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Treating Produced Water on Deepwater Platforms: Developing Effective Practices Based Upon Lessons Learned

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Abstract

Deepwater platforms in the Gulf of Mexico and elsewhere are transitioning from dry oil or low water cut production to higher water cut production. These platforms face unique challenges resulting from water and crude incompatibilities, high salinity, no advance characterization of the water treatment issues, and a lack of space for water treatment equipment. The lessons learned by deepwater operators can provide an experience base upon which future operators can draw to assist them with projects to debottleneck and/or improve produced water treatment on their deepwater platforms and FPSOs.

Equipment and practices which have worked well and not worked well for treating produced water on floating platforms are described and the issues pertinent to the deepwater operation of this equipment are identified. The impact of the deepwater operating environment on produced water treatment systems is discussed. Platform motion, high shear across control valves or pumps, production from multiple reservoirs, process recycle streams, and the use of hydrate inhibitors or other chemicals all impact the design of a water treatment process and the operation of water treating equipment. The experiences detailed in this paper are intended to help engineers avoid the process design and equipment selection issues which were problematic for earlier deepwater operations.

Introduction and Background

On floating deepwater facilities, separator vessel residence time is typically short due to the high cost of space and weight. During the design phase of such facilities, there is usually little knowledge of the produced fluid properties. Even in the best case where water and oil samples have been taken and carefully analyzed, such samples will not have contaminants with representative particle size distributions which exist in the produced fluids during actual production. In addition, as oil and/or water production rates increase during the life of the field, or as new fields are brought on, the fluid properties may change dramatically as a result of fluids from new fields being brought onto the platform via subsea tie-backs. Thus, designing oil/water separation systems for deepwater facilities is challenging.

It would be impractical to design a system that provides for all contingencies in future rates and fluid properties. Therefore, what is needed, and the lessons learned that are discussed here, are judicious design decisions that build in flexibility with minimal space and weight requirements. In other words, the original system design must have sufficient built-in flexibility to allow debottlenecking and capacity increase with minimal facility modifications.

This paper relies on the experiences of platforms in the Gulf of Mexico, South America, and the north Atlantic. However, the lessons are generic and should apply to deepwater facilities in most geographic locations. Some specific experiences from Shell E & P operations in the Gulf of Mexico (GoM) are discussed by way of example. The location of Shell's deepwater platforms in the GoM is shown in Figure 1. Bullwinkle was the first platform to begin production (1989) and this platform now processes fluids from a number of subsea and primary fields. Auger came on line in 1994 and currently handles production from a total of six fields. Mars receives production from ten sands.

The major issues relating to water treatment discussed here are: fluid compatibility, equipment design, process design, and technology selection. A Process Flow Diagram which is a composite of the systems on the various GoM platforms is shown, for illustrative purposes, in Figure 2.

Figure 1. Shell Deepwater assets and locations in the Gulf of Mexico. NaKika is operated by BP.

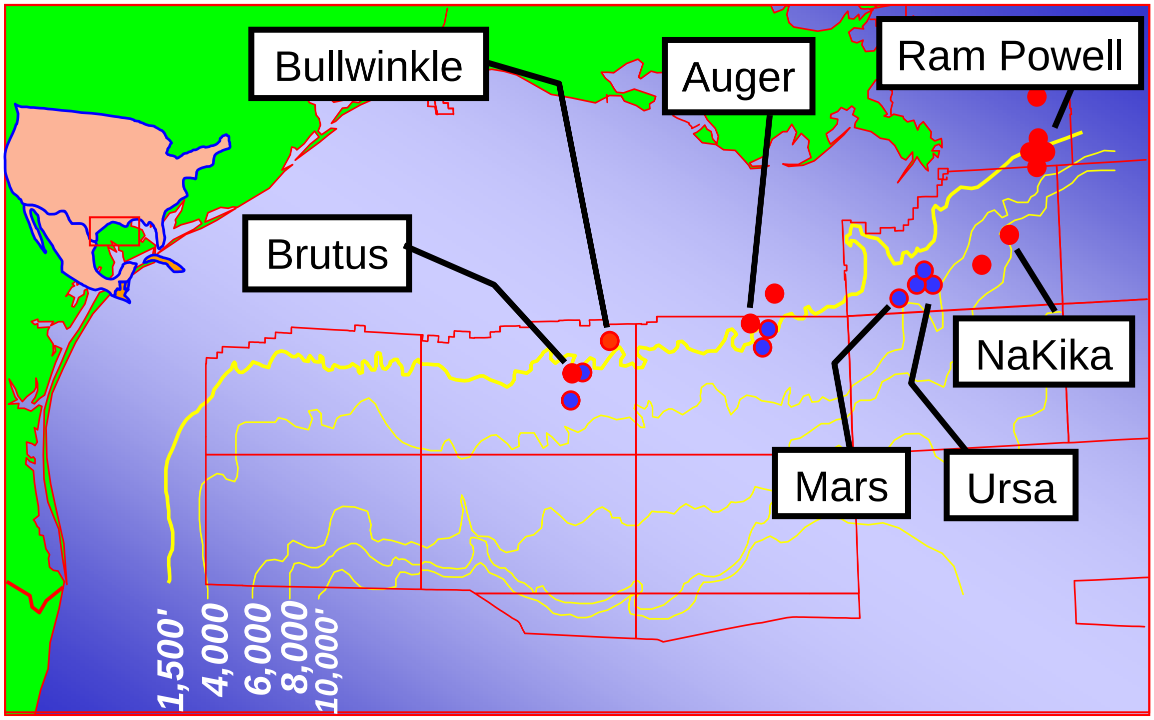
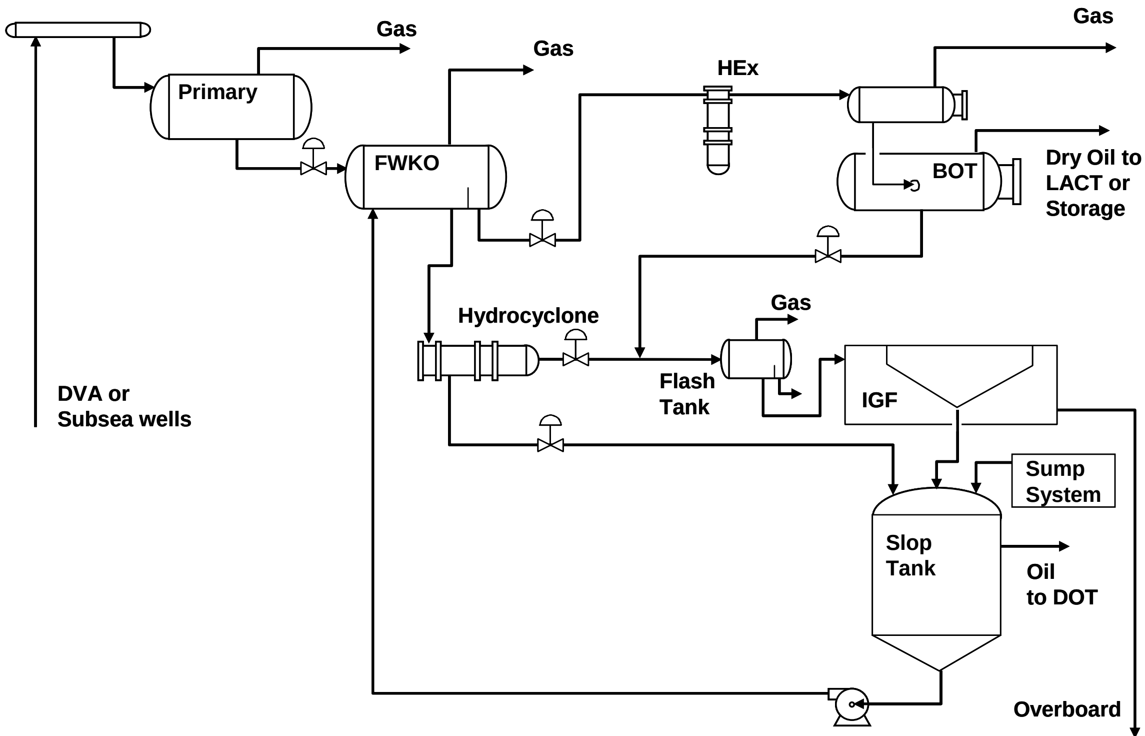


Figure 2. A composite Process Flow Diagram is shown which represents the essentials of the process systems installed on the Shell platforms in the GOM.



Most production in the Shell deepwater portfolio is driven by strong compaction forces, by moderate aquifer support, or a combination of both. For the most part, natural water drive is not significant in the deepwater GoM. Thus, as shown in Figure 2, most facilities are designed with two-phase primary separators. The producing sands are mostly unconsolidated turbidite sheets with a range of channel and fault densities from zero to a high degree of compartmentalization. The sands are highly compressible, in the range of 50 to 80 micro sips, so many reservoirs maintain pressure through compaction. Avoiding sand production is a major issue in well completion design and is for the most part successful [1]. Nevertheless, production of a small amount of very fine sand (1 micron or less) is typical. The fine sand has an impact on produced water quality as discussed below.

While individual wells have attained high water cuts, overall water production on any given platform has remained relatively low. As shown in **Table 1**, current water cuts are in the range of 10 to 30 %. But water cuts have been increasing steadily, and are likely to continue to increase for reasons such as the implementation of waterfloods, the implementation of improved hydrate flow assurance strategies, and artificial lift that will allow the continued production of subsea systems to relatively high water cut [2].

Table 1. Summary of Shell GoM Deepwater Platforms and their Current Production

Platform	Location	First Oil (date)	Oil Production (BOPD)	Water Production (BWPD)
Bullwinkle	Green Canyon 65	1989	64,000	24,000
Auger	Garden Banks 426	1994	56,000	30,000
Mars	Mississippi Canyon 807	1996	155,000	20,000
Ram-Powell	Viosca Knoll 956	1997	80,000	20,000
Ursa	Mississippi Canyon 810	1999	96,000	23,000
Brutus	Green Canyon 158	2001	40,000	8,000

Solids in Produced Water and Fluid Compatibility

A key component for designing a water treatment system and/or for understanding the manner in which a system does or does not effectively remove contaminants, is having an understanding of the physical and chemical character of those contaminants. Produced water solid contaminants come from three sources: scale mineral precipitates (often resulting from the mixing of incompatible waters, or a change in process conditions, such as a pressure or temperature change), asphaltene precipitation (from the mixing of incompatible crudes or from mixing condensates with crude), and formation fines.

Water compatibility can generally be predicted by the use of commercially available software [3]. The input to these programs includes the geochemical analysis of the water, the produced gas analysis, and process conditions (temperature and pressure). In determining whether or not any given water or mix of waters will have a scaling tendency, it is important to saturate the water with the gas composition at the conditions of specific points in the process, e.g., the FWKO, the point of mixing, etc. If this gas saturation is not taken into account, then the scaling tendency of the water cannot be correctly predicted. Predicting scale tendencies based solely on the laboratory analysis of a produced water can be misleading.

Figure 3 shows how the barium content varies for several water sources in the deepwater GoM. Based upon this variability, it can be expected that a well tailored scale inhibitor program will be required. Noting that scale inhibitors do not prevent the precipitation of scale, only its deposition onto surfaces, one can still expect that the cleaning of incompatible waters will require the use of induced gas flotation (IGF), media filtration, or both to capture the oleophilic scale mineral solids.

The Mars platform receives fluids from ten sands, as summarized in **Table 2**. For the most part, the aromatics content of the crudes are high, so the expectation is that the probability for asphaltene precipitation when mixing crudes will be low. Two exceptions would be the presence of either the Terra Cotta or the Ultra Blue crudes as the aromatics to asphaltenes ratio are lower for these crudes. Also, there is evidence that the Pink crude is bio-degraded, indicating the possible presence of organic acids which could impact water treatment.

Despite the expectation (and experience) that asphaltene precipitation from the subject crudes is unlikely to be an issue, the potential remains for the precipitation of asphaltenes when a condensate is mixed with the crude. For this reason, the mixing of a crude and a condensate is best delayed until both are fully dehydrated.

The third source of solids in produced water is fines which migrate from the formation. These fines are more often than not hydrophilic in nature and thus not a source for residual oil in the water. They can, however, impact total suspended solids (TSS) and turbidity. Also, they can have a tendency to become partially oil wet from the presence of waxes and asphaltenes. Oil-wet fine sand particles tend to stabilize interface emulsions in separators which then results in a degradation of produced water quality. They can also preclude the application of coalescing equipment or media due to the tendency to plug such equipment. Typically the solids content is not sufficient to justify installation of desanding cyclones which, because of the small particle sizes involved, may be of marginal value. Removing these solids generally requires the use of a high MW flocculent polymer for flotation. When these solids are present, then the regular draining of interface emulsion to a separate slop treatment system may be required if water quality is to be maintained.

Figure 3. **The Barium content of water from multiple deepwater GoM sources varies by nearly two orders of magnitude, indicating the potential for solids precipitation from mixing waters.**

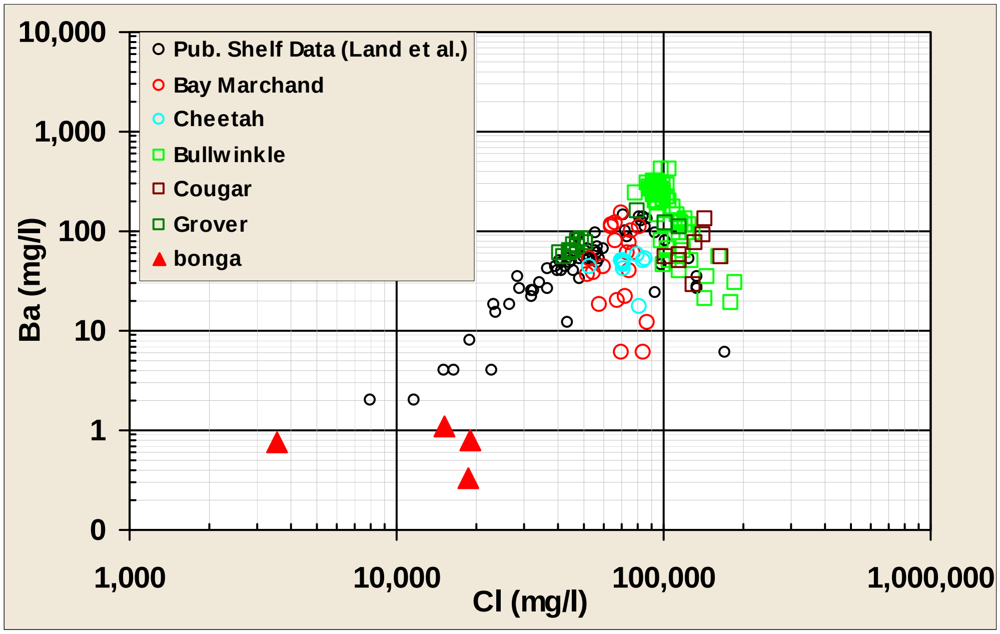


Table 2. Fluid Properties for the Mars Reservoirs

RESERVOIR	DEPTH	API	Sat.	Aromatics	Resins	Asphaltenes	Atomic Sulfur (wt %)	ACID No.
Lower Pink	11,821	19.6	23.1	58.4	15.2	3.3	2.5	
Pink	13,036	17.3	21.0	61.6	14.0	3.4	2.7	4.35
Lower Green	16,287	31.5	40.9	47.6	9.5	2.1	1.8	0.34
Ultra Blue	16,301	24.6	41.3	37.5	13.9	7.3	2.6	
Orange	16,550	24.4	27.4	54.5	14.5	3.6	2.4	1.00
Upper Green	16,910	23.5	24.3	55.6	14.9	5.2	2.6	
Magenta	17,610	24.2	28.1	54.1	13.5	4.3	2.6	0.61
Violet Ic	18,419	22.5	25.0	59.3	12.6	3.1	2.7	1.20
Lower Yellow	18,476	27.6	30.8	51.8	15.1	2.2	2.2	
Terra Cotta	18,476	22.1	25.2	50.2	13.4	11.2	2.8	0.95

Oil Droplet Sizes in Produced Water

Because of the low water cut on most deepwater platforms, making the primary gas/liquid separation in 2-phase vessels is logical. These vessels can be relatively small, with only 1 – 3 minutes liquid residence time, and gas is flashed at a relatively high pressure, thus minimizing compression costs. The problem for water treatment comes as the oil/water mixtures are transferred with a significant pressure drop to a lower pressure separator or FWKO. These pressure drops can be in the range of 200 to 600 PSI which shears water into small droplets in the oil and shears oil into small droplets in the water. As shown in **Table 3**, the oil droplet size generated by a 400 PSI pressure drop from an HP separator to a FWKO is small with a median on the order of 20 microns and a minimum size as small as 2 microns. An on-line survey of the oil droplet size distributions at various locations downstream of the 400 PSI pressure drop on one platform showed that the droplet size distribution remained essentially unchanged throughout the water treatment system. Thus the challenge was to select technology capable of recovering these small oil droplets from the produced water.

Table 3. **The oil droplet size distribution after a 400 PSI pressure drop had a median size of 20 microns, with drops being as small as 2 microns. Total oil increased as the largest droplet size increased, but the median drop size did not change with the oil content.**

Sample Time	Droplet Size (Microns) Min.	Max.	Mean	Oil Conc. (mg/liter)
11:14	5	52	20	280
11:21	2	75	22	380
11:50	5	35	20	140
16:00	5	37	19	115
16:49	5	63	24	520
07:21	5	31	17	50
08:03	5	50	20	185

Other factors which impact oil droplet size and the stability of the distribution include the presence corrosion inhibitors and/or methanol in the produced water. Methanol is commonly utilized for hydrate control and may be injected continuously or periodically. Methanol in the produced water decreases the oil/water interfacial tension, which in turn helps to stabilize dispersed oil as smaller droplets. Methanol has other effects as well. One effect is the precipitation of otherwise soluble divalent mineral salts (calcium, magnesium, barium sulfates and/or carbonates). These minerals tend to be hydrophobic and thus become neutrally buoyant oily solids which are not readily recovered by hydrocyclones or other gravity-based water treating equipment.

It should also be noted that methanol will tend to increase the solubility of some hydrocarbons in the produced water and that methanol is partially recovered by the solvent extraction method used for an EPA 1664 analysis. A direct IR analysis of the extraction solvent that contains methanol will register a higher TOG value than will an instrumental analysis which more closely approximates the evaporative methodology that is part of the EPA 1664 procedure. Thus using a wet IR instrument on a deepwater platform may yield higher TOG values that are somewhat sporadic since they will reflect when methanol is or is not present in the produced water.

Given that high pressure drops or the presence of chemicals that are related to deepwater oil/gas production may be present on a deepwater platform, the process designer would need to contemplate, for example, the need for higher efficiency oil/water hydrocyclones and the need to remove neutrally buoyant oily particulate from the water.

Deoiling Hydrocyclones on Deepwater Platforms

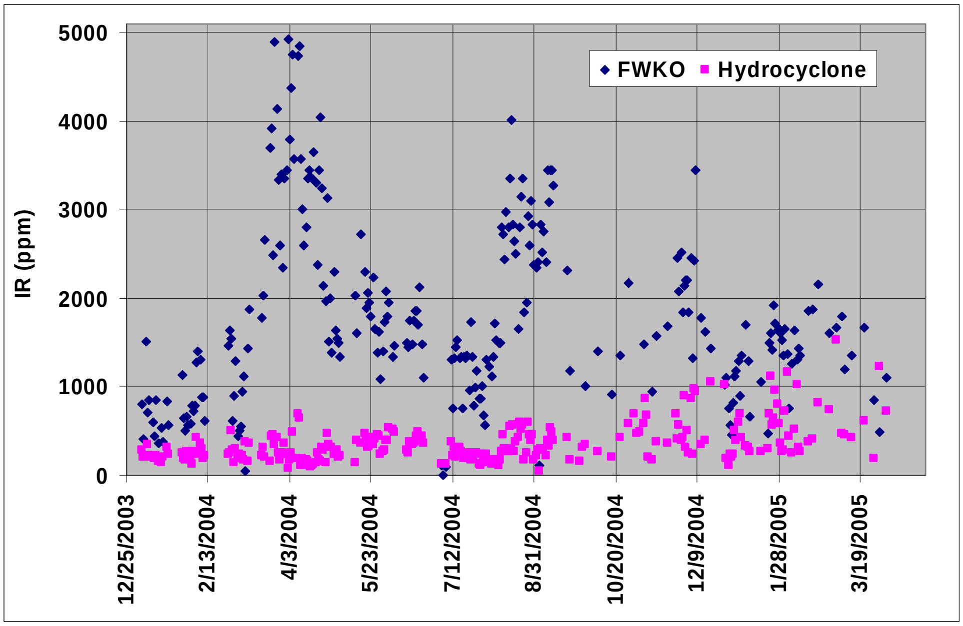
The initial experience with hydrocyclones in the GoM was somewhat unfavorable [4], due in part to a lack of operating experience with the devices in the region. Recent experience has been good and hydrocyclones are now regarded as ‘standard technology’ for many deepwater operations. Hydrocyclones on Shell GoM deepwater facilities are typically installed with 25 to 35 mm diameter liners on the water discharge of the FWKO. The pressure drop across and flow through the hydrocyclone depends on the FWKO level control system and can fluctuate significantly. The DPR (pressure difference ratio) is typically maintained in the range of 1.6 to 2.0, depending upon the manufacturer. In this setting, the hydrocyclone is not intended to produce overboard discharge quality water. Instead, it is intended to shave the peaks in oil content and provide an overall pre-conditioning for downstream flotation.

The design of piping for transporting rejects to a slop vessel is particularly important for maintaining effective hydrocyclone performance. The designer needs to understand that due to the pressure drop involved, this fluid will have a substantial gas volume fraction and the liquids may be laden with fine, emulsion-stabilizing solids (typically <20 microns). Also, the piping should contemplate a reject ratio that is in the range of 5% of the design capacity of the hydrocyclone unit, again with the expectation that the fluid will be multiphase. If there is CO_2 in the evolved gas, then the precipitation of scale in the reject orifice of the hydrocyclone can be expected and easy access to the hydrocyclone liners for maintenance purposes is essential. Without adequate design, it will be difficult to maintain the required Differential Pressure Drop Ratio and the fluid reject rate required for effective hydrocyclone operation.

As mentioned above, if the process anticipates that the produced water will experience a substantial pressure drop (> 50 PSI) upstream of the hydrocyclone, then the selection of a high efficiency liner designed with a D_{50} droplet size removal capability on the order of 10 to 15 microns is essential.

As shown in **Figure 4**, hydrocyclone performance on one platform was very good from December 2003 through October 2004. During this time period, the operating procedures for the hydrocyclone were being carefully followed. This included daily backwashing, routine cleaning of the liners, adjustment of the number of active versus blank liners, and maintaining the DPR in the manufacturer's recommended range of 1.6 to 2.0. Also, the chemical vendor had an effective treatment program in place to prevent scale deposition throughout the facility, and, in particular, across the hydrocyclones. Starting in October 2004, those procedures were not followed as diligently and hydrocyclone performance began to deteriorate. Various factors contributed to this deterioration including staff turnover and the fact that much of the routine maintenance of the unit was cumbersome. Therefore, new installations of hydrocyclones incorporate improved operability features as listed below.

Figure 4. The hydrocyclone performance on one deepwater platform is shown over time. The deterioration in performance was found to be related to inadequate unit maintenance.



A summary of Best Practices formulated by Shell for hydrocyclone operation includes:

- Select hydrocyclone liners for removal of oil drops greater than 10 micron
- Regularly adjust the number of liners to match the flow requirements.
- Avoid rapid flow fluctuations
- Minimize solids to hydrocyclones and anticipate scale deposition in the reject orifices
- Minimize entrained gas in feed since it will reduce the true volume of reject liquid
- Clean and backflush regularly
- Increase reject port size to prevent blocking with solids and to accommodate break out gas volume
- Any new installation should have the following operability features:
    - Automated backwash
    - Quick-open enclosure on the containment vessel
    - Spare liners readily available for quick change-out and offline cleaning

Hydrocyclone performance is summarized for a number of platforms in **Table 4**. Any unit downstream of hydrocyclones must be designed to safely release gas arising from the pressure drop through the hydrocyclone. A well designed flash drum (degasser vessel) can contribute significantly to deoiling,and to the suppression of surges which can lead to a produced water sheen. Therefore it is considered a best practice to install oil skim facilities in the flash drum. This allows the discharge of the Bulk Oil Treater, for example, to be tied into a downstream vessel, rather than requiring that the stream be pumped into an upstream location. The presence of a flash tank helps to eliminate of a major source of shear and thus the generation of small droplets.

Table 4. Hydrocyclone performance experience from various Shell facilities [5]

Location	Hydrocyclone Inlet (ppm)	Hydrocyclone Outlet (ppm)	Degasser Outlet (ppm)	Hydrocyclone System
N. Sea	400	17		35 mm liners No degasser
N. Sea	600	25		60 mm liners No degasser
N. Sea	400	45	30	35 mm liners
US	520	39	20	K-Liner Pumped Feed
US	2310	160	6	35 mm liners Pumped Feed
US – Auger	1500	200	100	K-Liner FWKO Feed
Dubai	327	88	39	35 mm liners
N. Sea	102	30	17	G-Liner Production system

Induced Gas Flotation on Deepwater Platforms

While the importance of horizontal Induced Gas Flotation Units (IGFU) on Shell facilities in the deepwater GoM is taken for granted, such equipment is not necessarily part of the essential water treating equipment in other parts of the world. For example, at least a few high volume water producing Shell assets in the North Sea do not have flotation units. Shell deepwater Brazil (Bijupira-Salema) has a vertical IGFU. Horn Mountain (BP), Holstein, and Thunderhorse in the deepwater GoM also use vertical IGF units with varying degrees of success.

A typical horizontal IGFU consists of a tank with six chambers in series. The first chamber is an inlet section that provides momentum reduction, a quiet zone for chemical residence time, and an opportunity for most of the dissolved gas breakout to be vented. Without this, the liquid level in the first flotation cell would be higher than that in the downstream cells, making it difficult to consistently remove floating contaminants from all the cells. The next four chambers consist of induced gas flotation with rejects flowing over a spillover weir and water passing under a partition into the next chamber. The final chamber is provided for the final evolution of gas bubbles in order to minimize gas carry-under to the discharge piping.

Vertical Column flotation units were originally designed to address concerns over the effect of wave motion on deep water floating structures. Baffles and other devices have effectively minimized the effects of wave motion on the performance of horizontal IGF units. Column flotation units were adapted for use in the North Sea and on FPSO applications where atmospheric tanks and horizontal vessels are typically not accepted. Although column flotation units have performed well, single vessel applications can be prone to upsets while offering no redundancy or protection against mechanical failure. When column flotation units are utilized, the use of two or more vessels should be considered.

Much of the design and operating experience regarding horizontal IGFU for the deepwater was transferred directly from decades of use in the shallow water GoM. C.A. Leech [6] describes the design capacities and operating parameters for horizontal IGFU at several shallow water GoM locations. Flotation units at all of these facilities are similar in many respects to flotation units on deepwater facilities. The consensus opinion among Shell operations staff in the deepwater GoM is that induced gas flotation provides efficient separation of oil to discharge quality on a consistent basis and with a minimum of operations adjustment and maintenance. To some extent, the success of gas flotation units in the deepwater can be attributed to the fact that many deepwater operators have many years experience operating the shallow water assets where they gained relevant operating experience.

The character and quality of the skim fluids from an IGFU will vary depending upon the presence of oily solids and the character of the water clarifier or polymer utilized to support the flotation performance. Some types of water clarifiers such as dithiocarbamates, are very effective, but tend to generate a heavy, sticky floc that is not easily recovered downstream. Other times, a high molecular weight polymer may be utilized which, if not fully hydrated, can tend to accumulate in and downstream of the IGFU, again causing difficulties with contaminant handling. Also, the presence of water clarifiers and flocculants in fluids which are recycled to an upstream separator will often result in the formation of stable interface emulsions that upset free water knock outs and LP separators. Since it is impossible to know the character of the water clarifier which will be required on any given platform, it is particularly important to avoid the recycle of contaminants recovered from a flotation unit into any upstream separator or tank.

Disc-Stack Centrifuges

The overall experience with disc stack centrifuges on Shell deepwater facilities has been poor. This experience is summarized in **Table 5** below. In general, the units did a good job of separating oil and water, when they were in operation. However, a combination of problems caused the uptime to be very low. In the case of the Auger platform, several weeks of troubleshooting were required to startup the unit. Once in operation, the unit ran for roughly a day before the shaft connecting the motor to the centrifuge bowl broke in two pieces. Given the time and effort that had gone into the unit it was decided to scrap any further work. The problems with the Auger centrifuge were characterized as rotating equipment problems with the final failure also being a rotating equipment failure.

Table 5. Summary of Operating Experience with Disc Stack Centrifuges

Location	Water Treating Effectiveness	Mechanical Reliability	Status
MP-252	Good	Difficult to maintain	Working
Auger	Not Tested	Failed immediately	Removed
Mars	Good	Failed	Removed
NaKika	Good	Failed	Removed
Holstein	Good	Failed	Removed

The centrifuge on Mars suffered some of the same problems as the unit on Auger plus control system problems, and fouling of the disc stack by sticky solids. The rotating equipment problems together with the control problems were sufficiently difficult that maintenance staff spent an inordinate amount of time working on the unit. A build up solids in the disc stack would cause an imbalance fault which required that the unit be disassembled for cleaning. This only increased the maintenance requirements to the point that the platform could not keep the centrifuge running with the available staff.

Mars:
Capacity: 6,000 BPD, usually operated at around 4,000 to 5,000 BPD.
Specifications: 4,140 rpm; g-force at periphery of the disc = 5,000 g.
Feed from Wet Oil Tank
The objective of this installation was to provide intermittent to continuous small volume use to clean up methanol containing produced water streams from the Europa subsea system. The original feed line was from the bottom of the Wet Oil Tank which contained bariums sulfate solids that had been collected using a dithiocarbamate water clarifier. The sticky solids adhered to the discs in the centrifuge, causing an imbalance to develop in a relative short time (a few hours).

Auger:
Capacity: 15,000 BWPD
Feed from Wet Oil Tank
The objective of this installation was to provide intermittent to continuous small volume use to clean up oily water having small oil drops. Auger was experiencing produced water problems and frequent sheens. When the unit was installed, the shaft broke within a couple of days of operation. The shaft breakage caused other damage so the unit was removed from the platform.

MP-252:
Capacity: 300 BPD and 750 BPD (2 units)
The objective of this installation was to provide continuous small volume use to clean up methanol containing oily water from Tahoe. These small units seem to have far less mechanical problems than the large units described above. Although they require relatively high maintenance, the offshore staff learned how to run and maintain them. The Tahoe water could not be treated without them. Only a slipstream of produced water is sent to the centrifuges, not the entire platform produced water volume.

The Shell experience with the use of Disc Stack Centrifuges can be summarized as follows:

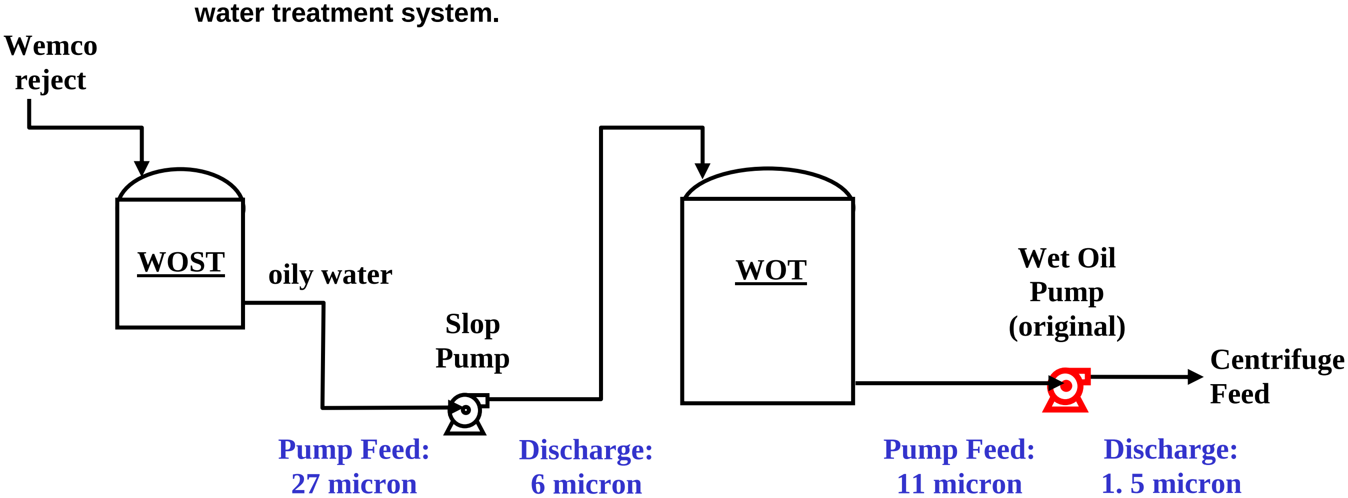
- Units were tested in the laboratory and pilot field settings successfully
- At some locations there is a potential need for treating production with small oil droplets, although this water can

probably be treated with induced gas flotation if an appropriate flotation polymer is utilized
- Insufficient on-board personnel were available for regular maintenance on the centrifuges
- Larger units (higher forces) failed in actual use
- Smaller units (1300 BWPD) clean water successfully, but require significant maintenance and operator training

Utilizing Low Shear Pumps
An oil droplet size distribution survey was conducted on the Mars platform to determine the impact of pumps moving oily water from the Wet Oil Storage Tank and from the Slop "Wet Oil" tank. The results are shown in Figure 5. In both cases, the pumps were operating far off their peak efficiencies and the recycle of the very small oil droplets made it more difficult to clean the produced water. Based upon this and other experience in the Gulf of Mexico, Shell's guidelines for pump selection for produced water handling are summarized as follows:

- Use low shaft speed pumps (< 1800 rpm)
- Select pumps with high hydraulic pump efficiency (> 60 %)
- Specify large impellor diameter (goes along with slow speed for given gpm)
- Use an oversized discharge nozzle (slow discharge speed)
- Maintain a limited pressure boost per stage (< 50 psi)
- Operate the pump with a low specific speed Ns < 700

Figure 5. An on-line survey of oil droplet size distributions on Mars shows that low efficiency pumps were generating very small oil-in-water droplets that were difficult to remove in the water treatment system.



Process Design for Water Treating
A composite, somewhat generic process flow diagram was presented in Figure 2 for a separation and water treating system on deepwater platforms. Based upon the above discussion of successful operational practices on deepwater platforms, several upgrades to the PFD of Figure 2 can be recommended. These include:

- Use of a DPR controller to the deoiling hydrocyclone system to maintain DPR above 1.6.
- The routing of all reject and skim fluids to a slop tank
- The limited blending of oil recovered from the slop tank with sales oil as long as the BS&W of the sales oil does not approach contract limits
- The return of clarified water to the produced water treating system, not to an upstream separator
- All pumps utilized are of the low shear variety and selected to operate near the peak efficiency on the pump curve

- Water clarifier is injected, as appropriate, immediately upstream of the cleaning technology that the clarifier is intended to support.
    - For example, any clarifier injected ahead of the flash tank would not be expected to retain activity that would support flotation in the IGF unit.

Summary

The general design considerations for a produced water treating system on a deepwater platform include the following:

1. Upstream separators
    a. Design to accept slug flow so that flow rates to the downstream water treating system can be more temporally uniform
    b. Include cyclonic inlets or similar technology to avoid shattering oil into small droplets which are difficult to remove in downstream treating
2. 1st stage of water treating – deoiling hydrocyclones
    a. Favor the installation of high efficiency hydrocyclones on the expectation that pressure drops from HP and IP separators will be sufficient for generating oil droplets in water with a size range of 5 to 50 microns
    b. Design and install the hydrocyclones such that maintenance is convenient.
    c. Plan for a minimum 5% hydrocyclone reject volume which must flow multiphase to a slop or wet oil tank.
    d. Install a Differential Pressure Ratio controller on the hydrocyclone
    e. Expect the reject stream from the hydrocyclone to be solids-laden and not suitable for being returned to an upstream separator
3. Induced Gas Flotation
    a. Plan for a 5 to 10% skim liquid volume from the IGF unit(s)
    b. Route continuously skimmed contaminants to a slop or wet oil tank
    c. Consider a degassing unit upstream of the IGF only if excessive gas evolution is expected ahead of or in the IGF Otherwise, use this dissolved gas breakout to augment flotation gas by installing the LCV for the upstream separator(s) near to the IGF unit
    d. When the use of a high MW polymer is required, continuously and on-line pre-mix the polymer into the water stream using a venturi injector.
    e. The injection rate for water clarifiers should be controlled by a flow meter which sends a signal to the chemical injection pump. Continuous modulation of the chemical injection rate is preferred.
4. Eliminate recycle streams
    a. The slop or wet oil tank should have facilities to send oil to the LACT unit. Typically the oily emulsion recovered from the produced water will contribute <0.1% to the BS&W of the sales oil
    b. Clarified water from the slop or wet oil tank should be returned to the inlet of the water treatment system and not to an upstream separator where residual chemicals and solids can contribute to the formation of stable interface emulsions
    c. Solids recovered from the slop or wet oil tank should be sent for disposal, preferably by injection into a well dedicated to and permitted for this purpose
5. Utilize Low Shear Pumps
    a. Proper process design can minimize but not eliminate the need for pumping contaminant-laden process streams. Pumps should be selected such that they can operate near their maximum efficiency, preferably above 60%.
    b. Avoid the use of PD pumps when feeding a hydrocyclone as the pulsed flow will degrade hydrocyclone performance.
6. General
    a. Be cognizant that upstream chemical use, e.g., methanol, corrosion inhibitors, scale inhibitors, oil demulsifiers, etc., can negatively impact a water treatment system.

References

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