Proceedings of the ASME/USCG 2010
2nd Workshop on Marine Technology and Standards
MTS2010
July 29-30, 2010, Washington, DC, USA

MTS2010-0201

EPS CONCEPTUAL DESIGN FOR GOM DEEPWATER FIELDS

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ABSTRACT

To avoid making billion dollar mistakes, operators with discoveries in deepwater (~3,000m) Gulf of Mexico (GoM) need dependable well performance, reservoir response and fluid data to guide full-field development decisions. Recognizing this need, the DeepStar consortium developed a conceptual design for an Early Production System (EPS) that will serve as a mobile well test system that is safe, environmentally friendly and cost-effective.

The EPS is a dynamically positioned (DP) Floating, Production, Storage and Offloading (FPSO) vessel with a bundled top tensioned riser having quick emergency disconnect capability. Both oil and gas are processed onboard and exported by shuttle tankers to local markets. Oil is stored and offloaded using standard FPSO techniques, while the gas is exported as Compressed Natural Gas (CNG).

This paper summarizes the technologies, regulatory acceptance, and business model that will make the DeepStar EPS a reality.

INTRODUCTION

Oil and gas field developments in deepwater are incredibly expensive, running into several billions of dollars each. However, at present, operators are forced to guess at productivity of the wells, sustainability of the reservoir performance and characteristics of the oil and gas when sanctioning these multi-billion dollar projects. That is because there is no way to flow a discovery well for more than a few hours due to the lack of a way to handle the produced gas. Flaring is not an option in the GoM.

Many deepwater reservoirs, particularly the GoM Paleogene, have very complex structures, often with faults and compartmentalization [ref. 1]. Also, there can be dissimilar fluids with a wide range of characteristics that restrict reservoir performance and deliverability. These issues make it very difficult to establish the design basis for the facility, and as a result, setting the number of wells, processing capacity, plateau rate and reserve life becomes pure speculation. Reservoir uncertainty is the single biggest risk confronting the industry.

Many deepwater developments have demonstrated the difficulty in “right-sizing” the production facility to match the expected reservoir performance. Some developments are facility limited, preventing the operator from realizing full commercial value from the field. Other operators over built for the recoverable oil and gas, leaving them with investments that under perform, or worse, realize big losses. To avoid making billion dollar mistakes, the industry needs a portable production system that can be mobilized to the field quickly, is self sufficient in connecting to a subsea discovery well, produce the well for an extended period (6 months to 2 years) to acquire the necessary reservoir data, and then can be redeployed to another location. To make such a system economically viable, the system needs to be provided by the owner to the operator as a service on a day-rate basis, similar to a Mobile Offshore Drilling Unit (MODU).

Realizing this need, the Deepstar (DS) research consortium initiated a conceptual study in 2009 to develop a hypothetical EPS that would meet industry’s need for extended well tests [ref. 2]. The EPS would be an FPSO in conjunction with a deep water riser. Unlike conventional FPSO’s [ref. 3], the EPS will have a Compressed Natural Gas (CNG) handling system, not a pipeline. These similarities and differences will be discussed in the paper along with a business model that would enable the creation of an EPS leasing industry in the GoM.

The EPS concept utilizes dynamic positioning (DP3 class) for FPSO station keeping and has a top tensioned riser similar to Petrobras's Seillean FPSO operating offshore Brazil as shown in Figure 1. Like Seillean, there is no drilling capability. Unlike Seillean, the proposed EPS is able to handle up to three production wells instead of a single well, and the water depth is extended to ultra deepwater (10,000ft).

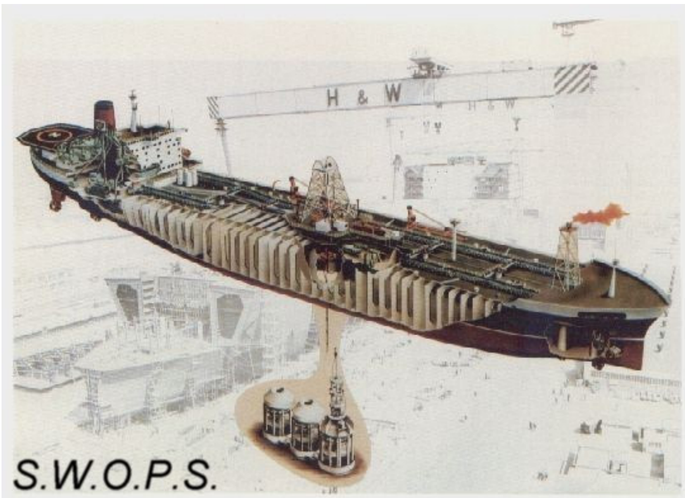

Figure 1: Seillean FPSO (Single Well Oil Production System, picture is from www.seillean.com)

The EPS operating philosophy, which consists of minimal surface facilities, is one where the EPS facility has the capability to move from one site to the next undertaking reservoir testing and production activities. Accordingly, the facility is designed to be flexible with respect to reservoir characteristics and transportable with respect to relocation. It is designed for a service life of 25 years and is expected to operate uninterrupted (except when disconnecting for hurricanes) at a single location for between six (6) months and two (2) years without major servicing.

Reservoirs targeted for use of the EPS will be in water depths greater than 1,000 feet. The reservoirs fall into two (2) broad age categories within the Tertiary Period. These are the Neogene, composed of the Pliocene and Miocene Epochs, and the Paleogene, composed of the Oligocene, Eocene and Paleocene Epochs. The boundary between the Pliocene and Pleistocene Epochs is sometimes hard to determine, and there is some minor production from the Pliocene reservoirs. Typically, the Paleogene play resides in deeper water than the Neogene, although the Neogene can be found overlying parts of the Paleogene. Much of the Paleogene is overlain by a salt canopy, which obscures the seismic signature of the reservoirs and makes interpretation much more difficult. Water depths in the Paleogene play range from 6,600 to more than 9,600 feet, making development costs much greater than in shallower water. The regions of these plays are illustrated in Figure 2.

The proposed EPS configuration is illustrated in Figure 3. Its goal is to conduct early production testing, at minimal cost, to resolve reservoir uncertainty. It was designed to achieve the following functional principles:

1. Configurable in two (2) modes of operation:
   a. MODE A - Multi-well with no direct vertical access. MODE A operation is the Base Case configuration.
   b. MODE B - Multi-well with one well having Direct Vertical Access (DVA). This mode of operation provides the EPS with the capability to modify the downhole configuration of one well in order to isolate and assess individual zones.
2. Maximum oil and gas production capacity to match the P50 values for three (3) simultaneously producing wells.
3. The EPS system shall be based upon existing commercially available equipment and services as much as possible.

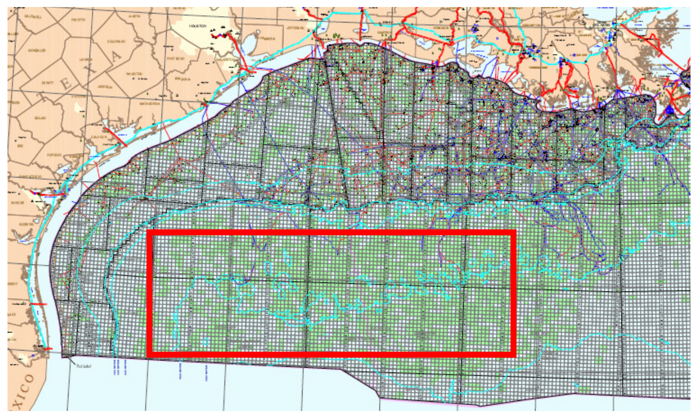

Figure 2 Map of GoM Outlining Neogene and Paleogene Plays

It should be noted that the proposed EPS system will be the first GoM offshore gas handling facility that does not depend on gas re-injection or export by pipeline. It is assumed that drilling, well completions and installation of subsurface grouted conductors will be completed prior to the arrival of the EPS.

The main sub-systems of the proposed EPS concept include:

a) Subsea System. It transports the hydrocarbons to the base of the riser, and provides fluid and control support to each of the wells.
b) Riser System. A top tensioned bundled riser, disconnectable from its base, self installable from the FPSO. This facet is key to enabling a low relocation cost.
c) Topside Systems. They treat, convert, store and offload the produced hydrocarbons.
d) FPSO Host. It supports the process facilities and personnel, collects and stores fluid outputs from the wells, and exports the crude oil and gas to market (not via a pipeline).

The design rates for oil and associated gas are 20,000 bopd and 25 MMscfd, respectively. These rates represent production from three (3) P50 Neogene wells.

Based on the flow assurance analysis of the system, a 6” NB flowline with a 6” NB riser is the optimal pipe diameter to achieve the target range of production rates. A 4” NB pipeline would restrict flow at the P50 and above production rates, and an 8” NB pipeline does not significantly increase the production capacity of the system.

The EPS facility and associated vessel, riser, subsea systems are designed for a service life of 25 years. The annual average availability of the EPS supply chain system is targeted to be greater than 80%.

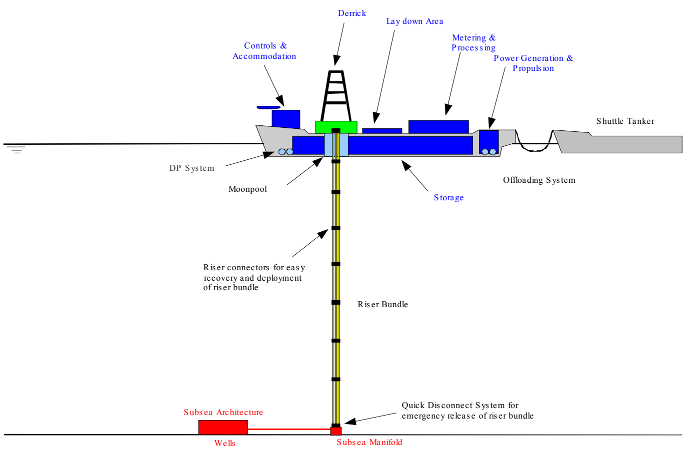

Figure 3 EPS Concept Illustration

TECHNOLOGIES

The majority of the EPS sub-systems and components are based on mature technologies, either field proven or being used in other field development or production concepts. Some highlights of the key technologies which distinguish the proposed EPS from its earlier version or other similar concepts are as follow.

READILY RELOCATABLE MINIMAL SURFACE FACILITY

One of the key characteristics of this proposed EPS is its mobility. The FPSO is held on station via DP system. The power system onboard the FPSO is designed according to DP Class 3 regulations with separate engine rooms and switchboard rooms in such a way that a fire or flood in one room will effectively lead to the loss of only one (1) thruster.

The host FPSO, as shown in Figure 4, allows certain range of heading variation (weather vaning) after the top tensioned riser is deployed and connected to the subsea wellhead. The allowable vessel heading will consider the limitations from the riser twist angles and other operational constraints. It is anticipated that the EPS will be able to adjust heading by up to +/- 270 deg on vessel heading (as per standard deepwater drillship operations). Further, the riser is suspended in the center of the moon pool near midships. That should broaden the weather vaning capability and provide extra flexibility to the vessel heading selection.

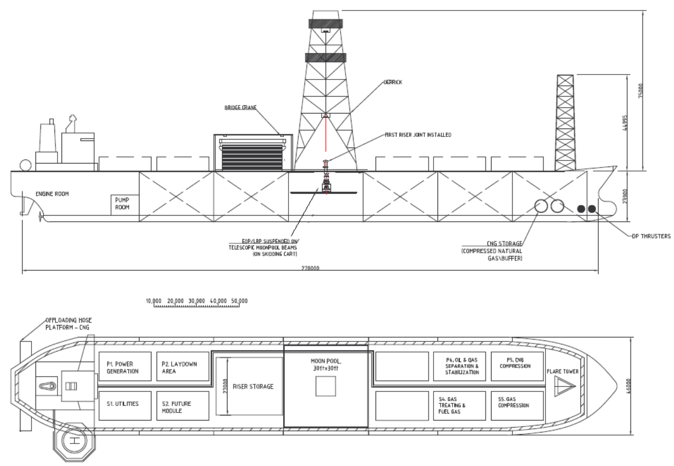

Figure 4: FPSO Deck Layout

The DP watch circle defines the radial limits of the stationkeeping. Where emergency situations occur the disconnect philosophy and associated Emergency Disconnect Sequence (EDS) times for the proposed EPS facility are set out as follows. These times are based on typical DP drill ship operations for the GoM.

- Disconnect; when the vessel reaches POD (Point of Disconnect) of the watch circle which is based on riser system limits.
- Red Alert; EDS sequence initiated 60 seconds before POD.
- Yellow Alert; preparations for disconnect begin 90 seconds before red alert (while in production mode). Note that when the facility is in suspended production mode ("State of Readiness") the EPS facility is considered to be in a yellow alert condition.
- Minimum allowable watch circle before any alarms are reached, based on practical station keeping limits, is 50ft (15.24m) from the subsea anchor base.

Watch circles are defined in Figure 5 and Figure 6 for both emergency procedures required during “Production Mode” and in “Suspended Mode” (State of readiness) modes respectively.

Several scenarios exist for an FPSO off station event, these include:

- Planned not due to weather, such as relocations, etc.
- Planned due to weather, such as hurricanes and severe winter storms with greater than 3 days warning.

- Emergency events, such as black-ship drift off, drive-off, process emergency, sudden change in weather with less than 3 days warning etc.

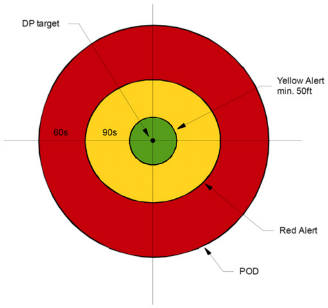

Figure 5: Emergency Disconnect Sequence for Production Mode

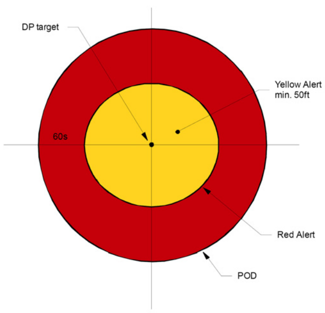

Figure 6: Emergency Disconnect Sequence for Suspended Production Mode ("state of readiness")

The EPS FPSO will stay connected to the riser system in conditions up to 100yr Winter Storm. For environmental conditions exceeding the 100yr Winter Storm, the FPSO and riser will be disconnected from the subsea system and sail away to a safe haven without the need for a massive evacuation operation or the need for aid by other vessels. Prior to the sail away the riser will be pulled from the water column and placed aboard the vessel and stowed for safe keeping. For drive-off and drift-off cases, the design 10yr winter storm condition shall be applied. As for more severe weather, the disconnect system should be ready to be activated and the crew should be on a high level of alert for quick disconnect of the riser system from the subsea infrastructure.

The readily relocatable surface facility is a ship shaped hull form. The proposed vessel at present is a SUEZMAX tanker (≈120,000 dwt) fabricated outside of the U.S. It should be noted that shuttles which export the produced gas and oil from the FPSO into ports are subject to the Jones Act and are required to be US constructed. The SUEZMAX FPSO can be a purpose build or a conversion of a second hand tanker. Currently preference would be for a purpose build as this constitutes the base case for the MMS EIS (Environmental Impact Statement) on use of FPSO's in the GoM outer continental shelf. In addition to the standard works required to construct a 'normal' DP FPSO (marine systems, accommodation, helideck, duel gas/fuel fired power generation, process equipment (~4000 Te)), the EPS would require installation of a derrick, a small amount of gas buffer storage and both gas and oil offloading systems.

BUNDLED TOP TENSIONED RISERS

Another key characteristic of the proposed EPS is its riser system. A Top Tension Riser (TTR) system akin to drilling operation is proposed for the EPS FPSO. This riser system has the capacity to disconnect at the seafloor in the event of:

1. A loss of station keeping due to a DP failure.
2. The advancing severe hurricanes.
3. The development of loop currents within the GoM.

The lower portion of the TTR is fitted with a flushing package which allows the riser to be clear of produced fluids prior to its retrieval.

Figure 7 presents an overview of the riser system. A summary of the key components is provided below:

- The EPS TTR is made up from 90ft or 75ft joints each containing four (4) x 6" nominal bore (8-3/4" OD x ¾" wall thickness, X80 grade) production tubes. Each joint is connected via standard choke and kill type stab connections and made up via a series of bolts mounted in the upper supporting plate.
- Each of the four (4) production tubes are bundled together axially along the length of the joint via centralizer clamps.
- Each of the production tubes are individually insulated with a coating system of syntactic and solid polypropylene (PP). The insulation system is designed be collapse resistant to the external hydrostatic pressure.
- The upper support plate houses four 5" umbilical support porches to house the umbilical for the slick riser joints. These umbilical support porches are also integrated into the riser joint buoyancy modules for the buoyant joints.
- A wireline type tensioner system with 25ft stroke range is used to provide top tension to the riser, and accommodate the relative movement between the FPSO and the riser. The wireline will be replaced periodically to ensure the fatigue performance. The tensioner system is designed for 25 year service life.

The riser system is retrievable with a continuous service life of two (2) years, and allowing for full detailed inspections and maintenance between each deployment. All riser seals are replaced after each riser retrieval, and NDT is performed on riser joint critical locations.

The EPS facility is fitted with a riser handling system to deploy and retrieve the riser from the production host within 48 hours. The riser handling system includes a derrick and a riser storage bay, and is similar to that used on a drilling vessel.

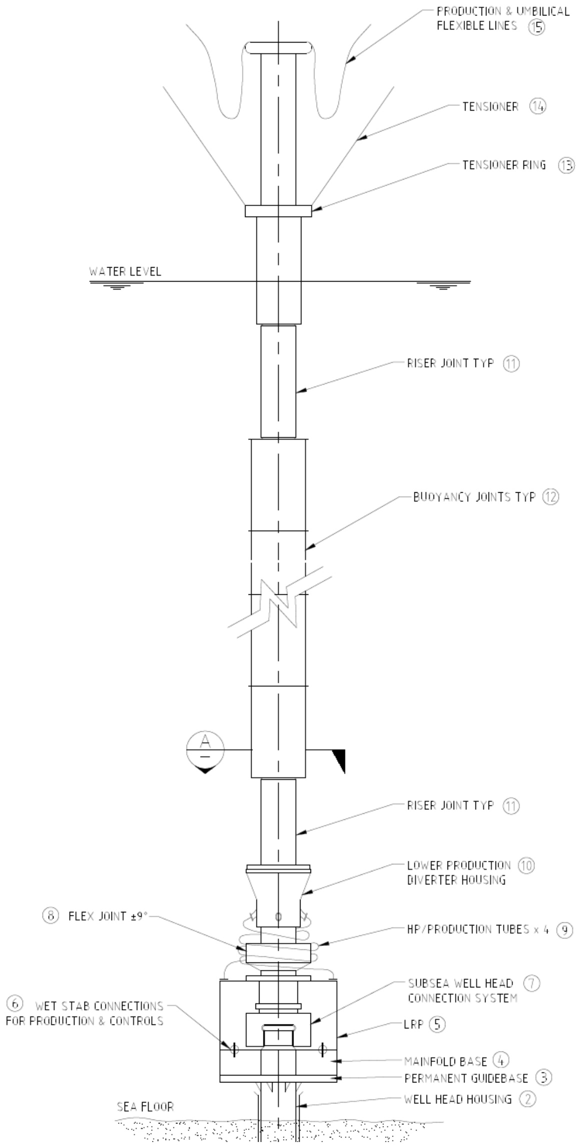

Figure 7: Riser System Configuration

NO GAS FLARING

Gas handling proved to be one of the biggest design challenges for the EPS since flaring is not allowed. In the gas handling pre-screening study, five associated gas-to-market options were evaluated. Associated gas at the inlet to the gas handling facility has a pressure of 10 bar and a temperature of 120°F. The maximum design gas rate is 25 MMscfd, however flexibility to produce up to 40 MMscfd is an option under consideration.

The five (5) options evaluated for taking produced gas to shore were:

1. Gas to Wire (GTW)
2. Compressed Natural Gas (CNG)
3. Gas to Hydrate (GTH)
4. Liquefied Natural Gas (LNG); and
5. Gas to Liquids (GTL)

The study shows CNG and FLNG are the two (2) most attractive solutions for associated gas transport. Neither of these two technologies has been used commercially offshore. CNG was chosen as the preferred gas handling option due to its lower CAPEX and OPEX, flexibility and simplicity of operation. Many previous CNG studies also confirmed its feasibility [ref. 4,5,6]. The CNG system in EPS service is illustrated in Figure 8.

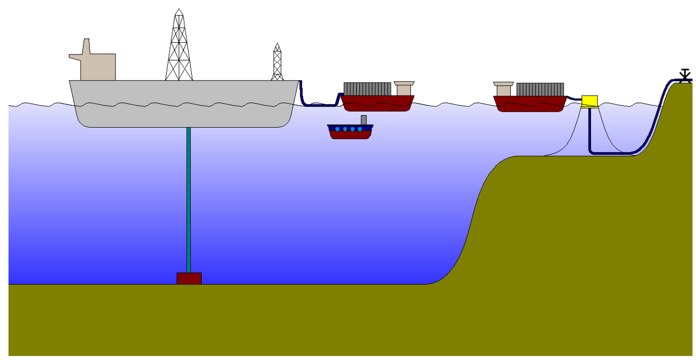
Figure 8: Gas Offloading Operation, including workboat assisting and near shore CALM buoy.

It is recognized that many technical, regulatory and financial uncertainties still remain with the use of CNG gas transport. DS has approved funding for additional studies in 2010 to investigate such issues. One critical element relates to the residual value of CNG facilities after the initial 5 year minimum lease period (see Business Case section for details). Since the CNG facility represents a significant fraction of the total EPS CAPEX, and that its useful life is in excess of 5 years (the entire EPS is designed for 25 years), it is imperative the CNG system be engineered for multiple purposes thus to minimize the chance of premature obsolescence and to help capture a high residue value. The lease day rate and economics of the EPS hinges on successful mitigation of this risk. This is not a problem with the FPSO and other associated facilities since they are conventional oil field equipment and can be easily reused on other projects.

TECHNOLOGY READINESS LEVEL

The Technology Readiness Level (TRL) was checked to identify the key risk items associated with integrating new technologies into field development projects. The oil and gas industry has begun to adopt this tool, developed originally by NASA, which rates the status of technology using a scale from 0 to 7. These eight levels are divided into four development categories: conception (TRL 0), proof-of-concept (TRLs 1-2), prototype testing (TRLs 3-5), and field qualified (TRLs 6-7) [ref. 7].

The majority of the EPS components are standard design and field proven. Most of the EPS riser system is similar to a typical drilling riser system, and tensioned by a conventional wire type tensioner system. Therefore, many of the field-proven technologies used by a drilling riser are also applicable to the EPS riser system. The main findings arising from the study and TRL assessment are highlighted in the following points:

- The riser joint has a TRL of 1 (Proof-of-Concept). A functional specification has been established. Preliminary global analysis has been performed to confirm the system feasibility. However, general arrangement of the bundled joint and its component design are to be carried out.
- The production tube bottom stab plate has a TRL of 2 (Proof-of-Concept). Wet-mateable connectors are available for production systems. However, further testing is expected to qualify this technology to EPS flowlines, i.e. high stabbing/inplace loads, external pressure (3000 m), high expansion (internal pressure and temperature), high misalignment, etc.
- The CNG offloading hose has a TRL of 2 (Proof-of-Concept). There are existing flexible hose systems available for tandem oil offloading. However, CNG offloading has different requirements to the flexible hoses, due to the high pressure, low temperature and low density content. It is likely that modification or redesign of the existing flexible hose systems and pipes will be needed to suit for CNG offloading. Consequently, prototype tests are to be carried out to verify the design changes and qualify the product for CNG offloading.

Based on the study results, further engineering design and prototype testing on the riser joint, riser joint connectors and bottom stab plate, and CNG offloading hose systems is needed to advance the TRLs to a higher level.

REGULATORY REVIEWS

This EPS study was conducted under the guidance of MMS, US Coast Guard (USCG), and ABS. During the course of the study, these regulatory entities were engaged through meetings, presentations, and report reviews.

MMS AND USCG

MMS and USCG were involved in the EPS concept development through workshops and progress meetings, and provided feedback on the regulatory issues that may be encountered. As a general comment the MMS and USCG did not see any great barriers to the development of the proposed EPS system as long as it was designed in accordance with MMS and USCG approved standards. The key items for the development of the EPS would be the design of the Riser system including allowance for NACE and multiple barriers in the riser system. In addition MMS and USCG expressed interest of further involvement in the CNG configuration studies.

ABS

As part of the Early Production System (EPS) concept development, ABS was engaged to provide Preliminary Planning and Advice (PPA) which is aimed at helping progress the EPS concept through the development process. As such ABS made available to the EPS project ABS technical personnel as necessary to serve as idea sounding boards, technical resources for drawing and document review. The key items identified by ABS are summarized as follows:

Focus issues:

- The Disconnecting and Re-connecting Procedures with the Riser System are to be established
- The Survivability of the Riser System is to be evaluated.
- The DP system will be used to control a workable watch circle for the riser system, and the wave-frequency vessel motions are not to be affected by the DP system.
- The hydrodynamic solver (computer program) to be used for analyzing the wave-frequency vessel motions coupled with the top tensioned risers in deepwater is recommended to be validated through model tests at a wave basin.

Regulatory notes:

- The vessel is proposed to be foreign flagged and operating in US waters. The USCG will be acting as the coastal state but not the flag state. The USCG review scope needs to be defined.
- Accommodations will be reviewed to SOLAS as a foreign flag, self propelled vessel.
- International Gas Code (IGC) will apply to living quarters. ABS guide for CNG Carriers will apply to CNG storage.

General comments:

- Since the base case of the MMS EIS for use of FPSO's in the GoM OCS was performed for a purpose built vessel, applicability to a second hand tanker conversion case may be an issue.
- It is suggested that communications at an early stage are started between AMOG/DeepStar and USCG–MSC, USCG-OCMI, MMS and ABS on regulatory issues.

BUSINESS CASE

A business case for the EPS was developed to demonstrate the economic viability of the system [ref. 8]. It is based on the EPS being a leased facility provided at an agreed day rate to a single Operator or group of Operators in succession, much like a drilling MODU contract. The primary mission for the EPS is to provide Value of Information (VOI) to enable a greater understanding of the reservoir and improve decision making for full field development. Accordingly, a VOI exercise was undertaken to estimate the value that can be provided by a deepwater EPS.

The value of the EPS to an operator is derived from the VOI it provides minus the Cost of the EPS:

Value of EPS = VOI provided by EPS – Cost of EPS.

VOI is the increase in EV (Expected Value) to the prospective field enabled by the EPS. Value enhancement is achieved by reducing uncertainties in production rate and reserve size which directly influence investment decisions [ref. 9].

FACILITY PROVIDER

The business case for the EPS facility provider is the financial incentive (15% rate of return on their investment) to build and lease the facility to the operator on a day rate basis. Additionally, there may also be an incentivized element to the final form of the contract to encourage the Facility Provider to maximize production, although this is not taken into account here.

The likely cash flows, including taxations and capital depreciations were estimated and are discussed below. Table 1 contains the calculated day rates for 3 EPS options investigated.

Table 1 Facility Provider Day Rate

Case	Day Rate providing IRR = 15% US$ Million / day
Base Case- CNG 'versatile shuttle' solution	1.1
Gas Export Pipeline option (~ 75 miles) with relocations	1.3
Dedicated CNG Ship solution	1.6

As shown in the table, the Base Case - CNG 'versatile shuttle' solution is the desired case at 1.1 Million USD per day; a gas export pipeline option is less attractive at 1.3 Million USD per day, unless the cost of each pipeline can be written off against other assets. The "Dedicated CNG Ship solution" is the most undesirable option. The "Dedicated" ship size is not suited to the relatively short distance to port from expected deepwater GoM prospects.

Facility provider gross revenue is shown in Figure 9. It shows that the facility provider invests heavily in the first two (2) years (EPS construction period), then begins to earn revenue in the form of lease payments over the next five (5) years. At the conclusion of the five (5) year lease payments the facility provider can realize some residual value in the facility (or extend the lease period). The economics is based on the facility provider realizing a 15% IRR after five (5) years only.

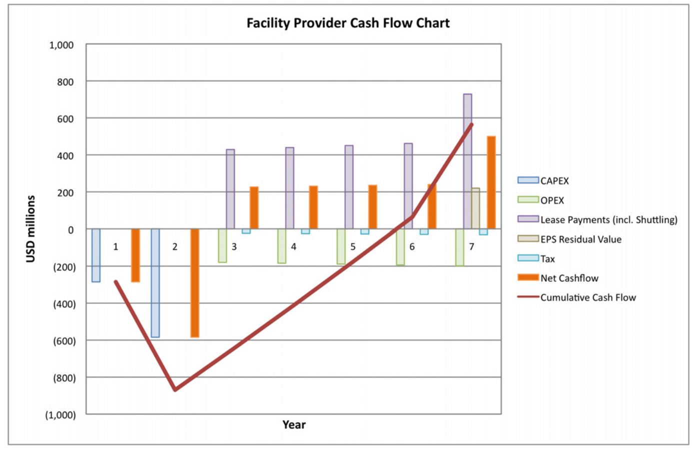

Figure 9 Facility Provider Gross Revenue

OPERATOR

The operator's business case for the EPS takes into account those expenses and cash flows specifically related to having an EPS. It does not include well related costs which would be occurred with or without the EPS. However, it does include special subsea facilities required specifically to accommodate the EPS.

For the purposes of the business case it is assumed that there is one (1) Operator and that the EPS relocates, on average, once every 20 months or three (3) relocations over five (5) years. Understandably, the net cost of the EPS for the operator is strongly dependent on oil and gas production rates. However, it must be remembered that it is not the primary objective of the EPS to 'create revenue'. The primary objective is to provide 'Value of Information'.

The cost of the EPS facility for the Operator is established by the following revenues and expenses:

- Lease payments to the facility provider (FPSO & shuttle services) to the amount of 1.1 Million USD per day
- CAPEX for the relevant subsea installation and equipment for each relocation
- Operator home office support
- Revenue from oil and gas sales
- Depreciation on capital expenditures and taxation on any gross profit derived from oil and gas revenue

The base case operator gross cashflow is shown in Figure 10 (based on Energy Information Agency EIA / US Department of Energy - DOE oil price forecast). This shows that lease revenue from oil and gas sales exceeds lease payments for the facility from year 3 onwards (once the EPS begins its lease period).

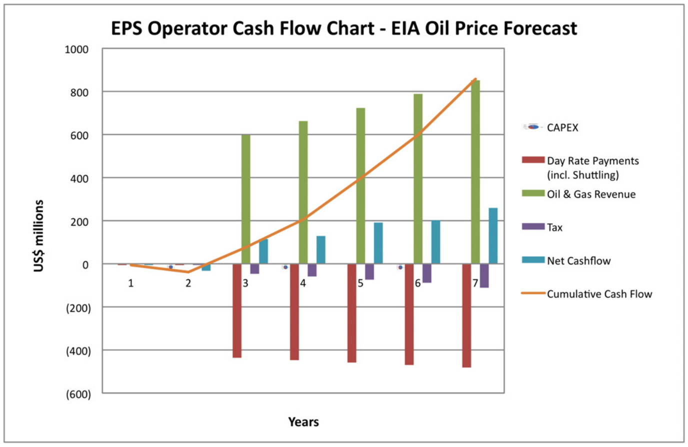

Figure 10 Operator Gross Cashflow – Base Case EIA oil price forecasts

From the expected operator cash flow and VOI provided, the economic analyses indicate a deepwater EPS can provide up to 1,200 Million USD of additional value per project. This is based on a 20 month operation of the EPS. The value is derived from reduction in reservoir uncertainties, thus enabling a more optimum Full Field Development (FFD) plan. Without knowledge obtained with the help of the EPS, a poorer than expected reservoir will result in the operator having over-invested in the FFD. Conversely, the operator is facility constrained from realizing full commercial value from the reserves if reservoir performance exceeds expectation.

CONCLUSIONS

In this paper an EPS has been proposed and its study results are presented. Some of the key findings are:

- Target reservoirs in deepwater GoM are the Neogene and Paleogene plays. Analyses indicate reservoir characteristics can be quite varied, and extended tests of the discovery well(s) and production samples from these reservoirs are critical for oil and gas operators to define the most appropriate full field development.
- Flow assurance assessments based on results from the reservoir study indicate a 6 inch NB flowline and riser would provide the greatest flexibility for EPS operations. It was further noted that riser cool down is a key consideration for planned and unplanned disconnect scenarios.
- Functional performance specifications were developed for the overall EPS, and each of the subsystems. These specifications are intended to help in the design of the EPS, and help in the selection of critical components. Feedback was also sought from industry experts on each of the specifications, including regulators/class societies such as MMS, USCG and ABS.
- Reviews and discussions with equipment and service providers indicate most of the technologies required by the EPS are field ready. However, there a few critical items still need to be qualified for EPS service. They include bundled production riser arrangement and connectors, CNG gas handling for associated gas on the FPSO, design of the riser and subsea equipment for potential H2S, and subsea electrical/hydraulic umbilical connections.
- In addition to the technical issues, there are also regulatory challenges associated with CNG transfer and storage from an FPSO to shuttle/articulated tug barge.
- A business case was proposed for taking the project forward. The business case pertains to both key stake holders in the development of the EPS: oil and gas operators and EPS facility provider (similar to MODU owners). The business case is based on the same basis as the current MODU day rate lease options. The estimated EPS lease rate is 1.1 million USD per day, which allows the EPS facility provider to recover capital investment over five (5) years with 15% IRR, taking into account residual value of the asset at the end of the period.

In summary, the DS EPS Study completed at the end of 2009 indicates a favorable business case can be made for oil and gas operators and to potential EPS facility providers. However, key technical and regulatory challenges still remain before EPS can be a reality. Some of these are design and qualification challenges best resolved in collaboration with vendors and equipment manufacturers. Other areas for further work are CNG related and obtaining MMS and USCG endorsement and approval for the GoM. A road map is being developed that would lead to the creation of an EPS leasing industry, similar to MODU, that would be mutually beneficial to operator and facility provider.

ACKNOWLEDGEMENTS

The following DeepStar participants/contributors as well as other non-DeepStar members are acknowledged for their contributions to various parts of the project:

✓ ABS
✓ Chevron
✓ ConocoPhillips
✓ Enersea Transport
✓ GE Vetco
✓ Granherne
✓ Huisman
✓ Knutsen

- ✓ Lonestar Deepwater
- ✓ MMS
- ✓ National Oilwell Varco
- ✓ Tek-Ocean
- ✓ Knowledge Reservoir
- ✓ Sea NG
- ✓ TOTAL
- ✓ Trans CNG International
- ✓ Transocean
- ✓ USCG

Special thanks to Philippe Remacle (TOTAL) and Jim Chitwood (Chevron-DS) for initiating this DS EPS study, and their guidance to the project.

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