COMMERCIAL EXPLOITATION AND DE-RISKING DEEPWATER DEVELOPMENTS WITH EARLY PRODUCTION SYSTEMS: BRIEF HISTORY AND ROADMAP FOR PLATFORM SELECTION

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ABSTRACT

In the early years of the offshore industry, Early Production Systems or EPSs were extensively utilized to develop marginal and/or complex reservoirs in progressively deeper and more remote waters. Their signature attributes were low capital and operating costs, simple designs and accelerated schedules to first oil. Today, Operators are emphasizing capital efficiency, design simplicity, compressed discovery to first oil cycle times and de-risking subsurface uncertainty as deepwater projects compete for capital allocation with onshore shale projects.
Discussing history and applications, the authors show, how an EPS can enable an Operator to sanction developments of marginal reservoirs, mid-size reservoirs with expansion capabilities to capture reservoir upsides and phased developments of giant reservoirs.
This paper addresses major subsurface uncertainties impacting development decisions and strategies to gather relevant dynamic information to mitigate risk. It provides a brief history of EPSs deployed in the North Sea, Brazil and GoM including a database of EPS platforms based on an extensive literature review. A case history in each region to demonstrate the utility of an EPS to de-risk and enable commercial production of marginal, mid-size and large fields.
A discussion is presented for EPS platform selection based on the research of platforms deployed in the three major deepwater regions. This discussion will facilitate to develop a roadmap for the Operators and Development Planners with tools to rapidly deselect or retain options in the early development planning stage while there is a high degree of reservoir uncertainty and pressure to compress cycle time to first oil following a discovery.

Keywords: **Reservoir de-risking, Deepwater, Extended Well Test, Early Production Systems, Phased Field Development, *SNAME, Offshore Symposium,***

INTRODUCTION

All field development decisions are made with the knowledge that there is a probability that the actual return on investment of a sanctioned development may not deliver expected returns. An Operator has to manage and mitigate project uncertainties and maximize the probability of success. Perhaps the single largest risk to the success or failure of a project is the subsurface uncertainty related to geologic complexity, reservoir and well productivity that are the main predictors of the two project critical success factors: expected well rates and ultimate recovery.

The risks associated with subsurface uncertainty are magnified in ultra-deepwater developments by the high cost of drilling and completing wells and the large capital investments required for the subsea infrastructure and floating production platform. There is also the long cycle time from project sanction (when large investments are made) and plateau production (when revenue is realized). The attraction for Operator's to develop deepwater fields is that a well-executed project that performs as well as or exceeds expectations at sanction, provides a very attractive return on investment. The challenge is that with oil prices expected to remain between $50/bbl and $60/bbl for a long while, Operators have low risk tolerance for underperforming deepwater projects. As a consequence, Operators are strongly emphasizing gathering quality subsurface and well performance information before sanctioning a project to reduce major risks and optimize the development.

There are several strategies available to an Operator for gathering requisite subsurface information following a discovery. The most common is to drill and stem test appraisal or delineation wells. But this still leaves a large uncertainty in long term well performance and measures to maximize per well recovery (completions and enhanced recovery). This information is best obtained by Extended Well Testing (EWT) or Early Production Systems (EPS) producing from single or multiple wells for extended durations. However these strategies require significant capital investment and dilute project returns by delaying a go-now decision. This, in short, is the Value of Information (VOI) conundrum that Operators must confront and manage.

In the following section an overview of processes and strategies for managing subsurface uncertainties is presented. The evolution of EPSs performed in the North Sea, Brazil and GOM with selected case histories in each region is presented next with a selected database of EPS platforms. A discussion on EPS platform selection factors are presented to facilitate the development of a roadmap unique for each Operator. The conclusion section summarizes the paper. Acknowledgements, Abbreviations and References section containing the reference list of relevant industry publications that were used to prepare this work round out the paper.

PROCESSES AND STRATEGIES FOR MANAGING SUBSURFACE UNCERTAINTIES

Commercial risks for frontier and offshore ultra-deepwater developments are significantly greater than developments in mature regions. In the past twenty years the E&P industry's Return on Investment (ROI) has averaged below seven percent (Narayanan et al., 2003) despite the fact that individual projects rarely receive committee sanctions unless the expected return is above a "hurdle rate", often 18 percent or more. The discrepancy between expected and actual returns can be traced to decision analysis process that fails to adequately address multiple, interdependent and correlated risks and uncertainties.

There are many risks that impact a successful project outcome (technical, commercial, project execution, operational) and the ones with greatest impacts have to be identified and managed. In frontier and ultra-deepwater developments the greatest risk is related to the uncertainty in reservoir characterization, its effects on production forecasting and ultimately the facility design. Failure of projects to meet their production and economic objectives can be attributed largely to improper or inadequate management of subsurface uncertainty in the field development plan and facility design. Uncertainty leads to risk and opportunity. Managing uncertainty and mitigating risk requires investment. An Operator, in early project phases, is faced with the decision of investing to reduce subsurface uncertainty to help decide whether or not to proceed with the development.

MAJOR SUBSURFACE UNCERTAINTIES

Subsurface uncertainties can be characterized as Static and Dynamic. Reservoir static uncertainties that significantly affect project NPV relate to physical properties of the reservoir, such as reservoir vertical and area limits; faults and transmissibility of the rocks; initial fluid characterization and rock properties (porosity, permeability, and productivity index) etc. On the other hand, reservoir dynamic uncertainties that significantly impact project NPV include: dynamic reservoir fluid behavior and distribution; secondary (or enhanced) recovery performance and wellhead pressure and flow rates.

Static uncertainties can be reduced by getting additional seismic data or drilling appraisal wells. Reducing dynamic uncertainty requires long term well flow.

STRATEGIES TO GATHER CRITICAL SUBSURFACE INFORMATION

Industry has several strategies in its toolkit to gather reservoir static and dynamic information to improve reservoir, geologic and depletion models critical to establish key field development parameters such as: number and location of production and injection wells, well construction (drilling and completions), well production profiles and expected ultimate recovery, impact of enhanced recovery options (water injection, gas injecting, water alternating gas injection (WAG), downhole, mudline or subsea boosting).

In ultra-deepwater one of the biggest cost drivers is the cost of drilling and completing a production well. Reducing uncertainties of key parameters in subsurface models will increase the fidelity of the models and confidence in estimating well rates and ultimate recovery. It also enables optimizing the development plan by increasing recovery factors while reducing well count.

EARLY PRODUCTION SYSTEM (EPS)

Well dynamic information is obtained by EWT and/or EPS (also referred to as Production Pilots in Brazil). Simply stated, an EWT is a production system (generally leased/chartered) that operates a single producing well for a period (typically ranging from 3 to 6 months) to acquire critical reservoir dynamic information, including time varying well rates, downhole and wellhead pressure and temperature, well pressure declines and production behavior.

An EPS or Pilot production system consists of a number of production wells (and occasionally injection wells) tied to a floating production platform, either leased or owned, for durations of 5 to 8 years. Associated gas is either monetized or injected. It is designed to investigate and gather a wider range of reservoir and well performance data than a EWT, with acquired information used to continually update and improve subsurface models. The data enables the subsurface team to optimize the depletion models and improve long term well productivity and ultimate recovery estimates. EPSs are also used to:

- Prove up enabling/enhancing subsea and platform technologies
- Test performance of various enhanced oil recovery strategies (water, gas, WAG injection, downhole ESPs, subsea boosting)
- Test relative efficiencies of various well construction (horizontal wells) and completions (Intelligent Completions)
- Evaluate effectiveness of stimulation treatments

The EPS requires considerable capital investment but is designed so that the expected revenue stream from produced oil and gas will generate an acceptable return for the Operator. Well performance and subsurface information gathered by the EPS is used to determine whether or not to proceed with a Full Field Development (FFD) and to optimize the development if it proceeds to sanction (Final Investment Decision/FID). An EPS can also be regarded as Phase 1 of a phased development strategy.

Evolution and Selected Case Histories of Early Production Systems

While one of the objectives is to supplement subsurface information obtained from 3D seismic and appraisal wells to optimize the full field development, the other is to ensure that it can meet an Operators' commercial hurdles (NPV, IRR) in its own right, as it represents a major capital investment. The decision is further complicated by the fact that the EPS will dilute the NPV of the full field development versus a go now decision. For an asset team to justify an

EPS to upper management on the basis that it could prevent sanctioning a project with a probability of failure is a challenging argument to make.

An EPS decision is closely tied to the size of field to be developed, as defined by a range of expected recoverables. For this paper we have bucketed ultra-deepwater field size into four categories: small, medium, large and giant with expected range of recoverable resources shown in Table 1.

Table 1 Four Categories of Discovery based on Expected Recovery (P50)

Field Size Category	Expected Range of Recoverable Resources (mmboe)
Small	Less than 100
Medium	100 – 250
Large	250 - 500
Giant	500 +

For a small or marginal field in ultra-deepwater, an EPS is the de-facto full field development. In this case the investment in acquiring subsurface information to reduce uncertainty is limited to 3D seismic data and one or two appraisal wells. A strategy to cope with the inherent uncertainty from this somewhat limited data acquisition is to design the EPS with the flexibility to respond to these uncertainties as they arise during development drilling or in the operational phase. Petrobras employs a “Value of Flexibility” strategy to manage and adapt to such uncertainties.

At the other end of the spectrum is the giant field, such as the ones discovered by Petrobras in the ultra-deepwater Campos and Santos basins. In such cases an Operator has significant leeway in investing in subsurface data acquisition to reduce uncertainties and optimize a full field development. A sequential or phased development is justified with a EWT, EPS (or Pilot) and the Definitive Production System (as Petrobras has successfully employed on the SBPSC). Petrobras sometimes fast tracks and overlaps the EWT, EPS and Definitive development phases to improve overall project profitability.

The Medium to Large fields present unique challenges. In the US GOM, Operators have rarely used EWTs and EPSs to manage subsurface uncertainties. The strategy has been to drill more appraisal wells, perform DST and acquire downhole data, use advanced seismic data processing and sophisticated subsurface earth and reservoir models. The commercial performance for many of projects sanctioned on this basis has been disappointing.

In the current low price environment (since 2015) an Operator will require robust justification before committing to the large capital investments required for a full field development for a deepwater development. Operators’ have severely curtailed capital spending for upstream deepwater projects since 2015 and major deepwater capital projects have to compete for capital with low risk, low capital projects (such as onshore shale). A deepwater asset team has to make a strong case for investing in data acquisition via an EPS to reduce uncertainty and project risk.

NORTH SEA

Leased, small, fast-track EPSs have been successfully deployed to produce several small or marginal fields in Central North Sea. A sample is summarized in Table 2.

Table 2 Selected EPS in North Sea

Field	Operator	WD (m)	EPS Platform	Owner	Type	Station – keeping	Oil Rate (mbopd)	Oil Storage (mbbl)
Huntington	EON	90	Voyageur Spirit	Teekay	Sevan	Spread	30	240
Chestnut	Centrica	120	Hummingbird Spirit	Teekay	Sevan	Spread	25	300
Varg	Repsol	84	Petrojarl Varg	Teekay	FPSO	Int. Turret	60	470
Ettrick	Nexen	115	Aoka Mizu	Bluewater	FPSO	Disc. Turret	30	600

Chestnut Field Development

The Chestnut field is an example of a successful, innovative development of a marginal field. The field was discovered in 1986. The reservoir had high quality sands, with an estimated 40-60 mmbbls of oil in place. An appraisal well drilled in 1988 confirmed a small complex reservoir. Coupled with weak oil prices at the time the project was shelved. In 2001, a EWT was conducted to reduce uncertainty about connected volumes and flow performance via a horizontal well. The well flowed 1 million barrels to the Crystal Sea EWT platform, over a 125 day period with well rates up to 16,000 bopd. The well was suspended and fully completed as a future producer. The EWT narrowed uncertainty in recoverables to a range of 30-35 million STB and showed the benefit of water injection to enhance recovery.

Centrica (became Spirit Energy in 2017) took over operatorship and with combination of the following factors:

- Improving oil price
- New seismic data and interpretation
- Availability of a leased innovative cylindrical FPSO with flexibility for future expansion

They sanctioned the full field development in late 2005 and first oil was achieved in 2008. The Sevan Hummingbird Spirit platform produced 5.5 mmbbls in the first 20 months with good facility uptime and was decommissioned in 2017 (Figure 1).

The project confirmed the viability of the cylindrical FPSO. A Sevan FPSO was also used as an EPS on the Huntington field in 2013. Petrobras leased the Piranema Spirit Sevan FPSO as an EPS on the Piranema field in 1600 m water depth from 2007 – 2018.

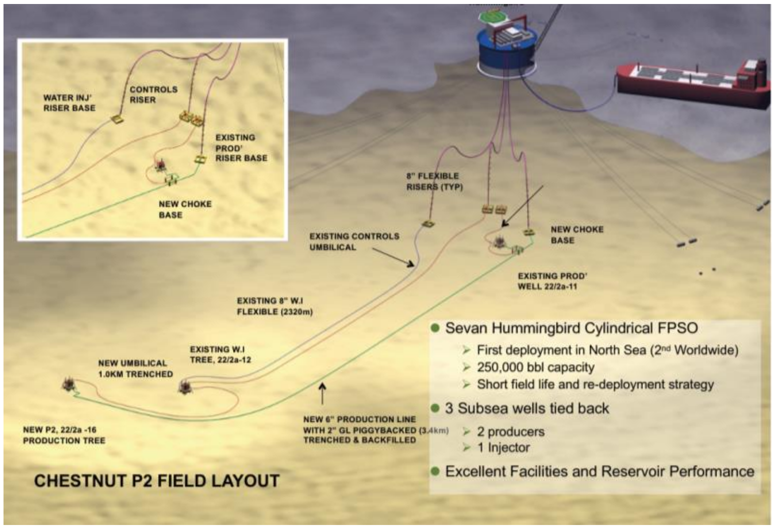

Figure 1 Chestnut Field EPS (Wood and Moore, 2009)

US GOM

Table 3 below presents selected field developments in the US GOM that have used and EPS either to produce a marginal field or a larger field with high subsurface uncertainty.

From published data, project execution and operational performance of Thunderhawk, Gomez and Phoenix EPSs were a success. The commercial performance of these projects is unknown.

Table 3 Selected EPS in GOM Deepwater

							Oil	
Field	Operator	WD (m)	EPS Platform	Owner	Type	Station – keeping	Rate (mbopd)	Storage (mbbl)
Thunderhawk	Murphy	1850	Thunderhawk	SBM	Semisub	Spread	60	-
Gomez	ATP	914	Innovator	ArcLight	Semisub	Spread	30	-
Cascade Chinook	Petrobras	2600	BW Pioneer	BW Offshore	FPSO	Disc. Turret	80	520
Phoenix	Talos	600	Helix Producer	Helix	Shipshape FPU	DP-2	30	-

<u>Cascade and Chinook EPS</u>

The Cascade and Chinook fields are located in the Walker Ridge area in the Central US GOM with Petrobras Americas (PAI) as Operator. Cascade was discovered in 2002 and Chinook in 2003. Two appraisal wells were drilled on Cascade in 2005. They are Lower Tertiary reservoirs in 2600 m of water at a total vertical depth of approx. 7600 m. At the time of the development decision, there were no production analogs for these reservoirs.

Several appraisal and development options were assessed during the conceptual phase including

- An EWT (single well flow test)
- Drilling additional appraisal wells
- Early production system

- Full field development

The first two options were discarded as it was concluded that neither would provide enough information to define mid to long term reservoir and aquifer performance. The risks of proceeding to a full field development were considered too high, which led to the decision of a phased development plan with an EPS as Phase 1.

The initial phase of development was to produce from two subsea wells on Cascade and one on Chinook to an FPSO with a disconnectable riser and mooring turret. Produced oil was transported by shuttle tankers and gas by a pipeline. PAI chose the FPSO option partly because of lack of pipeline infrastructure in the vicinity and partly because of their considerable experience with FPSOs and shuttle tankers in deepwater Brazilian fields and their flexibility for future expansion. The disconnectable turret was chosen to facilitate regulatory approval by the MMS and USCG and provide flexibility for relocation of the FPSO in the event of an underperforming reservoir or replacement with the Phase 2 full field development if warranted. The EPS decision was based on mitigating the reservoir performance uncertainty and optimization of the future development phase. First oil was expected in the first quarter of 2010.

The FPSO contract was signed with BW Offshore in October 2007 for the provision of a converted double hull Aframax tanker with a disconnectable internal turret design to keep the FPSO on station in a 100-yr winter storm but disconnect ahead of an approaching hurricane and sail away under its own power. The disconnected buoy with attached risers and 11-point mooring would submerge to a pre-determined depth of 60 m. The FPSO topsides can process a maximum of 80,000 bopd and 16 mmscfd of gas along with power to drive subsea pumps. The subsea infrastructure was designed to accommodate 8 wells and 25,000 bopd per flowline, connected by two Free Standing Hybrid Risers (FSHR) to the turret. One of the FSHRs collapsed on March 2011 before start of production as a result of a failure in the chain tether connecting the top of the rigid riser to the tensioning buoyancy cans. New chain tethers and dual back up synthetic tethers were installed on the replacement FSHR and all remaining risers.

The initial phase of the development began with Cascade wells starting production in February and December 2012 and one Chinook well in September 2012. The Cascade and Chinook EPS implemented a series of technologies new to the US GOM:

- First FPSO and deepest floater (at the time)
- First use of Jones Act compliant shuttle tankers
- Deepest and highest pressure rated FSHRs
- Deepest subsea boosting system
- First use of single trip multi-zone frack pack system in deep wells.

The EPS (Figure 2) is currently operational. In 2014 PAI began assessing the performance of the FPSO in Phase 1 and deciding on a development option for the next phase based on the information provided by the EPS. After assessing multiple options for Phase 2 – Return to BWO, Extend contract, Replace with full field development – PAI elected to exercise the option to extend the FPSO lease by three years to Q1 2020. Murphy Oil assumed the operatorship of Cascade/Chinook field upon completion of PAI's sale of ownership of their US GOM assets in April, 2019.

Figure 2 Cascade Chinook EPS, BW Pioneer

The implementation of so many new technologies and firsts entailed significant risks. However, PAI in doing so demonstrated the technical/regulatory feasibility of an FPSO in the US GOM and valuable lessons learned for future fast followers.

BRAZIL

Petrobras has pioneered strategies and technologies to develop their giant discoveries in the deep and ultra-deepwater Campos and Santos Basins. Campos Basin developments began with the giant Marlim and Albacora discoveries in 1984-1985 in water depths ranging from 250 m to 1800 m. The Santos Basin developments began with the giant presalt Tupi (now Lula) discovery in 2006. At the time these were frontier developments with very high uncertainties in subsurface characterization, well construction, subsea infrastructure and floating platform technologies – many without analogs or precedents. Spurred by the prospect of becoming a self-sufficient producer of oil and gas, Petrobras committed to a systematic program to develop these fields using Value of Information, Robustness and Flexibility strategies to manage risks and uncertainties while fast tracking the developments. Over time this evolved into a strategy of Phased developments – Pre Pilots (EWT), Pilots (EPS) and Definitive (full field) developments. This section provides a high level overview of the Campos and Santos giant field developments.

Campos Basin Developments: Table 4 summarize the progression of EPS developments on some of the giant discoveries in the Campos Basin that included Marlim, Albacora, Barracuda/Caratinga, Roncador and Jubarte. The progression is well summarized in Fraga, et al. (2003). The main project uncertainties were partially de-risked by using low budget pre Pilots and Pilot systems in the early phases converted from semisubmersible MODUs and tankers. The projects were used as a full scale laboratory for testing enhancing well construction and surface facility technologies. They experienced several failures in the process but used each failure as a learning experience to continually refine and improve the developments. The aggressive risk taking approach was enabled by the scale of the reservoirs. Major technology successes are documented in Fraga, et al. (2003).

Table 4 Selected EPS in Campos Basin

	Caratinga	Albacora Leste	Roncador Module 1A	Marlim Leste	Jubarte	Jabuti	Barracuda
Development Phase	Pilot	Pilot	Pilot	Pilot	Pilot	Pilot	
Discovery Year	1994	1986	1996	1987	2001	2005	1989
First Oil Year	1997	1998	2001	2000	2002	2008	1997
Duration (Months)	72	36	24	60	3	5	72
Water Depth (m)	1000	342	1800	1200	1350	1420	800
Facility Name	*FPU 34*	*FPU 25*	*Seillean*	*FPU 26*	*Seillean*	*Seillean*	*FPU 34*
Facility Type	Conv FPSO	Conv SS	DP FPSO	Conv SS	DP FPSO	DP FPSO	Conv FPSO
# of Producer Wells	3	1	1	1	1	1	8
Peak Production (mbopd)	60	20	25	20	20	20	60

The risk taking and fast tracking approach led to some spectacular failures, the most notable were the March 31, 2001 sinking of the P-36 Pilot semisubmersible in the Roncador field and loss of life, and the near sinking of the P-34 FPSO (ex. PP Moraes) while producing on the Barracuda-Caratinga fields in 2002.

The phased development strategy is one in which capital exposure was minimized in early phases to provide information that reduced risk and allowed cash flow to finance subsequent phases. The Seillean DP FPSO and the turret moored PP Moraes (P-34) as an EWT/EPS to rapidly and cost effectively gather valuable well dynamic data were widely utilized, and set the stage for Pre-Pilot FPSOs deployed for reservoir information gathering on the more challenging SBPSC developments.

Santos Basin Pre-Salt Cluster (SBPSC) Developments: The phased development strategies and technologies and lessons learned on developing the giant Campos Basin were applied and improved upon with great success while developing the giant challenging, frontier presalt reservoirs in the SBPSC. Petrobras was able to install nine production FPSOs, achieving an average oil rate of 700,000 bopd and a cumulative production of 400 mmbbls of oil from 34 production wells, just 8 years from the first discovery well on the giant Lula field (Figure 3).

Fraga and Pinto, (2015) provide an excellent summary of the evolution of SBPSC developments from the 2006 discovery to 2015. It addresses the technical challenges faced in the early years: the heterogeneous nature of the carbonate reservoir, the 2000 m thick salt layers, the variable CO2 content and compositional gradient of the reservoir fluids, flow assurance issues and special demands on subsea equipment, well construction and topsides. Development strategies were established and institutionalized: staged development based on EWTs, multi-well Pilot Systems (EPSs) and large Definitive Systems prioritizing standardization of wells, subsea infrastructure and production systems.

The use of EWT FPSOs Dynamic Producer and Cidade de Sao Vicente that relocated with relative ease between test locations, allowed gathering of valuable reservoir and well production dynamic data. This allowed the Operators to reduce risk and optimize the Pilot Production Systems or EPSs.

Moczydlower et al., (2012) discusses how the phased development evolved and the information gathering in each phase was used to reduce risks for subsequent phases. It also describes the institutionalization of the VOI, robustness and flexibility strategies employed to cope with critical uncertainties.

The Pilot Production Systems were spread or turret moored FPSOs with oil processing capacities between 100,000 and 120,000 bopd and water alternating gas injection capacities to enhance well rates from 4 or 5 production wells.

The Definitive Production Systems were "standardized" spread or turret moored FPSOs with oil processing capacity of 150,000 bopd. Andrade et al., (2015) describes the standardization of topsides on the Pilot and Definitive systems.

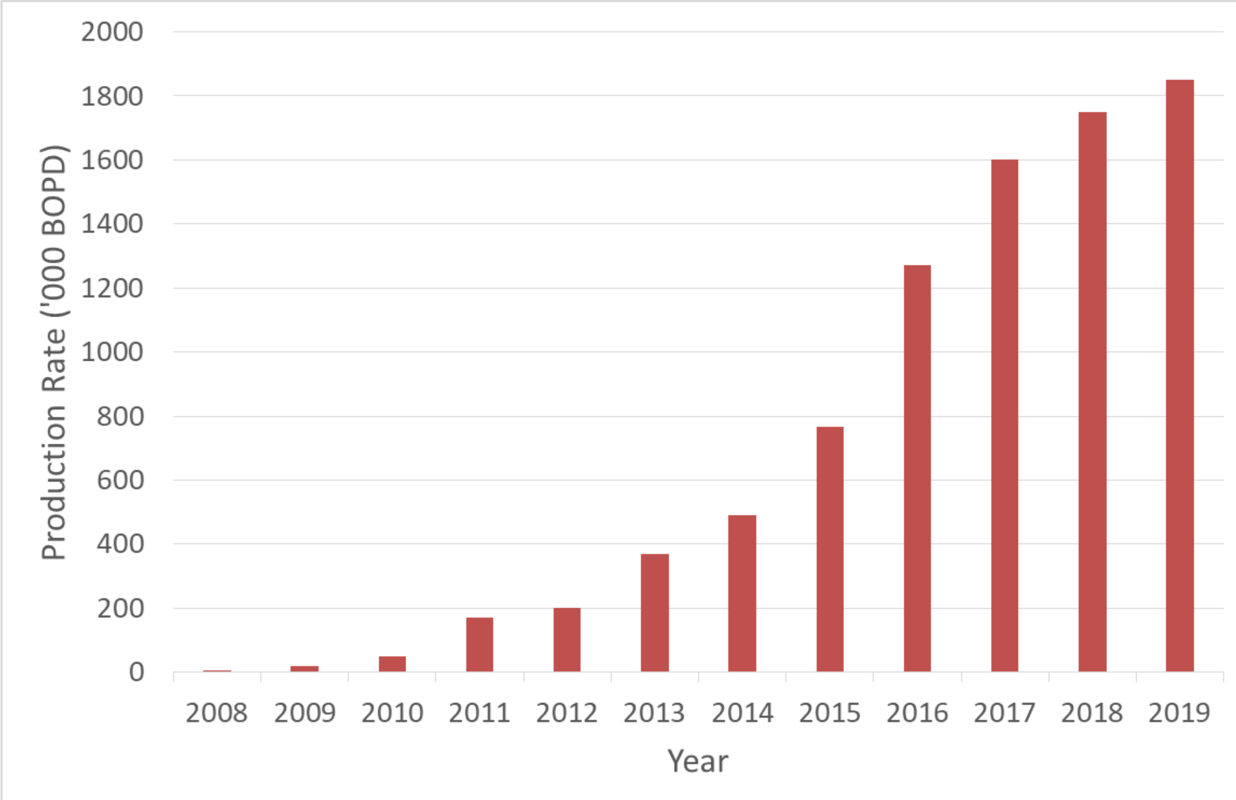

Figure 3 Oil Production in Santos Basin Pre-salt Cluster (Petersohn, 2019)

Cruz and Rosa (2016) and Nakano and Pinio (2009) provide excellent coverage of the progression of the EWT and Production Pilot on the Lula NE development from the planning phase to the operational phase, demonstrating the successful outcomes of the Petrobras' phased development strategy for the SBPSC ultra-deepwater developments.

Atlanta EPS

Situated about 185 km from Rio de Janeiro at 1550 m water depth, Atlanta is a heavy oil field (14º API grade). The reservoir is located about 800 m below seabed with a very low fracture gradient and temperature in the 40ºC range. The first vertical appraisal well in Atlanta was drilled in 2001, followed by a horizontal well to test potential of the field in 2006. This test brought to light the challenges to be solved to produce this reservoir. The API density of the crude makes it extremely difficult to characterize the reservoir, designing drilling and completion programs, tackling flow assurance issues from the well head to the FPSO, designing processing scheme as well as offloading stored processed crude to the tankers.

In 2013 and 2014, Operator drilled two wells for EPS production, followed by a third one in 2019. The FPSO Petrojarl-1 (Figure 4) was commissioned and reached first oil in May 2018 with the target production rate expected in Q4, 2019.

Every aspect of the Atlanta field development required multiple innovative solutions. This case history is limited to the ones related to the platform and a couple of examples from other aspects.

To generate and maintain the high production rate, each well in Atlanta EPS has two ESPs, one inside the well and near the reservoir. The other at the mudline, mounted on a skid. Presence of two ESPs provided redundancy and reduced the need for maintenance/workover. These ESPs were also designed to operate on variable frequency range between 40 and 65 Hz. The intentionally designed "inefficient" ESPs would dissipate a significant amount of imputed power as heat thus heating the crude and alleviating some of the flow assurance issues.

Figure 4 Petrojarl 1 operating in Atlanta (BS-4) Field (courtesy Enauta)

The FPSO also saw the use of the first drag chain system in Brazil for connecting high voltage electrical cables from the turret to the topsides power generation module via variable frequency drives. These were crucial to power the ESPs located in each well.

Converting the FPSO turned out to be quite challenging too. On one hand, the tight schedule and limited life span of the EPS meant maximizing the reuse of systems already installed on the FPSO. On the other hand, those original topsides equipment were not designed to process the heavy oil produced by Atlanta reservoir. The problem mainly arose due very low residence time in the 1st stage separator. To overcome that, a new Degasser vessel was installed with helical path design to enhance the gas/oil separation. The process philosophy was also updated and the crude was heated to help in separation.

The information currently generated by this EPS is being used to design and refine the Definitive Stage FPSO that will deal with a six-fold longer service life and substantially different water cut and fluid profile during that period (Rocha et al, 2019).

EPS Platform Selection Factors

Critical non-commercial selection factors for screening potential EPS platform types during Concept Selection are discussed below.

Sanction to First Oil Cycle Time: A key attribute for EPS selection is short cycle time. As the EPS is expected to last a very short duration compared to the overall life of the field, a concept that provides an earlier start to information gathering and revenue generation is desirable. This usually tilts the decision towards a conversion or an intercept (where typically a tanker already in fabrication is modified) rather than a purpose built platform.

Oil Export: In locations remote from existing infrastructure, such as a gathering pipeline network, platforms with integrated storage and direct offloading to shuttle tankers (FPSOs) will be preferable to semisubmersibles, which will require either an FSO or a pipeline. In the US GOM, depending on the location, it may be less of an issue if there is an accessible pipeline network. In Brazil, some infrastructure exist in the mature part of the Campos Basin and relatively shallower water. For the gigantic pre-salt reservoirs, remoteness and lack of any infrastructure self-selects FPSO systems rather than Semisubmersible and FSO combinations. North Sea, Far East and the Nigeria-Angola corridor also rely heavily on FPSOs. Any frontier basin is almost an automatic FPSO candidate as they lack any infrastructure at all.

Expandability: An EPS is sanctioned on the basis of limited or imperfect reservoir information and needs to be designed with flexibility to react to uncertainties as they are manifest during the operational phase. A concept that has greater adaptability to accommodate future expansion (topsides capacity expansion for additional subsea tiebacks or addition of enhanced recovery equipment) will be preferred.

Operational Risks and Complexities: The concepts selected to go forward should minimize operational risk and system complexities. For example, a disconnectable turret FPSO or DP FPSO has inherently greater operational risk and complexity related to disconnection, sail away and reconnection than a non-disconnectable or permanently moored platform. DP FPSOs also have a higher risk of brown out or drive off compared to a turret or permanently moored option. However, sometimes other considerations can push a development towards a particular option as discussed below.

Regulatory Approvals: This is an issue specific to the US GOM with its limited application of EPSs, particularly for non-disconnectable FPSOs. The Sevan FPSO or permanent turret moored FPSO would fall into this category if they were to be considered. US regulatory requirements for FPSOs stem from the FPSO EIS (USDOI, MMS, 2001) (EIS=Environmental Impact Statement). Though the EIS doesn't rule out a permanently moored FPSO solution, all FPSOs in the US GOM has been disconnectable solutions. As the first operational FPSO in US GOM selected a disconnectable solution, it set a precedence and became the de-facto standard.

Decommissioning: Decommissioning operations and associated costs in ultra-deepwater are not trivial. An EPS may be disconnected earlier than anticipated if the reservoir underperforms in which case it may have to be removed. Similarly a successful EPS will eventually have to be decommissioned and replaced with a larger full field production system. A disconnectable FPSO has some advantages in this regard over a permanent moored FPSO.

CONCLUSION

There is a history of Operators opting for EPSs, beginning in the mid 1980's in the North Sea and Brazil to gather critical subsurface information to increase confidence in making a final investment decision. This was especially the case for marginal, complex reservoirs in the shallow North Sea and giant reservoirs in deep and ultra-deep frontier (at the time of the discoveries) Campos and pre salt Santos Basins in Brazil. The conclusions from published literature researched and presented in this paper is that EPS projects have generally been successful in enabling Operators to make better decisions on whether (or not) to proceed with a full field development.

With the benefit of hindsight a strong case can be made that a phased development beginning with an EPS would have yielded significantly higher returns by minimizing subsurface risk and optimizing the full field development for most cases. A rigorous evaluation of these underperforming projects resulting from the discrepancy between actual and predicted well performance would bolster arguments in favor of conducting a EPS, especially for reservoirs lacking sufficient production analogs or with a high degree of subsurface uncertainty.

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LIST OF ABBREVIATIONS

bbl	:	barrels (of oil)
bopd	:	barrels of oil per day
BSSE	:	Bureau of Safety and Environmental Enforcement, previously MMS
DP	:	Dynamically Positioned
DST	:	Drill Stem Test
E&P	:	Exploration & Production
ESP(s)	:	Electric Submersible Pump(s)
FPSO	:	Floating, Production, Storage and Offloading
FPU	:	Floating Production Unit
GOM	:	Gulf of Mexico
IRR	:	Internal Rate of Return (on an investment)
mbopd	:	thousand barrels of oil per day
mmbbls	:	million barrels (of oil)
mmboe	:	million barrels of oil equivalent
MMS	:	Minerals Management Service, currently functions as BOEM and BSEE
mmscfd	:	million standard cubic feet (of gas) per day
MODU	:	Mobile Offshore Drilling Unit

NPV	:	Net Present Value
USCG	:	United States Coast Guard

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