SPE-187109-MS

Partial Processing: Produced Water Debottlenecking Unlocks Production on Offshore Thailand MOPU Platform

C.H. Rawlins, PhD, eProcess Technologies

This paper was prepared for presentation at the 2017 SPE Annual Technical Conference and Exhibition held in San Antonio, Texas, 9-11 October 2017.

Abstract

An operator in the western Gulf of Thailand installed two water management Partial Processing systems on their D and E Mobile Offshore Production Unit (MOPU) platforms to increase oil production. Electric submergible pump (ESP) wells connect to each MOPU for primary gas-liquid separation. The produced liquids, at ~90% water cut, are piped to a dedicated Floating Storage and Offloading (FSO) tanker for water separation and oil storage. The separated water is pumped back to the MOPU for re-injection disposal. High volumes of produced water created bottlenecks at the MOPU separator and the MOPU-FSO transfer lines (both directions), which then limited oil production. Additionally, substantial energy is spent on fluid heating to prevent wax formation in the flow lines to the FSO. Much of this heat is lost to the bulk water phase. In 2016, a Partial Processing system was retrofit on each MOPU process facility for bulk removal and treatment of produced water. Water removed at the production manifold is treated and transferred directly to the injection system, thus bypassing the primary separation, transfer piping, fluid heating, and FSO storage facilities. Water debottlenecking increases oil production by 80% and reduces the in-field transfer volume by 62%. This Partial Processing project is a step-change in field economics, allowing a three-month payback. Field layout, water cut issues, and the Partial Processing solution are detailed. Partial Processing has increased revenue and reduced operating costs at the facility.

Introduction

In mature oil basins – such as the North Sea, shallow water West Africa, and the Gulf of Mexico shelf – the ability to sustain oil production depends on managing an increasing volume of produced water. A common architecture for mature fields is the “spoke and hub” structure. In this arrangement, multiple wellhead platforms (WHP) connect to a centralized processing (CPP) or hub platform, with the latter forwarding fluids onshore for treatment. The infield transfer pipelines (WHP to CPP) and fluid processing equipment – three phase free water knock out (FWKO) separators and produced water treating (PWT) equipment – are designed for a fixed maximum liquid rate. Increased water cut from aging wells constrains flow within these lines and the separation systems, which in turn reduces oil production.

As an example, a processing facility designed for 50,000 BPD total liquids at 10% watercut handles 45,000 BPD of oil and 5,000 BPD of water. As the wells mature, the watercut may increase to 90%. If the processing facilities still treat 50,000 BPD of total liquids, then production becomes 45,000 BPD of water and 5,000 BPD of oil. To maintain oil production at 45,000 BPD, the amount of water treated increases to 405,000 BPD, which is a ten-fold increase in total fluids treated. The FWKO residence time in this scenario decreases from 5 minutes to 30 seconds, which is insufficient to provide effective oil-water separation. The field operator has a choice to restrict the overall fluid rate, which reduces oil production, or to retrofit equipment to debottleneck the facility. The production focus becomes a produced water management exercise.

Equipment retrofit onto existing platforms is hindered by the available footprint, weight limitations, utility constraints, and personnel availability, as well as capital cost. Adding new flow lines between the WHP and CPP is often cost prohibitive, and space and weight limitations prevent the installation of large scale separation equipment. Many of the satellite platforms are unmanned, so complex systems requiring operator attention are unwanted.

Compact, lightweight, simple technology to process the increased water fraction near the source – on the WHP for example – and debottleneck the flow lines and existing FWKO and PWT equipment is a desirable solution. The retrofit equipment must fit within the available footprint and remove the bulk of the water fraction for local treatment and discharge. Partial Processing technology, developed in the early 1990s, is designed for installation on the wellhead or hub platform to separate and treat bulk water and to debottleneck pipelines and processing (Ditria 1997; Sinker and Hess 1997). Based on cyclonic principles, which have the highest throughput-to-size ratio of any separating device, Partial Processing is compact, autonomous, requires minimal utilities, and offers consistent, flexible operation; therefore, it is well suited for retrofitting onto these facilities (Rawlins 2003). The increased field capacity created is a game changer – doubling to quadrupling oil production from a mature field within the existing facility space.

Partial Processing

The Partial Processing methodology seeks the bulk (not complete) removal of a throughput constraining phase from oil and gas production using compact processing equipment. Partial Processing technology is normally installed on facilities that have space or weight constraints, where traditional separation technologies will not fit. Fitting within or around existing process equipment, Partial Processing equipment maximizes the capability of an existing facility footprint. The constraining phase may be gas or water, and specific technologies are available to address each. The application detailed in this paper addresses produced water debottlenecking. Removal of the water constraint unlocks production potential from mature or marginal fields and has been shown to increase hydrocarbon production by 50-400+%.

History.

Development of the technology for produced water debottlenecking occurred approximately 10 years after the commercialization of the liquid-liquid (deoiler) hydrocyclone. The first commercial installation of deoiling hydrocyclones occurred in 1982 by Esso in the Bass Strait. During 1989-1990, individual deoiler liners designed for non-traditional oil-water separation were tested at the Conoco Grand Isle facility. This pilot test involved both pre-separating (bulk oil-water) and dehydrating (water removal from oil) applications (Ditria and Hoyack 1994). Around the same time, the first commercial dehydrating system for water removal from condensate was installed by Esso at the Longford Plant (Australia). This application reduced watercut in condensate from 10% to <1% using special liquid-liquid cyclone liners.

The next stage in development involved an eight-member joint industry project (JIP) conducted from 1996-1997 to test various compact gas-liquid and liquid-liquid technologies (Sinker and Hadfield 1997). Two pilot skids were built for the pilot field analysis. These two systems were tested in parallel from late 1996 to early 1997. The first skid, shown in **Fig. 1** (left), was tested at the Wytch Farm field in Dorset, UK. Three gas-liquid separation technologies were tested on this skid: an auger separator (originally

developed by Arco); a gas liquid cylindrical cyclone "GLCC" (developed by Chevron and the University of Tulsa); and the T-piece separator. The auger was shown to provide excellent compact bulk gas removal and simple operation while the GLCC showed more complicated operation but good gas-liquid separation. The T-piece was deemed too sensitive to process changes and not feasible for full scale operation. A two-stage liquid-liquid separation scheme, using a pre-separator hydrocyclone followed by a deoiler, showed that up to 90% of the water could be removed from a high water cut (85%) stream, with discharge water at <40 mg/l oil concentration. The control methodology and operating parameters were fully characterized for the system design. A second test was conducted for Thai Shell at the Lan Krabu field using a scaled down pilot skid (**Fig. 1**, right). Operation of the auger (bulk gas removal) followed by a two-stage liquid-liquid cyclone (bulk water removal and water treatment to discharge quality) was tested under a second set of field conditions. The operating envelopes for these technologies were further characterized.

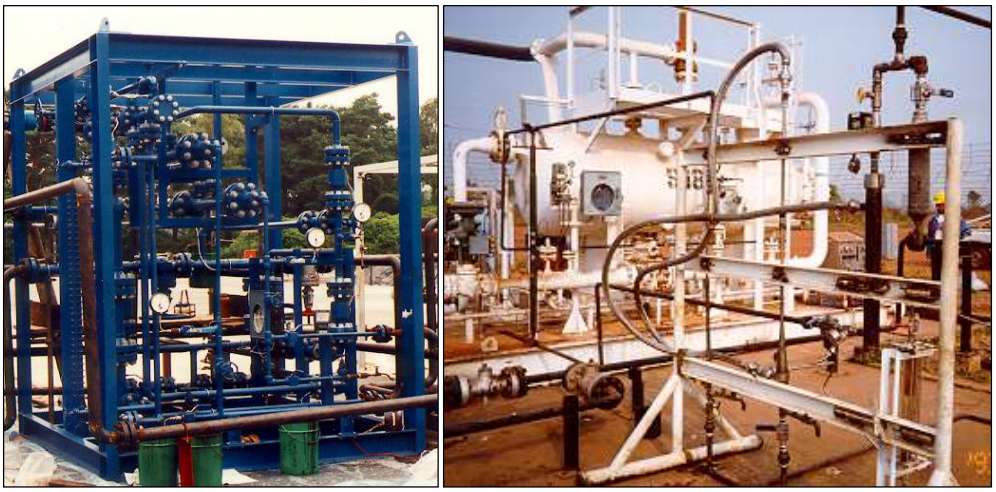

Fig. 1–Photographs of (left) the first Partial Processing skid undergoing the JIP test in 1997 at Wytch Farm in Dorset, UK, and (right) the second Partial Processing skid at Thai Shell Lan Krabu field.

Gaining traction with a new paradigm in facility operation required time to gain acceptance in the offshore industry, and the first full-scale produced water Partial Processing system was installed in 2012 by Apache on the Forties Bravo field (Sinker 2013). The system, shown in **Fig. 2** (left), comprises a two-stage liquid-liquid cyclone system (preseparator followed by deoiler) for treating 120,000 BPD of water. Operating at 80°C on 36 API oil, the water is treated to 10 mg/l oil content. Removal of the water constraining phase doubled oil production at this facility. A second system quickly followed in 2013, installed by Perenco on the Emeraud field as shown in **Fig. 2** (right). This system used three stages of produced water treating: a preseparator, deoiler, and compact flotation unit (CFU). Treating colder water (24°C) and heavier oil (22 API) required three stages to obtain the 30 mg/l discharge limit. A total of 80,000 BWPD were treated to quadruple oil production.

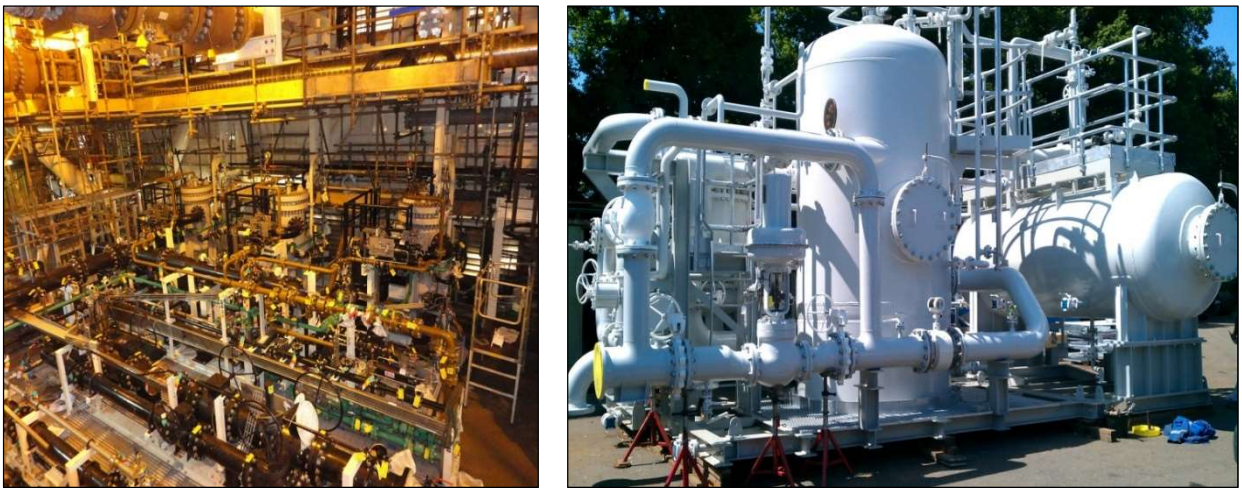

Fig. 2–Photographs of (left) the 120,000 BPD Partial Processing skid on Apache Forties Bravo (2012) and (right) the 80,000 BPD Partial Processing skid on Perenco Emeraud (2013).

Design Stages and Setup.

For water constrained systems, the most significant payback comes from the removal of bulk water as far upstream as possible. High watercut wells are combined into a discrete manifold that may be part of or all the field production. The Partial Processing system is located on this manifold, upstream from the existing process equipment. Debottlenecking at this point opens capacity in the flow lines, transfer piping, and processing facilities. The Partial Processing skid can be installed on unmanned platforms with limited utilities and space and weight constraints.

Bulk water removal and treatment may have two or three stages. Stage one is preseparation and involves bulk water removal from the multiphase flow stream (Ditria and Hoyack 1994). A specially designed liquid-liquid hydrocyclone (preseparator) removes a bulk portion (60-95%) of the water from the flow stream. Compared to a traditional deoiler hydrocyclone, the preseparator has a larger diameter, lower swirl factor (e.g., function of geometry and pressure drop), and larger reject port. The preseparator provides a simple bulk oil-water split and does not need the intense separating forces required in a deoiler, hence the larger diameter and lower swirl. A preseparator may have a main body diameter of 50-75 mm with a straight tapered cone, compared to the 30-40 mm diameter and concave tapered cone in a deoiler. The larger reject port (i.e., 3-5 mm compared to 1.5-2.0 mm in the deoiler) is required to allow both the high oil split and free gas to pass into the reject stream. A preseparator can handle up to 40% free gas volume, all which must report through the reject port with the oil stream.

Next, the removed bulk water passes to the deoiler hydrocyclone, which operates in a standard produced water treating mode. For example, the preseparator will reduce oil content from 10% to 0.2%. The deoiler will take the 2000 ppm oil down to or near discharge quality (20-50 ppm), depending on oil properties, pressure drop, and temperature. The deoiler operates at three to five times the pressure drop of the preseparator and is the primary consideration in energy consumption (Sinker 2007).

Tertiary treatment stage is optional and is used for difficult separation (i.e., cold fluids with heavy oil) or very stringent disposal requirements (i.e., low oil-in-water for enhanced oil recovery injection). This stage uses a CFU for both degassing and oil polishing. The CFU removes gas effervescing from solution after the deoiler (which can be 5-10% of the gas void fraction) and uses that gas to float the fine oil droplets. The target oil-in-water is 10-20 ppm with tertiary treatment.

An example schematic for produced water debottlenecking is shown in **Fig. 3**. In this scenario, producing wells have curtailed production due to high backpressure in the manifold. Manifold pressure increases due to high fluid throughput needed to maintain oil production at large watercut. Marginal or very high watercut wells are shut-in to reduce load on the manifold, and new wells cannot be brought online. Overall production is water continuous (>60% watercut) with low gas production (<40% GVF). Water breakthrough has also resulted in increased sand reporting to the facilities.

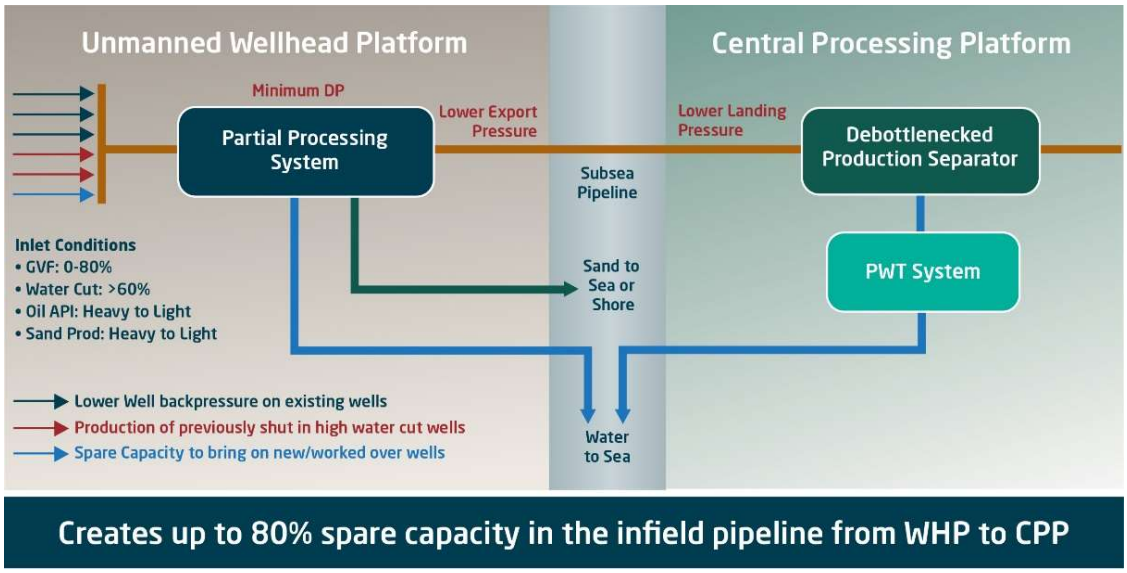

Fig. 3–Schematic of an example design, showing the location of a Partial Processing system on an unmanned wellhead platform. The benefits include reducing well backpressure, recovering production from shut-in wells, reducing export and landing pressure (pumping requirement), and debottlenecking the production separator and produced water treatment system.

A Partial Processing system is installed on the unmanned WHP to unload the bulk-produced water that is constraining processing and production. A bypass valve is installed after the Partial Processing offtake to push fluids to the system. The Partial Processing system has a two-stage liquid treating process. Stage one is a preseparating hydrocyclone to provide bulk oil-water separation. This is followed by a deoiler hydrocyclone to provide oil removal from the separated water. If required, solids are removed by a desander hydrocyclone. The preseparator reject stream is sent back into the production line (after the bypass valve), while the deoiler reject goes to the drains. Water is disposed, either overboard or through injection. The oil phase, with a lower watercut, continues to the flowline transfer to the CPP, where traditional separation and produced water treatment occurs. This methodology is also being investigated for subsea processing (Gul et al. 2014).

A mass balance example for the above scenario shows the capacity increase for the production flowline. Using 50,000 BPD total production at 90% watercut shows that only 5,000 BPD of oil is being produced. A Partial Processing system is installed to treat 40,000 BPD of water (89%) of the total. This water is removed from the production line and treated for disposal. The new production rate is 10,000 BPD at 50% watercut. Eighty percent of the fluid volume is removed from the production line, which enables the existing facility to operate more efficiently and allows more oil to be added from new, cut-back, or shut-in wells.

Design Guidelines.

To debottleneck water constrained systems effectively using Partial Processing technology, several design criteria must be met. The first is evaluation of the amount of free gas. If the gas void fraction is >40%, then an initial gas-liquid device must be installed to lower the content (i.e., bulk gas removal). A gas-liquid separation device must also be used if the inlet flow regime is severely (gas) struggling to smooth out the surges. The Partial Processing JIP tested several technologies to provide compact gas-liquid separation and found that the auger separator provided suitable duty. Most mature, high watercut wells, however, do not have a high gas fraction and the production flow can be sent directly to liquid treatment.

For effective bulk water removal from liquid flow, the production stream must have a continuous water liquid phase. In general, if the watercut is >60%, water will be the continuous phase; however, site specific fluids must be characterized to confirm. It is of primary importance to ensure the continuous phase matrix

has low viscosity. The water phase is effective at moving oil droplets and blobs because the aqueous matrix has a low viscosity. Conversely, moving water droplets through oil can be difficult if the oil has a high viscosity.

Chemicals, such as polymers or emulsions that increase the water phase viscosity, will degrade liquid-liquid separation performance. The effects of these chemicals or emulsions must be neutralized to restore separation. Clarifier chemicals can be used to break emulsions and should be injected prior to the first stage of liquid-liquid separation. The highly turbulent confined swirling flow regime in the cyclone vortex enhances mixing of the clarifier chemicals and allows their effect to be realized in the second stage of oil-water separation.

Field Layout

The Songkhla Basin is located along the western margin of the Gulf of Thailand, offshore from the province of the same name. The Bua Ban North Field was discovered in late 2011 and lies approximately 10 km offshore. Hydrocarbons are produced from an offshore block G5/43 in 18-20 meter water depth. As of September 2012, Bua Ban North was producing 18,000 BOPD from a total of 26 wells, with water disposal to two injection wells. Production facilities D & E each have a dedicated MOPU-FSO combination, as shown in **Fig. 4**.

Fig. 4–Photograph of D MOPU and FSO.

Process Overview.

Figure 5 shows a schematic of the existing production and processing systems. The wells are ESP driven and produce to the unmanned MOPU through a production manifold. Wellhead flowing pressure and temperature are 75-80 psig and 75°C, respectively. D and E facilities produce ~40,000 BPD and ~60,000 BPD of liquids, respectively, at approximately 90% watercut (~10,000 BPD of 26-28 API oil in 2015). Primary separation occurs in a two-phase gravity separator (on the MOPU) with gas going to the flare. The combined liquids (oil + water) are sent to a surge vessel, then heated, and pumped to the FSO. The liquids are heated (>60°C) to prevent wax formation in the infield transfer line. Oil and water separation occurs on the FSO by gravity settling. The oil is stored for offloading, while the water is returned to the MOPU via a separate infield transfer line. Biocides and oxygen scavengers are added to the water prior to injection into the disposal well.

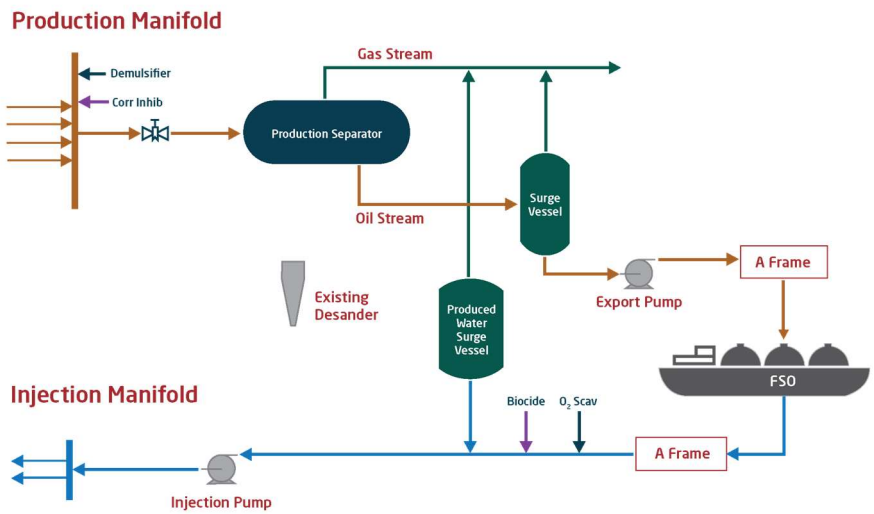

Fig. 5–Schematic of the process system prior to installation of the Partial Processing equipment.

Production Challenge.

As of early 2015, each MOPU process system was operating at full capacity. While fluids production had increased, oil production had decreased due to increasing watercut. An infield drilling campaign was planned to restore oil production and bring on new ESP wells; however, the facilities had no capacity for the additional production. The primary bottlenecks were two-phase separation on the MOPU and the infield transfer lines to/from the FSO.

The challenge was to increase total liquids production from ~100,000 BPD to >180,000 BPD (at 90% watercut), which should yield an 80% increase in oil production (e.g., from 10,000 BPD to 18,000 BPD). The additional water produced must be separated on the MOPU and treated to <50 ppm oil-in-water quality for local injection disposal. The MOPU did not have space for conventional separation and water treatment, so the retrofit equipment must be compact and highly automated to operate in an unmanned environment.

Debottlenecking Design Solution

A Partial Processing system solution that would meet all the design criteria was proposed in early 2015. A two-stage liquid-liquid hydrocyclone system could meet the space and operability requirements while providing the desired water separation and treatment levels.

Single Liner Field Trial.

Since this technology had not yet been employed in Southeast Asia or with the operator, an on-site field trial was proposed to prove the concept. Using a portable kit, a two-stage single liner test was conducted on the MOPU. The kit consisted of a single preseparation hydrocyclone followed by a deoiler hydrocyclone. Combined throughput of the kit was 190-200 BLPD. The equipment was tied into the production manifold via flex hoses and various flowrates were tested, along with effects of a water clarifier and de-emulsifier chemicals.

The testing identified the performance envelope and showed that a two-stage hydrocyclone system would remove and treat >90% of the water directly from the manifold. The preseparator reduced the oil content from ~10% to 100-300 ppm, while the deoiler further reduced the oil content to the 50-ppm target level. Photos of the field trial sample are shown in **Fig. 6**. These results were achieved using a low-pressure decrease (<75 psi total for both stages) and without the use of clarifier or emulsifier chemicals. Production watercut was reduced from 90% to 30-50%.

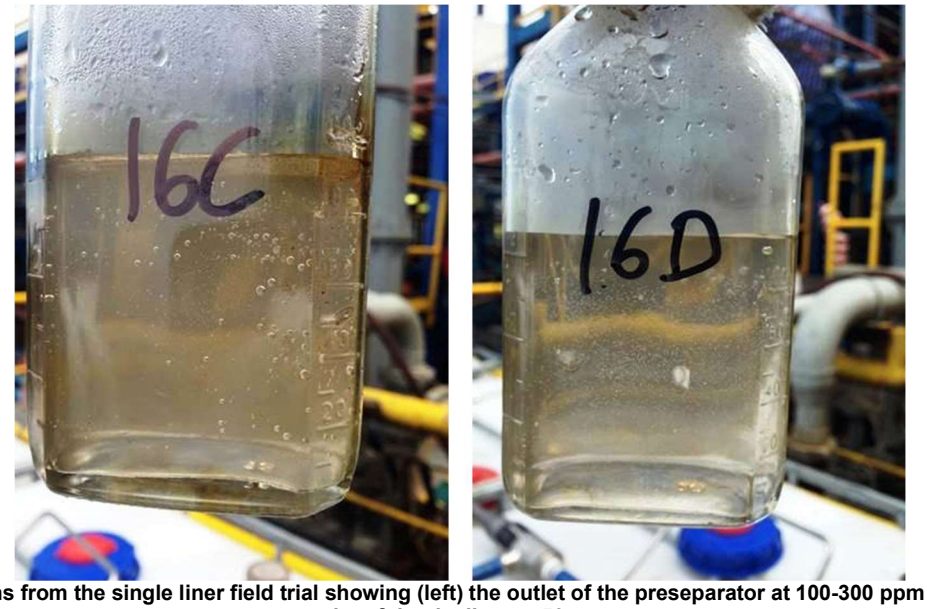

Fig. 6–Photographs from the single liner field trial showing (left) the outlet of the preseparator at 100-300 ppm oil and (right) the outlet of the deoiler at ~50 ppm.

Partial Processing Integration.

The success of the field trial led to the design and integration of a full-scale system for each MOPU. **Figure 7** provides a flow schematic showing the retrofit location of the Partial Processing system and other changes made to the MOPU for liquids processing. A dedicated two-stage hydrocyclone skid consisting of 1x100% preseparator and 1x100% deoiler was located to receive fluids directly from the production manifold. The target total liquid production on D was 80,000 BPD, of which 55,000 BPD would be treated by the Partial Processing system (69%), with the corresponding flows on E at 100,000 BPD and 75,000 BPD (75%), respectively. The watercut levels remained nearly constant on both MOPUs at 88-90%, and the Partial Processing skid was designed to handle up to 85-96%.

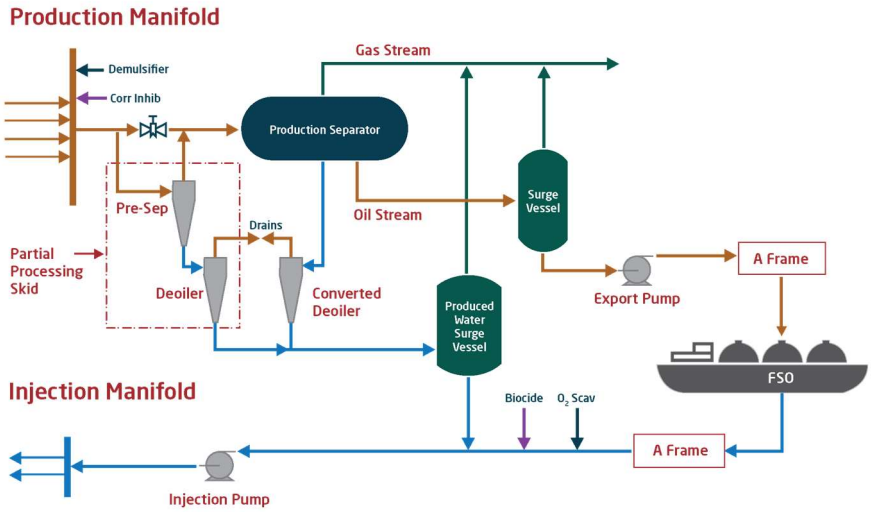

Fig. 7–Schematic of the process system showing integration of the two-stage Partial Processing system before the production separator on the MOPU.

Fluids from the manifold were directed to the Partial Processing skid with bulk water removal (~90%) occurring in the preseparator. The reject stream, containing ~90% oil plus any gas, was returned to the manifold downstream of the diversion valve to continue to existing facilities. The pressure decrease from the inlet-reject is 23 psi, which is the same pressure decrease as the diversion valve. The separated water

is treated by the second-stage deoiler operating at a 30-psi pressure drop (inlet-water), with water going to a surge (degasser) drum and the reject stream going to drains. The manifold fluids (reduced from 90% to 50+% watercut) continued to the existing gravity separator.

A retrofit was made to this vessel to allow for three-phase separation that provided additional water handling. The removed water was treated by a deoiler vessel that was converted from an existing desanding hydrocyclone vessel. Of the production water stream, 75% is removed and treated by the Partial Processing skid, 10% is removed and treated by the production separator and retrofit deoiler, with the remaining 15% reports to the FSO. The final transferred liquid stream was maintained at a minimum 50% watercut to prevent flow assurance issues when transferring to the FSO. All treated water is disposed by injection on the MOPU.

Skid System Design.

Upgrade of the water treating capabilities on each MOPU consisted of fabricating new Partial Processing skids and converting an existing vessel. While the main Partial Process skid was in fabrication, the first debottlenecking step was to convert an existing desander on each MOPU into a deoiler. This work could be done rapidly, as the vessels and piping were already installed, and only the liners needed to be modified. The desanders were installed within the original processing facility to remove produced sand and solids from the well fluids. Later production showed negligible solids production, so the desanders were removed from service.

The desanders were a standard multi-liner design with vertical vessels (D had a 660 mm OD vessel with 31 liners, and E had a 762 mm OD vessel with 43 liners). The desander liner plates in each vessel were welded in place, and the plate-plate distance was shorter than that required for standard deoiler liners (i.e., 381 mm vs. 1038 mm). Retrofit of deoiler liners first involved modifying the location and diameter of the mounting collars on the liners. These were used to seal the liners into the plate holes with O-rings. The deoiler liner top collar was changed to fit the existing desander bottom plate, and the tailpipe collar was moved further from the tailpipe end and changed to fit the existing desander top plate. In this manner, the liners were installed upside down. A short-flanged spool piece was inserted between the desander top flanges to permit room for the extended deoiler liner tailpipe. In this manner, with the liners inverted, the vessel inlet stayed the same, but the old accumulator section became the reject collection while the old overflow became the water outlet. This retrofit allowed early treatment of 7,700 BPD and 10,600 BPD on D and E production facilities, respectively.

Fabrication of the two-full size Partial Processing skids was completed within 16 weeks. The general layout of the skid design is shown in **Fig. 8**. Both the preseparator and deoiler vessels are oriented vertically to meet space requirements and to handle free gas. Vertical orientation prevents free gas build-up in the inlet chamber (primarily an issue with the first stage unit). The preseparator and deoiler vessels are 1200 mm and 1050 mm in nominal diameter, respectively, and both were built to a 150# rating. On-skid piping contains isolation valves, sample ports, pressure safety valves (fire case), and local pressure instrumentation. In addition, the control system monitors pressure differential (inlet-reject and inlet-underflow) for both stages. Reject pressure is set manually for both stages, and flow control is set on deoiler underflow. Control actions are maintained by an on-skid HMI panel, which has a remote signal interface to onshore operations. All vessel and piping components are carbon steel, with 316L stainless steel liner plates and duplex stainless steel preseparator and deoiler liners.

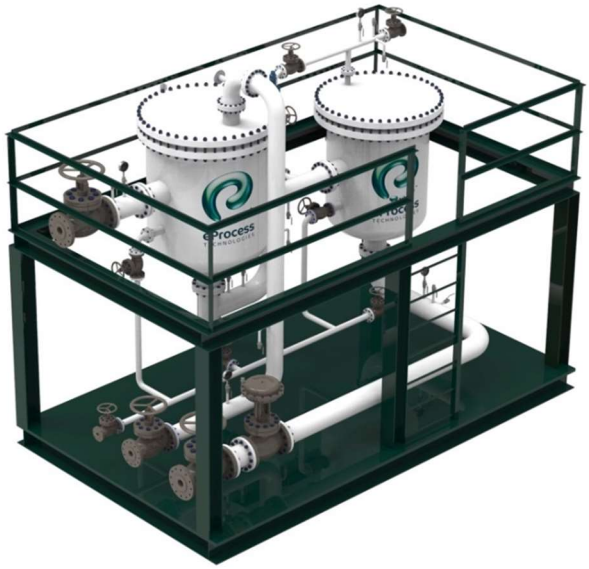

Fig. 8–Graphic showing configuration of the Partial Processing skid.

Each MOPU had an available footprint for the skid at 8.8 m length by 3.3 m width. The installed skid, an example shown in **Fig. 9**, had a final footprint of 5.0 m length x 2.5 m width, thus fitting into <50% of the allotted area. The dry and operating weight of each skid is 14.5 and 16.0 tons, respectively. Access to the vessel components is through a platform located at the top flange of the vessels.

Fig. 9–Photograph of the two-stage Partial Processing skid installed on the MOPU platform.

Project Gains

The primary goal of the water management retrofit was to allow increased fluid handling, which increased oil production from 10,000 BPD to 18,000 BPD – an 80% increase in hydrocarbon production. The reduction in operating expenditure (OPEX) proved to be as valuable as a production increase, and the entire project realized a three-month payback.

Table 1 lists the specific benefits achieved in fuel, power, chemicals, and storage. The removal of bulk water from the production stream reduced backpressure in the infield transfer lines, corresponding to a 73% reduction in pump power requirement to move liquids from the MOPU to the FSO and a 60% reduction to move the water back for disposal. Lower power use means decreased fuel consumption on

each facility. In addition, reducing the pipeline pressure also lowered the manifold pressure, which then lowered the pressure at the wellhead. Thus, the ESP wells generated more oil for the same input energy.

Table 1. OPEX Reductions

MOPU Fuel	Fluid pumping from the MOPU to the FSO reduced by 73%
MOPU Power	Lower backpressure on ESP wells – more oil for the same input energy
FSO Fuel 1	Fluid heating reduced – most significant reduction
FSO Fuel 2	Fluid pumping from the FSO to the MOPU reduced by 60%
FSO Storage	Less fluid storage required – potentially reduced size of the FSO
Chemical 1	Decreased biocide
Chemical 2	Decreased de-emulsifier
Chemical 3	Decreased oxygen scavenger
Equipment Expense	No extra pumps required for increased production

All liquids transferred from the MOPU to the FSO are heated to prevent cooling of the crude wax below the precipitation temperature in the transfer line (the piping lies below the sea surface). Wax formation in this piping would lead to flow assurance issues. The reduction of watercut from 90% to 50% removed 55,000 BPD and 75,000 BPD from D and E production facilities, respectively, which does not need to be heated. Less heat is lost to water, and the liquid heating reduction proved to be the largest cost savings.

A net chemical use reduction was also realized. A lower quantity of water for treating on the FSO required less de-emulsifier. Water transferred back from the FSO had to be treated with biocides and oxygen scavengers before injection disposal. Bypass of the bulk water directly to injection reduced the amount of water subjected to FSO treatment, thus reducing the amount required of both chemicals.

Two other benefits are still being quantified. The reduction in bulk water to the FSO requires less overall volume in the storage-separation hold tanks, and there is potential to reduce the size of the FSO. A future drilling campaign is planned to add production with new wells and pumps. By debottlenecking the facilities, the existing wells/pumps can be exploited more to add that additional production and the added drilling campaign may not be needed.

Summary

Partial Processing technology has a well-proven history and is shown to be effective for small and large scale offshore operations, and for cost-sensitive regions, such as West Africa and South East Asia. The equipment is compact, robust, applicable to heavy oil and light crude, and can be installed on unmanned facilities with limited utilities. The systems do not have to be pressure hungry and can be installed on artificial lift wells, as shown on D and E platforms.

Success in using Partial Processing equipment depends on several factors. Well-proven technology, in this case liquid-liquid hydrocyclones, with a well-experienced company is key. However, the other factors that are just as important are knowledge of process integration, the capability to design proper control philosophy, experience in treating a wide variety of fluids, and the wisdom to select the correct application. Part of the correct application is process factors, but equally critical is working with proactive operators to champion the technology. As is shown with the D and E production facilities, Partial Processing can increase mature field production by game changing double-digit factors.

References

Ditria, J. 1997. Design Basis of a Compact Production System for Minimum Size and Maximum Flexibility. IBC Conference on Production Separation Systems, Houston, TX, USA. November 17-18.

Ditria, J.C., Hoyack, M.E. 1994. The Separation of Solids and Liquids with Hydrocyclone Based Technology for Water Treatment and Crude Processing. Paper 28815 presented at the SPE Asia Pacific Oil & Gas Conference, Melbourne, Australia. November 7-10.

Gul, K., Grave, E., Wingaarden, H., Tienhaara, M. 2014. Performance Testing of a Two-stage Produced Water Deoiling System for Subsea Applications. Paper 170782 presented at the SPE Annual Technical Conference and Exhibition, Amsterdam, The Netherlands, October 27-29.

Rawlins, C.H. 2003. The Case for Compact Separation. Journal of Petroleum Technologies, May. 77-79.

Sinker, A., Hadfield, D. 1997. Final Report for the Design, Construction, and Field Testing of a Wellstream Partial Processing System Incorporating Krebs Petroleum Technologies Gas-Liquid and Liquid-Liquid Cyclonic Separation Technology. Unpublished, confidential JIP report.

Sinker, A., Hess, M. 1997. Applying the Compact Separation Methodology to Heavy Oil Separation. Presented at Heavy Oil Field Development, Aberdeen, UK. September 29-30.

Sinker, A. 2007. Produced Water Treatment Using Hydrocyclones: Theory and Practical Applications. Presented at the 14th Annual International Petroleum Environmental Conference, Houston, TX, USA.

Sinker, A. 2013. Field Water Debottlenecking Using Wellhead Partial Processing Technology. TUV NEL Produced Water – Best Management Practices Conference. Kuala Lumpur, Malaysia. November 20-21.

SI Metric Conversion Factors

°API	141.5/(131.5+°API)		=	g/cm³
BPD	x0.158 97	E+00	=	m³/d
°F	(°F-32)/1.8	E-01	=	°C
inch	x2.54	E+00	=	cm
psi	x6.894 757	E+00	=	kPa

Author Biography

C. Hank Rawlins (hrawlins@eprocess-tech.com) is the Technical Director for eProcess Technologies in Houston, TX, USA. He has 25 years' experience in research and process engineering in the upstream oil and gas industry. He is responsible for development programs in facilities sand management, produced water treatment, and compact separations systems. Dr. Rawlins has fifty-four publications and is an active member of SPE, where he served as a past chair of the Separations Technology Technical Section (STTS). He holds a PhD in metallurgical engineering from Missouri S&T University and is a registered engineer in the state of New York.