A CRITICAL ASSESSMENT OF CONTRACTING STRATEGIES AND CYCLE TIMES OF POST-2014 SANCTIONED FLOATING PLATFORMS IN THE US GULF OF MEXICO

RICHARD D'SOUZA
PRESIDENT, RICHARD B OFFSHORE

SHILADITYA BASU
TECHNICAL PROFESSIONAL LEADER, KBR

Proceedings of the 27th Offshore Symposium, February 22nd, 2022, Houston, Texas
Texas Section of the Society of Naval Architects and Marine Engineers

ABSTRACT

Since 1986, about sixty Floating Production Systems (FPSs) have been installed in the US Gulf of Mexico (GoM). They include Spar, Semisubmersible, Tension Leg Platform (TLP) and Floating Production Storage and Offloading (FPSO) platforms. They have been installed in water depths ranging from 500 m to 3,000 m, and production rates ranging from 40,000 boepd to 250,000 boepd. A floating production platform is a major capital investment of a deepwater field development and presents a significant execution challenge. An Operator that opts to install a floating platform for a greenfield development must select a platform type, decide on a contracting strategy and establish credible cycle times for the Appraise, Select, Define and Execute phases of the field development. In their 2021 OTC paper (OTC 31115) the authors undertook a critical assessment of ten major field developments in the GoM, that were sanctioned between 2006 and 2014. They included all four major platform types. A comprehensive database of the field developments including host platform particulars, concept selection, contracting strategies, major engineering, fabrication and installation contractors and cycle times for the four development phases was presented for each project. In the current paper the authors add to the prior body of work, conducting a similar assessment of the seven floating platforms (Appomattox, Argos, Vito, King's Quay, Anchor, Whale and Shenandoah) that were sanctioned between 2015 and 2021. Taken together, the two papers provide the industry with its most comprehensive accounting of the evolution of GoM floating production platforms, development strategies and cycle times. This information will assist Operators and Development Planners plan and benchmark future GoM deepwater developments with a floating platform. Emerging trends in GoM field developments, following the collapse of oil prices in 2014, and the industry pivot to Energy Transition are also addressed.

Keywords: Offshore Field Development, Semisubmersible, semisub, semisub FPS, FPS, Contracting, Cycle Time, Benchmarks

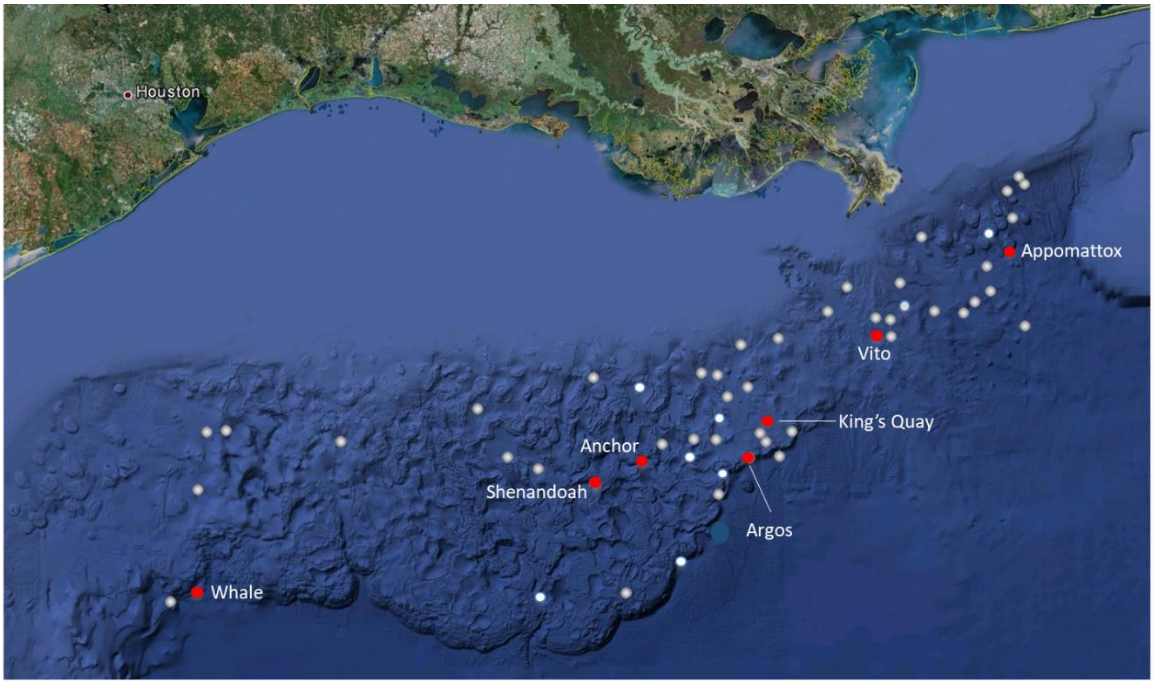

Figure 1: Location of the Seven Post-2014 FPSs sanctioned in US GoM

INTRODUCTION

Post-2014, seven greenfield developments with a newbuild floating platform were sanctioned in the US GoM (Figure 1). These developments cover a broad swath of GoM lease areas. Water depths range from 1,200 m (Vito and King's Quay) to 2,600 m (Whale). Nameplate production capacities range from 80,000 boepd (Anchor) to 175,000 boepd (Appomattox). The reservoirs include the Norphlet, Miocene and Lower Tertiary (Paleogene) plays. Estimated recoverable resources range from 250 mmboe (King's Quay) to 650 mmboe (Appomattox). The first post-2014 development to be sanctioned was Appomattox, and the most recent are the 2021 sanctioned Whale and Shenandoah developments. As of December 2021, Appomattox is the only development, among these seven, to come online. The rest are scheduled to begin production between 2022 and 2025.

A brief case history is provided for each development summarizing field development plans, platform particulars, contracting strategies, engineering and fabrication contractors and critical milestone dates (discovery, sanction, and first production). The information is consolidated in a project summary table (Table 1) and a bar graph showing cycle times for major development phases. Information on the Floating Production System (FPS) selection, size and contracting strategy trends, driven primarily by the severe oil and gas price contraction in 2014 and cycle times, exacerbated by the 2020 global Covid pandemic, are presented. The paper concludes with prognostications on technologies and decarbonization initiatives, driven by the energy transition, that are likely to have a significant impact on the future tranche of deepwater projects.

CASE HISTORIES

A case history of each of the seven field developments is presented. A list of primary source material is provided in the Reference section.

Appomattox Development

Shell discovered the Appomattox reservoir in Mississippi Canyon (MC) Block 392 in March 2010, about 120 km (80 miles) off the Louisiana coast in 2,200 m of water. The discovery well was drilled to a depth of 7,643 m, followed by several appraisal wells drilled in the next three years. The Vicksburg field was discovered in July 2013 in the adjacent block MC 393. The two fields cumulatively have an estimated ultimate recovery of over 650 mmboe. The reservoirs are in the Norphlet geological formation characterized by high temperatures and pressures and the presence of corrosive gas. These had a significant impact on the size and weight of the topside and platform. Shell made two additional discoveries within 16 km of Appomattox in 2014-2015.

Shell selected a large Semisubmersible hub platform to develop Appomattox and Vicksburg with a production capacity of 175,000 boepd from 15 production wells and 5 water injection wells. A Semisubmersible platform was chosen based on a combination of its ability to support a large topside weight, flexibility for future expansion and Shell's prior experience with the design and execution of large Semisubmersible and TLP projects.

Development engineering was well advanced by 2014, when the price of Brent crude fell by 44% from June 2014 to December 2014 and continued to decline in 2015. In January 2016, the price of oil fell below $30 per barrel, which was less than a third of the price when Appomattox development planning began. To sanction the Appomattox project, the Shell team assessed hundreds of cost-saving ideas, eventually realizing several billions of dollars in capex savings. The biggest saving came from halving the cost of drilling the 20 wells by negotiating a substantial reduction in drilling rig day rates and adopting batch drilling techniques. Shell reduced capital expenditure (capex) by about 20% pre-sanction and another 20% post-sanction by simplifying scope and specifications of the platform and subsea systems. As an example, substantial savings were attained by drawing source water, to cool the massive 150 MW power generation plant, from 600 m below the water line.

Shell sanctioned the Appomattox development in July 2015. The Appomattox Semisubmersible was to be the last of the giant platforms in the GoM, with the hull displacing 125,000 mt, and supporting a 27,000 mt topside operating weight. It was designed for a 40-year service life needed to deplete the known and yet to be discovered reserves that would be tied back to the platform. It was Shell's second Semisubmersible platform in the GoM after Na Kika, that was sanctioned in September 2000. Shell used their time-tested project execution model using handpicked topsides and hull engineering contractors that had worked on most of their previous GoM Semisubmersible and TLP projects. Hull and topside fabrication contracts were negotiated with preferred contractors Samsung Heavy Industries (SHI) and Kiewit Offshore Services (KOS).

Shell awarded the 42,700 mt lightship hull to SHI shortly after sanction. SHI had fabricated the 108,000 mt displacement Olympus TLP hull some five years earlier. On completion, the hull was floated onto one of the largest heavy lift dry transport vessels, COSCO's Xin Guang Hua, outrunning a super typhoon, that was aiming for SHI's Geoje shipyard, by a day. It arrived at the KOS Ingleside yard about two months later, shortly after hurricane Harvey had ravaged the area in October 2017.

KOS fabricated the four major topsides modules (150 MW Power, Process, Utilities, and 180 Person Quarters) and lifted them onto the hull with their 10,000 mt capacity Heavy Lift Device (HLD). Following about ten months of integration and pre-commissioning activities, the platform sailed to the Appomattox site (Figure 2) and was hooked up to the pre-installed 16-point chain-polyester-chain mooring system in August 2018. Export pipelines and production risers to the subsea drill centers were then hooked up to the FPS by Heerema Marine Contractor's (HMC) Balder Semisubmersible Crane Vessel (SSCV). Appomattox achieved First Production in May 2019. Shell is already considering debottlenecking options for future tiebacks.

Mad Dog Phase 2 Development

BP discovered the Mad Dog field in Green Canyon (GC) Block 780 in 1998. Production began in 2005 from a Spar platform installed in about 1,300 m of water, 304 km (190 mile) south of New Orleans. The platform was designed to produce 80,000 bopd and 60 mmscfd gas. Appraisal drilling in 2009 and 2011 in surrounding leases doubled the resource estimate of the greater Mad Dog field to more than 4 billion boe in place, justifying the need for a second platform in the field.

In 2010 BP began work on a second hub facility, a large wet tree Spar platform dubbed Big Dog, to develop Mad Dog Phase 2 (MD2). BP recycled the MD2 development in 2013, as the field development plan they were progressing was uneconomic even before the 2014 oil price collapse. This time BP selected a Semisubmersible host platform over a TLP and Spar, based in part on the excellent execution and operational performance of the BP operated Atlantis Semisubmersible platform that began producing in 2007 in the Green Canyon area. A key to the selection of the Semisubmersible FPS was the acceptance of Steel Lazy Wave Risers (SLWR) by BP riser engineers.

BP achieved a 60% capex reduction from the scrubbed development plan while producing the same resources. Much of this was achieved by simplifying and standardizing the host platform, subsea systems and well construction. Reservoir recovery factors were greatly improved by implementing ocean bottom nodes and advanced enhanced recovery technologies (Low Salinity or LoSal water injection) while reducing well count. Significant savings were also realized from industry collaboration and standardization.

Figure 2 Appomattox sail-away (source: Shell website)

The revised MD2 development plan includes a Kellogg Brown and Root (KBR) designed box-deck Semisubmersible hull with the capacity to produce 140,000 bopd from 14 production wells and inject 140,000 bwpd LoSal water into 5 water injection wells. The platform, named Argos, a reference to Odysseus' loyal dog from the Odyssey, is moored about 10 km southwest of the original Mad Dog truss spar. The project was sanctioned in December 2016 at an estimated break-even cost of $40/boe. Planned first oil at sanction was the fourth quarter of 2021.

BP deviated from the prevailing segmented execution model for large host platforms at the time, by awarding SHI a turnkey Engineer Procure Construct (EPC) contract to fabricate and integrate the FPS (topsides and hull) in their Geoje yard. The award followed several rounds of competitive bidding involving multiple contractors. Construction began in March 2018. The completed platform was loaded onto the BOKA Vanguard heavy transport vessel, setting sail for the KOS yard on February 8, 2021. After a 26,000 km voyage from South Korea, the Argos FPS was offloaded at the KOS yard on April 13, 2021. It underwent final preparatory work and regulatory inspections before being wet towed (Figure 3) to the site and hooked up to its pre-installed moorings in November 2021, after battling a strong, persistent loop current. It is currently undergoing final hook-up and commissioning to the subsea wells and export pipelines. First oil is anticipated in the second quarter of 2022, about six months later than planned. Much of the delay is attributable to the global Covid pandemic.

King's Quay Development

The Khaleesi and Mormont reservoirs were discovered by LLOG in 2017 in GC blocks 390 and 478 in about 1,200 m of water. They are Miocene reservoirs 9,300 m below the seabed. Murphy Oil assumed operatorship of the Khaleesi/Mormont field development, following their acquisition of LLOG's Green Canyon assets in May 2019. The reservoirs are estimated to contain a combined 165 mmboe of recoverable reserves. Murphy discovered the Samurai field in 1,060 m of water in GC 432 with recoverable resources estimated at 90 mmboe.

LLOG initiated the King's Quay project as a seven well subsea tieback from Khaleesi/Mormont to a Semisubmersible FPS host located on GC block 433. Following the acquisition of LLOGs assets, Murphy added Samurai as a four well, 10 km subsea tieback. Murphy formally sanctioned the King's Quay development in August 2019. In January 2020, Murphy entered into a memorandum of understanding with energy investment firm Arclight Capital Partners to sell its 50% ownership in the FPS, replicating a strategy employed by LLOG for the Delta House development.

Figure 3 Argos Platform Sail-away (September 2021)

The FPS is an Exmar standardized OPTI-11000(TM) design (Figure 4), much like the Delta House FPS operated by LLOG that began production in 2015. The topside nameplate capacity is 80,000 bopd and 100 mmscfd gas, with peak capacity of 100,000 bopd and 240 mmscfd gas. It has the flexibility to host future subsea tiebacks. The hull is a four column, ring pontoon configuration with a truss deck connecting the column tops. The deck offers a flat area that facilitates installation, hook-up and pre-commissioning topsides modules. The deck and topsides are fabricated and integrated at ground level and installed onto the hull in a single heavy lift.

Exmar Offshore provided engineering and construction supervision services for the hull, while Audubon Companies was awarded a contract for topsides engineering and procurement services. LLOG negotiated a turnkey EPC contract with Hyundai Heavy Industries (HHI) to fabricate and integrate the topsides and hull, which they later assigned to Murphy. The deck and topsides were placed on the hull in a dry dock in a single lift. This was a departure from the Delta House project execution, where HHI fabricated the hull in Korea and KOS fabricated and integrated the topsides and deck with their HLD in a single lift at their Ingleside facility in Texas. The completed FPS was dry transported on the COSCO heavy lift vessel Xiang An Kou (Figure 4) and delivered to the KOS shore base in September 2021 for final commissioning prior to sail away. First oil is expected in the second quarter 2022, following hook-up of the moorings and risers and final commissioning.

Vito Development

The Vito discovery well in the subsalt Miocene sands was drilled by Anadarko in July 2009 at a depth of 9,750 m below the mudline. Shell assumed operatorship in September 2009. After a four-year appraisal program Shell estimated that the field held recoverable resources of 300 mmboe, sufficient to support a stand-alone host platform.

Shell intended to sanction Vito in 2015, shortly after Appomattox, but the 2014 oil price collapse caused Shell to put the brakes on. A roughly three-year redesign exercise from the subsurface up followed. Shell succeeded in reducing the capex estimate by more than 70% from the original concept, which was a Semisubmersible FPS comparable in size to the Appomattox FPS. This was achieved in several ways: reduced well count, improvements in drilling efficiency, a smaller, fit for purpose FPS with limited spare capacity, and competitively bid fabrication. The leaner FPS design incorporated automation technology that reduced manning significantly. With this development plan, Shell estimated that they could develop Vito for a forward-looking breakeven price less than $35 per boe. Shell announced the final investment decision on April 24, 2018.

The Vito FPS topside is supported by a structurally efficient modular support frame (MSF) with knee-braces. The approximately 10,500 mt topsides can process 100,000 boepd setting a benchmark for topside design efficiency. The lightship weight of the four-column, ring pontoon hull, including the MSF, is about 13,000 mt. Hull displacement at a 27.5 m operating draft is 38,000 mt, like the OPTI-11000(TM).

Figure 4 King's Quay Dry Transport to KOS (source: see note below)[1]

Shell broke from their traditional split construction contracting practice for prior GoM floating platforms by tendering to a broad selection of EPC fabrication yards. Shell awarded a turnkey EPC contract to Sembcorp Marine (Sembcorp) to deliver the Vito FPS. The yard installed the topsides onto the hull in a single lift in a dry dock with twin gantry cranes (Figure 5). Shell awarded the contract in May 2018. Sembcorp handed over the FPS to Shell in the final weeks of 2021. Dry transport of the Vito FPS onboard Boskalis' Mighty Servant I, from Singapore to Texas began in the first week of 2022. The delivery was delayed by several months because of the Covid pandemic. The FPS is expected to arrive at KOS in March 2022.

Shell has advised that first oil from Vito is expected in the second half of 2022.

Figure 5 Vito in fabrication yard (source: Internet)

[1] The project is being executed by Murphy Exploration and Production. Owners of the semisubmersible facility include entities managed by Ridgewood Energy Corp., ILX III Holdings, LLC and Third Coast Super Holdings, LLC. The facility will be operated by Murphy.

Anchor Development

Chevron discovered the Anchor field in late 2014 on block GC 807 in 1,400 m of water. It lies about 225 km off the Louisiana coast and due North of their giant Jack and St. Malo fields, that began production in December 2014 from one of the world's largest Semisubmersible FPSs. The reservoir is in the Lower Tertiary Wilcox formation, about 10,300 m below the mudline. At an operating pressure of 20,000 psi, it is one of the first ultra-high-pressure projects in the world. Industry had begun the design and qualification of 20,000 psi subsea and drilling equipment several years earlier in anticipation of producing several of these massive, high-pressure reservoirs.

The timing of the discovery was not propitious as it coincided with the 2014 oil price collapse. Chevron, strongly committed to growing its already material production in the GoM, drilled two appraisal wells in the next two years to confirm reservoir productivity and recoverable reserves. From the appraisal program they estimated that the Anchor field had at least 440 mmboe of total recoverable resources, sufficient for them to begin Select phase activities for the Anchor development with a floating production platform in 2016.

Anchor is a staged development with an initial seven subsea production wells tied back to a Semisubmersible FPS. Chevron estimated it would take 250 days to drill and complete each deep, ultra-high pressure well. The FPS nameplate production capacity is 75,000 bopd and 28 mmscfd gas.

The Define phase kicked off in early 2017 with Wood designing the topsides and integrated deck and the hull designed by KBR (Figure 6). These were the same contractors that designed the successful Jack St. Malo Semisubmersible. Topsides operating weight, including the integrated truss deck, is 17,000 mt. The hull lightship weight is about 20,000 mt, displacing 69,500 mt at a 35 m operating draft. Chevron greenlighted the $5.7 billion development in December 2019 having reduced development costs for new projects in the GoM by nearly a third, compared to their last generation of greenfield deepwater investments. Anchor is a phased development with the FPS designed to accommodate future subsea tiebacks. The initial phase targets the southern fault block of the reservoir. The second phase targets the northern fault block with a four well drill center. The performance of the southern wells will inform the decision to move forward with the next phase.

Chevron awarded Transocean a contract to drill the Anchor wells just before project sanction. Transocean will upgrade a deepwater drillship under construction to accommodate 20,000 psi blowout preventers, a net hook load capacity of 3 million pounds and an enhanced dynamic positioning system.

Chevron opted for a traditional segmented project execution approach for the FPS i.e., hull built in the Far East and topsides built and integrated in the GoM. In December 2019 Daewoo Shipbuilding and Marine Engineering company (DSME) of South Korea was awarded a contract to build the hull. The award ended a five-year drought in new offshore platform orders for the yard. At the same time, KOS was awarded the topsides fabrication and integration contract. First oil date at project sanction is the second quarter of 2024. As of this writing, it appears that the project is on schedule.

Whale Development

Shell, the Operator of the Whale development, made the discovery in 2017 in Alaminos Canyon (AC) Block 773. The discovery, in 2,600 m of water, is approximately 16 km from their Perdido development, 320 km southeast of Houston. Perdido began production in March 2010 from a drilling-production Spar platform. Whale is a Paleogene reservoir some 9,000 m below the mudline. Shell labelled the find as one of its largest in the GoM in the past decade. Following several years of appraisal activities, Shell estimated a recoverable resource volume of 490 mmboe, sufficient to support a standalone greenfield platform. Well productivity, one of the biggest uncertainties in a Paleogene development, was largely derisked by their ten-year operating experience at the Perdido and Silvertip developments. In April 2020 Shell decided to postpone sanctioning Whale because of supply chain constraints and economic uncertainty created by the pandemic. However, they continued to advance a development plan that closely resembled the Vito development, sanctioned some two years earlier. The hull is a 99% replication and the topsides an 80% replication of the Vito platform (Figure 7).

The development plan features fifteen subsea production wells tied back to the Semisubmersible FPS. Shell describes the Whale FPS as a "simplified, cost-efficient host design" like the Vito FPS, as it is configurationally and dimensionally identical to Vito (Figure 8). Like Vito, the nameplate production capacity is 80,000 bopd and 100 mmscfd of gas, the topside operating weight is 10,500 mt and the displacement is 38,000 mt. To lower greenhouse gas intensity, Shell is utilizing energy-efficient gas turbines and compression systems.

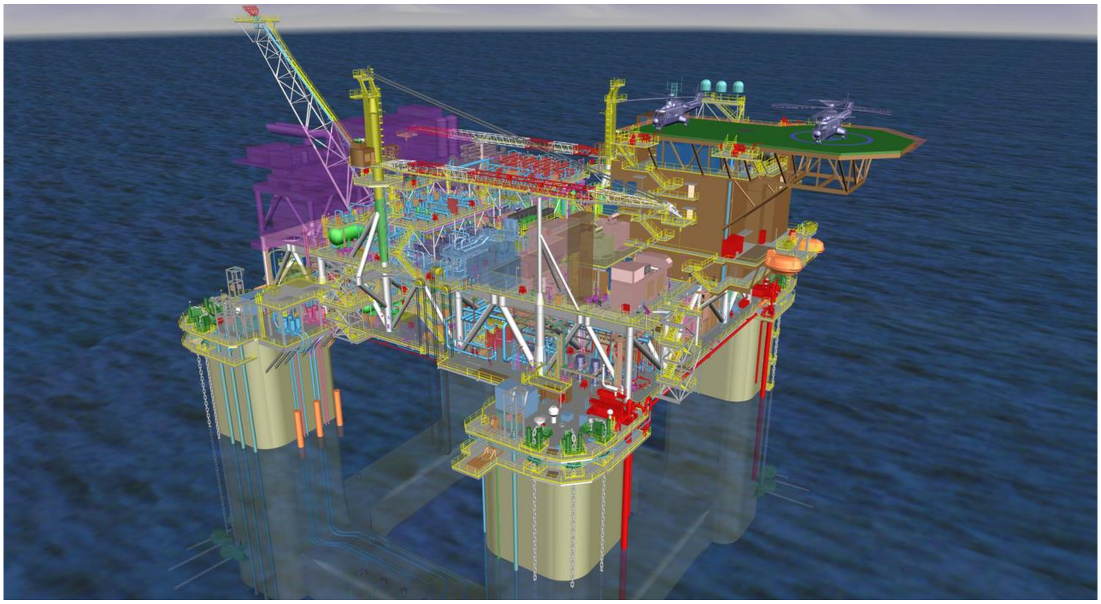

Figure 6 Anchor platform 3D model

Anticipating a final investment decision (FID), and to accelerate first production, Shell contracted Sembcorp to build and integrate the Whale FPS topsides and hull in November 2019. Shell had earlier contracted Sembcorp for the same scope on the Vito FPS (EPC of the FPS and deliver to a shore base in the GoM). By taking advantage of the synergies from the Vito FPS supply chain and construction processes Shell estimated that they could achieve first oil 7.5 years after discovery. Shell sanctioned the Whale development on July 26, 2021, at a forward-looking breakeven cost below $35/boe. Whale will be Shell's 12th deepwater platform in the GoM and is currently scheduled to begin production in 2024.

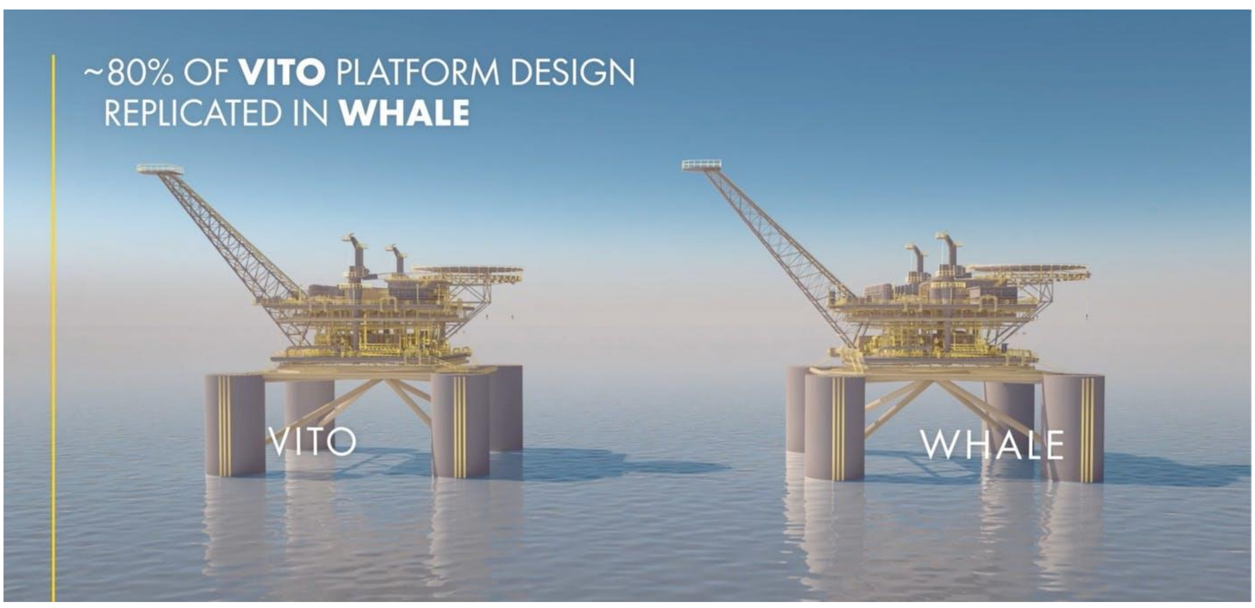

Figure 7 Whale replicates Vito platform design (source: OGJ.com)

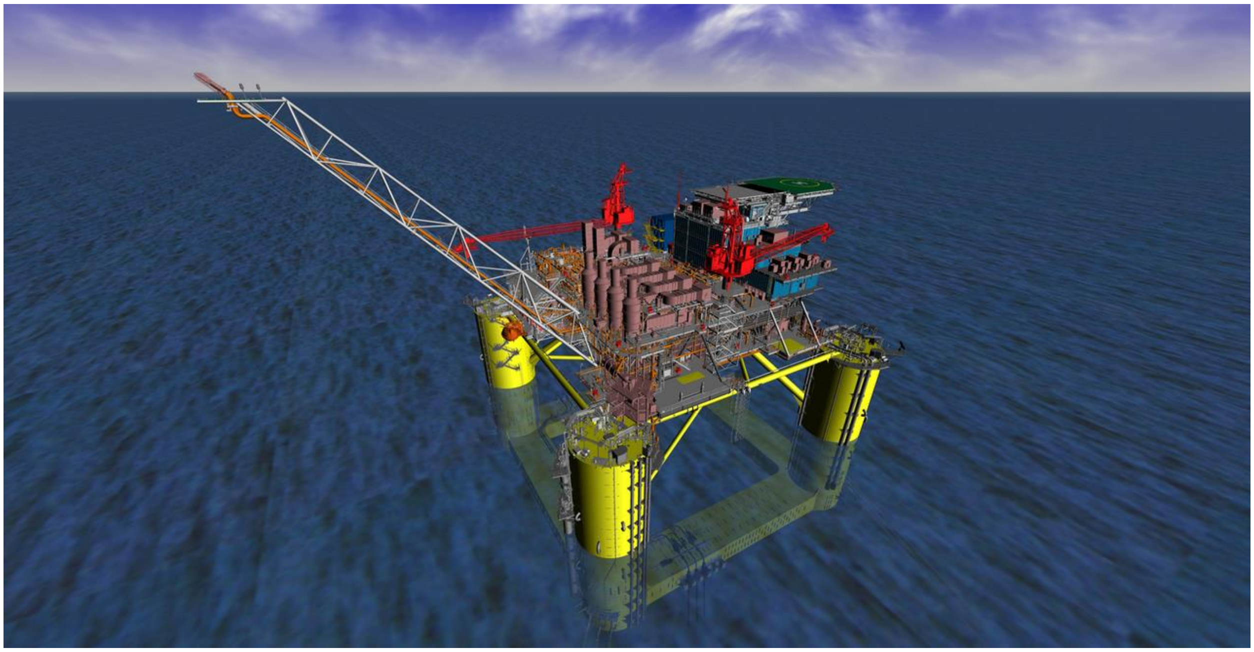

Figure 8 Schematic of Shell's Whale platform (source: Offshore Magazine)

Shenandoah Development

The Shenandoah field is located on Walker Ridge (WR) Blocks 51, 52 and 53. The discovery well was drilled by Anadarko in February 2009 in about 1,700 m of water. The reservoirs are in the Upper and Lower Wilcox sands about 9,500 m below the mudline. Like Anchor, the reservoir is ultra-high pressure, requiring 20,000 psi rated equipment.

There was considerable excitement surrounding the discovery, as the initial appraisal wells suggested the potential for upwards of 1 billion boe in place. After drilling five appraisal wells from 2012 to 2017, Anadarko concluded that the reservoir was highly compartmentalized, with recoverable reserves considerably lower than originally anticipated. Concurrent with appraisal, Anadarko had initiated a competitive FEED for a Semisubmersible and Spar FPS as the host facility and selected a Semisubmersible. Anadarko relinquished the field in 2017 after spending a reported $1 billion from 2009 to 2017 on exploration and appraisal.

The project was revived in 2018 when LLOG became Operator after Anadarko withdrew from the project and partner Cobalt Energy divested their interest in the project. Based on the results of the extensive appraisal program, LLOG concluded that recoverable resource from Shenandoah was about 280 mmboe. They quickly settled on a phased development plan, with the first phase consisting of tying back four producing subsea wells to a Semisubmersible FPS. The development plan drew heavily from LLOG's experience with Who Dat and Delta House developments. The second phase would add four more producers, informed by the performance of the four initial wells. LLOG contracted TechnipFMC to provide the 20K subsea trees in October 2019.

On 28 July 2020, Beacon Offshore (Beacon) acquired LLOG's stakes in Shenandoah and Yucatan, the latter being a discovery just southwest of Shenandoah that will eventually be included in the Shenandoah development. Beacon was formed in 2016 by private equity group Blackstone with the goal of building a significant, high-quality portfolio in the deepwater GoM.

Beacon sanctioned the Shenandoah development, as envisioned by LLOG, on August 27, 2021. The Semisubmersible FPS is an Exmar OPTI-11000(TM) (Figure 4), similar to LLOG's Delta House FPS and Murphy's King's Quay FPS , with a nameplate production capacity of 100,000 boepd. Shortly thereafter, they awarded HHI an EPC contract for delivery of the FPS following a competitive bid. HHI had delivered the King's Quay FPS in July 2021. HHI plans to start constructing the hull at its Ulsan yard in the third quarter of 2022. Work on the FPS is scheduled to be completed by September 2024, with installation in the field expected in fourth quarter of 2024.

Beacon awarded Transocean a contract to provide a drillship to drill and complete the first phase four well drilling and completion program. The eighth generation Deepwater Atlas drillship will begin drilling with a 15,000-psi rated BOP, and the program is expected to last 255 days. A 20,000 psi BOP will then be installed for the completion program, which is expected to last 275 days. Beacon anticipates first production from Shenandoah in the first quarter of 2025.

Critical Assessment of Post-2014 Sanctioned GOM FPSs

Table 1 provides summary information of the field development, FPS particulars, platform contracting strategies and contractors and significant project milestones (Discovery, Sanction, and First Production) of the seven post-2014 sanctioned field developments in the deepwater US GoM.

FPS Selection and Displacement Trends

Figure 9 is a bubble chart showing the type, displacement, and water depth versus sanction date of ten deepwater FPSs sanctioned before 2014 and the seven deepwater FPSs sanctioned from July 2015 to August 2021. The trends are very revealing.

Of the ten pre-2014 sanctioned projects, there were three TLPs, three Semisubmersibles, three Spars and one FPSO. The average displacement of the four projects executed by major Operators (Jack St. Malo, Olympus, Big Foot, Stones) was about 140,000 mt and average water depth about 1,900 m. The average displacement of the six projects executed by independent Operators (Who Dat, Tubular Bells, Lucius, Delta House, Heidelberg, Stampede) was about 45,000 mt and average water depth about 1,500 m.

Just seven deepwater greenfield projects were sanctioned in the seven years since Hess sanctioned the Stampede TLP in October 2014. Significantly, all seven platforms are Semisubmersible FPSs. Of these, five (Appomattox, Argos, Vito, Anchor, Whale) were sanctioned by three major Operators (Shell, Chevron, BP) with average displacement about 75,000 mt and average water depth about 1,800 m. Average displacement of the two Semisubmersible FPSs (King's Quay, Shenandoah) sanctioned by independent Operators (Murphy, Beacon) was about 38,500 mt and average water depth about 1,350 m.

The selection of a Semisubmersible FPS for all post-2014 sanctioned platforms is not coincidental. In 2018, the authors presented the case for a Semisubmersible FPS as a universal host for future GoM platforms (OTC 28970). It is informative to revisit the rationale for this selection as it has become a reality. In the run-up to the dramatic oil price drop in late 2014, deepwater projects witnessed a spectacular growth in investment, production and capex inflation. Much of the latter was attributable to inflation in drilling, equipment and labor cost, and lack of capital discipline. Oil prices in 2012-2013 averaged over $100/bbl and were expected to continue rising. Breakeven costs of deepwater projects in the GoM often exceeded $70/boe. Most deepwater projects were late and over budget.

In the wake of the 2014 oil price collapse, the industry was confronted with a stark choice: to enable sanction of future deepwater projects, break-even costs had to be reduced to $40/boe or less. By 2015, breakeven costs had fallen to between $50-$60/boe, driven largely by commercial gains extracted from the supply chain. Shell reduced capex of the Appomattox project, sanctioned in July 2015, by 40% without altering the development plan. They did this principally by halving the cost of drilling and completing the twenty wells.

To realize an additional $10-$15/boe reduction in breakeven costs, the industry had to do more. Significant break-even cost compression was achieved by simplifying and standardizing designs and specifications of everything from drilling and completions, subsea systems, and the floating platforms. Operators realized that by picking a universal FPS building block they could reap the benefits of greater project delivery certainty, accelerated cycle time to first oil and reduced capex, thereby achieving the harder to obtain cost reductions. The question was which of the four major platform types deployed in the GoM deepwater best fit the requirements of a universal host, i.e., water depth and payload bandwidth, flexibility for phased development, ease of integration and installation and contracting flexibility. The Semisubmersible FPS checked all the boxes.

BP sanctioned the MD2 development in December 2016 at an estimated breakeven cost of $40/boe. They achieved a 60% reduction from the original development plan while maintaining the same production rates by utilizing many of the cost reduction levers at their disposal. One of the levers was to replace the Spar with a Semisubmersible FPS, building upon their successful execution of and lessons learned from the Atlantis FPS.

Table 1 Summary Data of the seven post-2014 sanctioned FPSs in the GoM

	Appomattox	**Argos**	**Vito**	**King's Quay**	**Anchor**	**Whale**	**Shenandoah**
Block	MC 392	GC 780	MC 939	GC 433	GC 807	AC 772	WR 52
Operator	Shell	BP	Shell	Murphy	Chevron	Shell	Beacon Off
Water Depth (m)	2265	1370	1200	1190	1580	2600	1700
Reservoir Depth (m)	7650	7000	5500	9300	10300	9000+	9500
Reservoir Rock	Norphlet	Miocene	Miocene	Miocene	Wilcox	Paleogene	Paleogene
EUR (mmboe)	650+	500	300	250	440	490	280
Host Platform	*Shell Semi*	*KBR Semi*	*Shell Semi*	*Opti-11000(TM) Semi*	*KBR Semi*	*Shell Semi*	*Opti-11000(TM) Semi*
Peak Oil Rate (mbopd)	150	140	80	80	75	80	80
Peak Gas Rate (mmscfd)	250	75	100	100	30	100	100
Enhanced Recovery	WI	WI (LoSal)	Gas lift	-	SSB (Future)	-	-
Well Count	15 P, 5 I	14 P, 8 I	8P	11P	7P (staged)	15P	8P (staged)
Topsides Op Wt (mt)	27,000	24,500	10,500	11,000	17,000	10,000	11,000
Hull L'ship Wt (mt)	42,700	-	13,000	11,000	19,300	15,000	11,000
Displacement (mt)	125,200	101,500	38,000	39,000	69,500	38,000	39,000
Hull Type	Shell MSF with Knee-braces	GVA Box-deck	Shell MSF with Knee-braces	Exmar Truss-deck with MSF	GVA Integrated Truss Deck	Shell MSF with Knee-braces	Exmar Truss-deck with MSF
FPS Contracting	Segmented Fab, Int & Inst. Contracts	Turnkey EPC Contract for FPS fabrication	Turnkey EPC Contract for FPS fabrication	Turnkey EPC Contract for FPS fabrication	Segmented Fab Contracts	Turnkey EPC Contract for FPS fabrication	Turnkey EPC Contract for FPS fabrication
Top. Eng. Co	Jacobs	KBR	Jacobs	Audubon	Wood	Jacobs	-
Hull Eng. Co.	Shell	KBR	Shell	Exmar	KBR	Shell	Exmar
Top. Fab.	KOS	SHI	Sembcorp	HHI	KOS	Sembcorp	HHI
Hull Fab.	SHI	SHI	Sembcorp	HHI	DSME	Sembcorp	HHI
Int. Cont.	KOS	SHI	Sembcorp	HHI	KOS	Sembcorp	HHI
Int. Method	Quayside Lift	Floating Crane	Single Lift DD	Single Lift DD	Quayside Lift	Single Lift DD	Single Lift DD
Inst. Cont.	HMC	Subsea 7	Jumbo Offshore	Subsea 7	HMC	-	Subsea 7
Discovery	Mar 2010	2010	Jul 2009	2017	Q4, 2014	Jan 2018	Feb 2009
Sanction	July 2015	Dec 2016	Apr 2018	Aug 2019	Dec 2019	Jul 2021	Aug 2021
Hull Delivered	Oct 2017	Apr 2021	Mar 2022 (exp.)	Sep 2021	-	-	3Q 2024 (exp)
FPS Mooring Hook-up Completed	Aug 2018	Nov 2021	-	Jan 2022	-	-	-
First Production	May 2019	Q2, 2022	Q3, 2022	Q2, 2022	Q1, 2024	2024	Q1, 2025

Shell rewrote their deepwater GoM development playbook with the Vito development. They delayed a presumptive 2015 sanction and spent three years on a revised plan that could be developed at a break-even cost of about $35/boe. A key was scaling back the topside nameplate capacity, simplifying the topsides processing facilities and reducing manning with automation. This combination led to an enhanced production rate to topsides weight ratio and a semisubmersible that displaced about a third that of the Appomattox FPS. The tradeoff came at the expense of limiting flexibility for future expansion. Buoyed by the success of Vito, Shell sanctioned the Whale development about three years later with a near replica of the Vito semisubmersible design and project execution.

King's Quay and Shenandoah are being developed by independent Operators Murphy and Beacon. They are following the successful template developed by LLOG (a partner on both projects) for their Delta House project by utilizing the lean, standardized OPTI-11000(TM) semisubmersible design. The efficient topsides throughput (100,000 boepd) to topside operating weight (11,000 mt) ratio results in a compact and efficient hull (39,000 mt displacement). By standardizing and repeating the FPS design and using the same engineering and fabrication contractors (design one build two), the Operators were able to accelerate cycle times and realize significant cost efficiencies, much as Shell hope to do for their Vito and Whale projects.

Shenandoah, however, is a frontier development that falls into the ultra-high-pressure category (20,000 psi), requiring high specification subsea and drilling equipment. To manage the uncertainty in well productivity, Beacon has opted for a phased development where the second phase will be predicated on the performance of the first phase wells.

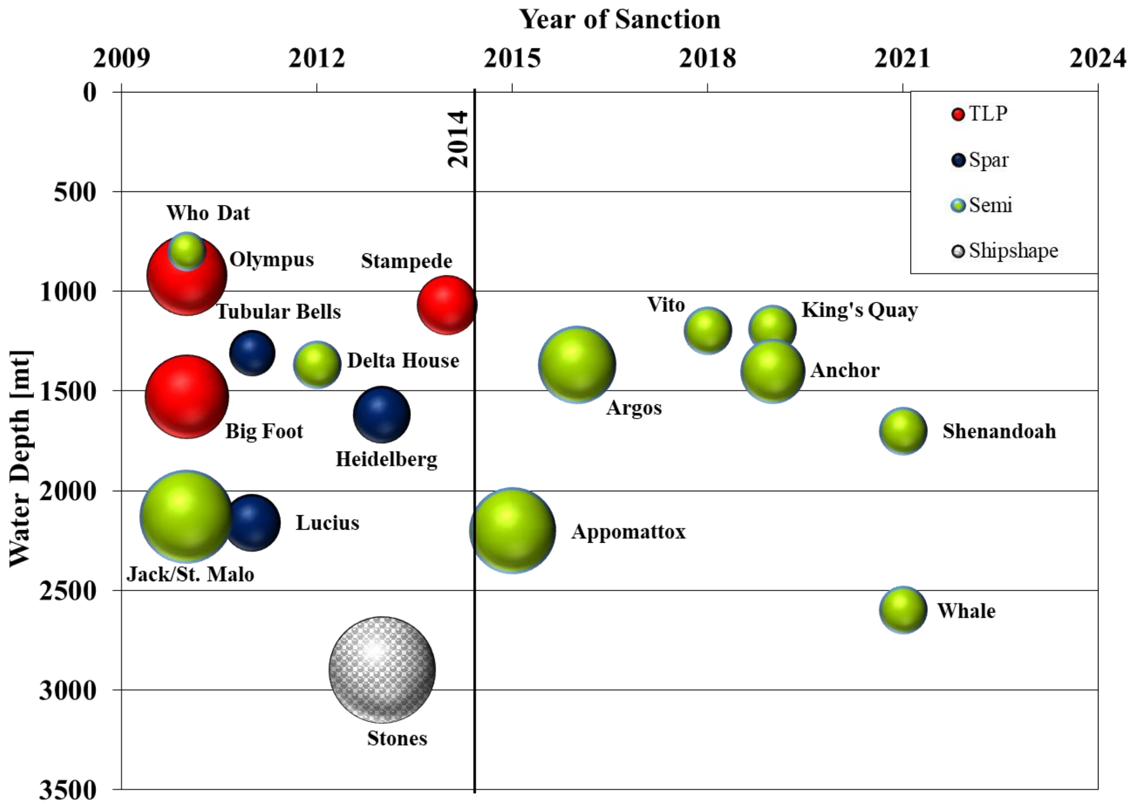

Figure 9 US GoM FPS Type and Displacement Trends since 2010. Bubble size corresponds to platform displacement

Chevron also opted for a phased approach for their ultra-high-pressure Anchor development that faces many of the challenges as the Shenandoah development. This provides the dual advantages of a) optimizing the second phase well designs based on information from the first phase and b) specifying a lower nameplate production (80,000 boepd) resulting in a leaner platform. The 17,000 mt topsides is about 50% heavier than the Shell Vito and OPTI-11000(TM) semisubmersibles partly because of the inclusion of subsea boosting to enhance ultimate recovery.

Figure 10 shows how FPS topsides operating weights are trending with time. Topside operating weight of Argos and Appomattox FPSs averaged about 26,000 mt. Topside operating weights of the later sanctioned Vito, King's Quay, Anchor, Whale and Shenandoah FPSs average about 12,500 mt, reflecting increased operator focus on capital efficiency.

Discovery to First Production Cycle Times

The Figure 11 bar graph shows discovery to first oil cycle times of the seven post-2014 sanctioned deepwater projects.

The average discovery to sanction cycle time is 75 months, sanction to first production, 46.6 months and thus discovery to first production, 121.6 months, or about 10 years and 2 months. First oil dates for six of the seven projects are current best estimates as the projects are still in execution. Contrast these with the ten pre-2014 sanctioned deepwater project corresponding cycle times, which are 46.4, 34, and 80.4 months respectively. The average topside operating weight of the post-2014 sanctioned FPSs is about 16,000 mt, whereas the average topside operating weight of the pre-2014 sanctioned FPSs is about 16,500 mt. It is instructive to assess why the cycle times for the post-2014 cycle times are so much longer than the pre-2014 cycle times, even though the average topside operating weights are similar.

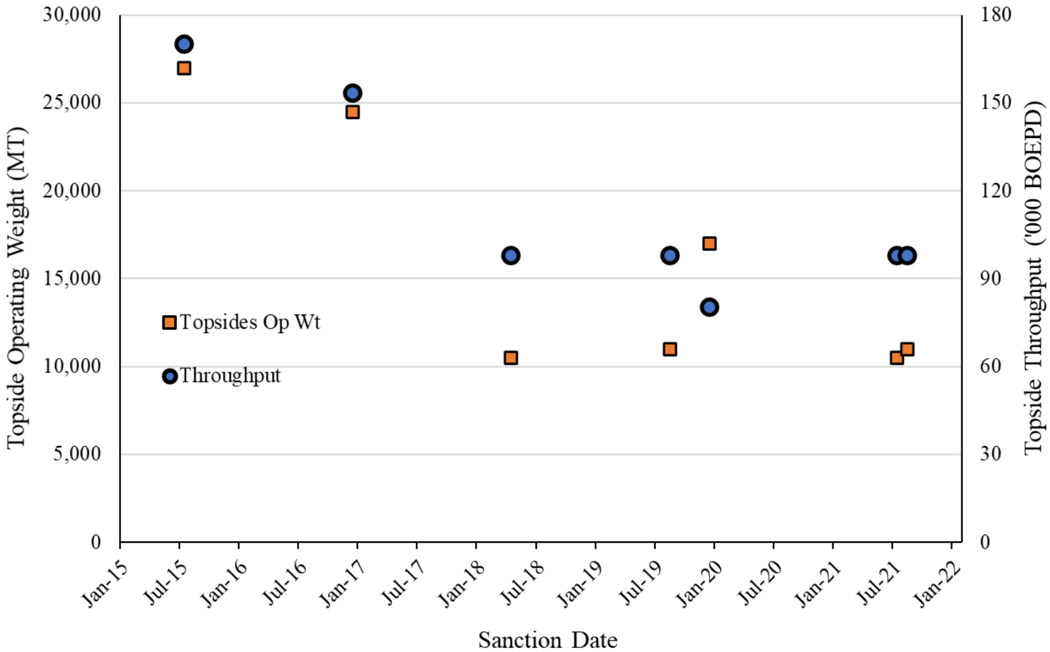

Figure 10 Post-2014 Sanctioned FPS Topside Operating Weight and Throughput Trends

Discovery to Sanction Cycle Times

Generally, the discovery to sanction cycle time is dictated by the appraisal programs. Deeper, high-pressure, Lower Tertiary reservoirs require more extensive appraisal drilling to derisk the reservoir and increase confidence in the expected recoverable resource. Four of the ten pre-2014 sanctioned developments were in the Lower Tertiary with an average 78-month cycle time. The five developments in the Miocene reservoirs averaged 28 months. Tubular Bells was an outlier as there was a change in Operatorship seven years after the discovery.

Four of the seven post-2014 developments were high or ultra-high-pressure and/or high temperature reservoirs (Appomattox, Anchor, Whale and Shenandoah) requiring either extensive appraisal drilling or technology qualification of subsea and drilling equipment. Shenandoah (152-month cycle time) is an outlier because Anadarko spent eight years in appraisal before relinquishing their stake to LLOG, who two years later sold it to Beacon. The project also had to deal with the 2014 price collapse. Considerable time for technology qualification of ultra-high-pressure (20,000 psi) equipment was required. Average discovery to sanction cycle time for the other three high pressure developments is about 58 months, about 20 months faster than the corresponding pre-2014 sanctioned high-pressure projects.

Average discovery to sanction cycle time for the three Miocene discoveries (Mad Dog Phase 2, Vito, King's Quay) was 64 months, almost three years longer than the corresponding pre-2014 sanctioned projects. The Mad Dog Phase 2 development plan was recycled three years into Select/Define activities, as the capex had ballooned to $20 billion. The recycled plan was executed in 36 months, despite being affected by the mid-2014 oil price collapse. Shell queued up the Vito project for sanction shortly after sanctioning the Appomattox development, about six years after the 2009 discovery. They then spent an additional three years redesigning the development from the subsurface up to drive the break-even cost below $35/boe because of the 2014 oil price collapse.

The King's Quay discovery to sanction cycle time of 20 months was consistent with Operator Murphy's aggressive approach to developing projects.

Sanction to First Production Cycle Times

Figure 12 compares pre-2014 and post-2014 sanction to first oil cycle times versus topside operating weight. The pre-2014 cycle time curve is the best fit of the ten projects assessed by the authors in their earlier paper. There is no discernable trend for the post-2014 sanctioned projects. Appomattox and King's Quay follow the pre-2014 sanctioned projects trend line. Cycle times for the other five projects are nine to twenty months greater than the pre-2014 trend line. Each was affected to varying degrees by the global Covid pandemic that created labor shortages, work stoppages and supply chain disruptions. In the last two years there has also been discernable escalation in equipment and bulk costs, labor rates and drilling rig day rates. These first oil delays and cost inflation may adversely impact sanctioned project rate of return, depending on the realized cost of the product (oil and gas) at the time of sale.

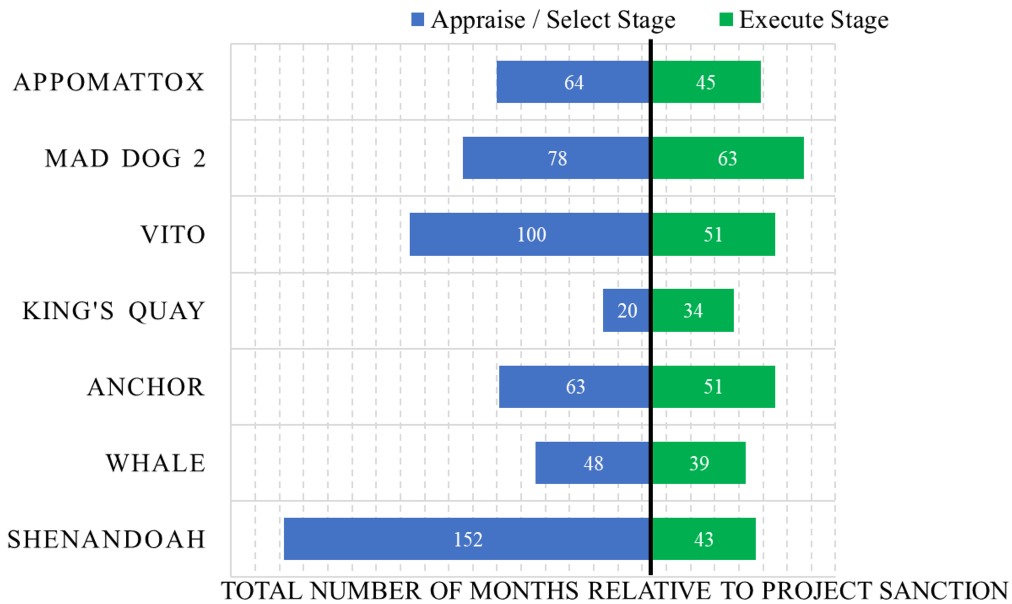

Figure 11 Discovery to First Production cycle time trends for Post-2014 GoM Projects

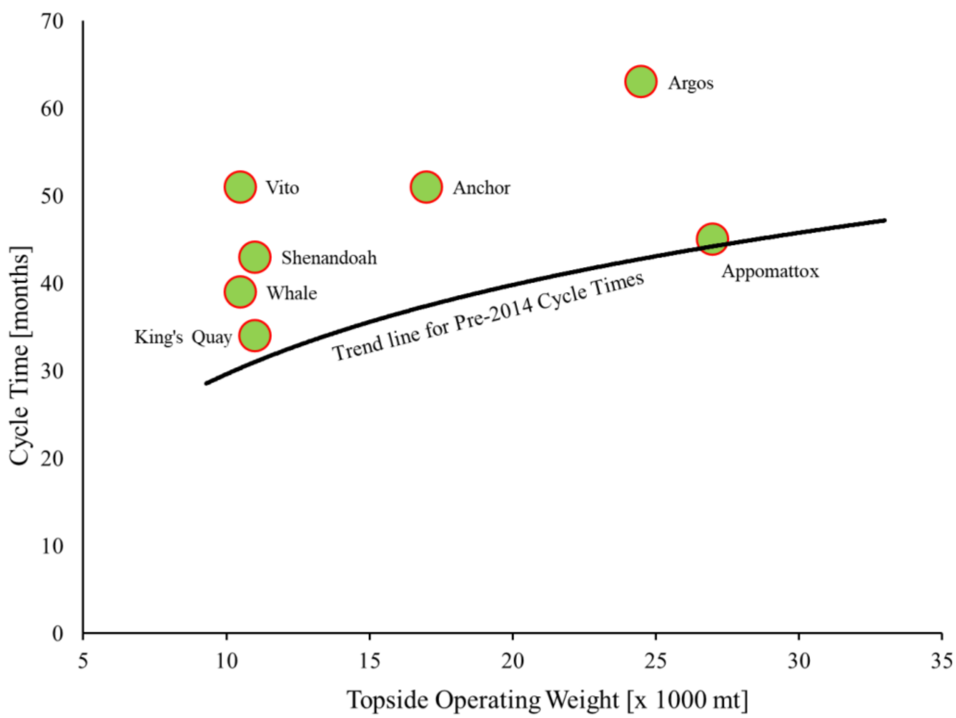

Figure 12 Pre- and Post-2014 FPS Sanction to First Oil Cycle Time Trends vs Topside Weight

FPS Contracting Strategies

Most FPS projects sanctioned from 2005 to 2014 followed a familiar template: build the hull overseas and fabricate the topside in a Gulf Coast yard. Topside integration to TLP and Semisubmersible hulls was mostly done quayside by KOS with their HLD. Topsides integration on Spar hulls was done on site with SSCVs. With a few exceptions, contracts for topside, hull fabrication and integration and installation were awarded separately. Shell, Anadarko and

BP installed a majority of the FPSs during this period. They typically negotiated engineering, fabrication, integration and installation contracts with preferred contractors. There was the occasional EPC contract (Red Hawk Spar) or a lease-operate contract (Gomez and Thunderhawk Semisubmersibles, Stones FPSO).

Post-2014, Operators were under relentless pressure to substantially reduce capex. The big breakthrough was to design leaner, standardized, repeatable FPSs. As the number of sanctioned projects fell, competition from Korean and Singapore fabricators became more intense, creating an opportunity for further cost reductions. By then many yards had established track records for EPC delivery of large integrated FPSs or sixth and seventh generation semisubmersible drilling rigs. In addition, the capabilities of heavy lift dry transport vessels kept growing, with the BOKA Vanguard (introduced in 2013 with Chevron's Jack St. Malo FPS as its first cargo) capable of transporting a large FPS with a dry weight exceeding 100,000 mt. This combination of events led to a rethink of contracting strategies of post-2014 sanctioned FPSs.

When Shell sanctioned Appomattox in July 2015, they had already committed to their traditional contracting approach of awarding segmented fabrication contracts for the hull (SHI), topsides (KOS) and integration (KOS). Their radical rework of the Vito development included the FPS contracting strategy. They awarded a turnkey EPC contract for the Vito FPS to Sembcorp following a round of competitive bidding. They repeated the contract strategy for the Whale FPS delivery but negotiated the contract with Sembcorp to take advantage of the efficiencies derived from the Vito FPS learning curve.

BP was the first major Operator to depart from the traditional contracting approach for a major FPS, when they sanctioned the Argos FPS. After several bidding rounds with multiple contractors, they awarded a turnkey EPC contract for the FPS delivery to SHI. The 70,000 mt FPS was dry towed from South Korea to the GoM on the BOKA Vanguard.

Chevron, however, elected to stay with the traditional segmented contracting strategy for the Anchor FPS: hull fabricated in South Korea by DSME, and the topsides fabricated and integrated by KOS in Texas.

Murphy (King's Quay) and Beacon (Shenandoah) chose a contracting strategy similar to that adopted by Shell for Vito and Whale, to take advantage of the efficiencies of building two similar hulls back-to-back. HHI was awarded an EPC contract for turnkey delivery of both FPSs.

The jury is still out as to whether a turnkey EPC contracting approach yields a superior commercial/operational result than the traditional segmented approach. The issue has been complicated by the pandemic that has caused unforeseen delays and distorted sanction to first production cycle times.

FUTURE TRENDS

In their 2021 OTC paper (OTC-31155) the authors identified three trends for the post-2014 tranche of FPS projects in the GoM. The first was the selection of the semisubmersible FPS as a universal host platform. The second was specifying leaner platforms, standardized specifications, and phased developments. The third was turnkey EPC contracting for FPS delivery. Taken together, these have enabled the more recent projects to be sanctioned at break-even costs in the \$35 to \$40/boe range.

The next tranche of GoM floating platforms will respond to two principal drivers:

- Continued focus on capex and opex reduction, and
- Reducing greenhouse gas emissions from operations

As we see it, these will be addressed by digitization, reduced manning, and decarbonization.

Digitization and Reduced Manning

Manning on an FPS is a significant contributor to capex, operating costs, safety incidents and greenhouse gas emissions. A substantial reduction in manning will reduce all the above. Reduced manning has been a particular focus of Operators in the North Sea and Western Australia for many years because of platform remoteness, harsh metocean conditions and high labor costs. By borrowing from rapid advances in automation, robotics, and digitization in other industries, they have reduced manning on several complex fixed and floating platforms. Several normally unmanned fixed platforms have been operating successfully for many years and some upcoming floating platforms will also be normally unmanned. An enabler has been industry collaboration with government and classification agencies who are also vested in improving safety, reducing emissions and driving new production.

The design of a minimally manned platform must use high reliability equipment to minimize inspection and maintenance, remote diagnostics for critical equipment, full control from a remote (preferably shore based) location, digital twins and special purpose walk to work vessels. Much of this technology is transferrable to/from offshore wind farms, that are normally unmanned.

As an example, Chevron, with partners Exxon and Shell recently (July 2021) sanctioned the Jansz-Io compression project offshore Western Australia. It includes the construction and installation of a 27,000 mt displacement normally unattended Semisubmersible platform in 1,350 m of water, powered by a 135 km long high voltage cable from shore. It houses electric drives, transformers and breakers for the subsea compression station on the seabed below, that will ship gas to the Gorgon LNG facility on Barrow Island.

Decarbonization

Energy transition is a reality as the world rebalances energy supplied by fossil fuels and energy supplied by renewables. The Oil and Gas industry is being pressed by governments, institutional investors, and other stakeholders to reduce its carbon footprint. Most Operators and NOC’s have expressed their intent to do so with some major Operators publicly declared their goals to achieve carbon neutrality by 2050. Fossil fuels will continue to be an important contributor to the energy mix, but greenhouse gas emissions related to oil and gas production will have to be substantially reduced.

Focusing strictly on an operational FPS, its largest source of greenhouse gas emissions is the power generation facility, followed by transport and resupply. Power generated on future FPSs will reduce emissions by some combination of

- Increasing engine efficiency
- Switching to cleaner burning fuels, and
- Using electrical power supplied from renewable sources

The implementation of these cleaner power options will mean added upfront costs but there will be value accretive savings from improved operational efficiencies, greater uptime, lower maintenance and carbon taxes. Many of these initiatives are underway, particularly in the North Sea, where electrification of offshore platforms with power generated from onshore renewable energy is being implemented. With rapid advances in floating offshore wind, where electricity generated from a single turbine could provide sufficient energy to power a medium sized FPS, and with costs becoming competitive with conventional power generation, it is quite possible that future deepwater FPSs in the GoM could have base power supplied by a floating wind turbine moored alongside.

Carbon emissions related to transportation and resupply will be substantially reduced by transitioning to minimally or normally unattended installations. Reducing manning and carbon emissions will be accretive to capex and opex reductions.

CONCLUSIONS

The dramatic oil and gas price drop in mid-2014 had a profound impact on deepwater developments in the GoM. Anticipating persistent low oil prices, the industry dialed back the number of sanctioned projects to about one a year. The focus shifted to greater capital discipline and shorter cycle times. The bar for project sanction was set at a breakeven cost of $40 per boe. Much of the early reductions came from capex deflation of the supply chain. A step change came from vastly improving drilling efficiencies and simplifying and standardizing designs and specifications of subsea and floating production systems. Further reductions were achieved by designing smaller, more efficient, repeatable platforms. By doing so, Operators gave up flexibility for future expansion and enhanced recovery. The Semisubmersible platform was selected for all seven of the post-2014 sanctioned developments.

Contracting strategy for FPS fabrication shifted from the traditional segmented approach to a turnkey EPC approach, in part to take advantage of Far East fabrication yards desperation for work. Discovery to sanction cycle times suffered as Operators reset and revised development plans to lower prices. An additional factor, in some cases, was developing high pressure Paleogene and Norphlet reservoirs that required qualifying drilling, completion and subsea equipment for these ratings and extensive appraisal programs. Unfortunately, sanction to first production cycle times increased relative to pre-2014 sanctioned projects because of the global pandemic that affected six of the seven projects causing delays up to twelve months.

The next capex and opex breakthrough will be from reducing or eliminating manning. Most operators have committed to or will be required to reduce carbon emissions for their next tranche of projects. Over the years, the offshore industry has shown great resilience in responding to oil price and external shocks by being flexible, adaptable and innovative. These qualities have been amply demonstrated by the post-2014 FPS projects sanctioned in the deepwater Gulf of Mexico.

Acknowledgements

The authors acknowledge the support of Richard B Offshore and KBR Consulting in preparing this manuscript. Thanks also to Bruce Beaubouef, at Offshore magazine; Jordan Barnes and Colin White at Rystad Energy and Rick Fowler for their input, relevant publications and feedback. Industry magazines (Offshore Engineer, Offshore Technology and Upstream) and conferences such as this SNAME Symposium and the Offshore Technology Conference, that provide industry with current and relevant information on field developments and technologies have been a wonderful source of material for this paper.

References

Shell Advances Deepwater Projects with Capital Efficiency, Re-Engineering; Offshore Magazine, November 2017

Khurana, Sandeep, D'Souza Richard et al, "Bringing Upstream Projects to Final Investment Decision", OTC 27949, Houston 2017

Aimin Wang et al, "Case Studies of Industrial Standardizing and Cost-Efficient Offshore Concept", OTC 27813, Houston, 2017

D'Souza Richard, Basu Shiladitya, "A Universal Field Development Approach for Advancing Stalled Gulf of Mexico Projects", OTC 28970, Houston, 2018

D'Souza Richard, Basu Shiladitya. "A Critical Assessment of Deepwater Gulf of Mexico Floating Platform EPCI contracting Strategies and Cycle Times", OTC 31115, Houston 2021

Turner William, "Floating Production Systems: What's next?", OTC 30715, Houston 2020

D'Souza Richard, Basu Shiladitya, "The Semisubmersible Floating Production System: From Argyll to Appomattox", OTC 30907, Houston 2020

Lagrange, Elgonda, "New Concepts for Normally Unattended Installation NUI-Design, Operation and Digitization", OTC 29367, Houston 2019

Francis Thomas, "Appomattox: The Energy Project that Defied the Odds", May 2019

Shenandoah gets the go ahead in the Deepwater GoM, Offshore Magazine, August 2021

Shenandoah Deepwater Oil Field, GoM, Offshore Technology, August 2021

Shell Sanctions Deepwater Whale Project in the GoM, Offshore Magazine, July 2021

Topsides and Hull Work moves Forward on Anchor, Whale, Offshore Magazine, April 2020

Chevron Hits Go on Anchor, Offshore Engineer, December 2019

Vito Deepwater Oilfield Development, Offshore Technology, April 2018

King's Quay Arrives in Texas, Offshore Magazine, September 2021

King's Quay FPS Facility, Offshore Technology, January 2020

Re-Engineered Mad Dog 2 Gets Greenlight, Offshore Magazine, January 2018

Mad Dog 2 FPU arrives in Texas, Offshore Magazine, April 2021

Shell Advances Deepwater Projects with Capital Efficiency, Re-Engineering, Offshore Magazine, November 2017

Nomenclature

20K	20,000 psi system
AC	Alaminos Canyon
boepd	barrels of oil equivalent per day
bopd	barrels of oil per day

bwpd	barrels of water per day
COSCO	China Ocean Shipping (Group) Company
DD	Dry dock
DSME	Daewoo Shipbuilding and Marine Engineering
EPC	Engineer-Procure-Construct
FID	Final Investment Decision
FPS	Floating Production System
FPSO	Floating Production Storage and Offloading
FPU	Floating Production Unit
GC	Green Canyon
GoM	Gulf of Mexico (US Exclusive Economic Zone)
HCM	Heerema Marine Contractor
HHI	Hyundai Heavy Industries
HLD	Heavy Lift Device, shore-based fixed 10,000 ton lifting system at KOS' Ingleside yard
I	Injection well
KOS	Kiewit Offshore Services
mmboe	million barrels of oil equivalent (m = millennium; 1,000)
mmscfd	million standard cubic feet per day
MSF	Modular Support Frame
mt	metric ton
MW	megawatt
NOC	National Oil Companies
OTC	Offshore Technology Conference
P	Production well
psi	pound per square inch
SHI	Samsung Heavy Industries
SLWR	Steel Lazy-Wave Risers
SSB	Subsea Boosting
SSCV	Semisubmersible Crane Vessel
TLP	Tension Leg Platform
WI	Water Injection
WR	Walker Ridge