2016 SPE Workshop on Gas Well Deliquification

The second SPE Workshop on Gas Well Deliquification was held in October 2016 in Amsterdam. A grand total of 56 participants weathered the harsh business climate and attended this year's edition of this very useful and technically interesting workshop.

The SPE Gas Well Deliquification Workshop aims at improving and accelerating the development of techniques for late life production of gas wells in Europe and other eastern hemisphere regions. This involves production or recovery losses due to liquid loading, water production and/or halite precipitation within depleted and tight gas fields. Attention is also given to topics such as 'Field Operations and Asset Integrity' and 'Data Management, Modelling and Optimization'. Finally, the workshop wants to promote interest for existing and new service providers to enter or increase their presence in the European market for gas well deliquification, water shut-off and scale remediation.

The ultimate goal of the workshop is increase awareness in the improvements in the deliquification methods and late life production in general. This concerns hardware, field experience as well as new prediction methods.

As the technical workshop committee we are very proud that we can call the 2016 edition a resounding success. Below you can find an edited version of the scribe report that was created by a team of three very enthusiastic students during the workshop: Ellis Bouw, Thomas Leo, and Youri Kickken. Many thanks from all members of the steering committee for your help! Also a big thank you is owed to Brian Scholtz: his relentless support from the SPE side has contributed tremendously to the success of our workshop. Happy reading!

Ewout Biezen

The workshop steering committee:

Stefan Belfroid, Co-chairperson	TNO
Marco Marino, Co-chairperson	NAM
Ewout Biezen	Shell
Wouter Botermans	B-PES
Ricardo Gijbels	EBN
Bin Hu	Schlumberger
Bjoern Lause	Baker Hughes
Pejman Shoeibi Omrani	TNO
Gerrit van Dijk	Nalco

Breakout session impressions

Workshop Summary

Keynote Address: Rene Peters, TNO

Mr. Peters welcomed everyone to the workshop. He introduced the subject of Gas Well Deliquification by talking about the future of energy in the Dutch sector of the North Sea. He told us how the Netherlands is transitioning towards a sustainable energy sector and about the Dutch prospective to reach this goal. He explained what the main drivers are for the Netherlands to convert to sustainability as our own gas reserves diminish. Based on proven reserves at this moment production will stop around 2030-2040. This means that the start of decommissioning is at this very moment. What could be the alternative use for the oil and gas industry infrastructure? Wind energy has a big potential in the North Sea area. Using wind in the development of a new offshore energy infrastructure. Offshore power use is dominated by 10 large platforms and comes down to 250 MW.

The vision should be **from segregation to integration**: 'Is there a potential for integration and re-use of gas infrastructure for offshore wind?' This goal could be reached by **system integration of offshore energy** by creating different goals for the future. Short term (2016-2023), Medium term (2023-2030) and Long term goals (2030-2050). The challenges to reach these goals are strategic spatial planning, physical network, society & government and health and safety.

Session 1: Liquid Loading, Water Production and Salt Precipitation

Liquid loading and water production are two of the most common issues affecting wells close to the end of field life. As a reservoir is depleted, the bottom-hole pressure decreases, resulting in a lower production velocity in the well, which is unable to carry liquids to surface. These liquids can be formation or condensed water, or also condensate or oil (if an oil rim is produced together with the gas). The result is the same: as liquids accumulate in the well, the backpressure on the reservoir increases, further reducing production and eventually killing the well. Also the precipitation of salt in gas reservoirs may severely diminish gas production in these mature fields.

In this session we will look at the overall picture of fields and wells in production in the Netherlands, and their related liquid loading/water production and salt precipitation issues. In addition, we will review novel tools and methodologies to identify liquid loading/water production and salt precipitation by using readily available surface data.

Presenter: Ricardo Gijbels (EBN)

Topic: Size of the Problem – Liquid loading and Salt Precipitation in the Netherlands

Presentation Summary

Mr. Gijbels introduced EBN as the Dutch state oil and gas company participating in over 90% of the Dutch gas fields, including the 'Giant' (Groningen gas field). The typical depth and pressure of Dutch gas fields are 3000 m and 300-350 bar. Mr. Gijbels also introduced his inventory and correlation study on Liquid Loading and Salt Precipitation in the Netherlands done in 2013 and kept up to date year by year. Liquid loading and salt precipitation in mature gas fields with low rate, low pressure wells is a common problem, and is an increasing challenge to operating these fields.

The study has been performed on the 330 gas fields with EBN participation in the Netherlands (excluding the giant Groningen gas field, shallow gas and Underground Gas Storages). For these fields, the historic development of the number of fields suffering from liquid loading or salt precipitation has been correlated in time with the depletion of the Dutch gas fields. This to arrive at a prognosis of the development of the number of fields with liquid loading or salt precipitation problems. The correlation study shows that **more than 50% of all fields will suffer from liquid loading or salt precipitation** once the reservoir pressure drops below 100-150 bar.

According to current field decline prognoses, the coming years some 6 fields per year will drop below a reservoir pressure of 100 bar. This means 2-3 additional fields per year will require GWD measures. Future additional recovery at stake therefore is 0.5-1 bln m3/yr. Also 1-2 additional fields per year will require Salt mitigation measures with future additional recovery at stake of some 0.2 bln m3/yr.
The main conclusion is that Liquid Loading and Salt Precipitation are here to stay and future **cooperation and sharing knowledge** is a must.

Presenter: Minos Konstantinidis (NAM)

Topic: Field Experience on Monitoring Gas Wells Performance Via Surface Pressure Build-up

Presentation Summary

Gas wells performance can change as a result of changes in in- and outflow. These changes are reflected in surface pressure build up data, which are usually abundant and routinely collected at no additional expenses. By analysing three field case studies, the value of surface pressure build-ups in monitoring changes in gas wells performance has been shown very valuable.

The tool was developed to collect and compare pressure build-ups to arrive at a calculated value of the WGR and a dynamic inflow performance relation. The inflow performance is described by the first formula, while the outflow is described by the second one.

$$P_R^2 - P_B^2 = A\,Q_g + F\,Q_g$$

$$P_B = B\,P_W^2 + C\,Q_g^2$$

The combination of both will give information about the liquid loading rate. The parameters A, B and C will increase with production of water. The accuracy of these calculations proved to be directly related to the accuracy and frequency of the recorded input data, as shown by a validation done on the three field case studies. The tool proved to be highly valuable in identifying changes in time of the inflow performance, providing key inputs to determine the best solution to prolong the well's producing life. Some limiting factors that make the use of surface pressure build-ups less accurate or inconclusive were also highlighted. This study concludes that analysing surface pressure build ups can reduce the need of expensive well and reservoir surveillance, improve the understanding of changes in in- and outflow performance and can reduce the reaction time to such changes.

Presenter: Nick van de Kolk (Siemens)

Topic: Technology and Economics of Wellhead Compression

Presentation Summary

Mr. van de Kolk introduced the mitigation method of Wellhead compression as very successful GWD tool. However, wellhead compressor packages must have the capability to cope with produced liquids and decreasing inlet pressures. Furthermore compression requires power, which is often not available at remote at remote gas production facilities.

The presented case study consisted out production modelling via Maximus, equipment via OGS and

TCO for economics. The main questions which were addressed are; How much compression power/capacity should be installed?; Which driver type should be selected: gas engine or electrical motor?; Is wellhead compression an economically sound solution?
Compression techniques increases production rate and the lifetime of a well, this was proven in 7 different wells. He explained that they went out from 10 different concepts from which 9 compression scenarios and 1 'do nothing' scenario.

The results were:

KPI NPV	→	600 kW (pgen) and 900 kW (pgen)
KPI Payout	→	300 kW (pgen) and 600 kW (pgen)
KPI ROR	→	300 kW (electric) and 300 kW (pgen)
KPI DPI	→	300 kW (electric) and 300 kW (pgen)

Presenter: Paul Egberts (TNO and TUD)

Topic: SaltMux, a Comprehensive Tool to Model Salt Precipitation in the Near Well Bore Region; Part 1: Modelling

Presentation Summary

Mr. Egberts introduced a new tool to model Salt Precipitation in the near well bore region called SaltMux. They added source and sink terms to the mass balance equations. With these additions they integrated precipitation and dissolution in the model for liquid to halite and vice versa. To develop this model, they used a simulator called DuMu^x to simulate flow and transport in porous media. The model has been extended to incorporate physics, which are essential to model salt precipitation such as, vapour pressure lowering and the transport of liquid below the (apparent) irreducible liquid fraction. Furthermore, Dumux code was adjusted to allow incorporation of experimental data for capillary pressure and relative permeabilities.

The main results shown were for the concept of drying: Transport balance can be used to explain differing locations and varying timescales of precipitation:

→ Figures shows the decrease of permeability over the course of ±200 days and the corresponding liquid saturations.

→ The permeability factor reduced from 0.65 to 0.15 (permeability factor ks/k or liquid Saturation S_L) in ±200 days.

The main conclusion was to implement a research tool (SaltMux) for salt precipitation and dissolution using DuMu^X.

Presenter: Aris Twerda (TNO and TUD)

Topic: SaltMux, a Comprehensive Tool to Model Salt Precipitation in the Near Well Bore Region; Part 2: Sensitivity Analysis and Optimization

Presentation Summary

Mr. Twerda explained that the SaltMux model is applied to perform a sensitivity study. The study had to main goals: Investigate the influence of parameters and optimize production. Two main

regimes in the reservoir for 'the concept of drying' could be distinguished: A liquid transport dominated regime, which results in clogging close to the well bore and is relatively fast. Secondly, a drying dominated regime, where the clogging occurs further away from the well bore and which is relatively slow.
The impact of vapor pressure lowering (parameter 1) due to salt precipitation was that the drying zone becomes smaller which leads to early clogging. The initial liquid saturation (parameter 2) has a huge sensitivity as clogging times ± 1-1000 days, location ± 1cm-10m.

A huge initial porosity leads to early and nearby clogging and it is transport dominated drying. Some preliminary results:

- Optimizing Cum. Gas
- Only optimizing Qg, crit
- Pw = 60 bar
- T= 1000 days
- 498 washes to 158 washes

Session 2: Field Operations and Asset Integrity

Assets in their tail end production phase often suffer from liquid loading problems, and the related mitigation measures such as foam injection, velocity strings or gas lift can have a large impact on how the wells and the asset are operated. Increased water production, for instance, can cause process upsets and may require increased operator attention to monitor and adjust process parameters.
Very often the efforts to keep liquid loading wells flowing lead to multiple extensions of field life. These may take field life many years beyond the originally planned period and lead to additional (preventive) maintenance or at the very least additional inspection activities. The original completion designs of gas wells often ideally should be designed with the complete lifecycle from initial plateau to tail end production in mind. Sadly, this is often not the case and considerable design work and modifications are needed before the original completion is ready for the deliquification solution of choice. Compatibility of the original completion materials with the to-be installed liquid loading solution is key.
In this session we will review several case studies and real life examples of optimisation, stimulation and artificial lift of late life wells. Furthermore we will take a look at the integrity consequences of both specific artificial lift choices and more general extension of end of field life.

Presenter: Josef Shaoul (Fenix Consulting Delft)

Topic: Case Study

Presentation Summary

Mr. Shaoul presented a case study showing the potential benefits of stimulation for a few examples of typical late-life gas wells with liquid loading problems. The workflow consisted of: 1) Three reservoir models were created which represent a large number of typical Dutch gas fields. 2) Critical liquid loading (LL) rate was estimated from Turner eq. For different tubing sizes, assuming TFFP of 43.5 bar. 3) A single-phase, single-layer reservoir simulator was used to determine the reservoir pressure at which the well reaches critical LL rate, for a range of positive skin values. 4) The simulation is restarted at the threshold number.

Two cases were used: Case A) Low permeability case (1 mD) with a smaller tubing OD = 2-7/8" and the critical rate lowered from 51.000 to 34.000 sm3/d. Case B) Mid permeability case (10 mD) with a smaller tubing OD = 3-1/2" and the critical rate lowered from 130.000 to 85.000 sm3/d.

The main conclusion was that fracturing can be an attractive option to mitigate LL issues by extending the production life of the well:

- Larger positive skin means best applicability of fracturing
- Lower permeability

But not waste our time talking about the high permeability reservoir, meaning not applicable in these cases as it doesn't really work. Fracturing can also delay the onset of salt precipitation by increasing the BHFP, or reduce the impact of salt precipitation on well performance, due to the different flow geometry. Combining workover & simulation operations (installing smaller tubing + fracturing) can be more attractive in some cases:

- 2-7/8" can potentially be used for fracturing down to ± 1500m
- 3-1/2" can potentially be used for fracturing down to ± 3000m
- 4-1/2" can potentially be used for fracturing down to ± 4500m

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Presenter: Joris van Lith (NAM)

Topic: Operational Challenges in Retrofit Gas Lift for Repeated Unloading of Gas Wells

Presentation Summary

Mr. van Lith explained a case; a conventional onshore gas well was converted to gas lift to enable extended unloading of formation water during kick-off. Bottom hole pressure data shows a column of water being pulled into the well during kick-off, killing the well before stable production is achieved. Retrofit gas lift was used to get the well back to producing. The main objective was to allow for an economical way of repeatedly unloading an onshore gas well unable to kick-off due to a water block. As CT interventions are costly and formation water cross-flow shut-in results in a water block. The objective during gas injection restoration was firstly to restore communication between annulus and tubing and secondly to diagnose plugging issues.

The main conclusions were:

- Concept of retrofit gas lift for repeated unloading can be an economical solution where lift gas is available.
- Gas contribution from the reservoir was lacking in this case, even after 2 weeks of unloading.

Consider the following aspects in the future:

- Thorough cleaning of annulus during conversion
- Halite scaling within gas lift valve
- Injection point

Presenter: Jeroen Smith (NAM)

Topic: Integrity Considerations when Installing Gas Lift as Artificial Kift in an Onshore Gas Field

Presentation Summary

Mr. Smith explained that without additional compression or deliquification projects to address liquid loading of the wells in the Anneveen gas field, the predicted end of system life is 2020. The current pressure of the onshore gas field is ~10 bar! The opportunities here are: 1) Wells in scope are completed with L80 CS tubing with SPM for corrosion inhibitor injection. 2) After A-Annulus fluid is removed, SPM can be used as injection point for gas-lift. They investigated the structural well integrity, well safeguarding and the corrosion management.

The main conclusions that were drawn are:

- Review the initial well functional specifications.
- Verify the evacuated casing load case with wellcat.
- Asses the casing leak paths to eliminate the chance of injected gas behind the casing into porous layers.
- Eliminate CT clean out cut by using condensate as intermediate circulation step.
- Using dry gas if available and lift gas injection pressure is sufficient.
- Consider the injection versus reservoir pressure on safeguarding requirements.

Presenter: Nico Vogelij (NAM); Anitha Immaneni (ONEgas)

Topic: Learnings from Continuous Foamer Application in Southern North Sea Offshore Gas Wells

Presentation Summary

Mr. Vogelij started with explaining that ONEgas is using continuous foam (CF) injection in the Southern North Sea area. They learned a lot about the candidate selection process, the design, commissioning and operation of capillary string CF installations in the offshore environment. He then presented the learnings from ONEgas with regards to candidate selection prior to installing CF on liquid loading wells. The candidates are identified during well reviews and future LL dates are estimated with models. Then ms. Immaneni went on to explain two different case studies from the 12 CF wells from ONEgas in the Southern North Sea. Case study 1 (foamer uptime 2016) consisted of 3 wells manned on the same production facility and were drilled around 1990. The LL started between 2005 and 2010 and the CF was installed in 2013. Case study 2 consisted of 1 well drilled in 1976 on a manned platform. Cyclic LL occurred in 2008 and CF was installed in 2011. Commissioning happened in 2012 and this resolved the cyclic behavior. Some major observations were noticed in these case studies: A) 2013: Cap string leak noticed, caused by erosion (aggravated by sand). B) Impact on reliability -> uptime (offshore intervention planning, delays). C) Cross-sectional flow area changes tubing and SV -> Erosional velocity peaks.

- They proved with these case studies that ‘CF injection enabled to unlock significant additional E reserves’. However, some risks need to be considered:
- Commercial (gains predictability & partner approval for new foam proposals).
- Technical (Foam performance uncertainty & Equipment reliability & Sand erosion of equipment).
- Economic (Incorrect prioritization of well opportunities).
- Political/External (Changes in production system pressure regulations offshore).
- Organisational (needs concerted, long-term effort form a multi-disciplinary team & unmanned platforms & mothballing S/SS equipment).

The main conclusions were:

- 12 offshore CF installed since 2011 at ONEgas and not all were successful.
- CF enabled to unlock significant additional reserves
- previous candidate selection process was reviewed

Learnings are being implemented to deliver even more value:

- Candidate select based on actual well behaviour
- Inflow performance optimized before installing CF
- Surface facility readiness (PWRI & liquid handling)
- Sand erosion risk considered / new design

Presenter: Damea Tebbes (NAM)

Topic: Production Gains and Cost Savings by Novel Implemented CoCoFoam

Presentation Summary

Miss Tebbes explained that NAM identified wells which require batch corrosion inhibitors treatments combined with liquid unloading strategy. This required a combination of corrosion inhibitor and foamer, hence the CoCoFoam. Capillary strings are installed for foam injection enabling liquid unloading. Consequently the downhole injection valve is not available for continuous corrosion inhibition to protect the carbon steel tubing. This was mitigated by frequently batch corrosion inhibitors treatments, which led to unwanted downtime of the well.

She explained that they did a trial with the goal of cost savings (tubing integrity – less chemical per liter) and production gains (maintain gas production – less downtime).

In the subsequent months, the well showed equal and stable production even with less CoCoFoam injection and the produced liquid showed sufficient corrosion protection. Sampled liquids were evaluated via kettle testing to confirm the corrosion rate. Overall the main conclusions were; implementation of the CoCoFoam resulted in significant chemical cost savings due to redundant batch corrosion inhibitors costs. Also production gains were obtained by less downtime because of the different mitigation strategy.

Session 3: Data Management, Modelling and Optimisation

During tail production of a gas well a large number of different aspects play a role: liquid loading, flow instabilities in the well, liquid drainage during production and during shut-in. With deliquification methods applied, such as foamer injection, gas lift, ejectors, the detailed prediction of all these aspects becomes even more complicated. In this session all modelling aspects of gas wells are covered. From foam film models up to real-time production optimization in case of wells suffering from salt precipitations. The goal of this session is to provide insights in the latest models and how to use them for optimization. This includes steady state models up to full transient models including the near-well reservoir. Additionally, the application of using historical and real-time production data to improve the predictions for surveillance and optimization purposes will be covered.

Presenter: Stefan Belfroid (TNO)

Topic: Instability in Gas Wells

Presentation Summary

In this presentation the experiments performed by TNO looking at the IPR (Inflow Performance Relationship)/TPC (Tubing Performance Curve) interaction are presented. The goal of this research was to investigate the influence of the reservoir IPR on the transition from concurrent flow to loading conditions and to determine how the transitions occurs. The research was done to form a link between lab and field. The difference to generally performed experiment is the replacement of the mass flow controlled setup in a pressure controlled setup. The research looks at the instability in multiphase flow, both at the static instability and dynamic, with the latter one being the more difficult one.

In short the setup description: liquid rate is fixed, pressure varies, different diameters and in between vessel and tubing there is an orifice of 6, 12, 20 mm in size.

The question arises: When does the flow become unstable?

When we have lower pressure, and thus a lower rate the disturbance is larger. The liquids drain below the upstream capacitance probe. When the pressure vessel very small we see a decrease of the rate at the end and the concurrent flow is earlier than the loading point. When the orifice is located higher up in the well, we will see a more horizontal IPR. The TPC is very predictive.

A stable operation is seen when:

$$\frac{\delta P_v}{\delta U_s} > 0$$

Conclusions:

- Depending on the IP, there can be stable production at the left side of the minimum on the TPC
- Up to real loading/loading point also almost no pressure disturbance is seen.

Presenter: Marco Marino (NAM)

Topic: Shifting Turner's Paradigm: Gas Wells can Produce in Slug Flow

Presentation Summary

When a gas well is liquid loading, the gas flow is insufficient to carry any associated liquids to surface. When looking at the TPC (Tubing Performance Curve) and IPR (Inflow Performance Relationship) curve slug flow happens at the left side of the minimum of the critical rate and the annular flow right side. This principle is described by Nodal analysis, and is a simplification of the surface conditions, reservoir pressure, BHP, the drawdown in between points and the operating point for a specific THP.

Stability is governed by the pressure drop. It can be read from the TPC and IPC curve, namely when the BHP goes down, and you move along with this pressure drop on your IPR curve, the system has the ability to go back to its original conditions after a disturbance, signifying a stable condition.

After this background information Marco Marino showed us an example of a well that is producing in slug flow, so on the left side of the minimum of the TPC. The TPC and IPR barely intercept, so the flow is becoming critical. Then the well is choked. When you are doing a stability analysis on this well, you have to take into account this additional pressure drop between FBHP and manifold, namely from the choke. The pressure drop now becomes equal to the pressure curve - well + choke. If you do not include this pressure drop in your analysis and only look at your TPC, the analysis will not be correct. So this well is still continuously flowing (stable rate and stable pressure), even though it is on 1/3 of the liquid loading rate. Well 2 is choked back due to sand production, 140,000 m^3 a day less rate than before. Slug flow is seen but it still it has a stable production. The third well is a tight reservoir, with a drawdown of 100 to 130 bar, again this flow is on the left side of the stable minimum and slugging is seen, but it is still has a stable flow. Choking seems like a good solution then, but a choke harms production in time, so not something to do if not needed.

Conclusions:

- Choked back wells can typically produce at lower rates than suggested by TPC. However TPC is still valid to identify changes.
- Stability is governed by pressure drop.

- Well stability is dictated by pressure drops across the entire system, not just by the TPC
- For choked back wells the minimum stable flow can be derived from a TPC with respect to the manifold pressure including choke pressure drop.
- Very tight reservoir: reservoir pressure drop can play a role
- Surfaced PQ curve can be used since this includes all pressure drops
- More field examples needed to further investigate
- Choking influences well productivity so just choking for stable flow is not handy
- Choking always concerns with costs: higher abandonment pressure

Remark from audience: We can see this as a dynamic slug control device, a fixed choke value with a pressure drop does not change point of liquid loading but simply adds a control.

Presenter: Rahel Yusuf (Schlumberger)

Topic: Dynamic Simulation to Predict Self-Restart Potential of Acid Stimulated Wells by Bullhead Treatment in Deepwater Environment

Presentation Summary

The objective of this research presented by Rahel Yusuf was: To evaluate the self-restart feasibility of a subsea gas well following matrix stimulation (acidizing) treatment by accounting for the saturation changes in the near wellbore

This was done by a transient wellbore model with two zones defined using IPR. A black oil fluid model was used for simultaneous tracking of nitrogen, produced gas or condensate, water and acid in the wellbore and near well bore models. The standard fluid property table used for the well bore model. From the black oil model a coupling needed to be made to near well bore reservoir, for which a grid was modelled. The reservoir damage and the impact of the stimulation treatment was characterized using skin parameter. This coupled model has a similar trend to the black oil model.

The well however was unable to restart without nitrogen displacement (additional sensitivity). So the displacement of Nitrogen after the nitrified fluid injection is seen to be the crucial step to ensure the self-restart capability of the well as without this step the well was unable to restart as was demonstrated.

This issue may be remedied in the field by pigging the production flow line or reducing receiving pressure prior to well restart.

Conclusion:
The important finding, no restart without nitrogen displacement, could not be made with a standalone wellbore model of the production system.

Presenter: Ruud van der Linden (TNO); Esteban Munoz (Wintershall)

Topic: Real-time Model-based Gas Production Monitoring and Optimization

Presentation Summary

In this presentation a summary of the developed model for real-time monitoring and future predictions is presented. This real time monitoring done in Matlab helps to optimise production. There are 2 phases in this project.

Phase I: Generic model based on real time optimization. Physics padded model to predict production performance of the asset. Models calibrated.
Phase II: This considers the optimization procedure of wells that are suffering from salt precipitation. The idea is to optimize the water wash time by a salt wash workflow.

Conclusion:

- TKI gas project about real time production optimization phase II will be completed Q4 2016
- Real time monitoring is a proven tool for early event detection of potential production problems example: Model advisory tool allows to optimize production 24/7. Quick recognition of well performance deterioration.
- Approach in DOF digital oil field given current developed infrastructure in Matlab can be easily extended for oil fields, for flow assurance, artificial lift, liquid loading(intermitted production/ foamers).
- The project has been executed with TNO by sept by step independent testing of individual project units.
- Fast development with potential exchange/correction of models at later stage and future scope of extension.

Presenter: Stephen Cannon (Weatherford)

Topic: Production Optimization, Am I There Yet?

Presentation Summary

The question asked by Stephan Cannon is the following; “Am I there yet?” We are very far in technology and optimization methods, but is this enough? How do you know you optimized your wells? The answer to this is actually very simple; you have to understand the problem! So the customer has to tell you exactly what they want to see. At the moment it seems that the problem is not understood properly as people only look at a single well and not at a whole system.

So address the problem, avoid focussing on solving individual problems of single wells or a piece of production equipment. Here automation (more than a single operation in time) is often used to help address these types of problems.

Automation, meaning more than a single operation in time, is different to optimization. The latter meaning having a target in mind.

The optimization process exists of several steps; appraise (reservoir/well data), select (hardware/software), design (hardware/software), monitor (sensors), analyse (math models) and adjust (controllers).

A “I want more production” is not enough. An objective needs to be stated for example “I want more production with the resources that I have/or with added resources”, etc..

Conclusion:

- Identify and understand the problem
- View the solution as a system instead of an individual well or equipment
- System change production in wells without knowing about it, customer limits the changes.

Presenter: Jos van ‘t Westende (TNO)

Topic: Foamers: A Comparison of Predictive Models

Presentation Summary

In this presentation three different research projects, performed by TNO, TU Delft and Tulsa, on foam flow are shown. The common objective is to improve the knowledge and prediction of foam flow. Foam is a good EOFL technique as it decreases hold-up and increases friction, thus increases pressure gradient. When modelling the foam flow it is assumed that the foam flows as a thin film along the wall, dragged upwards by gas shear and pulled downwards by gravity. The onset of liquid loading is coupled to flow reversal.
Difference is found in the closure relation between the 3 projects, with parameters; density foam density, foam viscosity, yield stress, turbulence, diameter lubricant, t_w, t_i and shear
Tulsa has a big scales setup, representing the field and Delft a small scale setup in the lab. TNO looks at scaling and the turbulent/laminar film velocity profile. While the TU Delft only considers the laminar film velocity profile. Delft also looked at scaling and liquid lubrication. Tulsa did not take liquid lubrication into account but did look at turbulent/laminar film flow (plug flow) like TNO. All 3 consider their own way of calculating the friction factor.

Results:
Both considering atmospheric conditions, it seems that the TNO and the TU Delft model have comparable performance. When extrapolating the changing pressure to high pressure, the model start to deviate more, becoming less exact.

Future JIP project:
- Minimize testing requirements in selection guidelines
- Improve foam flow model & usability
- Compare with field cases
- Test with real brines, HCs, acidity,
- Characterization of foam and foamer solutions (desk top & flow loop) and the relation of their molecular characteristics
- Cooperation with other groups

Session 4: Artificial Lift

The majority of mature gas and oil wells are suffering from liquid loading. The oil and gas industry worked on a variety of artificial lift systems as e.g. foamers, ESP, jet pumps, to deal with these often challenging conditions.
This session is intended to give an overview about possible approaches and their pro's and con's when dealing with these problems. Besides a field trial report dealing with check valves used for intermittent wells, the focus will be on the different dynamics of the different artificial lift systems as well as the possibility to model these different approaches using transient simulations.

Presenter: Rahel Yusuf (Schlumberger)

Topic: Evaluation of different Gas Well Deliquification Solutions Using Transient Simulations

Presentation Summary

In this presentation a transient modelling approach is presented to model gas well deliquification techniques. Several techniques were simulated, like wellhead compression, plunger lift and gas lift. All techniques showed successful production.

Wellhead compression → the WHP reduced from 35 to 20 bar
Velocity string → delayed the liquid loading thus allowing more gas production.

Plunger lift → well was flowing again for 5 hours after a 2 hour shut-in
Gas lift → doing half a day of gas lift and got a 1 day natural flow cycle

Conclusion:

- Transient simulations are conducted on a gas well to investigate the effectiveness of different gas well deliquification measures
- Lowering the FWHP to 20 bar or using a velocity string can delay the occurrence of liquid loading
- Well can be produced cyclically using plunger lift or intermitted gas lift
- Transient simulations can assist in primary screening and evaluation the effectiveness of different deliquification solutions

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Presenter: Marco Marino (NAM)

Topic: Check Valves as Artificial Lift for Intermittent Gas Wells: a Field Trial

Presentation Summary

This presentation showed us the possibility to have a plunger lift without the plunger!

Down hole check valve (DHCV) has the same bottomhole assembly as plunger lift system, but without the bumper string and the plunger. Thus the same intermittent production cycle can be considered, just different geometry.

The candidates for this method are wells that are already on automated intermitted production. They should have low WHP and low LGR.

Testing showed that after 50 hours of flowing and a 20-hour shut in, the well was opened for 9 hours but unfortunately was not flowing at all. It simply did not do anything. So after trying with an uptime of 50 hours, an uptime of 25 hours was tried but these results were even worse. So the trial failed, the average rate w/DHCV was lower than w/o DHCV.

Though not the technology was at fault, but the candidate chosen for this experiment was sub-optimum and the DHCV cycle was incorrect.

As the closed in pressure was relatively low, the following problems occurred:

- Limited decompression volume x pressure
- Limited liquid slug volume that can be lifted to surface

As the well was opened for too long period, the following problems occurred:

- Too large liquid slugs
- Insufficient decompression to lift liquids to surface

Conclusion:

- More trials are needed to delineate the potential of this low cost DHCV technique
- Test were time based, should be pressure based

Presenter: Steve Cannon (Weatherford)

Topic: Artificial lift: Gas lift

Presentation Summary

What is gas lift?

- Most closely simulates a naturally flowing well
- Only produce what the well would give up naturally
- Not a positive displacement pump, more injection gas is just wasted
- Injected gas simply reduces the hydrostatic head

Applications:
- Continuous or intermittent flow
- Tubing and casing flow (can inject in both)
- Wells where pressurized injection gas is readily available
- Insufficient BHP's or deep wells that cannot flow against hydrostatic head
- Desire increased production in naturally flowing oil and gas wells
- Unload water from gas wells

Advantages:
- High degree of flexibility and design with wells of varying flow regimes
- Handling sandy conditions
- Wellhead Equipment is minimal
- Multi well production from single compressor
- Deviated wells applicable

Limitations:
- Requires a gas source
- Requires high pressure source, either a high pressure gas well or a compressor
- Not economical for single wells

Components:
- Supply gas and compression at the top
- Lift gas manifold, servicing multiple wells
- Wellhead, looking what's going on at the surface, rate going in and also downhole, gas lift valves (designed for various pressures)
- Production separator
- Electronic gas meters – how much gas is generated and consumed
- Downhole tubing retrievable and wireline retrievable
- Gas lift valves over the whole tubing
- Automation & optimization
- Closed loop control ensure target injection rates are maintained throughout the gas lift process
- Preprogramed unloading and ramping functions designed to API guidelines
- Periodization and sequencing wells at start up and shutdown
- Intelligent distribution of compression/source gas based on priority
- Dynamic adjustment of injection rate
- Metering injection and produced gas and liquid prod.
- Case to reduce compression costs for intermittent gas lift

Objective:
- Determine optimum on/off injection time for intermittent gas lift wells
- How do we find the moment to turn injection on or off?

Challenges:
- No day to day optimization techniques available
- Intermitted injection controls lack intelligence in when to end the injection cycle

- Modelling tools are costly

Method:
- Implement wellhead controls to calculate optimum injection rate and duration
- Specific method detail tbd

Results:
- Reduced the customer energy by up to 50% of the cost of supply gas and compression. They were over-injecting and did not know it.