Deep Water Moored Semisubmersible with Dry Wellheads and Top Tensioned Well Risers
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Abstract
Depletion of deep-water reservoirs by means of dry completion units (for short: DCUs) have been confined to TLPs, Spars, and Deep Draft Floaters (DDF). The preference for DCUs is well motivated as they give maximum well access with ample well and riser condition monitoring and flow assurance control.

This paper proposes another step forward and that is, to exploit the potential of semisubmersible hulls as carriers of dry tree solutions. The paper describes the findings from a development study by Kvaerner Oil & Gas Field Development (KOG FD). The proposed solution may be seen as an extension of the classic semisubmersible/top tensioned riser combination technology, with which the industry has several thousand rig-years of experience.

This paper demonstrates that a DCU semisubmersible has several safety advantages in mitigating the risks from riser leaks/explosions/fire within the platform or its vicinity. The reduced consequential damages lead to less onerous riser specifications relaxing barrier/weight requirements and cost. The DCU semisubmersible will be a competitive alternative to Spar/ DDF solutions, and will fill the shortcomings of the TLPs beyond present waterdepth limitations.

Introduction
Significant new discoveries in offshore West Africa, offshore Brazil, and the Gulf of Mexico are currently attracting a lot of attention. The larger finds, however, are in ultra-deep locations with water depths of 3000 ft to 6000 ft.

Ultra-deep discoveries around the world have much of the same challenges i.e. frontier drilling/wells technology, unconsolidated sediments, and flow assurance problems. Economic exploitation of the large finds may be troubled by extreme water depths, lack of pipeline or other off-take infrastructures, and distance to terminals and refineries from consumer market.

While WA has favorable weather conditions its location imposes some special boundary conditions, which includes lack of local contractors of a sufficient size to handle major projects, limited local yard capacities and skilled work force and few harbors to provide operational service.

Lack of offshore infrastructure implies that an FPSO concept may be more attractive, as some form of storage vessel will be required. A storage vessel will offer a large deck surface thus emerging as a kind of “free issue property” for a process plant for which one would otherwise have to build a separate platform.

The “first wave” of WA projects of this type has homed in on large (or rather gigantic) stand alone FPSO’s. The “next wave” will show some preference for field developments that includes “on-board” drilling and work-over functions. In addition, some reshuffling in the target fields queue has taken place. Operators have developed a preference for reservoirs that may be depleted satisfactorily from one central location, together with a
system that solves or makes it easier to combat flow assurance problems without costly Mobile Offshore Drilling Unit (MODU) based work-over. TLPs, Spars and DDF’s have so far been considered for deep-water carriers of DCU units. Semisubmersible units (or semis, for short) with hydraulic tensioning have to some extent been overlooked in this context. Reasons may be that the industry has not been recognizing the semis as a “wellhead platform only” function. A semisubmersible can carry large quantities of process equipment, but it still offers no storage capacity, hence at first sight its capability is not appreciated. There may also be the opinion that no semisubmersible based tensioning system will cope with such a situation even in a favorable WA weather condition. References 2 to 12 inclusively, give the background to previous work carried out in this field.

Carrier Efficiency

Deck-load capacity discussion. What makes the semisubmersible interesting as a carrier of dry wellheads, is the cost effectiveness of the semi in terms of unit cost for providing carrying capacity for topside load. “Topside load” is used as the sum of fixed and variable payload acting at the top of column elevation (deck underside). Carrier efficiency is measured by the ratio of deck operating weight over carrier hull steel weight. These definitions are discussed in relation to the following carriers:

Semisubmersibles. A semisubmersible will normally have a deck over hull steel weight ratio in the range of 2 to 2.5. This means its capacity for carrying a deck box weight will be in the order of twice the steel weight of the hull.

Spars/ DDFs. In comparison, a “Classic Spar” will have deck over hull steel-weight ratio of something like 0.7 to 1.3. The hull steel-weight ratio for recent Truss-Spars designs and multi-leg Deep Draft Floaters designs (Kvaerner DDF) may be in the 1.0 to 2.0 range. The higher end here indicates that a large number of risers will be installed from day one, meaning a large number of wells will have to be predrilled.

Tension Leg Platforms (TLP). The corresponding ratio for TLPs is in the range 1 to 1.6. Tether technologies are being developed that may improve the TLP’s efficiency. However, its displacements will always have to carry the extra load of tether pretension (10 – 20% of displacement). In the above TLP tether weights are counted as a part of hull weight, and for the Spars, buoyancy tanks for riser tensioning are credited as topsides “weight”.

Cost Indicators. Floater deck-to-hull weight ratio is one of several illustrative indicators for measuring relative property costs of offshore plant carriers. Other contributors in a cost efficiency discussion are engineering, fabrication, platform assembly/ commissioning, drilling plant, marine operations / installation, mooring system, riser system, operating limitations, and early production and operational costs. Additionally, the existing infrastructure e.g. the quayside, transportation system etc. need to be addressed.

The Feasibility Study

The Study was carried out by KOG FD to assess the possibility of supporting an array of vertical top tensioned rigid risers from a traditional ring pontoon semisubmersible placed as a wellhead/ production platform in deep-water. To a large extent, the study is supported by the wide range of experience and data from earlier Kvaerner projects ranging from Sea Launch through the “Kvaerner semi family”, which includes Asgard B and Snorre B. No optimization was carried out. Response operators including general slow drift behavior were well documented and readily available from model tests. Model tests results based on taut leg synthetic ropes were also available in comparable water depths.

The chosen hull origin is a 55,000m3 displacement PDQ semi designed for the Norwegian Sea and a scaled model was tested in the deep-water ocean basin laboratory at MARINTEK, Trondheim, Norway. Slight modifications have been made to the corner column diameter (increased by 1.0 m) and the hull airgap (reduced from 20 m to 15 m) to suit WA conditions. This allows the initial 27,500 tonnes top of columns (TOC) load deck stability limit capacity to be upgraded to account for the large total tension load increase (3,200 tonnes), summing up to 30,700 tonnes. Obviously, the above approach indicates that there is room for considerable optimization for an emerging project. However, it serves the purpose of this feasibility study as it contains well-proven information on weights and performance.

In a real case one could expect significant reduction in vessel displacement, as well as improved performance data as one could then perform hull optimization/ tuning of the semi to in-situ conditions.

The West Africa Case

A typical deep-water case offshore WA was chosen as the basis of the study. See Appendix A: West Africa Case - Field Data Summary. The field in question is such that a major part of the reservoir can be reached from one location. A combination of favorable reservoir depth below the ocean floor and the use of extensive horizontal drilling techniques facilitate this.
While the case has been built for WA, the technical aspects can be transferred to offshore Brazil and the Gulf of Mexico. For this reason the study was extended to include simulation analyses to investigate the performance in these areas (offshore Brazil and GOM).

**Kvaerner DCU Semisubmersible Conceptual Design**

In a concept such as this, the most important question revolves around the support of the rigid riser system and its interface with the floating drilling and production facility. Two key interrelated issues are a) the relative motions between risers and the semisubmersible vessel and b) how to support the risers effectively.

In order to address these, the relative motion between the risers and the vessel must be reduced to a minimum. This can be accomplished by 1) optimization of the hull shape to minimize the wave-induced motion, 2) design of the mooring system to minimize the vessel horizontal excursions and the riser setdown and allow the vessel to offset to a prescribed position, 3) design the ballast system to ensure accurate control of the vessel operating draft, and 4) compartmentalization of the submerged part of the hull.

The rigid risers need to be top-tensioned to prevent overall column buckling of the riser pipe, and limited in terms of lateral displacement in order to, among other things, minimize riser interference.

The design of the risers, although challenging for this kind of water depth, is not anticipated to uncover any feasibility issues other than those mentioned above. However, handling of risers during installation or entry/re-entry operations presents a number of operational issues that will need to be resolved.

The semi used for calculating the riser system and adherent stroke is not an optimal hull configuration for the WA application is given in Table 1.

The design criteria used is for the more onerous Norwegian Sea conditions ($H_s = 16.0$ m). In a real case for WA/Brazil/GOM the semi would have smaller pontoons, as indicated in the hull shown in Fig. 1. This would allow "tuning" of the unit to suit the local wave data and lead to reduce heave over the entire range of periods.

The deck is configured very much in line with the layout of a conventional large TLP. The wellbay module is located centrally with the drilling substructure on top (skiddable in two directions). The rest of the arrangement is very traditional with Quarters and Helideck in the front, and the Process units in the rear. The airgap was set at 15 m but may be reduced in light of the results. The air-gap was chosen on the assumption that the drilling riser tensioning-ring should nominally remain above sea level. The ring pontoon allows good clearance to the risers under all circumstances.

<table>
<thead>
<tr>
<th>Main dimensions</th>
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<tr>
<td>Column Centers</td>
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<td>Pitch</td>
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**Table 1: Vessel main particulars**

Accidently damaged heel is always a critical condition for a semisubmersible. In order to protect the risers large heel angles must be compensated by the tensioning system. It may be optimal to allow the most extreme risers to loose their over-tension in this condition. In ultra deep-water the risers will easily absorb some sagging shape, for a limited time until the situation is rectified. As a matter of hull watertight partitioning it is proposed that hull compartment flooding heel angles should be limited to between 10 and 15 degrees.

**Mooring System Description.** The selected mooring system consists of 12 mooring lines, symmetrically spread in four clusters. A description of the system for WA is shown in the tables of Appendix B. A steel catenary system with line pre-tension of 1,985 kN is applied, leading to a total vertical down pull of 15,900 kN (1,620 tonnes). The horizontal distance from fairlead to bottom anchor is 2,700 m.

**Mooring Analysis.** The mooring analysis has been performed using the MIMOSA software (Ref. 13), and the
mooring lines have been dimensioned based on the safety factors specified in API RP2SK (Ref. 14). A requirement has been that the bottom chain at the anchor should not at any time be lifted from the seabed – i.e. no vertical loading at anchors. Both wave frequency and low frequency motions are included in the dynamic mooring analysis.

The main results for the West Africa case is presented in Appendix B, Tables. (The 100-year current case is not included in the table, as this condition is clearly less severe). The safety factor requirements are satisfied for all design conditions. It is realized that the 100-year wind conditions are governing with respect to offset and mooring line tension values. However, it is the offset values associated with the 100-year wave conditions that are important for the riser strokes.

Drilling Facilities and Operations
The selection of drilling equipment for the semi has been based on the utilization of simple and proven technology with specifications suitable for the offshore WA area. In addition, the equipment has been arranged with the goal of maximizing efficient and safe drilling operations. The following main drilling specifications have been assumed:

- Maximum drilling depth: 5,000 mTD
- Equipment load capacity: 450 tonnes
- Drawworks: 2.00 HP
- Pipe handling: "Hands-off" operations
- High-pressure mud pumps: 2 x 1,600 HP
- Mud tanks, active/storage: 400 m3 + 400 m3
- BOP, dry: 18-3/4", 3 rams + annular
- Well control spec.: 5,000 psi

The drilling facilities are arranged in a conventional manner. The main features include a skiddable Drilling Equipment Set (DES) including the derrick, drill floor and substructure located on top of a skid base that facilitates relocation to any of the 16 wells in the wellbay. An integrated Drilling Support Plant containing the mud mixing and storage facilities, high-pressure mud pumps as well as other relevant drilling support equipment and systems. Surmounting the drilling support plant are pipe decks with sufficient space for tubular storage and drill riser storage. Bulk Mud storage is located in columns.

A special feature of the drilling arrangement is the dedicated drilling center from which all drilling operations are performed. During drilling and initial completion of a well, the DES is positioned above this drill center, which is located in the wellbay center. Conductor and top-hole casings can be assumed to be batch set during MODU pre-drilling.

The BOP is connected to the high-pressure drill riser at X-mas tree deck level. A low-pressure riser including a telescopic joint connects the BOP with the diverter and bell nipple below drill floor.

The BOP may be lifted back up to the DES substructure for storage as well as service and maintenance. After drilling the well, the drill riser is disconnected from the subsea wellhead and re-connected ("parked") on the next well, and then tensioned by the drill riser tensioners. The DES is then skidded to the relevant well slot in order to run the production riser and perform final completion.

Wellbay Arrangement/ Subsea Arrangement. The risers are arranged in two 2 x 8 arrays, supported by two movable tree-decks in openings in the topsides structures. This pattern is preferred in order to reduce the roll/pitch-generated need for PRT stroke. The larger east/west dimension makes use the traveling deck systems delta motion reducing the roll coupled PRT stroke. See Figures 2, 3 and 4.

A projection of the riser spread from the platform deck center to the seafloor is shown in Figure 5 & 6.

Safety and handling analyses may show that some production wells need to be shut down during BOP handling operations. However, this is not considered to pose any major problem due to the relatively short time of operation and the rare occurrence.

The arrangement facilitates timesaving by eliminating time-consuming riser handling operations in deep water. Hudson et al. (Ref. 18) has proposed similar arrangements. Well intervention operations may be performed by means of wireline equipment, coiled tubing, or snubbing equipment, either through the drill floor or if the well is outside the DES shadow, directly above the relevant well slot. The large pipe deck area provides ample space for storage of well intervention equipment. The ROV handling facilities and service area are arranged on the port side of the vessel.

Risers. For this concept, single-casing production risers (9 5/8" OD) are assumed connected to the subsea wellhead with a hydraulic tieback connector. A taper stress joint will ensure appropriate stress levels and acceptable bending moment loads on the subsea wellhead. A production tubing (5") and a gas lift line (3") have also been assumed and it has been anticipated that inhibited seawater may be placed in the annulus. The production risers are terminated at their upper end by the surface wellhead housing, on which the X-mas tree is mounted.

Riser Arrangement/ Initial Sizing. For the purpose of defining the required top tension, the main pipe of the production riser (and associated internal pipes) and the
main pipe of the drilling riser have been preliminarily sized to resist burst, collapse and axial tension, with some margin to accommodate bending and fatigue loading. Bending has not been evaluated but is considered minor except at the bottom, where it can be handled by design of the taper stress joint. Steel of X80 quality and an internal design pressure of 265 bar have been assumed. Similar design criteria as stated by Kirkemo et al (1998) (Ref. 19), which compare well with those of API RP 2RD (Ref. 16) and DNV ’96 Pipeline Rules (Ref. 17), have been used. Estimated pipe wall thicknesses are given in Table 2.

<table>
<thead>
<tr>
<th>PRODUCTION</th>
<th>DRILLING</th>
</tr>
</thead>
<tbody>
<tr>
<td>Outer Casing</td>
<td>Outer Casing</td>
</tr>
<tr>
<td>OD 9 5/8</td>
<td>21</td>
</tr>
<tr>
<td>WT 0.375</td>
<td>0.875</td>
</tr>
</tbody>
</table>

Table 2: Risers Main Pipe Dimensions (inches)

An overpull factor defined as the top riser tension divided by the in-water weight of 1.4 was assumed to be suitable for estimating the nominal total vertical force that is required to support the entire riser. Buoyancy material or buoyancy modules along the upper part of the riser could result in lower nominal tension requirement at the top of the riser. However, earlier studies have shown that the increased immersed cross section leads to unwanted current-induced sag.

Tension is therefore applied at the top only. Based on these considerations and on the results of the above sizing exercise, it was calculated that the production and the drilling risers would require an in-line tension of 1,500 and 8,000 kN respectively. This also accounts for the weight of drilling risers would require an in-line tension of 1,500 and 8,000 kN respectively. This also accounts for the weight of the equipment at the top, including parts of the flexible hoses.

Relative Motion. The relative vertical motion between the riser top and the floater includes contributions mainly from the following:
1. The wave-induced vertical vessel motion (heave, roll and pitch).
2. The riser setdown induced by the horizontal excursion of the vessel and the effect of current on the riser.
3. The vessel draft variations.
4. The sea level variations.
5. The variation between operation and shut-off temperatures.
6. Accidental events.

The first two contributions have been evaluated for a number of design environmental conditions of both 100- and 10-year return period. A design factor of 1.25 was used, except for the 100-year wave conditions where 1.0 was used since, in that case, the production is assumed shut down. In damaged conditions, the design factor was also taken as 1.0. The variations in draft and sea level will be handled by ballast operations and their contributions are therefore limited to an operational margin only. Finally, the effect of temperature has been estimated based on an average temperature variation of 40 °C.

Vortex Induced Vibrations VIV/ Riser interference. There are two recurring phenomena for the kind of water depth considered here, i.e. vortex-induced vibrations (VIV) and riser interference. As these issues hold true for TLPs and Spars they have not been addressed in detail. A preliminary VIV investigation has shown that, for the assumed current conditions, there is a possibility of these vibrations and suppression devices may have to be installed. Such solutions are considered proven technology. Riser interference may be resolved by review of spacing, tension levels, drag and current conditions. Furthermore, prediction calculations (which must be iterative) are not straightforward. At this stage, it has simply been assumed that the adopted spacing and arrangement of the production and drilling risers are acceptable.

The DCU semi may in fact be a better starting point than a Spar or DDF, as one can start skewing the risers from the tree deck rather than from a keel joint at the – 200 m elevation. This is a benefit in the lower range water depths. As for deep-water solutions in general and TLP/Spar concepts in particular, the questions of riser installation and handling must be addressed. It can be assumed that guideline-less operations are mandatory.

Calculations show that, in a uniform 0.4 m/s current (say a 1-year condition), offsetting the floater by 16 m is needed to land the drilling riser without outside assistance from an ROV. Although it is quite certain that assistance will be available for such an operation, mooring adjustment of the floater is accounted for with dedicated machinery and procedures.

Riser Stroke Analysis. Riser stroke (relative motion between the vessel and riser) is in general caused by many different effects such as riser set-down arising from vessel offset, riser sagging, dynamic riser deflections, vessel motions, tide and loading condition variations, temperature elongation, etc. Furthermore, the riser stroke can be split into wave frequency (WF), low frequency (LF) and quasi-static (QS) components. The WF frequency components are because of WF riser and vessel motions, while the LF stroke is caused by resonant slowly varying vessel motions (mainly surge and pitch). Typical damaged conditions needing tensioner stroke compensation are riser up-stroke caused by hull partial
sinkage/heel and end cap force elongation in case of full well pressure under gas-kick circumstances. These accidental conditions will normally not be governing for the stroke capacity of the tensioning system. If the riser looses tension due to excessive up-stroke, it will tend to bend out in the lower part. However, this should occur in a “controlled” manner and no leakage is expected (which is the requirement for an accidental condition). A riser stroke analysis has been performed for the 100-year wave conditions using the non-linear time domain finite element package Flexcom-3D (Ref. 15). Riser and vessel motions have been included in the time simulations. The QS offset values obtained from the mooring analysis have been applied in the model. The main results from the analyses from the WA Case are given in Appendix B, Tables.

In Table B.4, the riser stroke has been split into riser set-down, WF motions, tide variations and temperature elongation. For semi-submersibles the riser strokes are to a large extent dominated by the WF heave motions if the offset is kept within reasonable limits. More than 95% of the WF stroke and the main part of the total stroke are due to WF heave. The riser set-down is mainly QS; the LF component is relatively small and the WF component is almost negligible. The riser sagging will typically give a down-stroke of about 0,1 m. LF stroke due to vessel pitch/roll has not been accounted for as this effect is small and not correlated to WF motions and hence, negligible in the combined stroke.

The 100-year wave conditions are governing for ULS riser strokes for the WA conditions. The vessel may be ballasted to adjust for tidal variations. However; a 1 m “allowance” seems reasonable in this case. Further, you will have uncertainties with respect to depth accuracy at site and riser joints resolution (pup joints).

For simplicity one may conclude that the design stroke for a WA DCU Semi will be in the order of 8.0 m double amplitude capacity. The number relates to the most critical riser. This riser is located 7.5 m off the vessel longitudinal centerline and 20 m from amidships. The design stroke can be reduced to 6.5 m for a riser placed at the center of the floater.

Increasing the total number of risers from 16 to, say, 24 risers will give slightly increased stroke requirements but has not been documented in the study. Corresponding results for the offshore Brazil case and the GOM case are given in Appendices C and D, respectively.

**Riser Tensioning System**

The DCU Semi presented in this paper includes a tensioning system, which was developed for the Kvaerner Deep Draft Floater in 1999/2000, in a joint effort with Hydralift Inc. Houston.

The system studied at that time gave a total compensation of 40 ft stroke. The system is denoted 4TS as it is a _Two Tier Top_ Tensioning System. See Ref. 1.

**4TS Tensioning System Principles.** The 4TS system was introduced in order to overcome several problems associated with the single acting large stroke cylinder systems. These units are very expensive. In addition the length of the stroke means that a major portion of the equipment will be hanging below the deck exposed to unfriendly environment and wave impacts.

Riser tensioner systems consist of hydraulic cylinders that are connected to pressured fluid/gas reservoirs. The actual compressed gas volume determines the “spring stiffness” for the system.

The 4TS system works as two tensioners mounted in series on top of each other; hence, two “tiers” of tensioners.

The first set or “tier” of tensioners consist of the ordinary TLP type production riser tensioners (PRTs) similar to the well established Conoco type. The next “tier” is on the tree deck itself and is supported by a set of tree deck cylinders. See typical deck motion principal trajectory for a stroke history below in Figure. 7.

The PRTs are designed with such a capacity that they can accommodate compensation of the individual risers and keep them properly tensioned at all times. In addition they will as a collegium fulfill the gimbaling function as the floater pitches and rolls. The idea of the 4TS system is that the heave compensation is shared between the PRTs and the tree deck compensators.

Theoretically all the PRT tensioners acts as parallel springs connected from DCU to the ocean floor and risers. However, the PRTs are not connected directly to the DCU body, but their forces have to be relayed through the tree deck and adherent suspension system (second tier).

Looking at the spring stiffnesses, we will have the following:

First Tier/PRTs contribution (parallel springs):

\[
K_{\text{Total PRT spring stiffness}} = n \times K_{\text{Unit PRT stiffness}}
\]

Second Tier/Tree deck stiffness:

\[
K_{\text{Tree deck stiffness}} = \text{is the sum of tree deck cylinders stiffness.}
\]

Acting in series gives:

\[
\frac{1}{K_{\text{Riser system}}} = \frac{1}{K_{\text{Total PRT spring stiffness}}} + \frac{1}{K_{\text{Tree deck stiffness}}}
\]

Ideally,

\[
K_{\text{Total PRT spring stiffness}} \text{ should equal total } K_{\text{Tree deck stiffness}}
\]
From the ideal still water workpoint the two systems can then be designed to reach their stroke maxima up and down, at the same time. Assuming a straight heave motion at even keel only of, say, 6 feet, this will ideally lead to a 3 ft collective stroke (pay-out) on the PRTs and 3 ft travel on the deck (working on the same spring stiffness “force slope”).

If desirable, a damping system can be introduced to the deck motion which makes the deck to behave more as an integrator of the PRTs offsets, meaning it will move by creeping to a new system equilibrium.

In practice the deck will have quite a lot of damping, both from hydraulics (can be adjusted to need) and equally important, friction in the guide wheels or rack/pinion lateral supports. A sort of physical interpretation of the system behavior will be as follows:

A person looking down into the riser bay will observe a 6 ft motion stroke on tree/wellhead/riser. By looking down at the tree deck he will observe that the deck is traveling 3 ft, at half the speed of the tree. A person standing on the tree deck will see the tree/wellhead/riser travel 3 ft relative to the deck he is standing on, while he will see the surrounding steel truss move 3 ft, again at half the speed.

**4TS Operational Features**

The two-tier philosophy of the 4TS system has several safety and operational features, especially when one considers a system designed as a tree deck with variable damping. The salient features compared to Buoyancy Can Systems are:

- Compact wellbay—8–10 ft well spacing frees deck space
- 4TS system has no need for buoyancy cans and adherent protective caissons/ guides/keel-joint below waterline. This simplifies design and makes documentation more reliable.
- 4TS sticktion/ friction phenomena are easy to control in comparison, and riser tension can be controlled at all times
- No need for keel joint as the 4TS system accommodates angular displacement in the top of the riser and can absorb horizontal pull at the top. Clearance between risers and ring pontoons is satisfactory at all times, including accidental condition.
- The freely ventilated wellbay and riser area of the DCU semisubmersible has several safety advantages in mitigating the risks and consequential damage from riser leaks/explosions/fire within the platform or its vicinity. The reduced consequential damages lead to less onerous riser specifications relaxing barrier/weight requirements and cost.
- The system is designed as 100% passive and is like a buoyancy-based system i.e. no active control system or power is needed.
- PRT cylinders will be fitted out with “hardening spring” action at the end of their strokes in order to prevent impact at bottom-in/out strokes. These “hardening springs” will be designed to trigger passive tree deck motions as required to break loose tree deck without impact to riser/risers. Tree deck cylinders will have the same to avoid tree deck traveling to extreme positions before PRTs are paying out.

**Special Safety Features of the 4TS.** Hydraulic failure: As the system is split in two components/tiers there should always be one intact. Also, the 4TS system will never pay out more than half of the stroke capacity. In fact, the pay out will always be less, as the other tier will engage and shift to a new equilibrium, picking up some of the troubled riser’s slack. These events are not combined with severe storm cases, as they are low probability events. The risers in question will be designed to resist the dimensioning set down without failing structurally.

The most common design failure scenario is breakage/rupture of a hose. Each PRT has four cylinders and is capable of working on two.

The tree deck system may loose one double cylinder unit but still be operational. The two-face rack/pinion system will keep the deck level at all times, even under heavy asymmetric loading. See Fig. 8. The tree deck damping system prevents rapid acceleration of the deck under break loose of friction circumstances, which may otherwise endanger personnel. Operating personnel will find the arrangement looking familiar to TLP tree decks. Trees will be 2 to 3 meters above deck, while buoyancy can systems will have the trees double height at least. The tree deck damping or its ability to change work point may prevent oscillations of the deck and riser system driven by vortex induced vibration.

Tree deck centralizer travels with the tree deck. In case of events with maximum up stroke actions the centralizer will move upwards and reduce the height of the production tree above pivot point centralizer. This will reduce the tree and hose motion envelope on in the wellbay area and avoid collisions tree against surrounding structures. This is especially important under damage condition where partial loss of buoyancy lead to riser upstream and large heel angles.

**4TS Cost efficiencies.** Kvaerner/Hydralift studies have show that cost of riser stroke on single stroke cylinders is exponential. i.e. an 8.0 m stroke cylinder is more than twice the cost of a 4.0m cylinder. Hence the cost of the
4TS hydraulics are at least comparable to single stroke systems for the same capacity. Additional benefits will be realized as the 4TS systems takes away the need for inspection platforms to reach tensioning rings 4-6 m below deck and also takes away the need for guiding of the wellheads within the wellbay.

Global platform behavior and daily operations. 4TS system may provide additional global platform damping which in most cases will improve overall platform behavior, especially in the close to resonance regime (platform subject to long periodic swell). Locking off the tree deck may change the platform heave resonant period by a second and make the platform stiffer with respect to large hook load handling or less sensitive for given downhole operations. This may be beneficial under light weather conditions.

For daily operations tree deck can be locked off for maintenance purposes. The deck can be driven to its upper position, making access to trees easy (access platforms almost down to deck level). Tensioner rings can be brought up to cellar deck level for inspection by driving tree deck up and ballasting platform. Re-positioning of tree deck from time to time may reduce wear on the piston rods.

Comparative Field Development CAPEX Model
In order to evaluate the cost efficiency of the DCU Semi a high-order cost comparison of two typical field development concepts for deep-water WA has been performed.

The cost comparison is based mainly on relative assessments of comparable building blocks and operations. The DCU Semi Concept includes a DCU Semi with full processing and drilling facilities and a FSO with 2 mill bbl storage capacity and alongside tanker loading capability. See illustration in Figure 9. The Benchmark Concept includes a Spar type floating wellhead platform with drilling and limited processing, an FPSO with 2 mill bbl storage capacity and full processing with water and gas injection and a remote off-loading buoy. See illustration in Figure 10.

Spar/DDF + FPSO + Loading Buoy scenario. The assumptions made for this scenario includes:
- Spar/DDF hull towed directly to WA for deck mating/lifting
- Deck mating/ lifting performed at final location
- Spar will have simple first stage separation, and pipe gas in two-phase transfer to FPSO
- 24 subsea wells
- Gas injection will be performed from the FPSO to distant subsea wellheads

Subsea wells and gas injection risers will be hung of the FPSO as metallic catenary risers.
 VLCC’s and Aframax tankers are not allowed to off-take alongside FPSO from reasons of safety.
 Separate loading buoy located 2,000 m away from FPSO
 DCU Semi + FSO scenario:
- 24 subsea wells
- Subsea wells, risers and gas injection catenary risers are hung from the DCU Semi
- FSO allows alongside off loading, as there are no process plant hazards.

Remarks to the cost comparison. The cost comparison indicates that the DCU Semi is competitive as a DCU unit in deep-water locations off WA. These potential savings relate mainly to marine operations, deletion of the requirement for a lifting vessel, the higher cost for an FPSO hull versus an FSO hull and the reduced offshore hook-up & commissioning time in the case of the DCU semi.

Marine operations and loading buoy, indicates a DCU Semi spread saving potential in the order of 70 to 80 million dollars US. In addition it is anticipated that the differences in the ship’s hull cost and all offshore hook-up and commissioning will add a smaller order saving.

Conclusions
The study has shown that the concept is technically and economically feasible within the parameters of present available technology for deep water offshore WA. The key features of the study areas follows:
1. The relative motion between the vessel and the vertical rigid risers does not impair the feasibility of the concept.
2. The required calculated riser strokes for the WA case can be provided by the present 4TS system with ample contingencies and without the need for additional buoyancy on the riser itself.
3. The result show that the system can be extended to take into accounts the larger Brazil and GOM stroke capacities.
4. Taut leg mooring systems seem to be needed in order to cope with the conditions of offshore Brazil and GOM.
5. Riser interference on the mudline can be eliminated with appropriate spacing at the topsides. Additionally vortex-induced vibrations can be managed by use of suppression devices on the 4TS system.
6. The total cost saving using a DCU Semi is potentially more than US$80 million.
7. There is a potential to optimize the DCU Semi concept even further to include a larger number of risers and increase the stroke capacity.
Appendix A - West Africa Case

Field Data Summary
500 Mill bbls recoverable reserves
200 km from shore
1400 m water depth
Peak production 150,000 bbls per day
Gas injected back into reservoir
20,000 tonnes of process plant deck load carried by floater/floaters
4,500 m² area required for process plant
Full drilling plant, heavy duty (not in the 20,000 tonnes)
LQ (not in the 20,000 tonnes)
No regional pipelines/platform infrastructure available
2 mill bbls of storage requirement
Off-loading system to accommodate commercial tankers – VLCCs/AFRAMAX discharge rate is assumed to be 7,000-9,000 m³/h.

Reservoir conditions
Reservoir depth below seabed 2,500 m
Oil specific gravity 0.87
Well shut-in pressure at surface wellhead 230 bar
Reservoir temperature 60 deg. C

Field Architecture
One central wellhead platform with 16 wells located below platform
24 tie-in subsea wells (producers & gas-injection)

Gas Injection/ water injection
It is anticipated that a substantial amount of associated gas will be re-injected, and that water injection will be required.

Environmental data
The water depth has been assumed to be 1,400 m.
Environmental data with 100-year return period that are typical for WA are shown in Appendix B, Table B.1, which also contains the load design combinations used in the study.

Subsea Flowlines/Umbilicals
Umbilicals and flowlines will be of the insulated type in order to prevent formation of hydrates. Tie in risers will be designed as metallic catenary type.

Drilling and Workover Capability
The DCU Unit drilling facility shall provide a skiddable derrick equipment set (derrick, drill floor, substructure and skid base), a drilling support plant containing all relevant mud storage and process equipment, and a pipe deck for tubular storage.
Drilling will be performed from a dedicated drilling slot with a 21” single casing drilling riser with a 3” mud boost line. An 18 3/4” BOP with annular preventer, deck mounted with two pipe rams and a shear ram will ensure well pressure control containment of the reservoir.
A dedicated MODU drilling unit could set 30” and 20” casings. 3-4 wells may be predrilled to terminal depth to obtain early production.
Heavy workover operations and sidetracking will be performed with the drilling riser or the workover riser. Light workover operations will be performed through the production risers.

Risers
The DCU rigid risers shall be single barrier types. The risers from subsea wells and injection well risers shall be of the metallic catenary type.

Operation Philosophy
All production risers are to remain permanently connected, but production may be shut off in wave conditions exceeding the 10-year return period.
Drilling operations are to be suspended for environmental conditions exceeding the 95% cumulative probability level.
The drilling riser will remain deployed and connected at all times, also in the off duty mode, where it will rest suspended from its deck tensioner, resting on a dedicated central riser anchor stump.
## Appendix B - Tables

### Environmental Data

<table>
<thead>
<tr>
<th>Design Event</th>
<th>Significant Wave Height [m]</th>
<th>Wind speed [m/s]</th>
<th>Surface Current Velocity [m/s]</th>
</tr>
</thead>
<tbody>
<tr>
<td>100-year Wave</td>
<td>4.50</td>
<td>5.0 (1 hour)</td>
<td>0.5</td>
</tr>
<tr>
<td>100-year Wind</td>
<td>1.25</td>
<td>18.0 (1 min)</td>
<td>0.5</td>
</tr>
<tr>
<td>100-year Current</td>
<td>1.25</td>
<td>5.0 (1 hour)</td>
<td>0.7</td>
</tr>
</tbody>
</table>

Table B.1: 100-Year Environmental Design Combinations for offshore West Africa

Notes:
1) The associated environment to be taken collinear with that of the design event
2) The spectral peak period ranges from 15-17 sec in case of significant wave height of 4.5 m.

### Mooring System – Steel Catenary System

<table>
<thead>
<tr>
<th>Segment type</th>
<th>Segment Length [m]</th>
<th>Nominal Diameter [mm]</th>
<th>Minimum Load [kN]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bottom chain segment</td>
<td>1,600</td>
<td>66.0</td>
<td>3,867</td>
</tr>
<tr>
<td>Wire segment</td>
<td>1,620</td>
<td>63.0</td>
<td>3,945</td>
</tr>
<tr>
<td>Platform chain segment</td>
<td>120</td>
<td>66.0</td>
<td>3,867</td>
</tr>
</tbody>
</table>

Table B.2: 12 line steel catenary mooring system for offshore West Africa

Notes:
1) Studless chain R4 quality
2) Spiral strand wire rope
3) Includes 6 mm corrosion allowance
4) A 8 mm plastic coating comes in addition
5) Length below fairlead

### Calculated Mooring Offsets

<table>
<thead>
<tr>
<th>Design condition</th>
<th>Mean Offset [m]</th>
<th>WF Component [m]</th>
<th>LF Component [m]</th>
<th>Maximum Offset [m]</th>
<th>Obtained SF / Req. SF</th>
</tr>
</thead>
<tbody>
<tr>
<td>100-year Wind, intact</td>
<td>19.9</td>
<td>0.5</td>
<td>7.7</td>
<td>27.9</td>
<td>1.67/1.67</td>
</tr>
<tr>
<td>100-year Wind, 1 line failure</td>
<td>49.4</td>
<td>0.5</td>
<td>8.7</td>
<td>63.1</td>
<td>1.39/1.25</td>
</tr>
<tr>
<td>100-year Wind, 1 l. fail., transient</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>57.6</td>
<td>1.44/1.05</td>
</tr>
<tr>
<td>100-year Wave, intact</td>
<td>8.3</td>
<td>2.8</td>
<td>2.6</td>
<td>12.6</td>
<td>1.74/1.67</td>
</tr>
<tr>
<td>100-year Wave, 1 line failure</td>
<td>35.0</td>
<td>2.8</td>
<td>2.7</td>
<td>44.5</td>
<td>1.48/1.25</td>
</tr>
<tr>
<td>100-year Wave, 1 l. fail., transient</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>43.6</td>
<td>1.56/1.05</td>
</tr>
</tbody>
</table>

Table B.3: Mooring analysis results offshore West Africa conditions

### Stroke Calculations

<table>
<thead>
<tr>
<th>Condition</th>
<th>Riser set-down [m]</th>
<th>WF motions [m]</th>
<th>Tide var. 2) [m]</th>
<th>Temp. elong. [m]</th>
<th>Comb. stroke [m]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Max down: 100 y Wave, line fail.</td>
<td>-0.75</td>
<td>-2.65</td>
<td>-1.0</td>
<td>0.00</td>
<td>-4.4</td>
</tr>
<tr>
<td>Max up: 100 y Wave, intact</td>
<td>-0.10</td>
<td>+2.65</td>
<td>0.0</td>
<td>+0.25</td>
<td>+2.8</td>
</tr>
<tr>
<td>Design Stroke range</td>
<td>0.65</td>
<td>5.30</td>
<td>1.0</td>
<td>0.25</td>
<td>7.2</td>
</tr>
</tbody>
</table>

Table B.4 West Africa – Calculated Riser Strokes

Notes:
1) No contingency included for pup-joints and or field subsidence
2) No contingency for vessel damage heel included (will not be in the load combination)
Appendix C - The Brazil Case

Environmental Data
Typical environmental data with 100-year return period for offshore Brazil and Gulf of Mexico are shown in Table C.1 (high wave). The same water depth and tide variation as for offshore West Africa is assumed.

<table>
<thead>
<tr>
<th>Location</th>
<th>Significant Wave Height [m]</th>
<th>Wind speed (1 hour) [m/s]</th>
<th>Surface Current Velocity [m/s]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Brazil</td>
<td>8.0</td>
<td>30.0</td>
<td>1.2</td>
</tr>
<tr>
<td>Gulf of Mexico</td>
<td>12.2</td>
<td>40.0</td>
<td>1.5</td>
</tr>
</tbody>
</table>

Table C.1: 100-Year Environmental Design Combinations for Brazil and Gulf of Mexico

Mooring System - Steel Catenary System
A 12 line steel catenary system has also been investigated in case of Brazil environments, see Table C.2. The line pretension is 2 970 kN in this case, giving a total vertical pull down of 27 700 kN (2 825 tonnes).

<table>
<thead>
<tr>
<th>Segment type</th>
<th>Segment Length [m]</th>
<th>Nominal Diameter [mm]</th>
<th>Minimum Breaking Load [kN]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bottom chain segment 1)</td>
<td>1 100</td>
<td>111.0</td>
<td>10 754 3)</td>
</tr>
<tr>
<td>Wire segment 2)</td>
<td>1 680</td>
<td>103.0</td>
<td>10 670</td>
</tr>
<tr>
<td>Platform chain segment 1)</td>
<td>120</td>
<td>111.0</td>
<td>10 754 3)</td>
</tr>
</tbody>
</table>

Table C.2: 12 line mooring system for offshore Brazil

Notes:
1) Studless chain R4 quality
2) Spiral strand wire rope
3) Includes 6 mm corrosion allowance
4) A 10 mm plastic coating comes in addition
5) Length below fairlead

Mooring Offsets
The results in case of a steel catenary mooring for offshore Brazil conditions are shown in Table C.3. The large vessel offsets in case of 1 line failure, it is realized that the riser (down) strokes will be large. It is of course possible to apply an even heavier steel catenary system, however, a TMS is a more natural choice. By this the maximum offsets can be limited to be less than 50-60 m, see the results below for the TMS for Gulf of Mexico.

<table>
<thead>
<tr>
<th>Design condition</th>
<th>Mean Offset [m]</th>
<th>WF Component [m]</th>
<th>LF Component [m]</th>
<th>Maximum Offset [m]</th>
<th>Obtained SF / Req. SF</th>
</tr>
</thead>
<tbody>
<tr>
<td>100-year Wave, intact</td>
<td>61.0</td>
<td>4.9</td>
<td>15.5</td>
<td>79.1</td>
<td>2.05/1.67</td>
</tr>
<tr>
<td>100-year Wave, 1 line failure</td>
<td>101.7</td>
<td>4.9</td>
<td>17.2</td>
<td>121.5</td>
<td>1.67/1.25</td>
</tr>
<tr>
<td>100-year Wave, 1 l. fail., transient</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>103.2</td>
<td>2.03/1.05</td>
</tr>
</tbody>
</table>

Table C.3: Mooring analysis results for offshore Brazil
Mooring System - Taut Leg Polyester System

A 12 line taut leg mooring system (TMS) has been investigated in case of Brazil environments, see Table C.4. The line pretension is 1 300 kN in this case, giving a total vertical pull down of 11 700 kN (1 195 tonnes).

<table>
<thead>
<tr>
<th>Segment type</th>
<th>Segment Length [m]</th>
<th>Nominal Diameter [mm]</th>
<th>Minimum Breaking Load [kN]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bottom chain segment(^1)</td>
<td>150</td>
<td>84.0</td>
<td>6 295(^3)</td>
</tr>
<tr>
<td>Polyester segment(^2)</td>
<td>2 165</td>
<td>150.0</td>
<td>7 000</td>
</tr>
<tr>
<td>Platform chain segment(^1)</td>
<td>120(^3)</td>
<td>84.0</td>
<td>6 295(^3)</td>
</tr>
</tbody>
</table>

Table C.4: 12 line TMS (polyester) for offshore Brazil

Notes:
1) Studless chain R4 quality
2) EA/MBL=31.5 is used (rope stiffness)
3) Includes 6 mm corrosion allowance
4) Length below fairlead

Mooring Offsets – TautLeg Polyester System

<table>
<thead>
<tr>
<th>Design condition</th>
<th>Mean Offset [m]</th>
<th>WF Component [m]</th>
<th>LF Component [m]</th>
<th>Maximum Offset [m]</th>
<th>Obtained SF / Req. SF</th>
</tr>
</thead>
<tbody>
<tr>
<td>100-year Wave, intact</td>
<td>28.9</td>
<td>4.9</td>
<td>9.0</td>
<td>40.5</td>
<td>1.87/1.84</td>
</tr>
<tr>
<td>100-year Wave, 1 line failure</td>
<td>43.6</td>
<td>4.9</td>
<td>10.9</td>
<td>57.1</td>
<td>1.39/1.38</td>
</tr>
<tr>
<td>100-year Wave, 1 l. fail., transient</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>45.9</td>
<td>1.69/1.05</td>
</tr>
</tbody>
</table>

Table C.5: Mooring analysis results for offshore Brazil (12 lines TMS)

Calculated Riser Design Strokes – Taut Leg Polyester System

<table>
<thead>
<tr>
<th>Condition</th>
<th>Riser set-down [m]</th>
<th>WF motions by var. 2) [m]</th>
<th>Tide elong. [m]</th>
<th>Temp. elong. [m]</th>
<th>Comb. stroke [m]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Max down: 100-year Wave, line fail.</td>
<td>-1.2</td>
<td>-4.25</td>
<td>-1.0</td>
<td>0</td>
<td>-6.45</td>
</tr>
<tr>
<td>Max up: 100-year Wave, intact</td>
<td>-0.1</td>
<td>+4.25</td>
<td>0.0</td>
<td>+0.25</td>
<td>+4.4</td>
</tr>
</tbody>
</table>

Stroke range

| Stroke range | 1.1 | 8.5 | 1.0 | 0.25 | 10.85 |

Table C.6: Design Riser Strokes for offshore Brazil
Appendix D - Gulf of Mexico Case

Environmental Data
Typical environmental data with 100-year return period for Gulf of Mexico are shown in Table D.1 (high wave). The same water depth and tide variation as for offshore West Africa is assumed.

<table>
<thead>
<tr>
<th>Location</th>
<th>Significant Wave Height [m] (2)</th>
<th>Wind speed (1 hour) [m/s]</th>
<th>Surface Current Velocity [m/s]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gulf of Mexico</td>
<td>12.2</td>
<td>40.0</td>
<td>1.5</td>
</tr>
</tbody>
</table>

Table D.1: 100-Year Environmental Design Combinations for Brazil and Gulf of Mexico

Mooring System – Taut Leg Polyester System
A taut leg mooring system (TMS) is applied for the Gulf of Mexico environment to limit the vessel offsets and hence riser strokes. The system is described in Table D.2. The applied pretension is 1,540 kN (total vertical load of 13,300 kN), and the horizontal distance between the fairlead and anchor is 2,000 m.

<table>
<thead>
<tr>
<th>Segment type</th>
<th>Segment Length [m]</th>
<th>Nominal Diameter [mm]</th>
<th>Minimum Breaking Load [kN]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bottom chain segment(1)</td>
<td>150</td>
<td>111.0</td>
<td>10 754(3)</td>
</tr>
<tr>
<td>Polyester segment(2)</td>
<td>2 165</td>
<td>220.0</td>
<td>12 000</td>
</tr>
<tr>
<td>Platform chain segment(1)</td>
<td>120(4)</td>
<td>111.0</td>
<td>10 754(3)</td>
</tr>
</tbody>
</table>

Table D.2: 12 line TMS (polyester) for Gulf of Mexico
Notes:
1) Studless chain R4 quality
2) EA/MBL=31.5 is used (rope stiffness)
3) Includes 6 mm corrosion allowance

Mooring Offsets Taut Leg Polyester System
The mooring analysis results for the Gulf of Mexico conditions and a TMS are shown in Table D.3. It is seen that the maximum offset is not more than 55.8 m in case of 1 line failure.

<table>
<thead>
<tr>
<th>Design condition</th>
<th>Mean Offset [m]</th>
<th>WF Component [m]</th>
<th>LF Component [m]</th>
<th>Maximum Offset [m]</th>
<th>Obtained SF / Req. SF</th>
</tr>
</thead>
<tbody>
<tr>
<td>100 y Wave, intact</td>
<td>25.8</td>
<td>6.1</td>
<td>11.8</td>
<td>40.8</td>
<td>1.99/1.84</td>
</tr>
<tr>
<td>100 y Wave, 1 line failure</td>
<td>38.8</td>
<td>6.1</td>
<td>14.1</td>
<td>55.8</td>
<td>1.48/1.38</td>
</tr>
<tr>
<td>100 y Wave, 1 l. fail., transient</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>41.2</td>
<td>1.96/1.16</td>
</tr>
</tbody>
</table>

Table D.3: Mooring analysis results for Gulf of Mexico

Calculated Riser Design Strokes – Taut Leg Polyester System.

<table>
<thead>
<tr>
<th>Condition</th>
<th>Riser set-down [m]</th>
<th>WF motions [m]</th>
<th>Tide var. 2) [m]</th>
<th>Temp. elong. [m]</th>
<th>Comb. stroke [m]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Max down: 100-year Wave, line fail</td>
<td>-1.2</td>
<td>-5.9</td>
<td>-1.0</td>
<td>0</td>
<td>-8.1</td>
</tr>
<tr>
<td>Max up: 100-year Wave, intact</td>
<td>-0.1</td>
<td>+5.9</td>
<td>0.0</td>
<td>+0.25</td>
<td>+6.05</td>
</tr>
<tr>
<td>Stroke range</td>
<td>1.1</td>
<td>11.8</td>
<td>1.0</td>
<td>0.25</td>
<td>14.15</td>
</tr>
</tbody>
</table>

Table D.4: Design Riser Strokes Gulf of Mexico
Figure 1: DCU Semi for WA
Figure 2: DCU Semi-Drilling/Wellbay Area
Figure 3: DCU Semi
- Below deck Riser Arrangement
Figure 4: DCU Semi - Wellbay Area - looking down/up
Figure: 5 Wellbay pattern DCU & Seafloor

Figure: 6 Well Riser pattern
Two Tier System Principle

Passive Mode with Deck Cylinders Damping

NO CONTROL SYSTEM
TWO SPRINGS IN SERIES
(tuned to “bottom out” at the same point in time)

Hydraulic damping + mechanical friction on deck motion gives smooth motion, accelerations.
Pressure override valves avoids PRT bottoming out

Figure 7: DDF with FPSO and tanker offloading buoy
Figure 8: DCU Semi
– Parallel/Synchronizing Mechanism (Passive)
Figure 9: DCU with FSO and alongside tanker

Figure 10: with FPSO and tanker offloading buoy
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