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Research Article

Artificial Lift Selection and Testing for an Enhanced Oil Recovery Redevelopment Project-Lessons Learned: From Laboratory Results and Pump Test Facility Experiments to Field Pilots

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ABSTRACT

OMV Austria E&P GmbH is currently focusing on a significant chemical enhanced oil recovery (EOR) redevelopment project for a mature oil field. Cost-effective and flexible artificial lift systems (ALS) for the production wells are seen to be crucial for the economic success of this project. This paper shows the artificial lift selection process and results for the enhanced oil recovery redevelopment project, based on laboratory results, pump test facility experiments, and field pilots.

The selected ALS for the chemical EOR field must be capable of dealing with changed fluid properties due to back produced polymer-water-oil mixture and achieve the target production rates at a reasonable pump run life. Field experience and an extensive testing program provided the information and data for the design of the ALS. Potential ALS types were screened according to their rate capabilities and flexibility, OMV Austria's in-house experience, necessary surface networks, and design constraints. A literature review showed that there is only limited information available about the required adaptations and mitigation measures for the pump designs for polymer back producing wells.

The consecutive risk assessment resulted in the necessity of testing the pump performance in the in-house laboratory, OMV Austria's fields, and the pump test facility at the Montanuniversitaet, Leoben. The effects of chemical and rheological behavior of the polymer solution on the production system were analyzed and demonstrated the complexity of handling non-Newtonian fluids. The detailed analysis of the gathered information resulted in the decision to select electrical submersible pumps (ESPs) and sucker rod pumps (SRPs) as the artificial lift methods for the field redevelopment. The ESP lab test results provided a clear indication for severe derating of the pump performance when pumping polymer fluid, which can reach more than 50%, depending on the polymer concentration. The performed polymer ESP pilot well tests provided the most realistic conditions and confirmed the lab test results. The SRP lab tests have indicated an increase of the viscous friction between 20% to 50%, depending of the strokes per minute.

This paper describes the selection process of ALS for the producing wells in a chemical EOR field, based on testing results and field pilot experience of ESPs and SRPs within OMV Austria. The required design adaptations due to the chemical and rheological behavior of the back produced polymer are identified, implemented, and installed in the field.

Keywords: Non-Newtonian fluids; Hydrocarbons; Polymers; Artificial Lift Systems for Field Redevelopment; EOR (Enhanced Oil Recovery)

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INTRODUCTION

For more than 80 years, OMV is producing oil and natural gas in Lower Austria. In the past decades, the large onshore oil field Matzen became super mature, and the economic recovery of hydrocarbons a challenge. In a significant field redevelopment project, the injection of polymer is supposed to increase the oil recovery of two heavily water flooded horizons. The objective of this paper is to describe the ALS assessment for the new horizontal producers on the one hand and ALS testing for the active producers, on the other hand, for the application in the redeveloped polymer field.

The typical EOR chemicals are polymer, alkali, and surfactants [1]. Polymers, mixed to the reinjected reservoir water, increases the viscosity of the aqueous phase. Its mobility is increased; thereby, oil recovery is increased by reducing permeability to water in the reservoir [2], as the waterfront moves from the injection well towards the producer. Surfactant solutions reduce the interfacial tension between the aqueous phase and crude oil by reacting with individual crude oil constituents. The change in interfacial tension reduces the capillary forces of trapped and residual oil. The surfactant adsorbs on reservoir rock grains and changes the rock wettability. Emulsification is caused by solubilizing interfacial films [3]. The mechanism of alkali flooding is similar to that of surfactant solutions, but chemicals that aid the oil recovery are generated in the reservoir by a saponification reaction [4]. A saponification reaction is defined as a reaction between a caustic alkali and an organic acid to form a soap. The caustic alkali is injected into the waterflood, whereas the organic acid is obtained from the acidic component of the crude oil. Nowadays, only polymer flooding has been applied on a large scale.

In contrast, combinations of the typical chemicals, surfactant-polymer flooding, alkaline surfactant-polymer flooding were limited to field pilots so far [5]. Once the mixture of the modified water phase and oil reaches the producer, the ALS needs to lift it to the surface. As the added polymer alters the fluid behavior of water from Newtonian to non-Newtonian, a particular focus needs to be set to the selection of the ALS.

In the past, several publications have summarized a guideline for the selection of ALS in conventional oil reservoirs [6]. Long-term reservoir pressure, well productivity trend, and reservoir fluid characteristics have been indicated to be the most critical parameters. Paraffin or sand production may cause early failures for some kinds of lift systems than for others. The producing gas-liquid ratio (GLR) is significant, as free gas at the pump's intake is a significant problem to most of the pumping lift method, but is beneficial for gas lift systems. Depending on the field's infrastructure and majority, surface facility constraints have to be considered. The literature contains two different types of selection methods: selection by advantages and disadvantages and selection by expert systems. The selection by advantages and disadvantages requires a detailed listing of the benefits and limits of each ALS [7] under a broad range of categories. Some benefits and limits are open to discussion, and the outcome is very subjective and depending on the design engineer. Advancement in the selection is achieved by using expert systems [8,9]. These systems include rules and logic to select the best ALS as a function of user input, well, and operating conditions. Nevertheless, the advancement in chemical EOR changes the operating conditions for most of the ALS, handing back-produced fluids. Besides, EOR fields are categorized as mature fields, where the infrastructure of the field itself gives many constraints.

Field experience from existing chemical EOR fields showed problems, which are untypical for conventional oil production. A review of the Daqing oil field in China reported severe problems with progressive cavity pumps (PCP) and beam pumps. Carbonate and silicate scale deposition on the surface of the rotor and stator of progressive cavity pumps destroyed the internal fit structure and resulted in a decline of the pressure capacity and an increase in leakage rate. Besides, a more fluctuating frictional torque load was measured, in comparison to PCP installation in conventional fields. Scales on tubing, rods, barrel, and plunger were seen in beam pump applications, which resulted in stuck pump situations and broken rods, as a result of fatigue [10]. Severe buckling and rod-tubing wear was reported for beam pumps because of considerable friction at the pump plunger [11]. Rotor fit, scale prevention, and removal techniques have been applied to increase the ALS meantime between failures. A new trend of well failures was observed at beam pumps in a polymer flooding oil field in the south of Oman [12]. The downhole equipment failures have increased significantly since the injected polymer is back produced. The high shear stresses, caused by the non-Newtonian mixture of polymer–water–oil, resulted in floating rods and massive rod – tubing wear. Besides, aggressive fluid caused severe corrosion problems.

A status report of electric submersible pumps (ESP) in the polymer flooded Mangala Field, India, indicated a significant pump performance reduction and a motor shaft break because of increased torque requirements [13]. The polymer can build a coating on the ESP motor housing since it precipitates under certain conditions on hot surfaces [14]. This coating reduces the heat transfer from the motor to the reservoir fluid, so that the motor further heats up until it either shuts down by automatic alarm setting or burns.

This publication shows an ALS selection methodology for chemical EOR fields, ALS lab testing, and verification in a case study in the field.

ARTIFICIAL LIFT SELECTION PROCESS

The proper artificial lift selection for polymer producers is one of the essential critical decisions to continue the redevelopment project successfully. In the following, the applied artificial lift selection process is presented in detail. The process consists of three elements:

- Technology Categorization
- Selection Criteria Definition
- Artificial Lift Assessment & Ranking

Technology categorization

One of the most practical manuals guiding through a technology assessment is the DNV-RP-A203 (DNV-RP-A203 Technology Qualification in 2013) [15]. Even throw this recommended practice cannot be fully applied for a whole redevelopment project; the basics of technology categorization can be followed. The assessment of DNV-RP-A203 describes within a matrix (Table 1) the combination of the degree of technological novelty and application novelty. Four categories are defined:

1 – No technical uncertainties (proven technology)

2 – New technical uncertainties

3 – New technical challenges

4 – Demanding technical challenges.

The table indicates that the uncertainty of a successful technology application increases with decreasing knowledge of the application area and of the technology itself.

Selection criteria definition:

The selection criteria for the artificial lift system application in polymer back producing wells have been defined as:

- **Surface infrastructure:** In general, ALS with a small footprint and low surface infrastructure requirements are preferred. Especially in mature fields, a potential new ALS needs to work with the existing supply lines.

- **Reservoir & well constraint:** The ALS needs to match the well trajectory, wellbore size, and pump setting depth. Furthermore, the requirements for the potential ALS are the production rate match, the long – term rate flexibility, and the compatibility with the produced fluid properties.

- **Experience & costs**: ALS with in-house experience and ALS with application experience under similar properties are preferred. HSE regulations and budget need to be fulfilled.

- **Handling of back-produced fluid:** The production of the polymer–laden water-oil mixture might result in several production issues like excessive corrosion, sand production, paraffin accumulations, and scale deposition. The selected ALS needs to achieve a substantial meantime between failures under these operating conditions.

Artificial lift assessment and ranking

The defined criteria from the previous step are applied to the ALS with a good technology category. A high technology category is an automatic drop out of the respective ALS. The artificial lift assessment is done in a tabular form, which allows a simple grading of each criterion with good, limited, and inadequate adjectives. Finally, the ALS are ranked according to the assessment. The following case study applies the presented concept for two groups of production wells, having a different production rate.

METHODOLOGY AND CASE STUDY

The 8.Tortonian Horizon (TH) and 9.TH of the Matzen oil field are shallow-marine deltaic oil and gas reservoirs with an average permeability of about 500 mD and 25% porosity. With oil viscosities of 16 cp in the 8.TH and 10 cPin the 9.TH at initial conditions, the oils are ranked as not very viscous. The formation water salinity is approximately 20000 ppm (total dissolved solids). The initial reservoir pressures and temperatures were 113 bar and 50°C for the 8.TH and 130 bar and 52°C for the 9.TH, respectively. The long history of water flooding results in the average water cut (WC) of about 95%.

Enhanced Oil Recovery (EOR) Redevelopment Strategy

The chemical EOR redevelopment project has the target to increase the recovery factor of the field. Therefore, a large number of new horizontal wells for polymer injection and reservoir flooding are to be drilled and operated. The wells are arranged to form polymer injection patterns with alternating producer and injector wells with approximately 200 m lateral distance from each other. The multilayer reservoirs are single targets; no coming led production of reservoirs or multilateral wells are planned. The new horizontal wells are drilled with a 100 m long tangent section before diving into the reservoir section. Figure 1 illustrates the target reservoir layers 8.TH and 9.TH, including the trajectories of all horizontal wells. The grey lines represent existing vertical wells. The pump setting depth in the new producing wells can be as deep as 1100 m measured depth (equal to about 1000 m true vertical depth) and is defined to be in the tangent of the wellbore trajectory. The maximum build and drop rate of the wellbore is 3°/30 m.

Additional information on the back-produced fluid viscosity and molecular weight was provided by bottle tests from the actual polymer pilot wells. Table 2 lists the variety of different properties of the fluid, is pumped to the surface by a SRP.

Completely degraded polymer with very low MW was seen on the surface, as well as a polymer with the initial MW peak of 20 MDa, which leads to the assumption that polymer solution is destroyed neither during injection, nor by migration in the porous media, nor by being produced by a SRP. So far, a maximum polymer concentration of 1400 ppm was produced back by a SRP, and a fluid viscosities range from 1-13 cP was seen. Statements found in literature describing the maximum polymer concentration being 50% of the injected concentration were proven wrong in the Matzen field.

Polymer description

The injected polymer was defined to be a standard partially hydrolyzed polyacrylamide (HPAM) with a nominal mean molecular weight (MW) of 20 MDa. The polymer is dissolved in produced filtered water to a polymer concentration of 1800 - 2000 ppm, which results in the target viscosity of 20 cp at shear rates below 10 s^{-1} and a temperature of 35°C. HPAM laden fluids are classified as non-Newtonian fluids, which is indicated by a change in viscosity with shear rate [16]. Furthermore, HPAM fluids are viscoelastic, thus combine the elastic behavior of solids with the viscous behavior of fluids [17]. Besides, the polymer solution shows shear thinning behavior at the macro scale of the borehole (Figure 2). The viscosity is dependent on the fluid temperature, the polymer concentration, its MW distribution, and the degree of chemical or mechanical degradation.

Especially the mechanical degradation of the polymer can dictate the rheological behavior of the back produced fluid. The shearing of long polymer chains has to be avoided on the injection well side to keep injection viscosity high. For the production wells, any degradation would help to back produce the less viscous polymer

Table 1: Technology categorization matrix according to DNV-RP-A203.

Application novelty	Degree of technological novelty		
	Proven	Limited Field History	New or Unproven
Known	1	2	3
Limited Knowledge	2	3	4
New	3	4	4

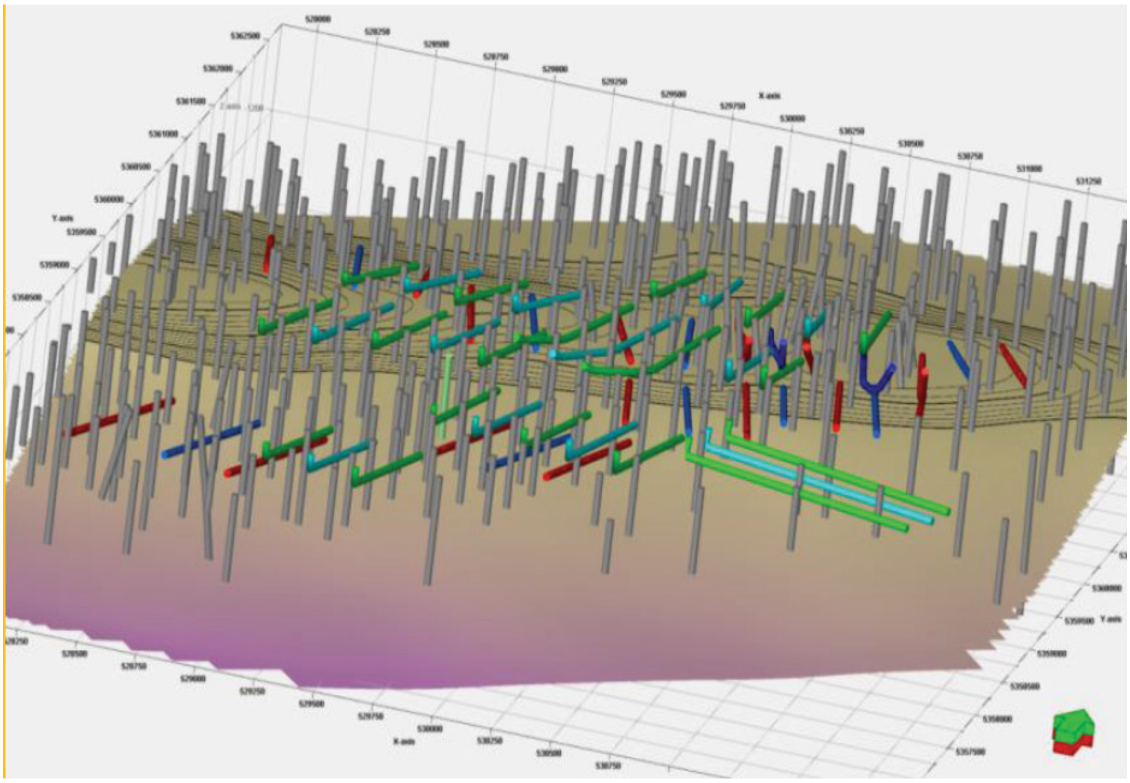

Figure 1: Planned pattern of producer and injector wells.

Table 2: Polymer concentration, viscosity and molecular weight peak of back produced fluid from polymer pilot wells.

Well	Viscosity	Polymer concentration	Polymer molecular weight
-	cP	mg/l	Mda
Well 1	2	76	20
Well 2	5	499	20
Well 3	9	545	20
Well 4	3	140	18
Well 5	3	159	7
Well 6	13	987	17
Well 7	4	254	18
Well 8	5	318	6
Well 9	4	621	13

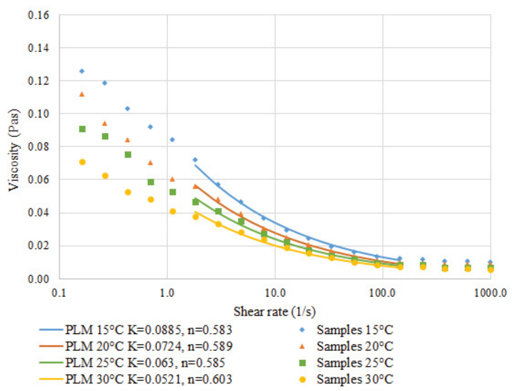

Figure 2: Shear-thinning behavior of 2000 ppm HPAM solution at various temperatures.

solution, in any case.

The artificial lift system selection process was performed according to the introduced procedure.

Technology categorization

The degree of technological novelty of the most typical artificial lift systems (SRP, ESP, GL, HP, PCP) was defined to be proven in the oil field and in-house OMV. The application novelty of SRP, ESP, and PCP for polymer back producing wells was judged with "limited knowledge" only, since polymer was not back produced in horizontal wells for an extended period within OMV and just limited experience is documented in the literature (Table 3). The application novelty of GL and HP in chemical EOR fields was defined to be "new," as neither in-house experience nor information from the literature is available.

To reduce the overall complexity of the redevelopment project, the approach "as much new technology as necessary, but as much standard or proven pilot equipment as possible" was formulated. As a result, ALS rated in the technology categorization three are not selected for the field application in the redevelopment project.

Selection criteria definition

The field redevelopment strategy considers two groups of production wells: the low rate group ranges from 100 to 250 m^3/d, and the high rate group ranges from 300 to 450 m^3/d gross rate. The high rate group represents the new drilled horizontal wells. In contrast, the low rate group represents the active neighbor wells, which are equipped with SRP, in the field are and will be producing back polymer. The existing SRP wells needed to be tested for their ability to produce polymer solutions.

- **Surface infrastructure:** At the wellsite, there is electricity supply and space for a container (e.g., for VSD for ESP). At most well locations there is no external gas supply.
- **Reservoir & well constraints:** The ALS is installed in the vertical section of the back, producing wells at moderate depths. The polymer rollout project contains wells over a large area in several reservoir layers. The inflow behavior and pressure of newly drilled wells in those heterogeneous sandstone layers are uncertain even for conventional oil production. At the time of the AL assessment, no long-term experience with horizontal polymer back producing wells was available. The layer pressure, as well as the inflow, could change with back produced polymer, but also with injection concentration and rate. Thus, the reservoir's productivity over time was evaluated to be uncertain. A flexible rate system is required. The fluid analysis in Table 2 has shown that the ALS needs to pump viscous, corrosive non-Newtonian fluid.
- **Experience & costs:** OMV Austria's internal experience with artificial lift systems is about SRP, ESP, and GL systems. Good knowledge of ALS cost is available.
- **Handling of back-produced fluid:** The field tends to sand production. Premium sand screens have to be installed to reduce the risk of ALS failures because of sand production. Corrosion mitigation measures have to be applied. No scaling tendency has been seen in the test wells so far.

Artificial lift assessment and ranking

The ALS are ranked according to the provided criteria for the low rate wells (Table 4) and the high rate wells (Table 5). SRPs operate about two-thirds of OMV Austria's oil wells, and Table 4 indicates that this type of ALS would match the requirements of the low rate group. All of the currently polymer back producing wells are equipped with a SRP. On these wells, the first experience regarding polymer back-production was gathered. Other companies report severe rod string wear problems associated with back produced polymer fluid [12]. The SRPs used in OMV Austria are limited to production rates of approximately 250 m^3/d, which is primarily based on the strength limits of the standard sucker rod string. A substitution by larger rod dimensions is not possible. This high production rate can only be achieved by a conventional pump jack, equipped with the largest tubing pump type (40-375 THM), and a speed of more than 10 SPM. Thereby, the standard sucker rod string is already highly overloaded. Larger production quantities cannot be reached.

The gas lifting systems in OMV Austria currently produce rates up to 200 m^3/d. The projected surface positions of the new horizontal wells do not have any GL infrastructure. The performance of gas lift systems depends on the produced fluid properties. Especially constant well productivity and fluid density (mainly WC) are essential for the performance of high rate GL installations. Trials to simulate the production of non-Newtonian fluids in GL wells request non-available fluid data. Besides, extensive literature

Table 3: Technology categorization matrix according to DNV-RP-A203–Case study.

Application novelty	Degree of technological novelty		
	Proven	Limited Field History	New or Unproven
Known	1	2	3
Limited Knowledge	2 (SRP, ESP, PCP, GL)	3	4
New	3 (HP)	4	4

Table 4: Artificial lift system assessment example-low rate wells.

Criterion	SRP	ESP	GL	PCP
Surface Infrastructure	Good	Good	Poor	Good
Reservoir & Well Constraint				
Trajectory & Depth	Good	Good	Good	Good
Low Rate &Bottomhole Pressure Flexibility	Good	Poor	Poor	Good
Long term Rate Flexibility	Limited	Limited	Good	Limited
Fluid Property Compatibility	Good	Good	Good	Limited
Experience & Costs				
Internal Experience	Good	Good	Limited	Poor
HSE Aspects	Good	Good	Good	Good
Costs	Good	Good	Limited	Good
Handling of back-produced fluid				
Polymer Pumping Ability	Good	Limited	Limited	Good
Corrosion Compatibility	Good	Good	Good	Good
Sand Production Compatibility	Limited	Limited	Good	Limited
Organic/Inorganic Accumulation Compatibility	Limited	Limited	Good	Limited

Table 5: Indicates that ESPs seem to be the best choice for the large rate group in the field redevelopment. A detailed literature review has been performed on ESP application in back produced polymer wells.

Criterion	SRP	ESP	GL	PCP
Surface Infrastructure	Good	Good	Poor	Good
Reservoir & Well Constraint				
Trajectory & Depth	Good	Good	Good	Good
High Rate &Bottomhole Pressure Flexibility	Poor	Good	Poor	Good
Long term Rate Flexibility	Limited	Limited	Good	Limited
Fluid Property Compatibility	Good	Good	Good	Limited
Experience & Costs				
Internal Experience	Good	Good	Limited	Poor
HSE Aspects	Good	Good	Good	Good
Costs	Good	Good	Limited	Good
Handling of back-produced fluid				
Polymer Pumping Ability	Good	Limited	Limited	Good
Corrosion Compatibility	Good	Good	Good	Good
Sand Production Compatibility	Limited	Limited	Good	Limited
Organic/Inorganic Accumulation Compatibility	Limited	Limited	Good	Limited

research indicates that no other company is currently using GL in polymer patterns. Consequently, flow assurance of this application is not proven. The high dependency of the gas lift system on the fluid properties, which are highly uncertain, and the unavailability of gas supply cause the elimination of this system for the planned rollout.

Various literature documents the efficiency loss of ESPs when pumping viscous oils. According to the Hydraulic Institute [18], three design parameters are impaired by viscosity-produced head, gross rate, and brake horsepower. Unfortunately, those derating tables are only available for dry viscosity, not for emulsions, non-Newtonian, and/or viscoelastic fluids [19]. Various models adapted the hydraulic institute model to account for the non-Newtonian behavior [20] and the complexity of fluid flow inside the pump [21]. Morrison described the pump performance curve as a function of dimensionless variables to state a universal correlation for viscous performance degradation [22,23].

Those models are focusing on high viscous fluids, whereas the worst-case polymer solution to be back produced yields only 20 cP. The critical question of the applicability of those existing models for polymer fluids could not be answered based on literature without testing. The real derating impact on the pump could significantly deviate from literature.

Consequently, at the time of assessment, the derating of ESPs by pumping polymer laden fluids is uncertain. In case that the pump head is significantly reduced, it might be possible that the ESP cannot deliver the total dynamic head. The ESP design must consider changes in head over time; otherwise, the desired production rates cannot be achieved. The reduction of desired production rates was intensively discussed with the responsible reservoir engineers. Limiting gross rates would have a significant effect on the forecasted oil production and thereby impairs the project economics drastically. By adding more pump stages to the system, the pump's head curve becomes steeper – the ESP can handle several heads and is more flexible. The use of VSDs in ESP wells is already standard in conventional wells at OMV. The VSD allows balancing of moderate head derating. For the first ESP pilots in polymer wells, the chosen ESPs were highly overstaged. With modular pump housings, containing different amounts of stages, the stage count can be optimized as soon as more production experience is gained. First field pilot test results do not show large differences in inflow until now; long-term experience is still missing. The informative value is limited, as the field pilots were all drilled in the same area of the reservoir layer.

ESPs represent a standard ALS in OMV Austria with more than 40 operating systems. Nevertheless, the operation of ESPs in polymer back producing wells were initially not experienced. As a result, two pilot back producing wells were selected to be equipped with ESPs for performance tests, which have not seen significant polymer concentrations yet. ESPs are used for polymer back-production in some polymer-flooded fields. The operators have reported a severe drop in rate and head as soon as the polymer front arrived [13]. The field experience represents the engineering basis for the AL design. It is demonstrated that the fluid to be produced may contain a significantly higher concentration of polymer than expected and that these polymer chains may have their initial MW and thus viscosity. Consequently, the AL design must account for the worst-case, being initial concentration and viscosity of the injected polymer solution.

LAB AND FIELD TEST STRATEGY

OMV follows the strategy to pilot and test new reservoir and production technologies before their application in rollouts. Since the first pilot trials in vertical wells demonstrated the efficacy of polymer injection at a smaller scale, starting with 2017, two horizontal polymer patterns were drilled. Those horizontal pilot wells provide valuable data about the baseline, water, and polymer injection phase for the planning of an optimized future field rollout.

The selection of adequate artificial lift systems usually represents a crucial decision for field redevelopment projects of very mature assets. In polymer flood projects, the impact of producing back a significant portion of the polymer further adds complexity to the selection and design of artificial lift systems. The artificial lift method for the producers must account for the back produced polymer and deliver the target production rates, requested by reservoir engineering. Until today, only limited experience with horizontal polymer flooding pattern exists in OMV Austria. With 100-450 m^3/d, the current pilot producers serve only half of the desired production rates necessary for the field rollout and its economics. As a result, an immediate investigation to understand the performance of ALS when pumping a polymer-water-oil mixture is essential to reach the economic target of the redevelopment project. The artificial lift assessment for the field rollout was executed in early 2018. All parameters regarding reservoirs, wells, and desired production were gathered. Since that time, hardly any changes in reservoir parameters came up; but the range of uncertainty could be furthered narrowed due to the horizontal pilot wells. As the composition of the back produced fluid is uncertain–WC, polymer concentration, and viscosity–and expected to change over time, the operational experience and pump testing are building the basis for the estimations of the back produced fluid properties.

Pilot and testing strategy

The execution of pilot tests is seen as a reasonable investment into the future of planned projects, as long as the following criteria are fulfilled:

- Both technology and application should be as similar as possible to those of the field rollout project
- Every pilot test shall be able to answer distinct questions regarding the applicability of the technology application
- Those answers need to be clear and quantifiable to enable successful upscaling for the rollout project
- The results of the pilot shall be ready to be implemented to the decision process in time

Pilot projects offer valuable information for the optimization of application design and operations by reducing technical uncertainties and highlighting hidden risks. The implication of lessons learned may significantly improve the technical and economic success of the application.

Since the first pilot trials in vertical wells demonstrated the efficacy of polymer injection at a smaller scale, starting with 2017, two horizontal polymer patterns were created. Those horizontal pilot wells are offering valuable data about the baseline, water, and polymer injection phases for the planning of an optimized future field rollout. Currently, all production technologies for the rollout project are selected based on field experience; detailed engineering for all subsurface installations has started [24].

SRP TESTING

Even though positive displacement pumps seem to suffer less from the polymer in comparison to centrifugal pumps, for the existing active SRP wells, the capability of producing back polymer solution with rates up to 250 m^3/d needs to be proven. Several publications [11,12] indicate severe erosion, wear, and corrosion failures of sucker rod pumps due to polymer back production. Depending on the polymer concentration, a significant reduction of the rod fall velocity was indicated, which is the result of the high viscous friction on the sucker rod string. Buckling might be a critical issue. Due to the high uncertainties and the large number of existing SRP systems, several test campaigns are necessary to analyze the influence of polymer on the SRP performance and vice versa, the impact of SRP pumping action on the polymer fluid.

SRP pilot wells

In pilot wells operated with SRPs, no substantial impact of polymer back-production on the pumping behavior could be monitored. Regardless, experience tells that the failure type of the polymer pump installations differs from the standard ones: while OMV Austria's majority of SRPs suffers from downhole pump failure, the typical well failure of the polymer wells is a combination of abraded and corroded tubing. It is observed that especially corrosion of the ordinary carbon steel tubing represents a more severe problem than in the rest of the field.

Therefore, an intense corrosion monitoring plan was implemented that consists of corrosion coupon measurements and chemical analysis of fluid and associated gas samples (microbiological activity, organic acids, iron content, CO_2 and H_2S concentration). In particular, the coupon measurements indicate significant changes correlated to the polymer. All polymer producers exceed the OMV Austria's internal limit of 0,05 mm/a, with corrosion rates up to 1 mm/a and beyond. The chemical analysis of fluid and gas samples does not give a clear trend or correlation to polymer production.

Laboratory autoclave tests were performed that show an increase of corrosion in a polymer containing brines. Electrochemical measurements confirm that the corrosion inhibitor is working; however, higher dosage rates are necessary. A possible explanation could be the polymer's ability to bind lose iron cations, preventing the carbon steel from building a sufficiently protective surface layer ($FeCO_3$). Additionally, an interaction between cationic constituents of the corrosion inhibitor and the polymer is considered probable.

To fight the increased corrosion rates, corrosion inhibitor dosing is adjusted on a well-by-well basis after each coupon measurement. Two to three times, the initial dosage is necessary to reach acceptable corrosion rates. The rise in corrosion rates after polymer breakthrough and the following corrosion inhibitor increase are illustrated in Figure 3.

SRP spike test

The SRP spike test was executed in an existing SRP well and with two main objectives:

- To identify any adverse impacts of polymer solution on standard SRP systems.
- Provide information about the fluid properties of the produced polymer in a worst-case scenario of pumping full polymer concentration and molecular weight (assuming no shearing and dilution in the reservoir).

Therefore, a 2000 ppm HPAM solution was filled into the annulus of a SRP operated test well and afterwards pumped by the downhole pump back to the surface. The pump speed was kept constant throughout the entire test. During the test, rod loads and valve action from dynamometer cards, wellhead pressures, as well as electrical motor power were continuously monitored. Additionally, fluid samples were taken at the wellhead in predefined intervals, followed by an on-site viscosity measurement and a detailed analysis in the laboratory (polymer concentration, molecular weight, and salinity). To provide constant conditions and reference

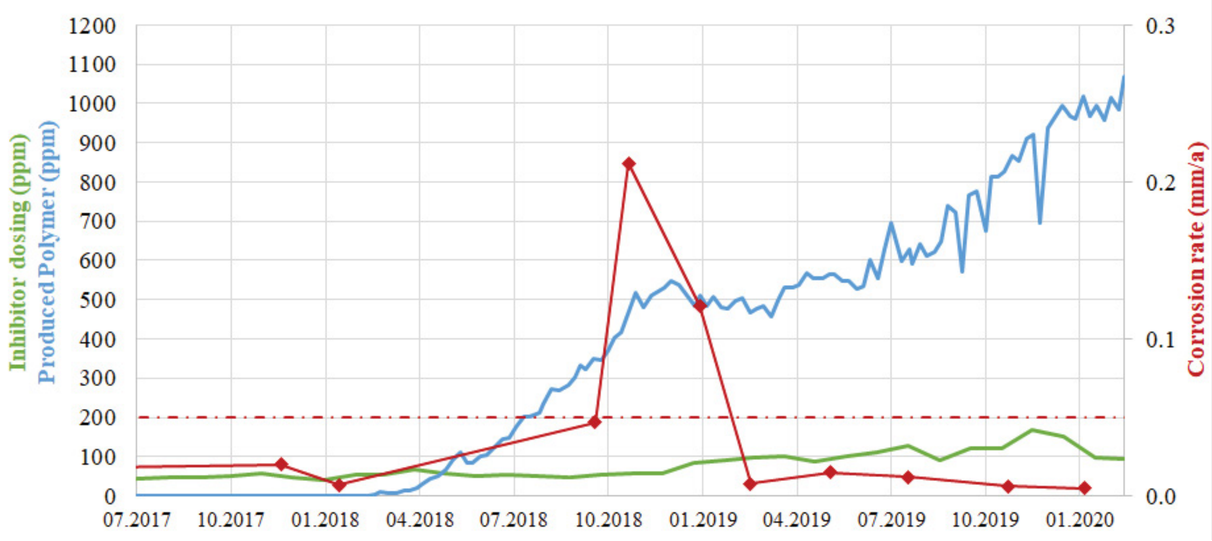

Figure 3: Polymer breakthrough affecting corrosion rates.

values for the regular operation, brine was filled into the annulus before and after the polymer solution test. The filling itself was done with a vacuum truck, pressure-less, and without rate control in order to avoided shearing the polymer solution before reaching the downhole pump.

Table 6 states the timeline of the fluid properties analyzed in the laboratory. As a reference, samples were also taken during the mixing, transport, and injection, since shearing or degradation of the solution could not be entirely excluded during these processes. For other analysis purposes, the timeline of the fluid samples is also shifted to the moment when entering the downhole pump under consideration of the tubing size and production rate.

The first observation that can be done is that the production of the injected polymer solution happened in three slugs. This is owed to the operational execution of the test: a time lag between the polymer and brine injection, as well as higher injection than production rates. However, this phenomenon is considered to not influence on the informative value of the test.

The primary outcome of this table is a viscosity reduction of the polymer solution from an initial 16.5 cP to 8-12 cP. Since most of the measurements show similar values of concentration. However, reduced values of molecular weight, the viscosity reduction comes from the shearing of the solution rather than dilution with brine or reservoir fluids. Nevertheless, one measurement indicates a molecular weight close to initial conditions, leading to the assumption that SRPs, in general, are not shearing or influencing the polymer solution. In this case, the degradation occurs most likely already during the injection in the annulus when the solution is soaked in and hits the liquid level. This means in a worst-case scenario, it must be assumed that SRPs lift fluids to the surface that have the same properties as the injected ones. Another explanation for polymer degradation is the contact with tubing and casing, which are out of carbon steel.

The shape of the dynamometer cards have changed slightly during the tests but did not deliver hints on relevant pump operation changes during polymer production. A change in electrical power requirements of the motor can be seen during the polymer production phase, which indicates an increase in energy consumption during these phases. On closer examination, this increase is mostly added to the system during the downstroke. The trend of average energy consumption per upstroke and downstroke, together with the viscosity of the produced fluids, is plotted in Figure 4. The upstroke indicates just a slight increase in average energy consumption during the test, with deviations less than 5%. Whereas during the downstroke, a clear trend is seen, that follows the viscosity of the produced solution. The energy consumption of the downstroke is increased by up to 30% when the polymer is produced compared to brine. As most operating conditions were kept constant during the test, it can be assumed that this increased energy consumption was induced by higher viscous friction on the rod string and its components such as couplings and rod guides.

One SRP pilot well showed short-term problems with a floating rod string after polymer breakthrough.

SRP test facility

The SRP test facility at the Montanuniversitaet Leoben was used to investigate further the viscous effect of polymer on the rod string. The test facility consists of three main elements: a housing of the downhole components, a polished rod, and a linear drive. The 8 m long stainless steel housing is a casing of size 6 5/8 in., allows for pressures up to 40 bar and temperatures up to 60°C, representing conditions of a 500 m deep pumping installation. On top of the pressure vessel, the linear drive is installed, which allows stroke lengths of 2 m and lift forces to 15 kN. The setup is constructed to perform vertical and inclined testing. Therefore, the whole test stand can be tilted stepwise from an upright position to 30 degrees of inclination, which is restricted by the construction of the facility (Figure 5).

Based on previous testing and field observations, the SRP testing focus within the polymer redevelopment project was set on the downstroke of the pumping cycle. Test runs were done for 7/8 in rod string elements with rod coupling and a total length of 1.8 m. Elements with one rod guide, prepared for a 3 ½ in tubing, have been chosen. The stroke length was defined to be 1.8 m, and the pumping speeds of 4 and 6 SPM were selected. All test runs were performed in vertical and 30° inclined conditions.

Two different polymer concentrations fluids were used, representing the boundary conditions before and after polymer breakthrough:

- 0 ppm polymer solution (saltwater)

Table 6: Back-produced polymer properties during SRP spike test.

Time at Surface - measured	Time at Downhole Pump - calculated	Polymer Concentration	Molecular Weight	Viscosity 30°C, 6 rpm	Comments
		(ppm)	(MDa)	(cP)	
		2000	20.0	18.0	After mixing
		2000	20.0	18.0	After transport
		2000	20.0	16.5	Before injection = Base line
10:00	09:20	0			
10:20	09:40	1270	13.1	8.0	
10:55	10:15	1870	10.8	9.5	
11:30	10:50	1670	6.4	9.5	
12:00	11:20	120	4.9	1.2	
12:40	12:00	51	8.8	0.9	
13:20	12:40	195	4.6		
13:55	13:15	1940	12.2	10.0	
14:25	13:45	2	20.0	1.0	
15:00	14:20	0	15.1		
15:30	14:50	1400	18.7	12.0	
16:30	15:50	3	2.1		
17:30	16:50	2	2.1		

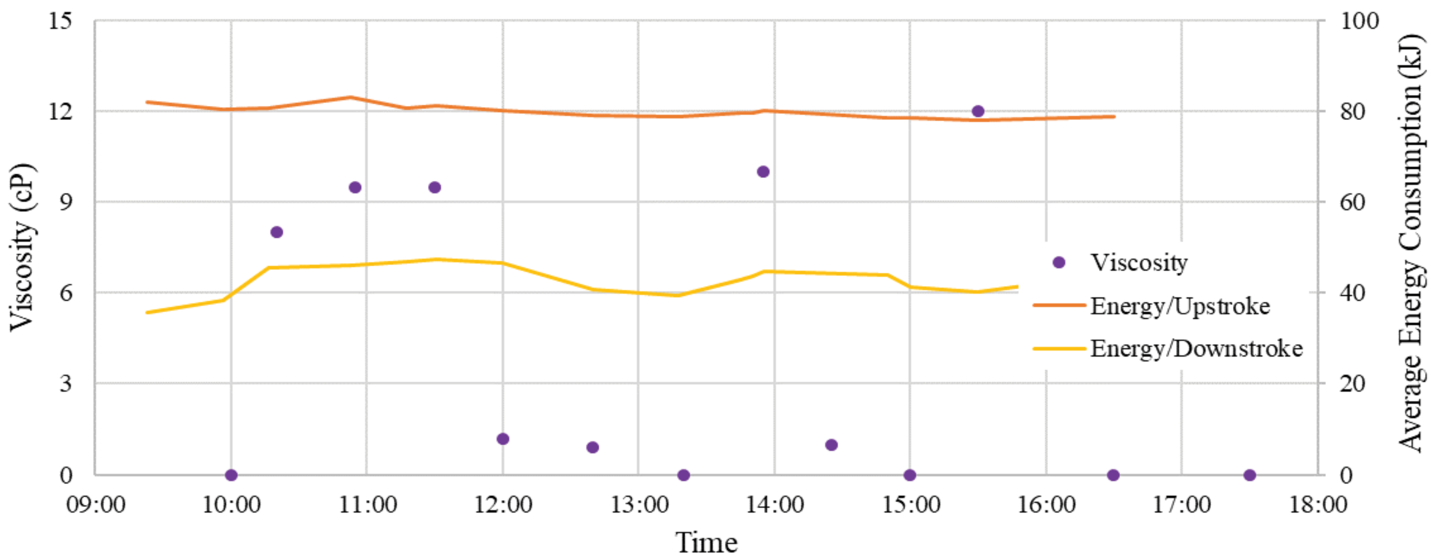

Figure 4: SRP energy consumption split into up- and downstroke.

- 2000 ppm polymer solution (maximum injected concentration)

The evaluation of the tests has shown that the viscous friction of the piece of rod increases on the one hand with speed, but with polymer concentration as well. For speed of 0.58 m/s, the viscous friction force increased from -9.77 N for pure water to -14.05 N for a polymer solution, having a 2000 ppm HPAM concentration for vertical testing arrangement. Lab tests with 30° inclination show less increase in friction, in comparison to the vertical arrangement. On the contrary, fluid friction is even lower than in the vertical tests, which might be the result of the non-concentric position of the rod guide in the tubing. Coulomb friction between the rod guide and the tubing wall is minimal.

For a sucker rod string in the field, the viscous friction changes, because of the back produced polymer solution, can quickly increase the downstroke forces by several thousands of newton. Floating of the rod string might be a severe problem in these wells.

ESP TESTING

As literature indicated a dramatically changed ESP performance with polymer breaking through of polymer to the producers, testing of ESP was done [13]. Parallel to testing SRPs for the existing polymer neighbor wells, several ESP testing campaigns were initiated for the new horizontal producers. Three different test approaches were defined: ESP pilot wells, ESP spike test, and ESP test facility. Each approach has advantages and disadvantages related to the controllability of the pumped fluid properties, the timing of expected information value, the upscaling potential, and the testing effort.

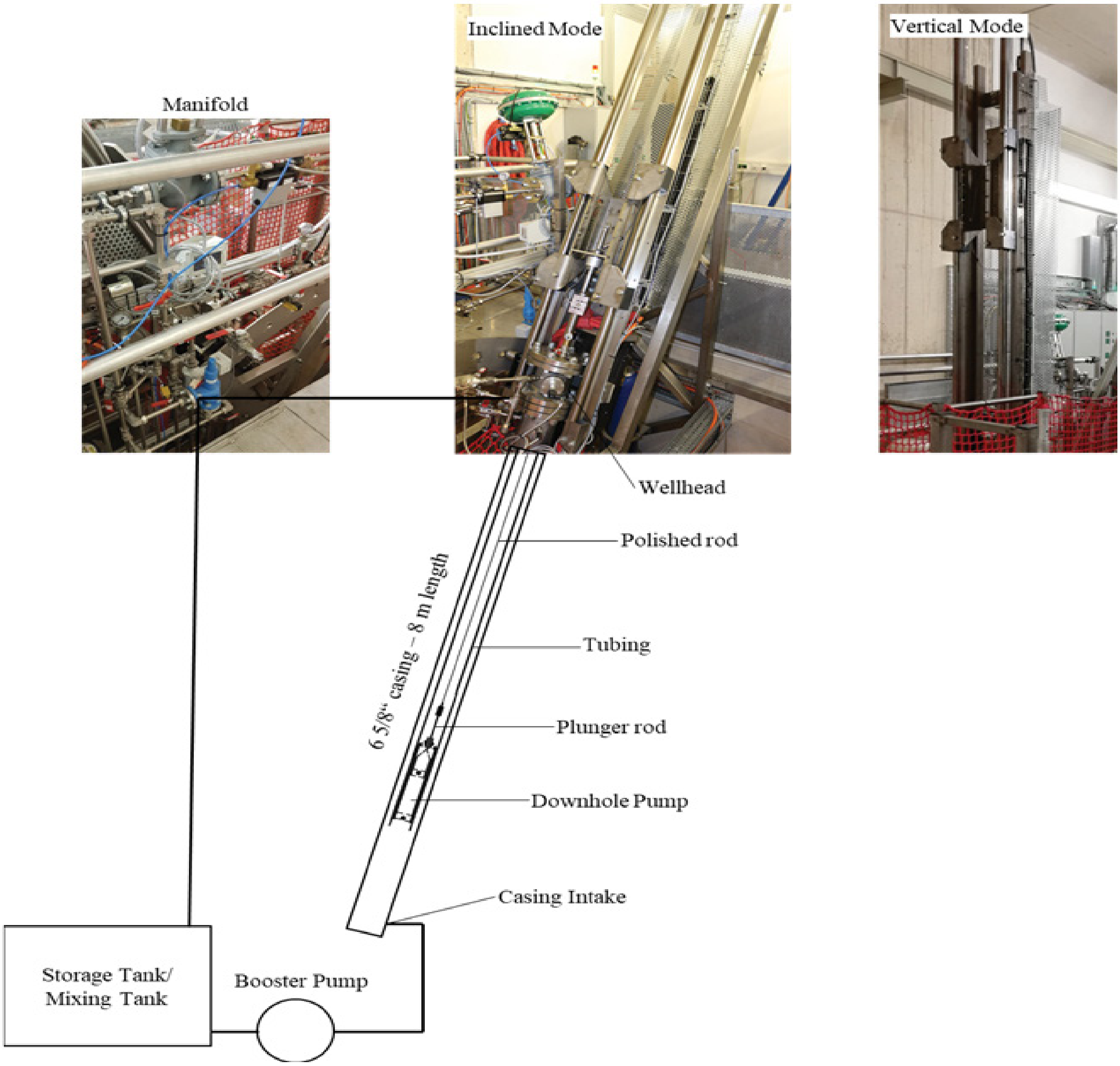

Figure 5: SRP test facility.

Polymer precipitation might be a severe issue when using ESPs. This risk is tackled by in-house and external laboratory testing. The first results of these tests confirm a change in scale type with increasing polymer concentration, from calcium carbonate deposits to finer pseudo-scale. The tests also show that the total amount of deposits is even slightly smaller when a polymer is present and that a small dosage of scale inhibitor is sufficient to reduce the scaling risk. If polymer precipitations turn out to be a problem in the future, though, remedial actions may be necessary for the form of motor design adaption (dimension, permanent magnet motor), motor housing adaption (unpainted, polished, coated), or by inhibiting chemicals.

ESP pilot wells

Even though OMV Austria is operating numerous standard ESP systems in the conventional oil field, ESPs were never installed in polymer back producing wells so far. To gain experience in this field of application, it was decided to equip two newly drilled horizontal polymer pilots with ESPs. Having the numerous uncertainties of producing a polymer with ESPs in mind, the decision was solely based on the additional information for the later field rollout.

Standard 400 series compression pumps were chosen to be used for the pilot wells. Lacking any experience or test data on the derating of both pump and motor section, an extremely overstaged pump with an overdesigned motor was selected. The ESPs have been designed to fulfill the gross rate requirements in both pre and post polymer breakthrough time, without any knowledge of productivity index, fluid composition, and rheology. The operating mode philosophy was based on the approach to operate the overstaged pumps at lowermost frequency before the breakthrough and then steadily increase the frequency, balancing the polymer derating of the pump. So far, both pumps have not seen large concentrations of the polymer. A substantial polymer breakthrough is expected for the future and will represent one of the most representative data sets for the ESP optimization of the redevelopment project.

ESP spike test

As for SRPs, a similar spike test was performed ESPs too. The test had similar objectives:

- To identify the possible negative impact of polymer solutions on the ESP performance and optimize ESP design regarding derating.
- To show the impact of the ESP on the polymer solution, such as molecular weight and thus viscosity. Substantialmechanicaldegradation due to shear forces was expected.

The test was performed by injecting a polymer solution with a concentration of 1200 ppm into the open annulus of an existing ESP operated well. The concentration of 1200 ppm was chosen since it represents the highest concentration that was seen so far is the back produced horizontal pilot wells. In comparison to 2000 ppm, the lower concentration limits the risk to damage the ESP during the test. Afterward, the polymer solution was pumped through the downhole pump back to the surface into production tanks.

All relevant pump and well parameters were kept constant during the test. Pressures at the pump intake, pump discharge, and wellhead, motor temperature, electrical power, and production rates were continuously recorded. Fluid samples were taken regularly and analyzed in the lab for viscosity, polymer concentration, and molecular weight. In order to have reference conditions, reservoir fluids/brine was produced before and after the polymer solution test. The initial baseline viscosity was measured with 6.5 cP.

The back-production of the injected polymer solution was observed to come in two slugs. This behavior was already seen for the SRP spike test and is again connected to higher injection rates than production rates. The maximum measured viscosity of the produced polymer solution was 6cP, which was only slightly lower than the initial baseline viscosity. Therefore, it can be assumed that the ESP does not cause significant shearing of the polymer solution during pumping. Figures 6 and 7 shows the recorded ESP parameters WHP (wellhead pressure), Pd (pump discharge pressure), PIP (pump intake pressure), and Dp (differential pressure across the pump). The recorded data are time-shifted to downhole conditions, and the windows of polymer production are shaded.

Even though the particular focus of the test execution was to rule out any other influencing factors, some of the observations are not related to polymer production in general but the test set-up conditions (Table 7).

The six-year-old ESP had a head derating of 84% under regular operation due to pump wear. When the polymer solution entered the pump the first time, this value decreased to almost 50%, which is seen as not representative. During the first polymer slug, the head derating stabilized around 60% and during the second one at 75%.

ESP test facility

The ESP test facility at the Montanuniversitaet Leobenwas used to investigate further the viscous effect of polymer on the performance of ESPs (Figure 8). The vertical facility fulfills all requirements for testing ESP pump sections according to API RP 11S2 [25]. The main components of the facility, besides the pump stage, are the rotary drive, which is a 55 kW standard electrical engine that is positioned below the pump stage, the inlet, where the three phases are mixed by a static mixer, and the pressure regulating valve at the discharge of the pump. The system can handle inlet pressures up to 40 bar and discharge pressures up to 160 bar, and a temperature range from ambient to 80°C. The inlet system can mix up to 20 m^3/h of polymer laden water that is stored in a pressure vessel charged by compressed air, with 3 m^3/h of synthetic oil provided by a screw pump, and together with 50 kg/h of separately provided compressed air. Regulating valves are installed to allow flexible mixing of the three phases at the inlet. A heat exchanger is additionally in place to keep the temperature constant in closed-loop circulation mode.

Since the derating of the pump section, caused by pumping polymer solution, represents a significant technical and economic issue, it was decided to execute realistic pump performance tests with standard pumps. Two standard ESPs with compression pumps and a different number of stages (82 and 7 stages) were selected. The scope of the tests was, on the one hand, to analyze the actual pump derating behavior for different polymer concentrations and pump performance. On the other hand, to either confirm the existing derating models from literature or to define a new way to account for derating caused by polymer solutions. During the tests, all relevant sensor data (intake pressure, discharge pressure, intake temperature, discharge temperature, flow rate, torque, vibrations, and rotational speed) were recorded. Before and after pumping, fluid samples were taken from all tested polymer concentrations (500 ppm, 1000 ppm, 2000 ppm) to measure viscosity and molecular weight.

First, the ESPs were tested with freshwater in a closed flow loop arrangement to check the performance against the manufacturers' catalog curves. The results of closed flow loop arrangements were compared to those of open flow loop arrangement. No performance difference has been seen. The consecutive polymer tests with 500, 1000, and 2000 ppm HPAM were performed in open flow loop arrangement to ban influences like mechanical polymer degradation, caused by polymer solution recirculation. The tests have shown a significant derating in terms of pressure and flow rate, independent on pump stage number. In contrast, the brake horsepower stays almost the same level, which causes a substantial decrease in the pump's efficiency. It is essential to mention that the magnitude of the shut-in head could not be reached, like for the water tests.

Figure 9 presents a performance comparison of the 82 stages ESP to the Hydraulic Institute Model and Morrison's Modified Affinity Law for 45 Hz rotation speed. The polymer fluid viscosity for the tests had a viscosity of 11 cp. The black line represents the manufacturer's catalog performance at the top, followed by the performance prediction of the above-stated models at a viscosity of 11 cP. In

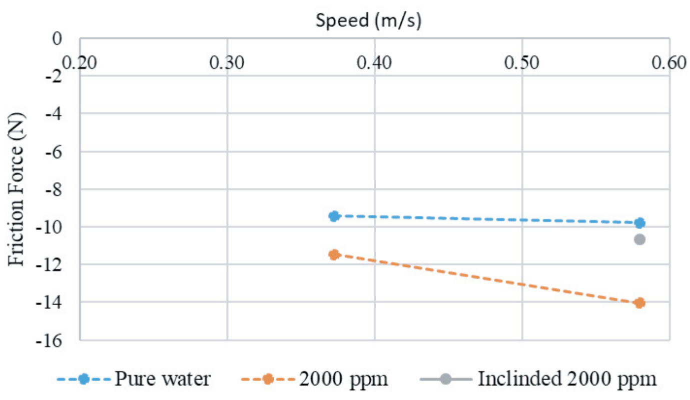

Figure 6: SRP viscous friction test results.

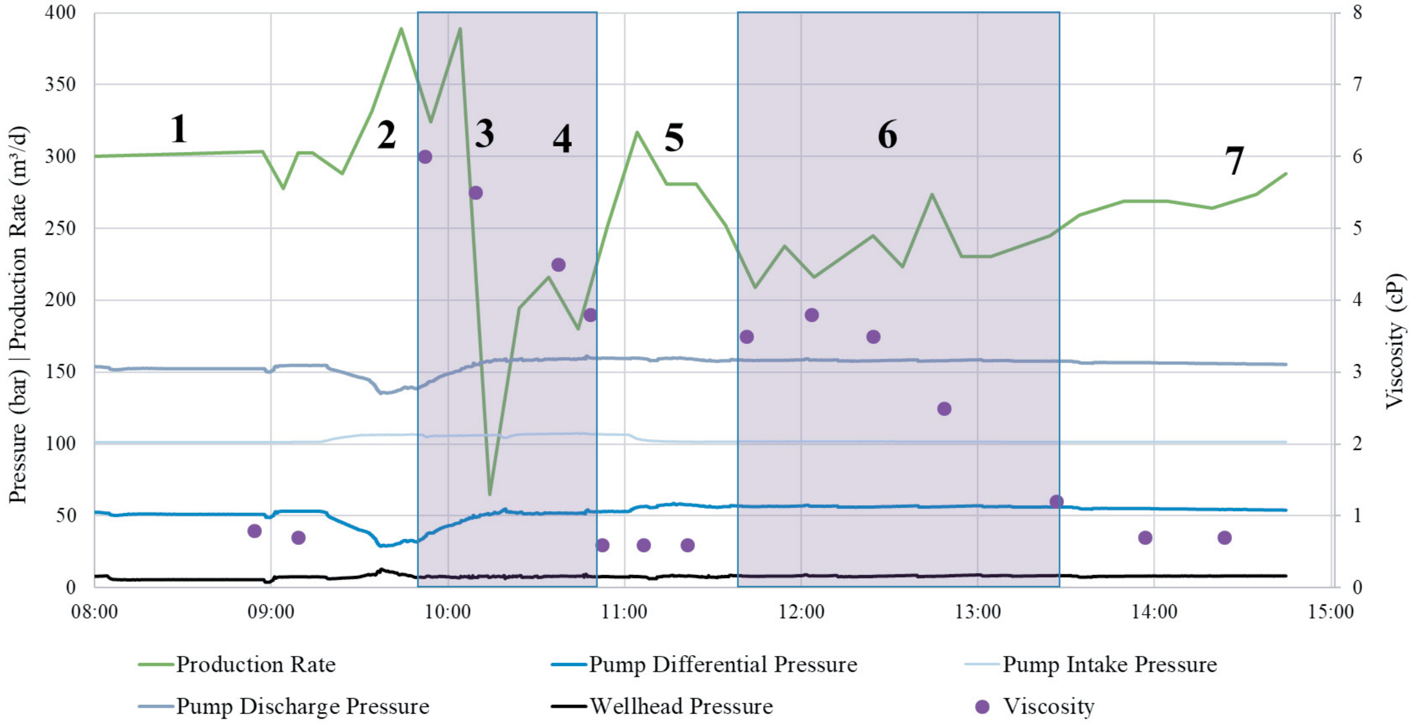

Figure 7: ESP parameters during spike test-phases.

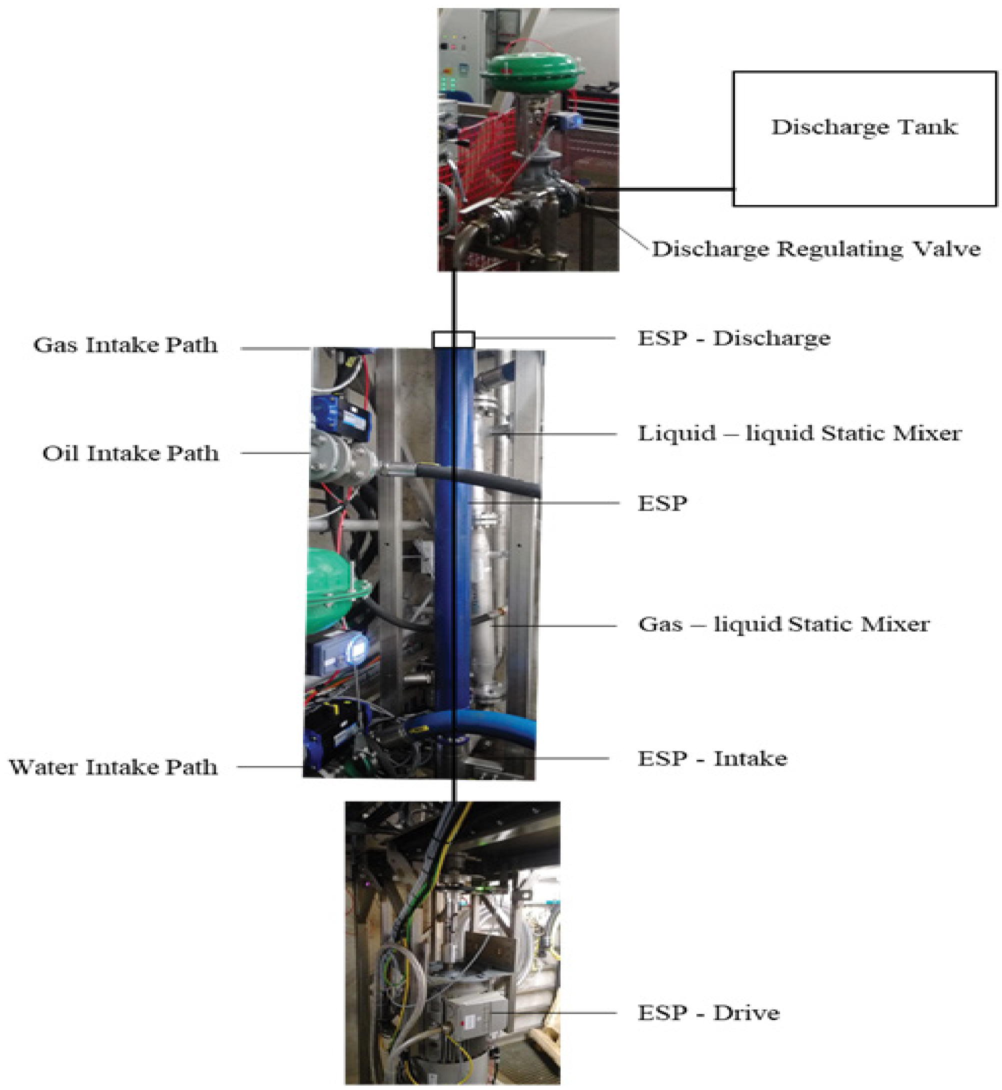

Figure 8: ESP test facility.

Table 7: Back-produced polymer properties during SRP spike test.

	Phase	Description	Impact
1)	Baseline production	Initial rate	
2)	Start of polymer injection	A slight increase in pump intake pressure due to the rising liquid level in the annulus. Increase in production rate, decrease in discharge pressure, and an increase in wellhead pressure with an open choke. Segregated crude oil and associated gas in the annulus are displaced into the downhole pump, lightening the hydrostatic column	Polymer independent
3)	First polymer at intake	A sharp drop in the production rate (short-term), when the polymer solution reached the intake. Indications in the fluid sample of forming an unstable emulsion of polymer and annulus oil	Irrelevant for continuous polymer production
4)	First polymer slug production	Stabilized polymer reduced rate (4 - 6 cP)	Polymer impact
5)	Brine slug	Initial rate	
6)	Second polymer slug	Stabilized polymer reduced rate (2.5 - 4 cP)	Polymer impact
7)	End of test	Initial rate, no irreversible wear of pump	

contrast, the dashed lines present the actual pump performance for the polymer-laden fluid at different concentrations. Comparing the Hydraulic Institute Model prediction to the experimental results, a head deviation of 10% for 400 ppm and 22% for 1600 ppm and a flow rate deviation of 30% for 400 ppm and 45% for 1600 ppm at the BEP can be seen. The figure indicates that the existing models (Hydraulic Institute Model, Morrison's Modified Affinity Law) for predicting the ESP performance for high viscous fluids are not applicable when pumping non-Newtonian fluids.

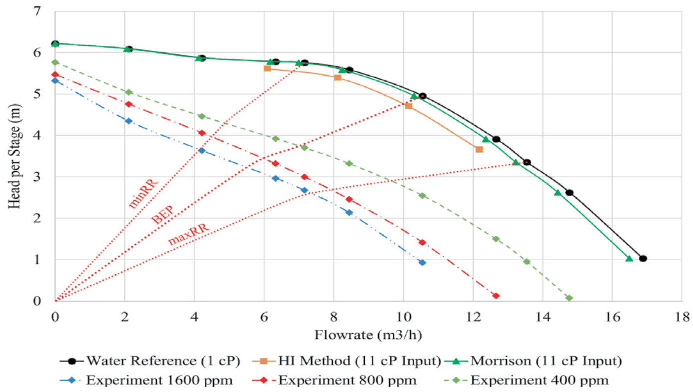

Figure 9: ESP performance comparison to hydraulic institute model and Morrison's modified affinity law for 45 Hz polymer breakthrough affecting corrosion rates.

Figure 9 indicates that the shut-in head changes with polymer concentration. The higher the concentration, the lower the shut-in head. The reason, therefore, is the elevated friction level inside the pump because of the long molecular chains. If the shut-in test condition is extended in time, then the long molecular chains break, and the shut-in pressure approaches the catalog curve.

Besides, the seven stages pump was equipped with pressure sensors at each impeller to check for changes in derating from one stage to another. The data show that the pump head produced by each stage is relatively constant (Figure 10). The head variations of approximately 0.5 m are insignificant and not related to the polymer-laden fluid. The same result was observed for other flow rates.

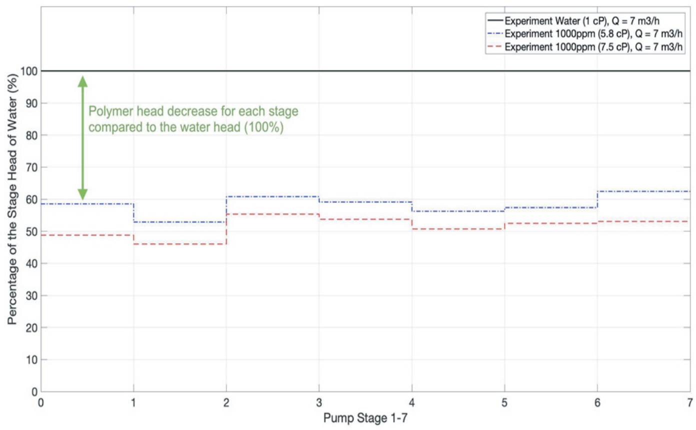

Figure 10: ESP performance comparison to hydraulic institute model and Morrison's modified affinity law for 45 Hz polymer breakthrough affecting corrosion rates.

The following main conclusions can be stated, based on the experiments at the pump test facility:

- The water tests confirmed the manufacturer's catalog reference curves within the allowed range of API RP 11S2
- Even though the input polymer solution was already degraded from an initial 20 cP to 11 cP by transport, significant derating of the pump could be monitored. Derating pairs down to 70%/70% for head and rate could be measured. Existingmodelspredictedfarlessderating at thislowviscosity
- Derating is increasing with decreasing rotational speed
- The impact of polymer is increasing with the concentration of the polymer solution
- In the 82 stages pump, mechanical degradation reduces the molecular weight by a maximum of one-third of its original value. It could be proven wrong that the pumping action destroys the polymer chains. Just during shut-in conditions as severe polymer degradation within the pump was seen
- The seven-stages pump demonstrates that there is no distinct difference in derating from stage to stage. The theory of unsheared polymer solution experiences the most shearing effect in the first stages could not be confirmed
- Comparing the test data to the existing derating models for high-viscosity fluids showed that none of the used models could predict the derating in the correct way

RESULTS AND DISCUSSION

All accomplished artificial lift tests for SRPs and ESPs indicated an efficiency reduction when pumping the polymer solution.

During the SRP spike test, a polymer viscosity of 16.5 cP triggered only minor effects on the production rate, but the energy consumption of the system increased significantly. Not the viscosity itself, but the polymer concentration and the rheological behavior of the visco-elastic fluid is relevant for the changes.

Even though the viscosity of the used polymer solutions was only 11 cP, significant derating to 60-70% of the initial head could be seen in the ESP tests. For the ESP spike test, even lower viscosity of 6.5 cP was resulting in a remarkable pump performance decrease during the stabilized periods. The ESP test facility offered the most accurate testing results under controlled conditions. The 500-1000-2000 ppm test series state a substantial additional derating with increasing concentration. Especially the fact of low degree of mechanical degradation in the pump is essential for subsequent facility engineering. Combined with the information derived from the back producing pilot wells, that in injection wells and the reservoir the polymer is not necessarily sheared, a worst-case scenario for pump design is the full polymer concentration and its viscosity. For the future ESP design for the polymer field redevelopment project, a significantly larger ESP dimension is recommended. It is essential to mention that the derating parameters derived from the tests are only valid under the test boundary conditions with the respective pumps. The derating factors change with the geometry and dimension of the pump. It is recommended to execute polymer tests with several polymer concentrations, as soon as the ESP dimension for the redevelopment project is finally defined.

CONCLUSION

This paper presents an effective ALS selection procedure for back producing polymer wells. AL assessment demonstrates that there is no ALS to be used without constraints to be used in back produced polymer wells. The case study has indicated that SRP and ESP perform best for the presented field. In general, PCP seems to be the right choice too for low rate production, if the internal experience is available in the company. Because of the rate constraint, ESPs were chosen for the field redevelopment.

Extensive testing campaigns and pilot projects were able to prove the capability of both pumping systems to handle polymer solution. Polymer spiking tests in the field and at the pump test facility on SRPs demonstrated the influence of the polymer concentration on the SRP performance. A severe reduction of the rod fall velocity was indicated and resulted in a redesign of the sucker rod string composition. The overstaged ESPs will be designed to pump with lowermost frequency during the pre-polymer phase. After the polymer breakthrough, the frequency can be sequentially increased to balance the reduced head capabilities by the polymer impact. Overall the big difference in the impact of polymer on centrifugal versus positive displacement pumps was demonstrated. While ESPs seem to suffer from concentrations of 500 ppm polymer already, the SRPs showed hardly any negative impact of the polymer.

The SRP test facility, combined with simulation models, has delivered critical information about the changed viscous friction regimes in polymer producing wells. The significant impact of polymer on the ESP pump section, depending on concentration and frequency, was proven.

DATA AVAILABILITY

The data used to support the results of this study can be obtained from the corresponding author upon request.

CONFLICTS OF INTEREST

The authors declare that they have no conflicts of interest regarding publishing this paper.

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