First Polymer Injection in Deep Offshore Field Angola: Recent Advances in the Dalia/Camelia Field Case

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Summary
The Polymer injection project on the Dalia field, one of the main fields of Block 17 in deep offshore Angola, is a world first in both surface and subsurface aspects. An in-depth integrated geosciences and architecture study culminated, in January 2009, in the start of polymer injection in one of the Dalia water-injection wells. The Dalia field is a high-permeability sandstone reservoir (> 1 D on average) and contains a medium-viscosity oil (1 to 11 cp under reservoir conditions).

The key challenges of the project were to start polymer injection
• Very early in the field development (first oil was in December 2006). 
• With much wider well spacing than in any other project 
• Under high-salinity conditions (>25 g/L)
• With the specific logistics of a remote deep offshore area

A phased approach has been retained in order to progressively de-risk the project, starting from a single-well, short-duration injectivity test, followed by a full line injection in the three injectors of one of the reservoirs, and hopefully concluding with an injection extension.

A single-well, short-duration injectivity test was successfully implemented in the first quarter of 2009. The Phase 1 project started on 8 February 2010 in the Camelia reservoir. Viscosified water was injected into one of the four injection lines of the Dalia field (average BSW) of 20% on the associated producers at beginning of Phase 1 polymer injection]. By December 2011, more than 5 million bbl of cumulative of polymer solution has been injected in the Camelia reservoir.

The specificities of the Dalia field (large well spacing and low BSW at polymer-injection startup) mean a late response if the usual EOR monitoring techniques are applied. Various monitoring options were considered to verify the injected-polymer-solution properties in situ, and to accelerate the sanction for a full-field development. The studies concluded with a recommendation to drill a well to sample in situ the injected viscosified water. Location of the sampler well at a distance of 100 m from an injector, and the best timing to drill the well, were based on a 4D-seismic-data history match and waterflood-performance forecast.

Introduction
Deep offshore exploration has been very successful in Block 17 Angola. After a first discovery with Girassol in the Oligocene levels, a Total operator discovered the Dalia field in 1997 in the Miocene levels, containing more-viscous oils (see Appendix A).

Very early in the geoscience studies, oil viscosity was identified as the main limiting factor in water-injection recovery. Considering the key parameters of the reservoir—including medium viscosity, low temperature, and high-permeability sandstones—polymer injection was positively screened as a potential EOR method for the Dalia field.

Extensive integrated architecture and geosciences feasibility studies of polymer flooding started in 2003, 3 years before production startup. Many challenges needed to be addressed because no EOR or polymer project had ever been implemented in deep offshore conditions.

Basic Field Data
The Dalia field is 130 km offshore Angola in Block 17 with an estimated 1 billion bbl of recoverable oil stretching over 230 km². Water depth varies between 1200 to 1400 m, with reservoirs 800 to 1000 m below the seabed.

The field comprises four main turbiditic reservoirs: Lower Main Channel, Lower Flanks, Upper Main Channel, and Camelia (see Appendix B).

The very high quality of the 3D-seismic data allowed direct mapping of the main architectural reservoir elements, such as sands and clays areas only 6 to 10 m thick. The channel complexes can be as thick as 100 m, but are divided and subdivided into different heterogeneous sections with alternating layers of oil sands and clays, piled in complex geometries.

The field permeability ranges from a few hundreds of millidarcies to several darcies, with an average permeability greater than 1 darcy.

The reservoir temperature is between 45 and 56°C, and the pressure in the range of 215–235 bar. The 21 to 23°API oil is slightly undersaturated, with medium viscosity ranging from 1 to 11 cp under reservoir conditions. The shallowness of the reservoirs partly explains the viscous nature of Dalia’s oil.

Water viscosity is in the range of 0.5 cp under reservoir conditions.

The field is developed by water injection, using a floating production, storage, and offloading (FPSO) vessel with 31 deviated or horizontal subsea injector wells and four injection flowlines. A single flowline generally injects in several reservoirs as well as several systems. Maximum water injection is 405,000 BWPD.

Production is achieved through four production lines and 37 producers. First oil was on 13 December 2006. The 240,000 B/D oil-production plateau was reached after a few months and has been maintained since then. More details on the field development can be found in Thebault (2007) and Caïe et al. (2007). A schematic of the layout is given in Fig. 1.

Seawater is desulfated to prevent any risk of sulfate barium deposit, and is injected from the start. Produced water is to be re-injected after water breakthrough. Table 1 provides the characteristics of the desulfated seawater and formation-water compositions.

By June 2010, 25 producer wells were connected; water cut has occurred on some of them. Water cuts range from a few percent to more than 40%. The current water-injection salinity is in the range of 50 g/L.

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Polymer-Injection Feasibility Study

In 2003, an integrated geoscience and architecture feasibility study was launched, with four main objectives to demonstrate the feasibility and potential benefits of injecting polymer in the Dalia field:

1. Viscosification—A dedicated internal laboratory program was launched to select a polymer and acquire the basic data required to make a sound evaluation of incremental oil.

2. Resources Estimation—Simulation with and without polymer using specialized software and laboratory input parameters, including the design and optimization of the injection strategy (start date(slug concentration/post slug concentration/partial or full-field injection).

3. Pilot—Objectives and design.


An extensive description of the feasibility study can be found in Morel et al. (2008). The key findings were the selection of a high-molecular-weight (18,000–20,000 Daltons) commercial hydrolyzed polyacrylamide, which allows developing adequate viscosity in the salinity conditions of Dalia (25 g/L at start, up to 52 g/L based on the simulation of the recycling of produced water). Polymer-solution viscosity strongly decreases when the salinity increases from 25 to 40 g/L, but does not vary beyond [measurements in Morel et al. (2008)]. Design concentration is 700 ppm of active material. Significant mechanical degradation can be anticipated in the surface facilities, and values from 25 to 50% were measured during tests through the subsea well chokes. Adsorption was measured in different core samples, from 200 md to several darcies, and remains low, below 30 microg/g of rock.

Incremental oil is estimated to be in the range of 3 to 7% of original oil in place, depending on the reservoir (four different reservoirs with different oil viscosity and permeability heterogeneity) and on the start date of polymer injection.

Very early in the studies, it appeared that the most unfavorable scenarios of polymer injection were met when the injectivity of the viscous-water solutions did not achieve sufficient reservoir voidage. Consideration of the voidage replacement was then considered as mandatory in the concept studies.

A phased approach was therefore set up, comprising three key steps:

1. A single-well injectivity test to demonstrate injectivity and operability of polymer injection in the Dalia conditions.

2. A Phase 1 involving injection of polymer in the full injection flowline of Camelia to demonstrate long-term injectivity and operability and to ensure that the polymer is efficient (that is, it remains viscous in the reservoir, bringing additional oil).

3. The extension to full-field injection if positive results were observed in previous steps.

Architecture studies selected the concept of a polymer solution prepared from powder, under a continuous process that is described in the following.

Surface Facilities and Logistics for Injectivity Test and Phase 1

Even if the EOR schemes were studied very early on in the Dalia field development, the FPSO was already under construction, when the preliminary studies of polymer injection ended positively and any major change to the vessel’s specifications would have delayed the development.

Fortunately, some small space of a few tens of square meters could be selected to install the powder polymer process unit (skid) for the first tests.

The Phase 1 skid was designed for a single-well injectivity test followed by polymer injection in the 3 to 5 wells of the 10-km subsea injection line W764.

The injection is prepared in two steps. First, a mother (concentrated) solution is prepared from desulfated seawater and is matured during a 30-minute to 1-hour time period. Then, the mother solution is injected under pressure (maximum 150 bar) into the injection-water system for dilution through a static mixer and then sent to the riser.

The maximum capacity of the skid is 21 m³/h of high-concentration solution at 9,000 ppm. It is possible to prepare a lower rate but higher concentration solution, making subsequent dilution in the static mixer more difficult to achieve.

The 700-ppm initial diluted concentration was increased to 900 ppm after the injectivity test to obtain the target viscosity of 2.9 cp in the reservoir (50°C, shear rate a few sec⁻¹), thereby mitigating some degradation during the process, pumping, and transit through the choke at the subsea-tree level.

It is important to highlight the fact that polyacrylamide solution exhibits a strong shear-thinning behavior, and that control measure-

### TABLE 1—WATER COMPOSITIONS

<table>
<thead>
<tr>
<th>Salt (g/L)</th>
<th>Formation Water</th>
<th>Desulfated Seawater</th>
</tr>
</thead>
<tbody>
<tr>
<td>Divalent</td>
<td>21.3</td>
<td>0.3</td>
</tr>
<tr>
<td>Monovalent (global)</td>
<td>96.4</td>
<td>24.6</td>
</tr>
<tr>
<td>NaCl</td>
<td>93.9</td>
<td>23.6</td>
</tr>
<tr>
<td>TDS</td>
<td>117.7</td>
<td>24.9</td>
</tr>
</tbody>
</table>

Fig. 1—Injection and production layout of the four Dalia reservoirs.
ment cannot be achieved at the ultralow shear rates prevailing in the reservoir (lower commercial Brookfield viscometer operating shear rate is 72 sec⁻¹). QA/QC target viscosity should be set accordingly.

The skid was tested to produce 200 m³/h of viscosified water at 900-ppm polymer concentration. The schematic shown in Fig. 2 describes the main principles of the injection scheme.

After partial qualification tests in France during construction, the skid was installed, commissioned, and readied for injection on the Dalia FPSO by the end of December 2008.

The polymer is supplied in 750-kg big bags (Fig. 3) imported from Europe and stored on shore in Luanda. Shuttle boats deliver the bags to the FPSO, where they are emptied into a silo by a pneumatic-transfer process using a combination of transfer screw and dry air blowing.

A diagram and a description of the polymer process used for producing the mother solution are detailed in Appendix C.

A general view of the skid installed on the FPSO Dalia is shown in Fig. 4. The actual skid in operation on the FPSO Dalia is shown in Fig. 5.

Procedures for QA/QC at the delivery of the polymer onboard and during fabrication of the mother solution have been written and are executed in a dedicated laboratory onboard the FPSO (see Appendix D). Specific training of the local operators has been achieved by the Total-headquarters specialists, who regularly come aboard the FPSO to check the equipment, perform maintenance, and eventually adapt the protocols for better reliability.

**Design and Sequence of the Preliminary Injectivity Test**

**Line/Well Selection.** As mentioned previously, the Dalia field contains four different reservoirs, as noted in Fig. 2. Water injection is through four subsea lines, each generally injecting in at least two different reservoirs. Nevertheless, this is slightly different for Line W764, which will mainly deliver water to a single reservoir (Camelia). This has been the key reason for selecting the Camelia reservoir for the phased approach. The DAL710 well was selected to validate the injectivity of polymer solutions based on the following criteria:

1. It is one of the Camelia water-injector wells.
2. It is a deviated well (and not a horizontal well), making interpretation of pressure falloffs less uncertain.
3. It was already drilled and tested, allowing reliable data for designing the injectivity-test sequence.
4. A significant water-injection baseline was available at the time of the injectivity test.
5. Last but not least, it is equipped with bottomhole-temperature and -pressure gauges, allowing a precise injection monitoring, and with a two-zone selective completion.
6. A schematic of the well completion is provided in Fig. 6.

**Sequence of Tests.** The objectives are (1) to characterize the mode of injection by successive flowrate steps, carefully monitoring the levels of pressure, and (2) to demonstrate our capability to prepare...
high-quality polymer solutions at the target rate and concentration under offshore operating constraints.

Two viscosity values were tested, for geosciences purposes, not only to observe the well injectivity at different viscosities, but also to determine operating issues to test the polymer skid at a higher mother-solution flow rate. Injection was interrupted from time to time to observe the pressure falloffs. Geoscience success criteria were defined as

- A minimum injection rate of 3,500 BWPD at the target viscosity, based on the field-voidage requirement for that well.
- A minimum cumulative injected volume of 75,000 bbl of viscousified solution to characterize the injectivity and the operability of the polymer skid.

Operational Results of the Injectivity Test

The test started on 24 December 2008 and ended on 3 April 2009. The operability of deep offshore polymer injection using desulfated seawater was demonstrated successfully. Uptime averaged 80%, and polymer solution prepared onboard the FPSO was of good quality. Since the beginning of polymer injection (December 2008), filterability has been good (FR < 1.1) and the insoluble content low (< 0.5%). The oxygen content of the diluted polymer solution at the riser departure is also very low (< 10 ppb).

Permanent pressure-drop measurement upstream and downstream of the subsea well choke recorded a pressure-drop (ΔP) change on the shift from pure water to polymer solution; this was further confirmed during Phase 1, as demonstrated in Fig. 7. The test largely fulfilled the geosciences objectives (Fig. 8):

- An injection rate of 13,000 BWPD at the target viscosity of 3.3 cp at the riser head (vs. an objective of 3,500 BWPD).
- An injection rate of 12,000 BWPD at the second target viscosity of 5.6 cp at the riser head.
- A cumulative injected volume of 390,000 bbl above 3.3 cp (vs. an objective of 75,000 bbl).
- No indication of plugging or loss of injectivity was observed.

The test also highlighted the fact that polymer injectivity was better than anticipated in the unconsolidated sands of Dalia. Unfortunately, interpretation of the pressure falloffs was very difficult, mainly for operational problems. The closure of the well was not instantaneous, and the derivative curves were highly noisy.
Status of Phase 1

After the successful completion of the single-well polymer-injectivity test on DAL710, an interim period of water injection only was initiated with different objectives:

• Measure the pressure behavior of DAL710 after polymer injection.
• Establish the water-injection baseline for each of the other two injectors, DAL713 and DAL729.
• Inject a tracer ahead of the polymer front in the three injector wells of Camelia.

Simultaneously, the polymer skid was fully inspected and some improvements made based on the lessons learned from the injectivity test, such as reinforcement of the piping to reduce vibration in the high-pressure sections and revision of the automated sequences of the powder-slicing unit (PSU) to reduce downtimes.

The interim water period was followed by single-well polymer injection in DAL713 and DAL729 to acquire data for managing the full-line injection of Phase 1. Highly consistent data were obtained when comparing the pressure drop ($\Delta P$) across each of the subsea well chokes when water or viscosified water are injected, as shown in Fig. 11.

Phase 1 officially started on 8 February 2010, with injection on the full injection flowline of Camelia. By June 2010, a total of 3.284 million bbl of polymer solution had been injected in the three wells on the line, including the 0.390 million bbl of the injectivity test, as described in Fig. 9.

Careful pressure monitoring indicates that injectivity is still excellent, and no impairment has been observed after the high overall volume of polymer injected. The quality of the solutions remains in line with the specifications, maintaining a low filter ratio (1.1) and low insolubles content (0.5%).
Polymer solution are consistent with retained hypotheses under the in that well, and to demonstrate that the in-situ properties of the deeper horizon. The objective will be to sample water with polymer sampler well close to an injector, including a production target in a full-field implementation from 3 to 4 years after Phase 1 Camelia polymer injection are increased when the polymer is injected early, particularly if a fixed production period is considered. This represents a strong incentive to move to full-field implementation as soon as possible.

On the other hand, full-field injection cannot be sanctioned until Phase 1 injection in Camelia has proved successful, and our best estimates indicate that 3 additional years are required to build the full-field polymer facilities once the project is sanctioned.

Because of the long distance between injector and producer (1000 to 1500 m), the production response to polymer injection is slow; whether polymer breakthrough or water-cut decrease (or slowdown of the water-cut increase), the phenomenon takes between 3 to 5 years (Fig. 10).

Different options have been considered to try to demonstrate polymer efficiency in a shorter time, and move the sanction of the full-field implementation from 3 to 4 years after Phase 1 Camelia startup to 1 to 2 years before.

Sampler Well. The drilling of an infill well (a producer, an injector, or an observation/sampler well) was considered. After sound evaluation of pros and cons of each option, including feasibility, value of information, and economics, the choice made was to drill an infill sampler well close to an injector, including a production target in a deeper horizon. The objective will be to sample water with polymer in that well, and to demonstrate that the in-situ properties of the polymer solution are consistent with retained hypotheses under the salinity and concentration conditions of the sample. Polymer flooding being a proven EOR technique in highly permeable sandstones onshore, it is assumed that if the in-situ viscosity of the polymer is in line with the retained design, after passing through the whole set of injection facilities specific to deep offshore implementation, incremental recovery should be as expected.

Location. The location of the sampler well has been selected close to the DAL713 injector to minimize the risk of drilling in an area with no polymer. The high quality of the 4D-seismic data acquired in mid-2008 was of great help in identifying a water-flow path between the existing injector DAL713 and producer DAL708, as already suspected based on reservoir monitoring analysis. The 4D anomalies can be nicely reproduced by numerical simulation (see Appendix E). Based on these simulations and the concentration-evolution forecast, the timing of the well drilling is fine tuned in order to secure the in-situ sampling (Fig. 11). The concentration map is linked to the volume of polymer injected in DAL713.

Sample-Tool Qualification. An extremely detailed study was undertaken in our laboratories to check that representative samples of the in-situ polymer solutions can be taken with existing sampling tools, and that all analytical issues might be solved to measure the key properties of the solution. Different modular-dynamic tester (MDT) tools were tested on shore to check that the solution of polymer did not undergo significant mechanical degradation during sampling. The low-shock sampling configuration MDT tool was qualified during these tests.

Mud Contamination. Another issue with the sampling in a newly drilled well is mud contamination. The MDT will be equipped with a live-fluid analyzer (LFA) to prevent the sample from contamination as much as possible, and with a DV rod to measure the viscosity of the fluid in the flow line. The samples will be taken on the rig floor with PVT bottles and a control protocol then transferred to the FPSO laboratory for evaluation of the in-situ properties (concentration, viscosity, and degradation). If samples were found to be contaminated (presence of oil, mud, or solids), analytical procedures have been set up in order to remedy the situation.

Production Testing and Analyses. During the second phase of the drilling of the sampler well, 35 days later, the part of the reservoir swept by polymer will be tested (flowed) on the rig. The produced water will be sampled on the rig upstream of the choke valve using a special sampling tool connected to the HP line in order to pre-
The single-well injectivity test was successfully implemented in Angola in the Dalia/Camelia reservoir started in the first quarter of 2009. High injection rates of polymer solution were achieved (15,000 BWPD at 3.3 cp for a target of 3,500 BWPD), demonstrating that the same level of reservoir voidage injection was achieved (15,000 BWPD at 3.3 cp for a target of 3,500 BWPD). Laboratory and onshore tests have demonstrated that it is possible to sample a polymer solution with minimum acceptable mechanical degradation with a specific MDT tool (“low-shock” MDT). A full set of analyses and procedures has been defined so that in-situ properties of the polymer solution may be evaluated from the collected samples.

Secondary Objective of the Sampler. Besides the primary objective of polymer monitoring, and after closing the completions in the layers submitted to polymer injection, deeper reservoirs that are not yet developed and were identified thanks to seismic data will be put under production with that well.

Conclusions
The world’s first deep offshore polymer-flooding injection started in Angola in the Dalia/Camelia reservoir in early 2009.
- Many parameters favorable to polymer injection are found in conjunction with this field, including highly permeable clean sands, medium oil viscosity, and low temperature.
- Nevertheless, it is a true step change compared with the many previous polymer projects because of the specific logistics of a deep offshore remote area, the much larger well spacing, the salinity of the injected water (>25 g/L), and the very early implementation of EOR in the field life.
- There were two key factors in effectively initiating polymer injection only 3 years after first oil: (1) early screening of EOR opportunities, during the development studies; and (2) integration of geoscience and architecture studies from the beginning of the project.
- A phased approach has been retained in order to progressively derisk the project. These phases include (1) a single-well, short-duration injectivity test; (2) a full line injection in the three injectors of one of the reservoirs; and, ideally, (3) a full-field implementation.
- The single-well injectivity test was successfully implemented in the first quarter of 2009. High injection rates of polymer solution were achieved (15,000 BWPD at 3.3 cp for a target of 3,500 BWPD), demonstrating that the same level of reservoir voidage is as achievable with viscosified water as with water only. A cumulative volume of 390,000 bbl has been injected without any injectivity reduction. The operability of the polymer-powder skid has been proven during the test, and very-high-quality solutions have been prepared, fully in line with the QA/QC requirements.
- Phase 1, consisting in the injection of polymer in one full line of the Dalia field, dedicated to the Camelia reservoir, started in the first quarter of 2010. An overall volume of more than 3 million bbl had been injected by June 2010. No impairment of the well injectivity has been observed, and very-high-quality solutions have been prepared.
- The drilling of a sampler well was proposed to ensure proper sanction to full-field implementation in 1 or 2 years. Laboratory and onshore tests have demonstrated that it is possible to sample a polymer solution with minimum acceptable mechanical degradation with a specific MDT tool (“low-shock” MDT). A full set of analyses and procedures has been defined so that in-situ properties of the polymer solution may be evaluated from the collected samples.
- The very promising results obtained during the injectivity test and the beginning of Phase 1 open the door for many other offshore polymer-injection projects.
- This project is also a major step toward the implementation of more complex chemical EOR techniques offshore, such as surfactant and any combination of alkali, surfactant, and polymer.

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References
Appendix A
Fig. A-1 shows the Dalia field discovered in 1997.

Appendix B
Fig. B-1 shows the four reservoirs of the Dalia field.

Appendix C
Fig. C-1 shows a schematic of the powder polymer process. The polymer is transferred from the silo (1) to a feeding storage tank called the weighing hopper (2). It is then dosed with a regulated screw and poured into a grinding machine called the PSU (3), where it is brought into contact with water. The water used at this stage is a desulfated seawater of almost constant characteristics (29-g/L salinity, no oxygen, and no bacteria). Grinding proved to clearly reduce the time needed for maturation of the solution, which is achieved in four successive maturation tanks (4). 30 minutes were sufficient for maturation: Samples were taken and, under further stirring in the laboratory, viscosity was measured after 45, 60, and 75 minutes without any significant change in the viscosity. The concentrated-polymer solution (mother solution) is then pumped (5) up to 3 bars and filtered (6), and then a triplex pump (7) is used to raise the pressure to the injection level, with a maximum of 150 bar.

It is worth noting that a nitrogen blanketing (8) is in place as well as a nitrogen injection behind the dosing-screw outlet. This is required for two primary reasons—to maintain the integrity of the injection line on the seafloor because it is made of carbon steel and to prevent the risk of oxidation reaction of the polymer with the Fe ions.

For these reasons, the oxygen content in the water must be kept below 30 ppb. The dilution water for making up the required injected solution will be a combination of production water and desulfated water.

Appendix D
Fig. D-1 shows the laboratory of the Dalia FPSO. The QA/QC protocols are used throughout the process of polymer delivery, transport and dissolution and polymer-solution injection. In order to ensure the preparation of a good polymer solution, the main properties to be checked include the following.

**Hygrometry.** The powder must contain as little water as possible. Humidity effectively causes the grains to aggregate, which is risky for pneumatic transfer. But the polymer powder must not be completely dry either so as to avoid the formation of fish eyes during the dissolution process. The halogen-desiccator method is used.

**Viscosity.** This is the target property of the application. The method used is the Brookfield measurement at 50°C and 72 sec⁻¹ (because polymer solutions are non-Newtonian fluids, it is important to always achieve control measurements at the same shear rate).

**Insoluble Content.** During the dissolution process, the powder may not be completely and efficiently wetted for various reasons. This can result in the formation of non-dissolved particles referred to as “insoluble.” Several possible reasons for the creation of insoluble substances have been identified. The first of these is humidity/temperature; if the humidity rate in the local atmosphere is too high, aggregated grain may be poured into the water. The second possible reason is drying of the powder. Various systems are used by the powder producers to dry the ground polymer at the end of the production chain. Basically, the more smoothly the drying is carried out, the better the powder will dissolve. This test run on the mother solution is an indication of the quality of dissolution. The method used is vacuum filtration on a 100-micron mesh grid.

**Filterability.** This test mimics the entrance of the polymer solution in the porous medium by passing the diluted solution through a filter with circular pores. It is an indicator of the solution injectivity. The method used is filtration at 2 bar on a 5-micron nucleopore membrane.
Fig. C-1—The polymer process onboard the FPSO *Dalía*.

Fig. D-1—QA/QC laboratory for polymer on the FPSO.

Simulated Injected Water at DAL713 at Time of 4D and 4D dv/v From Warping.

Fig. E-1—4D seismic to locate the sampler well.

Fig. E-2—4D-seismic anomaly between DAL713 and DAL708.
**Free Acrylamide Content.** Acrylamide monomer is labeled carcinogenic (R45 risk phrase). There must be less than 100 ppm in the polymer powder. The method used is high-pressure liquid chromatography.

**Particle-Size Distribution.** Fines and coarse particles promoted the formation of fish eyes in the past, but it is no longer a problem with the PSU. The vibrating-sieve method is used.

**Hydrolysis Degree.** This is the proportion of acrylate monomer in the chains. This characteristic plays a key role in the viscosification mechanism, the adsorption, and the precipitation behavior. The colloidal-titration method is used.

**Oxygen Content.** The presence of oxygen is highly detrimental to the integrity of the polymer solution. The water used for the polymer dissolution must be deoxygenated. The oxygen-probe method is used.

The powder lots leave the plant with a certificate of conformance, guaranteeing the key properties just listed. On reception of the big-bag containers on the FPSO Dalia, the properties of the powder are quality-controlled. In regard to the prepared-polymer solution, different sampling points are installed all along the dissolution process. Special sampling devices are installed on high-pressure points to avoid polymer degradation caused by shearing [see API (1990)]. The mother solution can be sampled at the exit of the PSU, on each maturation tank, and downstream of the high-pressure pump. Insoluble content and viscosity are measured. A correlation has been established for estimating the polymer concentration based on the mother solution’s viscosity. The diluted solution is sampled downstream of the static mixer. Oxygen content, filterability (filter ratio), and viscosity are measured on a routine basis. Most of the measurements are performed every 6 hours in the dedicated polymer laboratory.

**Appendix E**

Figs. E-1 and E-2 show the 4D seismic to locate the sampler well.

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