The toxicity of hydrogen sulfide in hydrocarbon streams is well known in the industry and considerable expense and efforts are expended annually to reduce hydrogen sulfide content to a safe level. In large production facilities, regenerative systems are typically installed for treating sour gas streams. During the development stages of relatively small, low sour-gas fields at remote and normally unmanned locations, regenerative systems are neither practical nor economical. In such fields, sour gas production is treated with non-regenerable scavenging processes.
In the development of its low-sour Zechstein gas reserves in the Coevorden field in the north-east region of The Netherlands, the Nederlandse Aardolie Maatschappij (a Shell operating unit, hereafter referred to as NAM) decided to adopt continuous direct-injection of liquid scavenging agents as the lowest overall cost process having the least environmental impact and the highest energy efficiency. At the inception of the project, the operating parameters controlling the scavenging efficiency using direct injection of liquid scavengers in this system were largely unknown. Consequently, numerous field trials using different chemistries and different injection mechanics had to be carried out.

This article presents the results of these field trials, which ultimately led to a very successful and profitable field development strategy. A variety of very challenging operational problems were encountered and solved. Reference is made to injection nozzle blockages, fouling of glycol gas dehydration systems, severe scaling problems in production and downstream water treatment/injection facilities, inadequate hydrogen sulfide removal efficiencies and HS&E-related issues. A better understanding has been gained of the fundamental relationships between operating parameters governing direct-injection processes and associated chemical development and application methods. Communication and integration of experience and knowledge between the operating unit and its chemical supplier were key success factors in this achievement, as was the endurance and continuing support of field operations staff in facilitating the resolution of difficult problems.

Introduction
NAM’s Ten Arlo system (Fig. 1) produces gas from 32 satellite locations and four gas treatment/compression plants. The majority of the fields in the system produce sweet gas from the Limburg reservoir. However, the system’s heavily compartmentalized Coevorden field also contains gas accumulations in the Zechstein reservoir with H2S concentrations up to 300 ppm(v). Developing these accumulations would require extensive modifications to existing (sweet) gas production/treatment facilities to ensure safe operations and the prevention of H2S emissions. The producible reserves were small, yet economically attractive. However, due to their geographical scatter, a pipeline grid connecting these low sour-gas accumulations to an existing nearby plant utilizing a regenerative solvent process for gas sweetening was found to be economically unfeasible. In-field desulferisation with, for example, a...
solid-bed adsorption process, was found to be technically feasible, but the required capital investment and perceived life-cycle costs could not be justified.

To allow production of the low sour gas without violating the Ten Arlo sales gas specification for maximum allowable \( \text{H}_2\text{S} \) concentration (5 mg/Nm\(^3\) or 3 ppm(v)), NAM evaluated in-field desulphurisation utilizing a commercially attractive alternative technology.

**Direct-Injection \( \text{H}_2\text{S} \) Scavenging**

The injection of chemicals into produced gas streams to remove \( \text{H}_2\text{S} \) is a fairly old industry practice. Formaldehyde has been one of the most frequently used materials, but its use is strongly discouraged owing to the reported carcinogenic properties. Chemistries such as sodium chlorite, caustic soda, glyoxal and others have been tested as well. These chemistries often have severe disadvantages associated with them, ranging from handling and operational problems as a result of high reactivity to slow reaction rates.

The development of a non-regenerable class of chemistry, commonly referred to as triazines, was disclosed in 1990. The term ‘triazines’ is used for a group of compounds, which in reality, are substituted hexa-hydro triazines. In this article, the terms ‘triazine’ and ‘hexa-hydrotriazine’ will be used interchangeably. A general representation of a substituted hexa-hydro triazine is given in Fig. 2, in which R1 to R6 may be arbitrary hydrocarbon groups. Two well-known triazine forms are disclosed in patents\(^1\), in which R1, R2 and R3 are ethanol or methyl groups, respectively, and R4, R5 and R6 are hydrogen. The products are produced on a technical scale by reacting either monoethanolamine (MEA) or a trimethylamine (TMA) with formaldehyde.

The actual reaction mechanisms of triazine compounds with \( \text{H}_2\text{S} \) are not well understood. The reaction is complex and produces multiple reaction products. However, repeated laboratory analysis of spent MEA triazine using NMR C13 spectroscopy has established that \( \text{H}_2\text{S} \) reacts irreversibly with MEA triazine with the S-atom being built into the ring structure, forming primarily two sulfur containing products – thiazine and dithiazine. In the reaction of MEA triazine with \( \text{H}_2\text{S} \), the sulfur atoms are in the S\(^2\) oxidation state so that solid elemental sulfur does not form and the reaction products are liquid.

Depending upon treatment rates, the reaction also releases either one or two molecules of water-soluble alkanolamine molecules: R-NH\(_2\). Because at least one R group is retained in each product, the primary products of the reaction of MEA triazine with \( \text{H}_2\text{S} \) are low volatility liquids that are soluble in water (Fig. 2).

**First Field Experiences**

A first field trial was carried out in 1995 at the Coevorden-24 location utilizing a 1,3,5 trimethyl-hexahydro-1, 3,5 triazine (prod-
uct A from supplier A), with injection upstream of the glycol dehydration unit (Fig. 3). During the trial, gas production originated primarily from two wells, with the gas containing 24 and 45 ppm(v) H₂S respectively. Injection took place without the use of an atomizer and at a dosage rate of approximately 6 L/kg H₂S. As a result of the injection, the H₂S concentration in the location’s export gas decreased to well below the 5 mg/Nm³ limit. However, it was found that 40% by weight of the chemical did not react and ended up in the produced water phase. Not only did this result in a potential water disposal problem (owing to prevailing legislation), an unusual accumulation of solids was encountered in the glycol system. The subsequently required change-out of the wet glycol filters resulted in unacceptable amine-type emissions spreading well beyond the location. Furthermore, the functioning of the in-line H₂S analyzer (of the type utilizing a lead acetate tape) was disrupted.

Given the disappointing product yield (i.e., percent reduction in H₂S) and the encountered operational problems, the decision was taken to repeat the trial with a more concentrated version of the same triazine. Initially, this product was injected downstream of the glycol dehydration unit

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Table 2. Test Results with Product B
directly into the location’s export gas flowline with the aid of an atomization nozzle at a dosage rate of approximately 4 L/kg H₂S. Repeated blockages of the nozzle quickly resulted in its removal and the trial was continued without it. Emphasis was placed on determining the product yield and substantiation of the manufacturer’s claim that reaction products would preferentially dissolve in the co-produced condensate. The injection of the more concentrated product in the pipeline-wet export gas stream rapidly reduced the H₂S level to well below the contractual limit, with an H₂S reduction of approximately 97%. This represented a major improvement with respect to the first trial. As illustrated in Table 1, both unreacted and reaction products were preferentially soluble in the produced water phase. The presence of unspent and reacted scavenger in the water necessitated permit application for the installation and use of permanent injection facilities on the location, which were installed in 1996. The chemical cost associated with the subsequent continuous H₂S scavenging treatment of the export gas stream amounted to approximately US$30 per kg H₂S.

Field Development Progression
Several problem areas developed over time with the chemical scavenging application as described above. Ten Arlo’s central gas treatment plant was confronted with increasing pH levels in the glycol dehydration system and amine emissions from vessels and drain pits, which were traced to the scavenger application on the Coevorden-24 location.

Development of low sour gas accumulations at certain satellite locations lacking gas drying facilities was not feasible with this scavenger application, not only because transport lines did not meet the NACE specification for sour service but also chemical costs would quickly become prohibitive. By 1997, the requirement for H₂S scavenging at the wellhead, driven by economics of the operation, combined with increasing operator complaints about amine emissions, triggered field testing of an alternative H₂S scavenger consisting of 1,3,5-tri (2 hydroxyethyl)-hexahydro-1,3,5-triazine (product B from supplier B). To distinguish between the tests, three principal injection regimes were tested as depicted in Fig. 4, without the use of atomization nozzles. Results are given in Table 2.

Test A: Wet Gas Injection Regime, Moderate Residence Time
Scavenging of H₂S from 40 ppm(v) to the required <3 ppm(v) required a scavenger dosage of approximately 10 L/kg H₂S. In order to establish whether the H₂S is indeed removed via the produced water phase, a sulfur balance was made on the water, condensate and gas phases. During the test period, the sulfide concentration in the produced water phase is seen to increase and the sulfur balance (gas to liquid) climbs from an initial 44% to an 85% fit at the end of the test. The slow establishment of equilibrium is explained by the inability to fully drain produced water from the test separator prior to test execution.

During the test, the pH of the produced water increased from an initial 5.6 to 7.4 as the scavenger dosage increased. Massive overdosing of the scavenger raised the pH to 7.6. Throughout the test period and even for a prolonged period thereafter, no solids or scale formation was
observed in the sampled fluids. However, produced water samples developed a yellowish color over time.

**Test B: Wet Gas Injection Regime, Short Residence Time**

Decreasing the contact time between the scavenger and gas had a negative impact on the consumption of the product. Given the short duration of the test, no other conclusion from this observation was drawn other than that it could possibly support an observation from other work that the chemical injection rate has an effect on the mass transfer of the chemical.

**Test C: Dry Gas Injection Regime, Long Residence Time**

In this regime, we expected the scavenger to scavenge H₂S from the dry gas, albeit inefficiently, with the reaction products falling out as solids in the absence of water. In this test, injection of the scavenger in the dry gas stream downstream of the glycol dehydration system had no noticeable effect on the H₂S concentration in the gas. This confirmed the earlier observation that the scavenging reaction takes place in the produced water phase. The product’s manufacturer claimed that a minimum required water content of 2 L/million Nm³ of gas was needed.

One of the objectives of the above tests was to prove that neither the chemical nor its reaction products would cause any adverse effects on water-condensate separation/quality and on the performance of the glycol dehydration system. No such effects were observed, but the relatively short test period could not provide conclusive evidence. From the test results, it was concluded that the scavenger was very effective at removing small quantities of H₂S from wet/saturated gas streams. If sufficient contact time was provided for the required dosage of 10L/kg H₂S, while a factor 2.5 higher than that required for the export gas scavenger, still provided a reduction in chemical costs to approximately US$ 10 per kg H₂S. Given the positive trial outcome, permanent injection facilities for product C were installed on the location’s main Header, while retaining the scavenger (product B) injection into the export gas stream as back-up facility. To gain confidence that product C could also be used on satellite locations by direct-injection at the wellhead, a more rigorous field trial was designed that was also aimed at optimizing the treatment to achieve further cost reductions.

**Extended Field Testing**

Well Coevorden-26 on the Coevorden-24 location was selected for this field trial. This well is completed on both the (sweet gas producing) Limburg reservoir and the (low sour gas producing) Zechstein reservoir. The pressure balance quickly favors (fractured carbonate) Zechstein production after the well is opened up to the extent that steady state gas production with an H₂S concentration increasing to approximately 130 ppm(v) can be maintained for a period of about 10 days (Fig. 5). After this time, the on-set of liquid loading necessitates well shut-in for several weeks to achieve pressure build-up.

In early 1998, the well was connected to the test header (Fig. 4), with the injection point (without atomization nozzle) as per Test A of the previous field trial. Injection of product C commenced simulta-
neously with gas production, with the scavenger injection rate set at the maximum expected H2S level at the recommended dosage of 10 L/kg H2S. The implied over-injection of the chemical was intended. During the trial period, the H2S scavenging performance matched that of the first trial, yielding H2S reduction in excess of 99%. However, a gradual increase in the pressure drop across the flowline connecting the well to the test header from an initial (normal) 2 bar to 8 bar was also observed. Subsequent internal inspection of the flowline revealed that massive calcium carbonate scaling had occurred at and several meters downstream of the injection point. Following flowline clean-up through acidization, a repeat trial was carried out, this time utilizing an atomization nozzle and preventing over-injection by tailoring the scavenger injection rate to the actually produced H2S concentration. Although this reduced scale deposition to a certain extent, the net results were far from satisfactory.

Given the potential threat to the Coevorden field development plans, a major effort was undertaken in conjunction with the chemical supplier to solve the scaling problem. An experimental scavenger was developed (product D from supplier B), in which product C was blended with a phosphonate-type scale dispersant. Late 1998 through 1999, a prolonged period of often-problematic field-testing followed utilizing this experimental product. The following observations were made during this period:

- The experimental product appeared to be effective in mitigating the deposition of calcium carbonate scale. However, the chemistry employed in formulating the product resulted in excessive formation of a very viscous foam, disrupting flow and liquid-level control systems and carrying the risk of spillover into the glycol dehydration facilities.
- Sludge formation occurred in the flowline (Fig. 6), in the test separator and in downstream water/condensate storage facilities to the extent that it became unacceptable.

Irrespective of the encountered problems, it was observed that the scavenger injection rate had an effect on the product yield, but contrary to published results from earlier work, no clear pattern could be established. Factors complicating the resulting interpretation are that a) lowering of the flowing tubing head pressure results in higher linear gas velocities in the flowline, and b) the concomitant increase in the hydrostatic head in the well results in higher water-gas ratios. The dilution resulting from the latter could alter the stoichiometry of the reaction between the triazine and H2S such that the triazine could possibly react with more H2S (on a molar basis) than in the (relative) absence of dilution effects.

During the various trials, in going from...
higher to lower linear gas velocities, the net reduction in H$_2$S was seen to decrease at first, but after passing through a minimum, a higher reduction in H$_2$S was observed again. This would seem to indicate higher scavenger injection rate requirements at lower linear gas velocities, when there is less water production. The significance of these observations could only be ascertained after a solution was found for the encountered problems. It was conceded at the time by the incumbent chemical supplier that such a solution could not be made available in the time remaining for the required firming up of field development plans.

**Further Product Developments**

The field testing of hydrogen sulfide scavengers carried out thus far had generated a number of very clear technical performance criteria for wet gas application. Claiming the successful development of a combined scavenger/scale inhibitor formulation, which could meet these criteria, Baker Petrolite was invited to participate in field testing of this product (SX 2656).

SX 2656 was developed specifically to minimize calcium carbonate scale formation that would normally arise from using a highly alkaline triazine scavenger in calcium and/or high bicarbonate produced water. Based on extensive laboratory evaluation of various scale inhibitors, a proprietary phosphonate scale inhibitor was identified as the most effective at combating calcium carbonate scaling resulting from injection of triazine into a produced brine. The laboratory experiments indicated that a) addition of the chosen scale inhibitor significantly reduced calcium carbonate scaling tendency, b) it had no adverse effect on H$_2$S scavenging efficiency of the triazine, and c) it did not cause fluid foaming. The result was the development of SX 2656 that contained an optimum percentage of the chosen scale inhibitor.

The scale inhibitor is completely soluble in high pH brines and it exhibits a high efficiency at inhibiting high pH induced scale precipitation. This is a nucleation inhibitor, i.e., it inhibits the nucleation of calcium carbonate scale crystals, thus keeping the scaling ions in solution.

**Next-Generation Field Testing**

Following flowline clean up through acidization, field testing of SX 2656 was initiated on well Coevorden-26 in the same manner as the preceding field test, i.e., injection at the wellhead through an atomization nozzle. Injection at a dosage of 10 L/kg H$_2$S (slightly higher than the supplier recommendation of 8 L/kg H$_2$S) yielded an average H$_2$S reduction of 70%. By increasing the dosage to approximately 15 L/kg H$_2$S, the reduction in H$_2$S rose to approximately 93% (against a stipulated performance criterion of >99%). Reducing this dosage to lower levels was immediately coupled with increasing residual H$_2$S levels.

The influence of the linear gas velocity on the product yield is shown in Fig. 8, whereby the observed data have been fitted to a calculated trend utilizing Holt’s two-parameter linear exponential smoothing method. The trend appears to indicate the existence of a threshold limiting value above which the product yield is independent of the linear gas velocity; the injection rate seems to have little influence. During the test, no increase in the pressure drop across the flowline was observed. However, a camera-run revealed the presence of a thick layer of calcium carbonate scale blocking the top half of the flowline (Fig. 9). The conclusion was that the flow-
line acidization preceding the test had only been partially effective.

It was decided to repeat the test after cleaning the flowline through sequential high-pressure water jetting and acidization, followed by a camera-run to confirm that the required clean-up had been achieved. With the scavenger injection rate set at the maximum expected H₂S level (and hence an initial massive overdosing), the results shown in Fig. 10 were obtained. Throughout the test, as the amount of overdosing decreased with increasing H₂S level in the produced gas, an average H₂S reduction (product yield) of 97% was achieved at the expense of an overall average dosage of 20 L/kg H₂S. Again, no increase in pressure drop across the flowline was observed, but a camera-run revealed the presence of thick sludge layer on the bottom of the flowline and randomly deposited cauliflower-like deposits (Fig. 11). Overdosing to achieve the targeted H₂S reduction was not the way forward. The disappointing product yield at higher than expected dosage requirements seen in the first test also indicated that an alternative approach was required to reach our objectives.

**Challenge of Chemical Delivery Method**

Following a period of consultation with Baker Petrolite, the suitability of the hitherto used chemical delivery method was challenged. Preceding field tests had used an atomization nozzle specifically designed to avoid the blockage problems experienced some years earlier with the conventionally designed nozzles. Design review raised the suspicion that an inefficient atomization process might be the key contributing factor to the problems experienced. It was proposed to utilize Bete® PJ series direct-pressure atomization nozzles, adapted to allow the use of high-pressure gas to boost the velocity in the atomizer nozzle. Both laboratory and field evaluation of such gas-assisted (2-phase) atomization nozzles had shown approximately 30% efficiency improvement over the normal single phase atomization.

Again, utilizing sequential high-pressure water jetting and acidization, the flowline was cleaned (confirmed through a camera-run) and a 2-phase atomization nozzle installed, the high-pressure gas being delivered via nitrogen batteries. Injection was subsequently initiated, initially at the supplier recommended product...
dosage and gas-assist pressure of 20-25 bars above the flowing tubing head pressure. Results of this next test are provided in Fig. 12. The percentage H₂S removal initially obtained with the 2-phase atomizer was disappointing. However, scavenging performance could be improved by changing product injection rates and nozzle sizes.

Ultimately, the desired reduction in H₂S was achieved, but only at a high product dosage of some 20 L/kg H₂S. By reducing the gas-assist pressure to only 2-3 bar above the flowing tubing head pressure, an H₂S reduction (product yield) >99% could be consistently achieved at a product dosage of approximately 15 L/kg H₂S. This result was maintained at the end of the test, when the gas-assist needed to be shut-in due to depletion of the nitrogen batteries. A subsequent camera-run through the flowline showed the complete absence of any scale deposits or sludge.

Mitigation of scale build-up in the flowline was only one of the two objectives that were successfully met by the use of the gas-assisted atomizer. The other objective was to obtain higher scavenging efficiencies as was observed in previous laboratory and field trials using the gas-assisted atomizer. However, further evaluation indicated that such increased scavenging efficiencies were primarily observed in low-pressure systems with operating pressures less than 5 to 10 bar. In the Coevorden field, the operating pressures were significantly higher, ranging from 35 to 75 bar. The higher pressure is thought to be the key contributing factor in not achieving further improvement in scavenging efficiency using gas-assisted atomization. The matter was not further pursued, principally because very few of the locations targeted for development had gas available at sufficiently high pressure to achieve 2-phase atomization (implying a compression requirement) and commercially available nitrogen gas generators could not deliver the required pressures. Given the observation at the end of the last test that product yield could be maintained without gas-assist, the decision was made to carry out an additional trial.

Prior to discussing this additional trial, it is of interest to revisit the trial discussed above. The influence of the linear gas velocity on the product yield is shown in Fig. 13. As earlier, the observed data have
been fitted to a calculated trend utilizing Holt’s two-parameter linear exponential smoothing method. Comparing with previously obtained results (in which different atomization nozzles are compared), it is again seen that the product dosage (and hence injection rate) seems to have little influence. In this test, the linear gas velocity did not enter the region lower than 4 m/s where the earlier test showed evidence of the existence of a threshold limiting velocity value. A more rigorous examination of the data obtained from the current test revealed that they could be fitted to the equation:

\[ \text{Product yield (\%)} = m \times \text{linear velocity (ms}^{-1}) + b \quad (r^2 = 0.71) \]

through linear regression analysis with the same mean absolute percentage error as the fit obtained with Holt’s method.

**Dual Injection**

In gas systems where short contact times and high H₂S loading are present challenges to efficient reduction in H₂S, injection of chemical at multiple injection points has often been used to improve the scavenging efficiency. After the 2-phase atomizer trial, a dual-injection approach was utilized in the Coevorden system by injecting the chemical both at the wellhead and at the test header. Use of dual injection resulted in >99% removal of H₂S and thus yielded the desired results in scavenging efficiency. Improved scavenging efficiency in a multiple injection system (in this case two-point injection) can be explained as follows. First, the volume of scavenger injected at the first injection point (wellhead) is typically less than the stoichiometric amount needed to react with the total H₂S in the gas. Presence of scavenger in limiting quantities allows for optimum utilization of the scavenger. Therefore, scavenger injection at the first point removed the bulk of the H₂S (75–85% reduction). Second, injection of the scavenger at the second point (test header) provides a polishing or finishing effect. The neat high-strength scavenger contacts the lean gas (low in H₂S) to react with the residual H₂S molecules that were not removed after the first scavenger injection. The limiting reactant at the second point is the H₂S and can be removed by the high concentration of the scavenger. The dual-injection system using SX 2656, applied through single-phase Bete® nozzles, yielded removal efficiencies in the range of 99%, reduced scavenger consumption to, on average 9 L/kg H₂S, and provided effective control of calcium carbonate scaling.

**Current Development Status**

Prior to the high gas nomination period of Winter 2000/2001, two satellite locations of the Coevorden-17 gas treatment plant were converted to facilitate the production of low-sour gas wells with H₂S levels of up to 220 ppm(v) through dual-injection of SX 2656. An extended optimization program, through which overall product dosages of as low as 7 L/kg H₂S could be achieved as well as consistent product yields of >99%, is coupled with further investigation of the operating parameters affecting the scavenging reaction.

The following observations show that H₂S scavenger injection systems must be specifically designed for each well. Well Coevorden-31 produces gas at an initial rate of 420,000 Nm³/day, gradually declining to 310,000 Nm³/day at a constant flowing tubing head pressure of approximately 90 bar and with a constant H₂S concentration of approximately 220 ppm(v). The linear gas velocity is in the range 9-12 m/s. Injection of SX 2656 at the wellhead alone does not result in the desired H₂S reduction (product yield), and it needs to be augmented with a second point injection at the main production header. At another satellite location, well Coevorden 36 produces gas at a fairly constant rate of 400,000 Nm³/day at a flowing tubing head pressure of 70 bar and with a constant H₂S concentration of 220 ppm(v). The linear gas velocity is approximately 6 m/s. Injection of H₂S scavenger at the wellhead alone yields the desired H₂S reduction, and at this location no second point injection is required. As other wells are being brought on stream, more data can be gathered to hopefully unravel the apparently complex role of interlinked process parameters on the physical chemistry of direct-injection hydrogen sulfide scavenging.

No evidence of scale formation has been encountered to date at any of the locations where it is being applied.
Chemical costs are approximately US$ 11 per kg H₂S (slightly lower or slightly higher in individual cases). Back-up facilities utilizing product B (in pipeline-dry export gas treatment) are required during well start-up, but only when fast production ramp-ups are employed. The benefits of automation of the hydrogen sulfide chemical scavenger injection systems, combining currently available technology into a multifaceted cost saving and reliable tool, are recognized and its economic implementation is being pursued.

Conclusions
1. Selection and application of direct-injection liquid hydrogen sulfide scavengers requires an understanding of the fundamental relationships between operating parameters and scavenging (physico-)dynamics.
2. More fundamental research, preferably executed 'in the field,' is required to unequivocally identify these relationships and to allow 'Best in Class' design of treatment applications.
3. In applying direct-injection liquid hydrogen sulfide scavenging technology, a systematic as well as a systemic approach, with continuing challenge of chemical supplier claims, is required to achieve the desired results.
4. Mutually beneficial solutions to problems can be found between operating companies and their preferred chemical suppliers by not concentrating on internally focused commercial ambitions but by concentrating on: “solving this problem together, regardless,” and reaping the benefits of such solutions.

About the Authors:
J.G. R. Eylander joined Shell as a physical chemist in 1975. Following six years of fundamental research into the dynamic interfacial properties of crude oil/water systems at Shell’s Rijswijk research laboratories in the Netherlands, he was transferred to the Production Technology department. Following assignments in Shell operating units, he was transferred to the Nederlandse Aardolie Maatschappij (NAM) in 1995 as Senior Production Chemistry and Shell Global Production Chemistry consultant. Hanneke Holtman is currently a maintenance engineer with the Groningen Long Term team in NAM. She joined NAM in 1999 after attaining a Mechanical Engineering degree from the Groningen Hogeschool, the Netherlands. During her first assignment as an Operations Engineer, she actively participated in the team responsible for implementing H₂S scavenging technology and operation within NAM. Tauseef Salma is the group leader for Microbiocides and H₂S Scavenger Technologies for Baker Petrolite. Dr. Salma obtained her B.S. degree in Chemical Engineering from University of Engineering and Technology in Lahore, Pakistan, and Ph. D. in Chemical Engineering from Rice University in 1997. Mingdong Yuan is the Oilfield Scale group leader at Baker Petrolite. Mr. Yuan obtained his B.S. degree in Applied Chemistry from Southwest China Petroleum Institute in 1982 and Ph. D. in Petroleum Engineering from Heriot-Watt University in 1989. He conducted postdoctoral research at Heriot-Watt for five years and joined Baker Petrolite in 1994. James Johnstone is the NAM Account Manager for Baker Petrolite. Mr. Johnstone obtained his BSc. (Hons) degree in Chemistry from Aberdeen University. He has over ten years of experience in offshore oil & gas industry in the U.K., Norway, Denmark and Netherlands.

References:

Acknowledgment
We thank NAM and Baker Petrolite for their permission to publish this paper. In particular, very special thanks go to NAM’s operations staff, not only for providing gas treatment plants and field personnel to support this project while maintaining active production operations, but more importantly also for their continuing support and dedication in the face of adversity. We have exceptional pride in mutual refusal to yield. This article is based on paper SPE 71541 (see reference 6).