Oil and gas on the continental shelf: potentials and constraints in the Asia-Pacific region. Ocean Management, 1984. 9(1-2): p. 73-100.
56. Childers, M.A., Operational Efficiency Comparison Between a Deepwater Jackup and a Semisubmersible in the Gulf of Mexico, in SPE/IADC Drilling Conference. 1989, 1989 Copyright 1989, SPE/IADC Drilling Conference: New Orleans, Louisiana.
57. Harun, A.F., Cochran, S.W., Choate, T.G.A., Optimization of Ramp-up Operations in a Dual Large Diameter Long-Distance Subsea Wet Gas Pipeline System, in SPE Annual Technical Conference and Exhibition. 2002 San Antonio.
58. Wilson, A., Overaa, S.J., Holm, H., Ormen Lange – Flow Assurance Challenges, in Offshore Technology Conference. 2004 Houston, Texas.
59. Henry, L., Pipeline engineering. 2003: Lewis Publishers
60. Manian, L. and A.M. Hodgdon, Pipeline integrity assessment and management. Materials Performance 2005: p. 18–22.
61. Larry G. Rankin, Pipeline integrity information integration. Materials Performance, 2004: p. 43–46.
62. Ernest W. Klechka, Pipeline integrity management and corrosion control. Materials Performance, 2002: p. 24–27.
63. Stair, C.D., et al., Planning and Execution of Highly Overbalanced Completions from a Floating Rig: The Ursa-Princess Waterflood Project, in SPE Annual Technical Conference and Exhibition. 2010, Society of Petroleum Engineers: Florence, Italy.
64. Yang, M., F.I. Khan, and R. Sadiq, Prioritization of environmental issues in offshore oil and gas operations: A hybrid approach using fuzzy inference system and fuzzy analytic hierarchy process. Process Safety and Environmental Protection. In Press, Corrected Proof.

65. Kartikasurja, D.O., et al., Produced CO2 Storage into Aquifer in an Offshore Field, Malaysia, in SPE Asia Pacific Oil and Gas Conference and Exhibition. 2008, Society of Petroleum Engineers: Perth, Australia.
66. Lyons, W.C. and G.J. Plisga, Production Engineering, in Standard Handbook of Petroleum and Natural Gas Engineering (Second Edition), C.L. William and J.P. Gary, Editors. 2004, Gulf Professional Publishing: Burlington. p. 1-447.
67. Curran, K.J., P.G. Wells, and A.J. Potter, Proposing a coordinated environmental effects monitoring (EEM) program structure for the offshore petroleum industry, Nova Scotia, Canada. Marine Policy, 2006. 30(4): p. 400-411.
68. Gallagher, K.T. and D.F. Bond, Redefining the Environmental Envelope for Surface Bops on a Semi-Submersible Drilling Unit, in SPE/IADC Drilling Conference. 2001, Copyright 2001, SPE/IADC Drilling Conference: Amsterdam, Netherlands.
69. Harrold, D., et al., Reliability by Design - HP/HT System Development. 2004.
70. Kam, J.C.P. and M. Birkinshaw, Reliability-based fatigue and fracture mechanics assessment methodology for offshore structural components. International Journal of Fatigue, 1994. 16(3): p. 183-192.
71. Christiansen, P.E., et al., Remote Field Control and Support Strategy - Umbilicals versus Control Buoys, in SPE Asia Pacific Oil and Gas Conference and Exhibition. 2004, Society of Petroleum Engineers: Perth, Australia.
72. Kjärstad, J. and F. Johnsson, Resources and future supply of oil. Energy Policy, 2009. 37(2): p. 441-464.
73. Gregg, M. and S. Ramachandran, Review of Corrosion Inhibitor Developments and Testing for Offshore Oil and Gas Production Systems, in CORROSION 2004. 2004, NACE International: New Orleans, La.
74. Kishawy, H.A. and H.A. Gabbar, Review of pipeline integrity management practices. International Journal of Pressure Vessels and Piping, 2010. 87(7): p. 373-380.
75. Hagesaether, L., Bruvold, R.S., Postvoll, W., and Albrechtsen, R., Rich Gas Pipeline Operations during Tail-End Production, in PSIG Annual Meeting. 2004 Palm Springs, California.
76. Roller, P.R., Riserless Drilling Performance in a Shallow Hazard Environment, in SPE/IADC Drilling Conference. 2003, SPE/IADC Drilling Conference: Amsterdam, Netherlands.
77. Psarros, G., R. Skjong, and E. Vanem, Risk acceptance criterion for tanker oil spill risk reduction measures. Marine Pollution Bulletin. In Press, Corrected Proof.
78. Kjellén, U., Safety in the design of offshore platforms: Integrated safety versus safety as an add-on characteristic. Safety Science. 45(1-2): p. 107-127.
79. Rashdi, K.R., M.R. Sainal, and M.N.M. Yusoff, Samarang Pipeline-Replacement Project: Application of an Innovative Approach for Shallow-Water Pipeline Installation, in SPE Annual Technical Conference and Exhibition. 2008, Society of Petroleum Engineers: Denver, Colorado, USA.
80. Goodstein, E., Saturday effects in tanker oil spills. Journal of Environmental Economics and Management, 1992. 23(3): p. 276-288.
81. Eriksen, R. and B. Saucier, Selecting Cost-Effective and Safe Deepwater Completion Tieback Alternatives. 2000.
82. Hammett, D.S., Semi-Submersible Used as Floating Production Facility, in International Meeting on Petroleum Engineering. 1986, 1986: Beijing, China.
83. Wojtanowicz, A.K. and D. Zhou, Shallow Casing Shoe Integrity Interpretation Technique, in SPE/IADC Drilling Conference. 2001, Copyright 2001, SPE/IADC Drilling Conference: Amsterdam, Netherlands.
84. Grinrod, M., O. Haaland, and B. Ellingsen, A Shallow Gas Research Program, in SPE/IADC Drilling Conference. 1988, 1988 Copyright 1988, IADC/SPE Drilling Conference: Dallas, Texas.
85. Schuberth, P.C. and M.W. Walker, Shallow Water Flow Planning and Operations: Titan #1 Exploration Well, Deepwater Gulf of Mexico, in SPE/IADC Drilling Conference. 1999, Copyright 1999, SPE/IADC Drilling Conference: Amsterdam, Netherlands.
86. Schuberth, P.C. and M.W. Walker, Shallow Water Flow Planning and Operations: Titan No. 1 Exploration Well, Deepwater Gulf of Mexico. SPE Drilling & Completion, 2000. 15(4): p. 234-240.
87. Williams, M.R., P.A. Atkins, and G.E. Lochte, Simple Subsea Trees for Shallow Water: An Economical Alternative. 1987.
88. Witting, F., Snohvit and Beyond - Setting New Standards For Subsea to Shore Developments, in SPE Russian Oil and Gas Technical Conference and Exhibition. 2006, Society of Petroleum Engineers: Moscow, Russia.
89. Meier, T., T. Backers, and O. Stephansson, Study On Support Design For Subsea Tunnel, in ISRM International Symposium on Rock Mechanics - SINOROCK 2009. 2009, International Society for Rock Mechanics and the University of Hong Kong.: The University of Hong Kong, China.
90. Bass, R.M., Subsea Processing and Boosting-Technical Challenges and Opportunities. 2006.
91. Subsea separation has environmental benefits. Filtration & Separation, 2007. 44(7): p. 8-8.
92. Lappin-Scott, H.M., et al., Survival mechanisms of hydrogen sulphide-producing bacteria isolated from extreme environments and their role in corrosion. International Biodeterioration & Biodegradation, 1994. 34(3-4): p. 305-319.

93. Johnston, I.W., H.L. Young, and J.R. Huntington, Toward Unmanned Oil and Gas Production Offshore, in European Petroleum Conference. 1986, 1986 Copyright 1986, Society of Petroleum Engineers: London, United Kingdom.
94. Mclnturff, T.L., Troika Subsea Production Template and Manifold System. 1998.
95. Hannegan, D. and R. Divine, Underbalanced Drilling-Perceptions and Realities of Today's Technology in Offshore Applications, in IADC/SPE Drilling Conference. 2002, Copyright 2002, IADC/SPE Drilling Conference: Dallas, Texas.
96. Tioe, E., et al., Understanding the Plumbing in your Field - Application of Reservoir Connectivity Analysis to Improve Oil and Gas Recovery, in International Petroleum Technology Conference. 2008, International Petroleum Technology Conference: Kuala Lumpur, Malaysia.
97. Frank Busby, R., Underwater inspection/testing/ monitoring of offshore structures. Ocean Engineering, 1979. 6(4): p. 355-491.
98. Dunford, R.W., Ginn, T.C. , Desvousges, W.H., The use of habitat equivalency analysis in natural resource damage assessments. Ecological Economics 2004. 48 p. 49–70.
99. Hylland, K., et al., Water column monitoring near oil installations in the North Sea 2001-2004. Marine Pollution Bulletin, 2008. 56(3): p. 414-429.
100. Katamish, H.E., Steel, N., Smith, A., Thompson, P., WDDM, The Jewel of the Nile, in SPE Europe/EAGE Annual Conference. 2005 Madrid, Spain.
101. Hannegan, D.M. and G. Wanzer, Well Control Considerations - Offshore Applications of Underbalanced Drilling Technology, in SPE/IADC Drilling Conference. 2003, SPE/IADC Drilling Conference: Amsterdam, Netherlands.
102. Kaiser, M.J., World offshore energy loss statistics. Energy Policy, 2007. 35(6): p. 3496-3525