Abstract
Offshore deepwater discoveries have driven the development of new compact separation technologies, a core aspect of subsea processing. Compact separators are much smaller than conventional separators and have the potential to significantly reduce capital expenditure for deepwater developments. Unfortunately, reducing the size of separators generally reduce the separation performance and the robustness to handle fluctuations in flow rate and composition. It is therefore essential to find an acceptable balance between the realized reduction in overall capital expenditure and reduced tolerance to fluctuating conditions. To maximize the economics of a subsea development, it is important to understand how the technology selection impacts performance, risks, costs, and ultimately the attractiveness of deepwater subsea processing. Proactive technology screening and qualification are required. This paper presents one of several ongoing joint industry projects to develop and screen separation technologies for deepwater applications, the DEMO 2000 project: Next Generation Deepwater Subsea Gas-liquid Separation System. An overview of available technologies for separation in deep water is disclosed, including cyclonic separators, compact gravity-type separators, and slug dampening technologies. Their characteristics, typical performance and maturity level are discussed. Finally, the program activities are explained and some highlights from the separation test program are shared.

Introduction
Value Drivers for Subsea Gas-liquid Separation
In recent years, subsea processing, and more specifically subsea separation, has been recognized as one of the most promising technology developments in the offshore industry. With the recent success at Perdido [Ju et al., 2010], Parque das Conchas (BC-10) [Iyer et al., 2010; Deuel et al., 2011], and Pazflor [Eriksen, 2012], subsea separation is attracting interest from industry because of its ability to increase production, enhance recovery, and improve field economics on a commercial scale. Subsea separation is, in general, still considered an emerging technology area; therefore the benefits and capabilities must be clearly demonstrated to infuse acceptance and confidence as the preferred development option. McClimans and Fantoft [2006] and Di Silvestro et al. [2011] have presented a detailed review of the value drivers for subsea gas-liquid separation, which is the topic of this paper. In summary, subsea gas-liquid separation has proven to provide strong business incentives with enabling capabilities, including (i) more efficient liquid boosting, (ii) longer range gas compression from subsea to onshore, (iii) cost efficient hydrate management, (iv) effective riser slug depression, (v) and access to challenging field developments that otherwise would be abandoned or not developed (due to their remote location, harsh conditions, longer tie-back requirements, or low reservoir drive). The main drivers are discussed below.

Deepwater oil reserves from lower energy reservoirs usually require artificial lift to overcome pressure drops in the wellbore, pipeline, and riser, increasing the production rate and the hydrocarbon recovery factor. The back-pressure on the well can be reduced by subsea pumping or gas lift, with the former offering increasing benefit as water depth increases. Gas-liquid separation can substantially improve the efficiency of subsea boosting by reducing and controlling the amount of gas in the liquid stream. Subsea separation and boosting can thereby improve the project economics by increasing the production rate, prolonging the plateau production phase and/or increasing ultimate recovery [McKee et al., 2011]. As a result, the net
present value of a field development is maximized [Bell et al., 2005]. As explained by Ju et al. [2010], artificial lift was required for developing Perdido due to relatively low reservoir pressure and high hydrostatic pressure in the riser at 7,800 feet of water depth. Gas-lift was not a viable option, due to already moderately high gas-oil-ratio of the reservoir fluids, as well as additional Joule-Thomson cooling occurring in the riser [Ju et al., 2010]. Cooling effects from gas expansion in the riser may limit applicability of gas-lift at great water depths, especially for low-temperature reservoirs [Bass, 2006]. Another demonstration of subsea separation and boosting is the pilot of the Vertical Annular Separation and Pumping System (VASPS) at the Marimbá field in 2001. Do Vale et al. [2002] demonstrated how the production rate increased by one-third of the original daily production by replacing gas-lift with separation and boosting. Similarly, Dover et al. [1990] reported an increase of 15-20% in the production rate when using subsea separation and boosting (ESP) at the Highlander field in 1985.

For gas fields, the subsea gas-liquid separator (usually a scrubber) is considered as an essential component for subsea to onshore developments by use of gas compression. Cooling and scrubbing is necessary upstream of a “dry gas” compressor that enables longer distance transport from large fields such as Ormen Lange and Åsgard. Davies et al. [2010] have explained the characteristics of near future opportunities for subsea gas compression on the Norwegian Continental Shelf. The Ormen Lange and Åsgard projects are currently in a qualification phase and will, when implemented, represent a new step change in subsea processing development.

A very important value driver for the subsea separation and boosting concept is the cost-effective flow assurance opportunities it provides. One of the opportunities is that the gas-liquid separator, along with the separate production piping for liquid and gas, enable hydrate management by depressurization from the host through the gas line. Separation of liquid water from the gas line can also eliminate or substantially reduce the amount of glycol required for hydrate prevention while reduced gas levels in the liquid line reduce Joule-Thomson cooling of the liquid stream, enabling a beneficial shift of the hydrate curve. The thermal requirement and associated costs for hydrate preservation are reduced [Di Silvestro et al., 2011]. Subsea separation and boosting afford other benefits for riser operation in ultra-deep water, as demonstrated by the Perdido [Ju et al., 2010], BC-10 [Iyer et al., 2010], and Pazflor [Eriksen et al., 2012] field developments. The mentioned flow assurance benefits were important drivers for making these developments attractive.

In addition to hydrate management, subsea separation and pumping at the riser base provide slug depression in the riser and the topside facility. Iyer et al. [2010] show how the BC-10 seabed topography can induce slugging over a broad range of intermediate gas-liquid ratios. The Caisson/ESP prevents the onset of slugging by separating the multiphase well stream into an oil flowline with high liquid loading and a gas flowline with sufficiently high gas velocity to sweep liquids. In 1985, the Highlander development successfully coupled subsea slug catchers (used to separate gas and liquid and dampen incoming slugs) with ESPs to reduce the backpressure on the well and increase production back to the Tartan platform in the North Sea [Dover and Cooling, 1990].

Subsea separation also makes it possible to assign gas and liquid to different platforms with different availability for power and processing capacity. The economics of a development can be analyzed and optimized, as in the case of Astaro, where one of the options considered is a subsea tie-back of gas and liquid to different facilities [Davies et al., 2010]. In summary, subsea separation is emerging as an enabler for capturing challenging deepwater and Arctic resources that could otherwise be uneconomical by increasing the degrees of freedom for field design in challenging conditions, both in green field development and also in regions with existing infrastructure.

**Compact Separation and Available Technologies**

There are certainly strong arguments for moving gas-liquid separation processes from the surface facility to the seabed, especially for deepwater and Arctic developments. However, with water depths approaching 1500-3000 m (~5,000-10,000 ft), new challenges emerge. Some critical technical challenges are well known, whereas others are not sufficiently analyzed. This paper focuses on the separation process for gas-liquid which in topside plants takes place in large separation vessels. Previous subsea separation developments at the Troll, Tordis, and Pazflor fields use large separator vessels. Even though the Tordis separator at 210 m (690 ft) water depth is a semi-compact separator with its innovative gas bypass design, it still has an internal diameter of 2.1 m and a length of 17 m long (tan/tan). Most would consider such a separator unfeasible for deeper water due to mechanical constrains and fabrication challenges. This is a convenient conclusion when arguing for development of ultra-compact separation technologies, but it might be valuable to get an impression of the real limit. To illustrate, consider the exercise of installing the Tordis vessel at a water depth of at least 2,000 m (6,600 ft) for a design pressure of 180 bar (2,600 psi). The vessel shell would have a wall thickness of 110 mm (4.3 inches) according to European Standard EN 13445, without stiffening rings. For higher internal pressure, stiffening rings or reduced diameter is required. As an example, a 1.5 m diameter separator could have a design pressure of 480 bar (7,000 psi) at 2,200 m (7200 ft), without stiffening rings. Fabrication of such vessels should be feasible as vessels for similar mechanical constrains are made for other applications (nuclear). So if the mechanical constrains and fabrication techniques do not always disqualify vessels for deepwater installation, what’s the driver for making compact separators? The motivation is to improve project economics. Large vessels for deep water are heavy and impact the overall cost of the subsea station, as well as the availability for
maintenance. Retrievalability of separators is impacted by module weight and availability of installation or intervention ships, which can impact project economics. If retrieval of a large separator vessel for deep water requires use of an installation ship, the response time increases, along with the revenue loss from production shut-in. Further, for extreme shut-in pressures, compact separators may be the only alternative, especially if a high-integrity pressure protection system (HIPPS) is not allowed or preferred.

Unfortunately, reducing the size of separators and their control volume generally reduce the separation performance and the robustness to fluctuating flows. Even if compact and ultra-compact separators minimize the capital expenditure for the subsea station and increase the availability for retrieval, the risk of non-conformance with separation requirements is increased, especially under slugging conditions. Consequently, the risk for loss of revenue due to reduced separation performance is increased compared to a large separator. The reliability of a subsea station is expected to be high, for example with target availability of 97.5%, so a minor drop in availability makes a large impact on the overall business case. It is therefore essential to find a good compromise between the realized reduction in overall capital expenditure and the reduced robustness to fluctuating conditions, when making separators smaller. So how far should the industry go in making smaller separators for deepwater and ultra-deepwater applications? At the moment, the question cannot be answered since a complete cost, risk, performance analysis, as explained by Bell et al. [2005], is not available. Different oil producing regions have different needs and requirements, resulting in an expanded toolbox of available technologies. A screening of these technologies and their separation performance under realistic conditions should be established.

Currently, deepwater subsea separation and boosting applications have only been met by ESP/Caisson technology, which is in operation at Perdido (7,800 ft) and BC-10 (5,900 ft). The Caisson is a tall (e.g. 91 m or 300 ft) separator which is installed in a dummy well. The system has a tangential inlet to a tall narrow separator which accommodates slugs, provides surge volume for the separated production fluids, and supports the ESP. The projects at Perdido and BC-10 are impressive and represent key milestones for development of deepwater resources. Still, there are potential drawbacks for the ESP/Caisson technology. Bass [2006] has stated that ESP/Caisson technology has a relatively high capital and intervention cost, and Alhanati and Trevisan [2012] have recently raised some concerns about the reliability gaps in ESP technology for deepwater applications. Additionally, Deuel et al. [2011] highlight that control of foaming is critical to successfully operate Caissons, especially for oils with a tendency to foam. Gas carryover, when operated successfully, is expected to be less than 10%. The Vertical Annular Separation and Pumping System (VASPS) technology is somewhat similar to the Caisson separator and has a subsea reference from the installation at the Marimbá field [Do Vale et al., 2002]. The VASPS has an internal helix between the pressure housing and the inner gas annulus in the tall separator which is also installed in a dummy well. Even though the ESP/Caisson and VASPS technologies have several subsea installations and are attractive for future developments, the industry is requesting development of alternative technologies to meet the requirements for deepwater application.

The Gas Liquid Cylindrical Cyclone (GLCC) technology is well documented in literature and has several (more than 1000) installations, mainly onshore [Kouba et al., 2006 and references herein]. Kouba et al. [2006] have reviewed the GLCC technology and shared experiences from field applications. The GLCC is a compact and light weight vertical cyclone with tangential inlet. In its original design, the GLCC is a cyclone with minimal or no internals and a downward tilted (27°) inlet pipe to force the liquid level below the inlet zone. This is required to retard liquid carryover, which could be problematic with a perpendicular inlet. Being compact, performance under slugging conditions is expected to be problematic. Consequently, a slug damper system has been developed. The slug damper system is an inlet flow conditioner (pipe configuration) which provides volume for liquid accumulation. Under stable flow, the gas carryover should be less than 5-10 % gas-in-liquid. The GLCC was tested subsea in Brazil by a joint industry project to ensure liquid presence for a subsea multiphase pump under high gas fractions [Campen et al., 2006]. When extended to a longer separator and including an ESP or an ESP and a helix, the GLCC becomes an ESP/Caisson system or a VASPS, respectively.

Di Silvestro et al. [2011] are developing a separation concept composed of an array of vertical pipes with a common multiphase inlet and common outlets: the Vertical Multi-Pipe Separator. The individual pipes are designed as a GLCC with tangential downward tilted inlet, but the liquid level is operated far from the inlet. The dimensions are in the same order as a GLCC. As for the top section of the Caisson separator, liquid follows a spiral motion along the separator wall and hits the liquid interface. Di Silvestro et al. have highlighted that special internals could be incorporated to avoid foaming and have tested an internal helix as used in the VASPS. Gas carryover is reported to be below 5-10%, which is in line with that reported for similar technologies. The Vertical Multi-Pipe Separator will add the benefit of a simplified fabrication process of the separator and a higher design pressure limit, whereas the weight of the combined array of pipes will be similar to a semi-compact vertical separator with the same volume.

Several other vertical separator designs are potentially attractive for subsea gas-liquid separation. Compact versions of traditional vertical vessels with separator internals for flow distribution and gas demisting should not be disregarded as potential solutions to subsea separation. They might provide better separation performance than more compact technologies...
and may be attractive despite being larger and heavier. Tee and Verbeek [2004] have presented a principle for cyclonic separation of gas and liquid which involves a tangential inlet into a vertical separator. A concentric gas extraction pipe extends from the top of the separator to below the multiphase inlet. When compared to the GLCC design, the proposed separator has a lower K-factor and the liquid level is operated at a greater distance from the inlet. The intent is not to maintain spin of the liquid phase, but to provide an efficient multiphase inlet. Tee and Verbeek incorporate an internal (perforated pipe extending from the bottom liquid outlet of the separator) to ensure homogeneous production of oil and water through the liquid outlet. This outlet design can serve to dampen variations in gas concentration to a multiphase pump, a concern introduced for serious slugging scenarios.

Compact scrubbers exist from several suppliers with different design features. When designed to accommodate large liquid fractions, compact scrubbers can be attractive for subsea gas-liquid separation. One example of compact scrubber technology is the CDS-Gasunie cyclone scrubber [CDS-Gasunie cyclone scrubber fact sheet]. The separator has a normal or tangential inlet with internal swirl blades (spiral vane) to promote gas-liquid separation. When compared to the GLCC, the cyclonic scrubber is operated with a liquid level at a greater distance from the inlet. Consequently, the cyclone scrubber has a conical plate to prevent foaming when liquid droplets approach the liquid phase. An anti-swirl blade prevents gas vortexing in the bottom section of the vessel, whereas the GLCC design intentionally maintains swirling flow in the liquid phase. The volume of the lower part of the separator is designed to accommodate hydrodynamic slugging. The experience with such technology continues to grow, although the technology is still less mature than conventional large vertical scrubbers.

Cyclonic inline separation technologies have received a lot of attention due to the considerable weight and space savings that can be realized [Schook and Haaland, 2004; Fantoft et al., 2010]. For gas-liquid separation, three applications of this technology are available: a DeGasser for removing gas from liquid-dominated streams, a DeLiquidiser for removing residual liquid from gas-dominated streams, and a PhaseSplitter for bulk separation of gas and liquid. Combined, the three technologies have had about 40 installations and are emerging as attractive options for topsides, remote, and de-bottlenecking applications [Bymaster et al., 2011]. Since these inline cyclonic separators are studied in this paper, a more detailed explanation of their operation follows.

A schematic of the cyclones is provided in Figure 1. All inline cyclones are equipped with a static mixer upstream of a stationary swirl element, both of which are positioned within an otherwise ordinary pipe spool. The function of the static mixer is to ensure even distribution of the dispersed phase in the continuous phase. The stationary swirl element is used to induce swirling flow and centrifugal phase separation down the length of the inline device. Liquid forms on the inner wall of the cyclone, while a gas core is formed in the center of the pipe. For the DeLiquidiser, the thin film of liquid formed on the cyclone wall is captured within the annular space between the gas exit and the inner wall of the cyclone. The liquid is drained into the liquid collection boot where it is allowed to degas. Gas entering the liquid boot is routed back to the primary

![Figure 1: Schematic representation of the inline cyclonic test units: PhaseSplitter (left), DeLiquidiser (middle), and DeGasser (right)]
separation chamber through the gas recycle line and re-injected radially into the lower-pressure gas core. The majority of the gas core formed in the primary separation chamber is captured by the gas outlet and sent through an anti-swirl element. For the PhaseSplitter, the gas core is extracted through the center of the static swirl element and sent to the gas outlet, whereas the liquid is sent through the anti-swirl element. In the DeGasser, the gas core formed in the center of the primary separation chamber is extracted and sent to the gas scrubber. Dispersed liquid separates and is drained back into the main flow upstream the anti-swirl element. A small pressure drop is induced (here with a valve) to allow liquid from the scrubber to drain to the liquid outlet. The liquid level in the liquid boot of the DeLiquidiser and in the gas scrubber of the DeGasser is controlled by level detectors and control valves (not shown in Figure 1). The PhaseSplitter typically achieves separation to 1-5% dispersed phase in the two outlets, whereas the DeLiquidiser and DeGasser typically separate more than 80% of the incoming dispersed phase under challenging conditions and up to 90-99.5% for optimal conditions [Fantoft et al., 2010]. As expected, performance depends strongly on the droplet/bubble size of the dispersed phase and on physical and interfacial properties of the liquid and gas.

Finally, subsea slug catchers may provide gas-liquid separation for boosting as demonstrated by Dover and Turiough [1990]. Such slug catchers were of a “beams” configuration consisting of superimposed piping. Large finger-type slug catchers or “beams” configurations have been highlighted as potential deepwater solutions [Abrand et al., 2007]. Sarica et al. [1990] pointed out that more accurate design tools were required to avoid oversizing of finger-type slug catchers. Grenstad et al. [2007] patented the concept of a subsea slug catcher with improved design features which could potentially enable dramatic size reductions. This slug catcher has recently been analyzed for its feasibility as a compact separation component for deepwater developments. Highlights of the study are presented in this paper. Figure 2 shows a possible configuration of the MultiPipe slug catcher with four fingers.

Figure 2: Schematic representation of the MultiPipe finger-type slug catcher.

The basic principle of the MultiPipe technology is to distribute the multiphase flow into several parallel pipe sections. This will dampen flow fluctuations and provide a short settling distance for droplets/bubbles (Figure 2). Short settling distance and large interfacial area are generally favorable features for improving efficiency of gas/liquid separation. The slug catcher has an inlet followed by a header which distributes the flow into several parallel branches. Flow stratifies in the beginning of each branch and is distributed to the gas pipe and the liquid pipe through a tilted downcomer. The gas pipe has an upward tilted section to a common gas header so that liquid accumulating in the gas pipe can drain into the liquid pipe through the escape pipe. Gas produced to the liquid pipe can escape through the same pipe to the gas header. The escape pipe is an important design feature since countercurrent flow in a finger-type slug catcher may result in severe carryover, as confirmed by Sarica and Shoham [1990], and references herein. Finger-type slug catchers are considered as mature technology when used on onshore gas terminals. The much more compact slug catcher in Figure 2 is a new technology, but is based on mature components. Literature and experience from transient analyses, level control analyses, pig bypass philosophy, and fabrication is available. Consequently, the MultiPipe separator is considered to have a high technology readiness rating. The separation principle is the same as in a traditional gravity separator. The slug catcher may be integrated within a subsea station as a load bearing structure, thereby reducing installation weight considerably. This is important for some oil producing regions where the lifting capacity for retrieval determines the maximum allowable separator size. The
MultiPipe slug catcher concept can potentially include demisting technology and/or water/oil separation in primary or secondary liquid pipes.

Offshore discoveries in ultra-deep water have driven the development of new compact separation technologies. As a basis for optimal technology selection, it is essential to screen available technologies to understand how cost, risk, and performance impact the attractiveness of different technologies. The next part of this paper gives some highlights from a joint industry project where some of these technologies have been studied.

Scope of Work

DEMO 2000 Program and Activities

DEMO2000 is a program from the Norwegian Ministry of Petroleum and Energy with the objective of reducing costs and risk for industry when commercializing and piloting new technologies. The DEMO2000 project: “Next Generation Deepwater Subsea Gas-liquid Separation System”, was executed in the period from autumn 2009 to summer 2011. The project aimed at qualifying compact gas-liquid separation components and systems to enable economic recovery from deepwater discoveries. The test separation system design was scaled based on a generic field producing 85% gas and 60 kBPD of liquid with a theoretical slug size of 5 m³. The program was planned and executed with the following work packages:

<table>
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<tr>
<th>Work Packages</th>
<th>Description</th>
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<tr>
<td>1. Flow distribution and dynamics in MultiPipe</td>
<td>Design, experiments, and CFD model development</td>
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<tr>
<td>2. MultiPipe sand handling</td>
<td>Experiments in low pressure facility</td>
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<tr>
<td>3. Separation tests of individual components</td>
<td>Experiments in high pressure facility of: MultiPipe, PhaseSplitter, DeLiquidiser, and DeGasser</td>
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The first work package focused on the MultiPipe. A transparent slug catcher with 4 branches was designed and analyzed for flow distribution and dynamic behavior in a low pressure test loop with air and water. The work proved the concept of the compact finger-type slug catcher, provided optimization of the design of the inlet/outlet headers, and provided the necessary input for CFD model development (Figure 3, left). 27 separation tests at different conditions were run. The second work package involved establishing a sand handling strategy for the MultiPipe. Being a horizontal separator with moderate to low liquid velocity, sand accumulation must be addressed. A single branch slug catcher was tested in a low pressure sand handling loop with air, oil, and water. Here, 70 tests were run to analyze sand build-up, different desanding designs and operational strategies. High-speed cameras, particle size analyses, and gravimetric analyses were used to find the optimal solution. Figure 3 (right) shows a picture of the sand handling test setup.

Figure 3: Example from the developed CFD model (left) and a picture of the MultiPipe sand handling test system.

The primary objective of work package 3 and 4 was to map the performance of individual compact separators and systems built from these individual components. A high pressure test facility was constructed to support a large experimental campaign. The separation components and systems were studied under varying conditions such as variable temperature (liquid viscosity), pressure (gas density), gas flow rate, liquid flow rate, slugging scenarios, different control strategies, and
shear/mixing at the test unit inlet. The program successfully executed 277 high pressure tests on single components, which served as input for the selection of systems. As previously mentioned, two separation systems were tested, collecting 168 test points between the two systems. The next sections provide some highlights from work package 3 and 4.

**Experimental**

**Facilities for High Pressure Separation Tests**

A test loop was constructed in a test facility in Drammen, Norway. The rig has a high degree of flexibility with regards to operating conditions, an important feature when mapping the operating envelope of the different separation technologies at turn-up and turn-down conditions. The test rig consists of three main items: i) a high pressure loop for testing of separation equipment, ii) a low pressure water-glycol heating/cooling loop for temperature control, and iii) a separate compressor system for pressurizing the main test loop prior to fluid circulation. The loop has an advanced control and logging system with a total of 11 temperature sensors, 6 pressure sensors, 12 differential pressure sensors, 8 Coriolis flow meters, two vortex flow meters, one orifice flow meter, and three nucleonic density meters. In total, 394 parameters are continuously logged by the system, which is operated from a control room. The main part of the system is the closed high pressure test loop, where the separation equipment is tested with air and oil. The test rig characteristics are listed in Table 2 and pictures of the closed loop are presented in Figure 4 and Figure 5 (the main compressor system is not included).

<table>
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<tr>
<th>Table 2- Test Rig Characteristics.</th>
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<tr>
<td><strong>Gas Flow Rate</strong></td>
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<tr>
<td><strong>Liquid Flow Rate</strong></td>
</tr>
<tr>
<td><strong>Max. Pressure</strong></td>
</tr>
<tr>
<td><strong>Max. Temperature</strong></td>
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<tr>
<td><strong>Test Gas</strong></td>
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</table>

Oil and gas are continuously circulated in the flow loop, therefore a large reservoir (25 m³) is required to provide sufficient residence time for the two phases to separate properly. A gas circulation compressor and an oil pump feed the test section with multiphase flow at a controlled temperature. A slug generator U-pipe is included upstream the test section to generate slugging flow with a controlled frequency and volume (using a configuration of valves). A shear valve controls the mixing intensity of the multiphase flow entering the test section. The test section can be configured with single separation components or systems as described later, and has several flow and composition meters to quantify the separation performance. The MultiPipe includes high-pressure sight glasses to enable visual inspection of flow regimes and qualitative performance. Finally, the system has high-pressure sampling and a gas scrubber with a narrow bottom to accurately quantify low concentrations of liquid carryover from the test section.

![Figure 4: Drawing of the flow loop of the high-pressure separation facility.](image-url)
Test Section Configurations and Experimental Conditions

As explained, tests were conducted on individual compact separators, including the MultiPipe slug catcher, the PhaseSplitter, the DeLiquidiser, and the DeGasser. The PhaseSplitter was tested with and without a downstream compact gravity separator. The slug catcher was tested with a single branch (see Figure 2). Based on results from these standalone tests, two systems were selected for further testing, consisting of either the MultiPipe or PhaseSplitter as the primary bulk separator, with the DeLiquidiser and DeGasser treating the gas and liquid streams from the primary separator, respectively.

Table 3 - Physicochemical properties of test liquid and gas at operating conditions.

<table>
<thead>
<tr>
<th>Property</th>
<th>Range</th>
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<tr>
<td>Gas Density</td>
<td>23 - 47 kg/m³ (1.4 – 2.9 lbm/ft³)</td>
</tr>
<tr>
<td>Surface Tension</td>
<td>22 - 28 mN/m (dyne/cm)</td>
</tr>
<tr>
<td>Liquid Density</td>
<td>815 - 845 kg/m³ (50.9 – 52.8 lbm/ft³)</td>
</tr>
<tr>
<td>Liquid Viscosity</td>
<td>4 - 15 cP</td>
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The high pressure separation tests were conducted over a wide range of experimental conditions corresponding to design rate, extreme turn-down and turn-up. Flow rates ranged from 20 to 60 m³/h for liquid, and 50 to 300 actual m³/h for gas. Temperature ranged from 23 to 70 °C (73-158 °F), whereas the pressure ranged from 20 to 40 bar (290 – 580 psi). As previously mentioned, the influence of mixing intensity, slugging size and slug frequency was analyzed. A number of operating conditions were varied and studied thoroughly, including liquid levels (in the MultiPipe, DeLiquidiser liquid boot, DeGasser scrubber), as well as the influence of split ratio between the outlets of the PhaseSplitter. For the test fluid, an aliphatic hydrocarbon fluid (Mobil DTE 21) was used. The model oil has surfactants which reduce the rate of degassing processes and produce challenging operating conditions for cyclonic and gravity based separators. Typical properties for the oil and gas at operating conditions are presented above in Table 3. The program successfully executed 277 high pressure tests on single components and 168 test points over the two systems for a total of 445 test points.

Results and Discussions

Performance of Primary Separators

Since a very large amount of results were acquired for single components, we will limit the discussion to the two primary separators tested: the cyclonic PhaseSplitter and the MultiPipe finger-type slug catcher. While only qualitative results are shared in this paper, the trends presented can be used to further understand the performance of the separator components, as well as the key parameters for optimal design and control of the units.
Cyclonic PhaseSplitter

Similar to the level control of a gravity separator, the performance of the cyclonic PhaseSplitter depends on the selected split of incoming multiphase flow to the liquid and gas outlets. Cyclones are generally operated with a control valve by adjusting the pressure drop from the inlet to the gas outlet and the pressure drop from the inlet to the liquid outlet. The ratio between these two parameters can be described as the differential pressure ratio (DPR), given as: \( DPR = (p_{in} - p_{gas\ outlet}) / (p_{in} - p_{liquid\ outlet}) \). If the flow rate towards the gas outlet is increased, the pressure drop over the gas outlet increases and the pressure drop over the liquid outlet decreases, thus resulting in an increase in DPR ratio. As a result, the liquid quality improves and the gas quality deteriorates. By adjusting these parameters, it is possible to operate the cyclone in different modes based on what is preferred:

- Clean gas mode (by reducing the liquid quality)
- Clean liquid mode (by reducing the gas quality)
- Bulk separation mode (neither gas or liquid outlet are optimal, bulk separation is achieved)

Figure 6 (right) shows a simplified schematic of a gas-liquid cyclone when operated in the different modes. The main flow direction is from left to right, with the gas-liquid interface highlighted in green. The narrow outlet depicted to the side of the cyclone is the gas outlet, which extracts gas from the center of the cyclone. Figure 6 illustrates gas carryunder and liquid carryover plotted as a function of the differential pressure ratio. It can be seen that the purity of the separated gas and liquid depends heavily on the operational strategy. If the primary objective is to obtain clean gas, the cyclone can be operated with a low DPR. If obtaining clean liquid is the primary objective, the cyclone can be operated with a high DPR. Finally, if the quality of gas and liquid are equally important, the cyclone can be operated in the sweet spot (bulk separation mode), as characterized by intermediate DPR. As illustrated in the figure, the data points show very little scatter over a wide range of experimental conditions. This is very convenient, demonstrating that the cyclone performance can be reliably predicted and tailored for multiple processes by using a control valve to adjust the differential pressure ratio and desired separation mode.

In general, compact cyclonic separators are more sensitive to fluctuations in flow rate and composition compared to more conventional separation vessels. Consequently, gas-liquid cyclones cannot absorb large variations in flow during slugging. There are several opportunities to improve performance under slugging, including advanced monitoring and control, and pairing the cyclone with a buffer volume. Although not presented in this paper, tests were done, as part of this project, combining the PhaseSplitter with a compact downstream separation vessel. Bymaster et al. [2010] have experimentally demonstrated the performance of a combined separation solution consisting of a cyclone and a downstream compact vessel. It is also possible to include upstream slug dampening solutions.

MultiPipe

In Figure 7, results for the MultiPipe demonstrate a sharp drop in separation performance with increasing superficial gas velocity in the gas pipe of the MultiPipe. As expected, the gas velocity in the inlet and gas pipe will reach a critical point where an excessive amount of liquid is carried by the gas flow as re-entrained liquid droplets. The flow behavior in the slug catcher was observed through the high pressure sight glasses shown in Figure 7. When operated below the critical gas velocity, a dramatic improvement in gas quality is realized. Similarly, good liquid quality can be achieved by ensuring a proper range of liquid velocity through the liquid pipes and outlets. Considering its compactness, the MultiPipe
demonstrated surprisingly good performance under slugging conditions. The quality of results achieved confirms its applicability as a stand-alone slug catcher or in combination with downstream separation components.

Figure 7: Photo of the slug catcher and a graph showing the influence superficial gas velocity has on liquid carryover.

Performance of Systems of Primary and Secondary Separators

Based on the performance of the individual separation components, two systems were selected for further testing. The first system was equipped with the cyclonic PhaseSplitter as the primary separator, with the DeLiquidiser and DeGasser located downstream treating the gas and liquid from the first cyclone, as presented in Figure 8. It is convenient to plot the performance of the PhaseSplitter operated with different control strategies (Figure 6) on a master curve with liquid carryover on one axis and gas carryunder on the other axis. Figure 8 below compares the separation performance of the stand-alone PhaseSplitter (blue circles) to the separation performance of the combined separation system (red circles), discussed above. Introducing secondary cyclones clearly improves the performance. The system performs better than the stand-alone PhaseSplitter when operated in bulk separation mode, as indicated by the shift of the data points towards zero. Moreover, the scattering of data points is considerably less for the system compared to the stand-alone PhaseSplitter, as the secondary cyclones perform progressively better with increasing concentration of the disperse phase. The system is consequently less dependent on accurate control, as the secondary cyclones polish any carryover from the primary cyclone. To our knowledge, there is limited industry experience operating compact separation systems (consisting of cyclone technologies only). The system represented here is more compact than most applications in the near future. Still, this testing provides valuable experience and insight as industry moves to employ, and successfully operate, more compact technologies and systems.

Figure 8: Photo of the system of a PhaseSplitter, DeLiquidiser, and DeGasser. The graph shows the improved separation performance realized when introducing secondary separators after the PhaseSplitter.
The MultiPipe technology was tested both as a stand-alone separator and in combination with the DeLiquidiser and DeGasser. Figure 9 compares the results. As previously shown in Figure 7, the MultiPipe has a low liquid carryover when operated below the critical superficial gas velocity in the gas header. The gas carryunder depends on the liquid retention time in the liquid pipe of the MultiPipe. Figure 9 demonstrates that the overall liquid carryover and gas carryunder is reduced when incorporating the secondary cyclones. The DeGasser removes any gas carryunder from the Multipipe, while the DeLiquidiser removes any liquid carryover, thus providing clean phases from the system. Combining the MultiPipe with downstream cyclones therefore improves the ability of the unit to handle larger production rates.

![Figure 9: Photo of the system of a MultiPipe, DeLiquidiser, and DeGasser. The graph shows the improved separation performance realized when introducing secondary separators after the MultiPipe.](image)

**Conclusions**

The DEMO 2000 project: “Next Generation Deepwater Subsea Gas-liquid Separation System”, was executed in an effort to analyze the performance of stand-alone separation technologies and systems for deepwater applications. High pressure separation tests were conducted on cyclonic separators and a finger-type slug catcher over a wide range of operating conditions. In total, 445 high pressure tests were successfully executed, thereby establishing an extensive database to be used as a reference for future technology selection and continued comparison with other technologies. While only qualitative results are shared in this paper, the trends presented can be used to further our understanding of the design, control and performance of compact separators. Further, the project has enhanced confidence that subsea gas/liquid separation will play an important role in future deepwater developments.

**Acknowledgements**

The authors gratefully acknowledge the dedication of project manager Lars Grønnæss and Bendik Huflåtten when managing the project, building the test systems and operating the flow loop. The authors also wish to thank Marit Storvik, Erica de Haas, Rene Mikkelsen, Paul Verbeek, and Menno Graafland for their contributions and support throughout the project. ExxonMobil Upstream Research, Woodside Energy Ltd, FMC Technologies Inc, and the Norwegian Research Council are acknowledged for their financial support and for permission to publish this paper.

**Nomenclature**

- **BPD**: Barrels per day (0.067 m³/hour)
- **CFD**: Computational fluid dynamics
- **DEMO2000**: Research program by Norwegian Ministry of Petroleum and Energy
- **DPR**: Differential pressure ratio
- **ESP**: Electrical submersible pump
- **GLCC**: Gas liquid cylindrical cyclone
- **HIPIPS**: High-integrity pressure protection system
- **kBPD**: 1000 barrels per day
- **VASPS**: Vertical annular separation and pumping system
References


