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Department of Earth Science and Engineering

Centre of Petroleum Studies

Modelling of a Gas Cap gas lift system

By

Junior Chukwudi Okenwa

In conjunction with

Statoil

A report submitted in partial fulfilment of the requirements for The MSc and/or the DIC.

September 2011

DECLARATION OF OWN WORK

I declare that this thesis

‘Modelling of a Gas Cap Gas lift system’

Is entirely my own work and that where any material could be construed as the work of others, it is fully cited and referenced, and/or with appropriate acknowledgement given.

Signature:……………………………………………………………………………………………….

Name of student (Please print):…………………………………………………………………….

Name of Supervisor: Professor Matthew. D. Jackson

Name of Industry Supervisor: David Hume

Abstract

Gas lift is a common artificial lift method that is applied in starting up dead wells or oil production optimization. The gas lift method involves allowing gas into the production tubing to lighten the liquid in the production tubing and hence enhance liquid production. Recently, gas from the gas cap of a hydrocarbon bearing reservoir have been applied in oil production optimization using the GCGL valve. Using gas cap gas for gas lift has an advantage over a conventional gas lift system as it does need extra equipments essential to conventional gas lift methods such as compressors and pipeline. However gas cap gas injected into the production tubing needs to be monitored to ensure oil production increase and prevent negative effect in a reservoir with an active gas expansion drive.

The main aim of this project is to describe the development of a GCGL system modelling method that can be used to optimize oil production and prevent negative effects on a reservoir with a gas cap expansion drive recovery mechanism by actively controlling the chokes and valves in a field model during a prediction run. A generic methodology was developed to address the following issues: how to find optimum gas injection rate, ability to check if optimum gas injection rate is possible and definition of a control mechanism for the system chokes and valves to ensure production optimization effects. Consequently, the GCGL methodology was implemented by adapting current industry standard software by using coupled simulation. Tests were done on a field known as the K field which is known to have a pressure barrier between the gas cap and oil zone using a tank model (based on material balance) initially to ensure that the production optimization rules set were working. The tests were then repeated with a numerical simulator replacing the tank model so that a comparison could be made to a standalone numerical field model of the same field to see if any benefits could be noticed in the production profile.

The tests confirmed that using field management logic of allowing gas injection at an optimized injection rate (obtained from a non-linear optimization algorithm) when the topside choke is fully open and the desired production rate cannot be met, increases oil production rate during a prediction simulation run and therefore can be used to advise on topside choke and GCGL valve configuration of a real field production network. The tests done also show that the modelling technique also provides a means of obtaining the maximum gas withdrawal rate from the gas cap. It also introduces a means of being able to monitor the gas withdrawal from the gas cap which could be used for a reservoir with an active gas expansion drive to determine the amount of gas that will have adverse effects on the gas expansion drive recovery mechanism.

Acknowledgement

I would like to give special thanks to David Hume, Espen Halvorsen, Perrine Gomel, and Sidsel Spilde of Statoil ASA, Bergen for technical assistance and for making my experience in Statoil ASA, Bergen a pleasant one. I also want to thank Matt Jackson for his invaluable advice.

I dedicate this thesis to my family; especially my mother, Mrs Eunice Okenwa, for all the encouragement and support given to me. I also want to give special thanks to God almighty for making completion of this project possible.

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Thesis title: Modelling of a Gas cap gas lift system

Student name; Junior Chukwudi Okenwa, SPE, StatoilASA
Imperial College supervisor: Dr Matthew Jackson
Company supervisor: David Hume, Statoil ASA

Imperial College London

1.0 Introduction

A gas cap gas lift (GCGL) valve is a device that is used to allow in-situ gas into the production tubing to enhance liquid production by making the fluid column in the production tubing lighter (Vasper, 2006). The GCGL valve is located in a production tubing passing through a perforated gas cap (figure 1) and is controlled at the surface by hydraulic pressure through a control line from surface to GCGL location on the production tubing (Schlumberger, 2010). The GCGL valve consists of a variable window orifice that can switch to one of six positions ranging from 0 to 100% open (Schlumberger, 2010). The GCGL system works on the same principle as a conventional gas lift system, but has an advantage as capital cost of gas-transport or gas compression facilities are eliminated and load requirements on the platform due to gas compression are also avoided (Vasper, 2006). An estimated 60 GCGL valves have been installed in the North Sea as at 2006; most of them in the Scandinavian sector (Vasper, 2006). Statoil applies the GCGL system in several fields, most notably Troll and Grane as an artificial lift to start up difficult wells (Hume, 2011).

A novel method has previously been used to model the optimum GCGL valve configuration for the Norne subsea field by using a numerical simulator and wellbore hydraulics simulator (Al-kasim et al., 2002). The Norne subsea field is the northern most field in the Norwegian continental shelf. The Norne subsea field consist of the Garn and Ilje formations. The Garn formation contains mainly gas while the Ilje formation is mainly an oil reservoir. The Garn formation is under higher pressure. It was discovered that there was a pressure barrier between the two formations which means gas can be taken from the Garn formation without any penalty to the Ilje reservoir recovery mechanism (Al-kasim et al., 2002). An initial quick look evaluation of the potential of applying gas lift as an artificial lift method with a full field numerical model by altering the vertical lift performance curves was done. Potential benefits in applying a GCGL valve were found which led to further design analysis. A commercial wellbore hydraulics simulator and a numerical simulator were applied in the design analysis. The commercial wellbore simulator approach was applied to investigate well and gas cap gas lift performance for specific scenarios encountered during the prediction run to obtain the best GCGL valve configuration while the numerical simulator approach involved running simulations of different gas lift injection scenarios (Al-kasim et al., 2002). Although both approaches achieved consistent results based on the optimum gas lift valve configuration, they both have disadvantages. One disadvantage to these modelling methods is their inability to control the gas lift valve dynamically as conditions are changing during a prediction run and hence are not able to obtain the optimum GCGL system configuration at different conditions. Another disadvantage is that both approaches concentrate on particular parts of the production system. An example of this is when the numerical simulator approach gave an optimum gas injection rate that was too high when considering the surface facility handling capacity (Al-kasim et al., 2002).

The aim of this paper is to design a standard generic modelling method that can be used to advise on how to increase oil recovery by using gas cap gas for gas lift and prevent adverse effects (due to drawing gas cap gas) on a reservoir with an active gas cap expansion drive recovery mechanism by actively controlling the GCGL valve system in a field production prediction run using industry standard software packages. To achieve this, various ways of modelling a vertical lift performance relationship (VLP) for a production well hydraulic system will be obtained and models representing different parts of the production system of a field known as the K field are integrated (coupled simulation) to test the proposed modelling method.

The main objectives are:

- Identify key considerations in developing generic GCGL methodology.
- Define methodology.
- Adapt industry standard software to implement methodology.
- Test adapted methodology on K field.

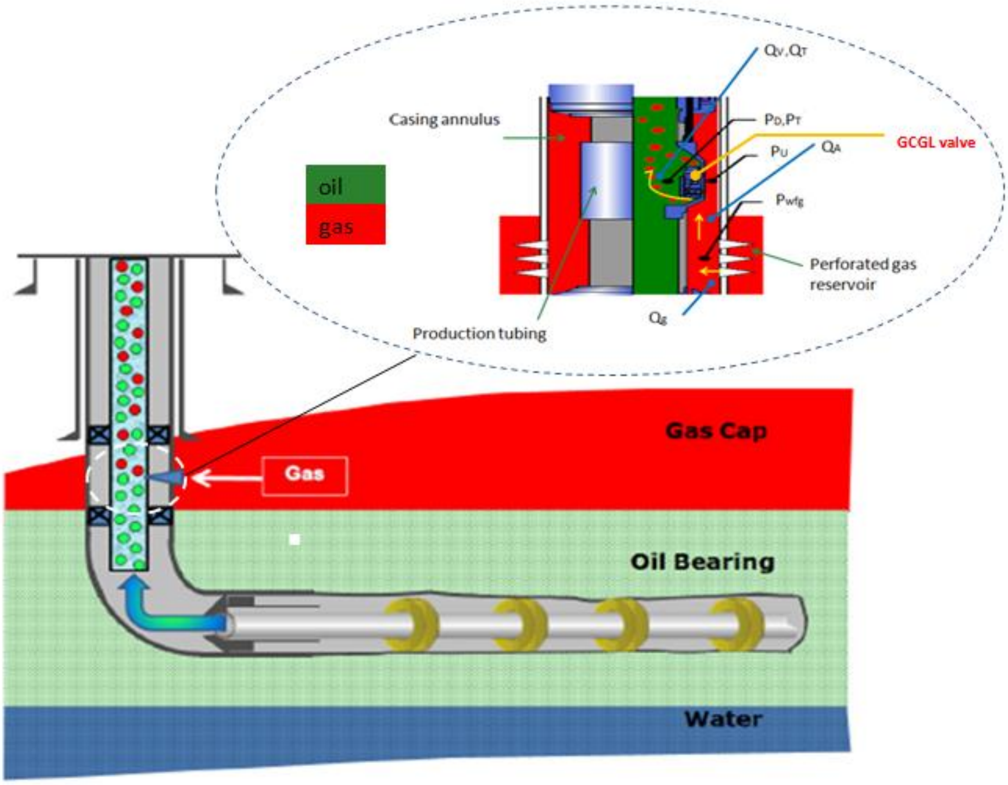

Figure 1: Relationships affecting gas deliverability (Vasper, 2006; Warren et al., 2009)

2.0 Research Methods

2.1 Important considerations for GCGL methodology development

Important points considered for the development of the GCGL methodology:

1. Finding optimum gas injection rate.
2. Ability to inject gas at optimum gas injection rate.
3. Choke-valve optimization rules and ability to monitor gas withdrawal to check for adverse effects on the long term recovery of a reservoir with gas cap expansion drive.

The optimum gas injection rate in this case can be defined as the gas injection rate responsible for the highest oil production rate. Obtaining the right amount of gas in the system is essential to the success of oil production optimization. The optimum gas injection rate is usually obtained from sensitivity plots of liquid production rate against gas injection rate or gas liquid ratio which will have a bell shape as shown in figure 2. At low gas injection rate into production tubing, liquid production is increased due to the reduction of the hydrostatic pressure loss factor; the pressure loss due to the frictional factor also increases slowly (Brill *et al*., 1999). As gas injection rate is increased, a point will be reached where the rate of increase of the frictional pressure loss factor is more than the rate at which the hydrostatic pressure loss factor decreases and therefore will lead to a decrease in liquid production (Brill *et al*., 1999). The optimum gas injection rate from the sensitivity plot will typically be selected from a part of the sensitivity curve where the rate of liquid production increase relative to rise in gas injection rate starts reducing thereby making it less economical to inject more gas (Brill *et al*., 1999). In a complete production system, the optimum gas injection rate is further limited by the fluid handling capacity of the surface facilities.

The optimum gas amount in a production system can be obtained from the marginal gas oil ratio (GOR) term. Urbanczyk and Wattenberger suggested that if gas-handling capacity is the only constraint, it can be shown that at optimal liquid production, the marginal GOR of the wells are equal (Urbanczyk et al., 1994). The marginal GOR can be defined as the rate at which gas rate is changing to the rate of change in oil rate. The marginal GOR concept was applied in building a short term (1 or 2 weeks) network optimization model for the Troll field facilities (Hauge *et al*., 2005). Another method that could be used is the application of a non-linear optimizer with an objective function of finding the maximum oil production rate to determine the optimum gas injection rate of the system. Non-linear optimization algorithms are found in some industry standard multiphase flow simulators such as GAP which makes it a suitable option (Petroleum Experts, 2010). GAP applies a non-linear sequential quadratic programming technique for optimization. It compares the rate of change of production rate to the rate of change of controllable variables such as gas lift injection rate to find the optimum oil production rate (Petroleum Experts, 2010).

The second important point involves checking if the well hydraulic system is capable of delivering the optimum gas injection rate. The deliverability of optimum gas injection rate depends on the following relationships:

1. $Qg = f\ (Pwfg^2, Pr^2)$
2. $Q_A = f\ (Pwfg, P_U)$
3. $Q_V = f\ (P_U, P_D)$
4. $Q_T = f\ (P_T)$

where P_D = pressure downstream of gas valve, P_T=pressure in tubing at gas valve depth, Pwfg=bottom hole flowing pressure of gas reservoir, Pr=average gas reservoir pressure, Qg=gas flow rate from reservoir. Q_A=gas flow rate through annulus, Q_V= gas flow rate through gas valve, Q_T=gas flow rate into tubing (Vasper, 2006).

The first relationship represents the inflow performance relationship (IPR) of the gas reservoir and completion. The IPR describes a relationship between the average reservoir pressure and the bottom hole flowing pressure (Vasper, 2006). To dynamically portray this phenomenon, a reservoir-well interaction model is needed.

The second relationship represents the flow of gas through annulus and is only thought to be necessary when there is considerable difference between Pwfg and P_U. The difference between Pwfg and P_U can be assumed to be negligible when the gas valve is close to the gas zone and frictional pressure loss in annulus is minimal (Vasper, 2006). Since the methodology has to be generic, a model that can give the mathematical function relating Pwfg, P_U and Q_A is needed. The second relationship can be represented by single-phase or multi-phase pressure drop equations which account for hydrostatic, friction and acceleration pressure loss factors (Vasper, 2006).

The third expression can be defined as the gas lift valve performance equation. The gas lift valve performance relationship is usually defined using the Thornhill-Craver equation (Vasper, 2006) but can be defined using either an API Recommended Practice 11v2 correlation (American Petroleum Institute, 2001) or Perkins model (Perkins, 1993).

The fourth expression relates Q_T to P_T. These two terms are found to be inversely proportional to each other as shown in figure 2. Figure 1 also shows a diagrammatic representation of these relationships (Vasper, 2006). The operating point of the well (ability for well to inject gas at a certain gas rate) is the solution to these equations where the gas rates (in terms of mass flow rate), upstream pressure and downstream pressure to gas valve are consistent (conservation of mass) (Vasper, 2006).

$$Q_G = Q_A = Q_V = Q_T \qquad (1)$$
$$P_D = P_T \qquad (2)$$

A different approach of finding the ability of gas to be injected into production tubing would require the use of pressure balance equations from oil zone to tubing gas injection point, gas zone to tubing gas injection point and well head to tubing gas injection point. The solution of these three pressure balance equations gives the tubing pressure at the gas injection point. An implicit problem is created by this approach and therefore requires trial and error to find a solution (Warren.*et al.*, 2009). It is also worth noting that for a reservoir with an unconnected (no pressure communication) overlaying gas cap, gas injection is possible provided that the pressure in the gas cap is in hydrostatic equilibrium with or greater than the pressure in the oil zone (Betancourt, 2002).

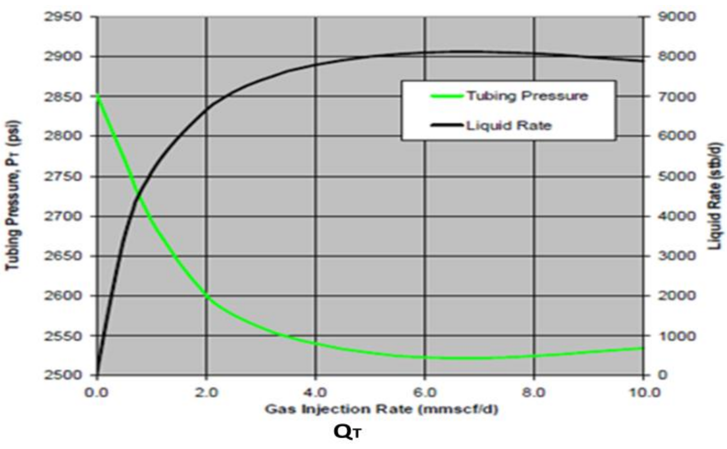

Figure 2: An example of a relationship of gas injection rate into tubing (Q_T), tubing pressure (P_T) and liquid production rate (Vasper, 2006)

A set of rules need to be defined to assist in oil production optimization with the gas lift gas valve system during a prediction run. These rules should involve altering well and network controls in a manner that will optimize oil production dynamically during a prediction run. In a field production network, the topside choke plays a major role in network productivity. Due to limited fluid processing capacity at the surface, the topside choke differential pressure (Dp) should initially be as high as practically possible while wells are only choked to meet individual constraints and deal with variations in production. As the average reservoir pressure declines, the topside choke Dp is progressively decreased (opened) to reduce back pressure effect. When the topside choke is fully opened (minimal differential pressure) and the desired production rate cannot be achieved then extra measures such as artificial lifting or bringing wells online can be taken (Petroleum Expert, 2010). A good point to start gas lift injection is when the topside choke is fully opened and desired production rate cannot be reached.

Knowing when gas drawn from the gas cap begins to affect the gas cap expansion drive of the reservoir is also important as it would help to determine when the gas cap gas injection becomes uneconomical. A method that can be used to obtain the amount of ejected gas that will affect the gas cap expansion drive of the reservoir is to use a model that can reflect the dynamic effects within the reservoir. Such a model should consist of a well in the gas cap and another well perforated in the oil zone. A reference prediction run will be done with the gas cap well offline to reflect the natural production profile of the well without interruption from gas cap production. A second prediction will then be done with the well in the gas cap turned on. The new production profile will be compared to the production profile obtained from the reference case to determine when the two production profiles begin to deviate. The cumulative produced gas from the gas cap well corresponding to the deviation point is the amount of gas that will cause disruption to the gas cap expansion recovery mechanism (no pressure barrier between gas cap and oil reservoir) and can be defined as the 'critical cumulative gas cap gas production'. The critical cumulative gas cap gas production can also be used to recommend a gas withdrawal rate from reservoir. The proposed methodology is described in the figure below.

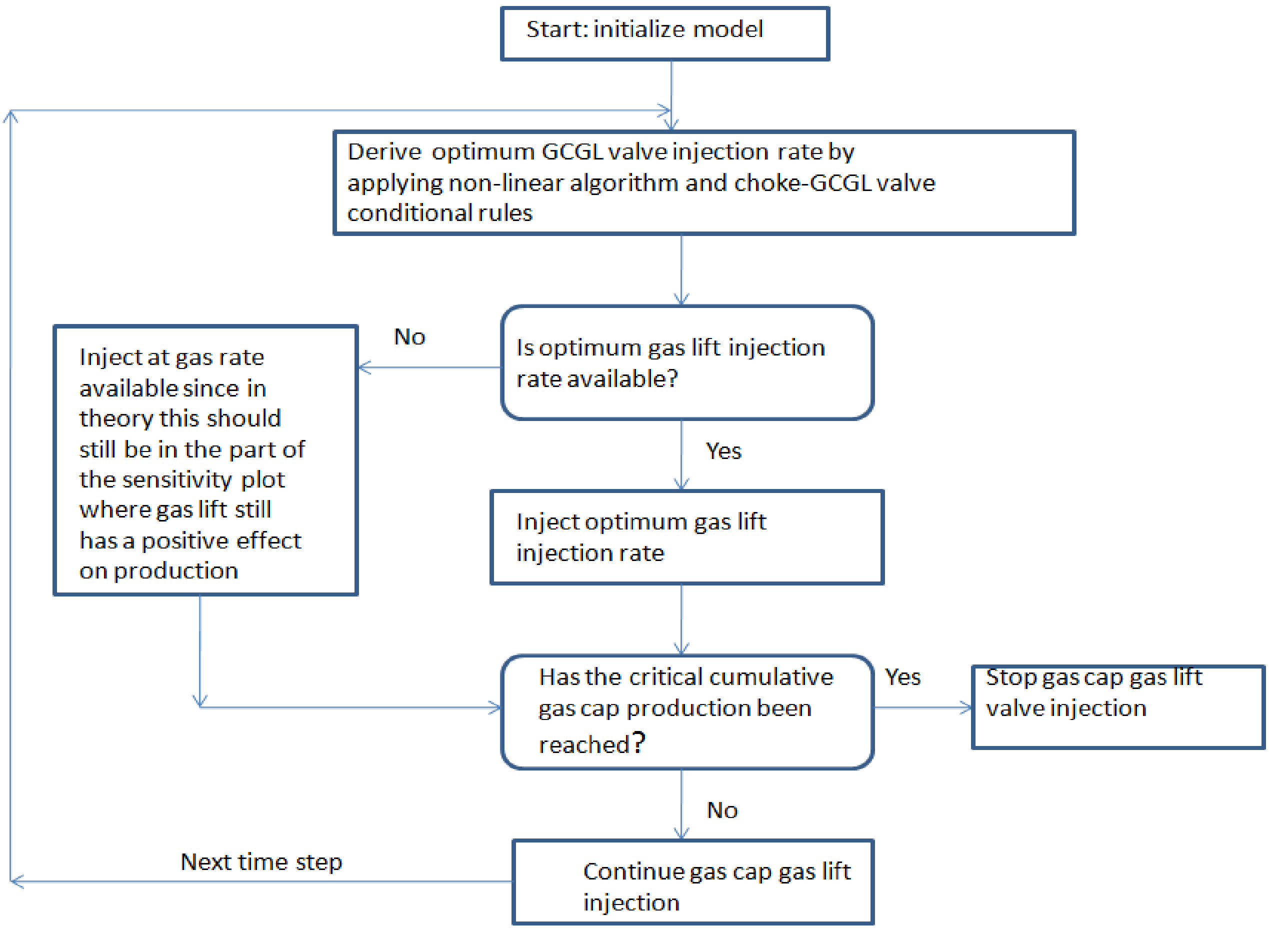

Figure 3: GCGL system production optimization methodology

2.2 Adapting Industry Standard Software to implement methodology

A method of adapting industry standard software to implement the methodology suggested can be done with coupled simulation. Coupled simulation can be described as the dynamic integration of models representing different elements of a production system with an integrator-controller tool which allows integration of specialist software such as reservoir simulators and nodal analysis software. Coupled simulation allows for dynamic transfer of data from one specialist software to another and also permits setting up rules for model parameters to obey at any specified condition (Petroleum Experts, 2010). This section describes two methods that can be used to create a GCGL field system model by applying the coupled simulation concept. These methods are described below.

2.1.1 Full wellbore description

In this method, the vertical lift performance (VLP) relationship generated (using PROSPER) for the artificially lifted production wells, describes the tubing pressure gradient from oil zone to surface and also accounts for continuous gas injection at a particular depth. After successfully generating the VLP curves, the curves are transferred to an industry standard multi phase flow simulator model of the GCGL field network (built in GAP). The Non-linear algorithm in GAP is used to find the gas lift injection rate and well head choke pressure change (Dp) for each gas lifted well that will yield the optimum oil production rate at each time step during a prediction run. The downside to this approach is that any value can be defined as maximum gas injection rate for non-linear optimisation and therefore, there is a need for a secondary gas injection rate verification tool that can satisfy equations 1 and 2 or provide a similar relationship to describe the maximum gas injection rate and a tool that can extract gas from the gas reservoir at a similar rate to the optimum gas injection rate at each time step. Consequently, the completed model will be introduced to an integrator-controller software (RESOLVE) which will then be used to include: the secondary gas injection rate verification tool, a model (with a numerically simulated IPR or an IPR based on material balance) representing a dummy well connected to a gas cap reservoir to extract gas from the gas cap at the same rate as the optimum gas injection rate and a net present value (NPV) calculator (built on Excel) to help identify the benefit of applying the GCGL methodology.

The final step is setting up the control mechanism for the topside choke and conditions to trigger gas injection at optimum gas injection rate into production tubing which is done with an event driven scheduling mechanism on the integrator-controller software. The main advantage of the full wellbore approach is the reduction of controllable variables in the system since very few components of the production well hydraulic system is modelled in the multiphase simulator making it easier for the multiphase simulator to reach a solution. Too many controllable variables (which is a property of a typical well hydraulic system) in the multiphase flow simulator will disrupt the solution obtained by the optimizer (Statoil ASA PTEC, 2010). The main disadvantage is the need for secondary verification tools.

2.1.2Partial wellbore description

The main difference between the full wellbore approach and partial wellbore approach is in the VLP curve description. The VLP relationship used in this approach concentrates on modelling the wellbore from above the GCGL valve to the surface for the oil producing wells. The rest of the wellbore is modelled using a multiphase flow simulator which makes it possible to capture the essential components of the wellbore that contribute to the availability of optimum gas injection rate. These key components consist of a gas IPR model to represent the inflow performance from the gas reservoir, a pipeline model to capture the pressure drop that will be encountered by gas flow through the casing annulus and the GCGL valve represented by an inline choking element in the multiphase simulator. The inline choking element uses the Perkins valve performance relationship (Petroleum Experts, 2010). Although the inline choking element can be programmed to other gas valve relationships, it was not done as it is more complicated. Linking the models of the key components with the rest of the multiphase flow modelled wellbore defines the relationship described by equations 1 and 2 meaning no verification tool is needed. Although the partial wellbore approach allows for optimization of GCGL valves and well head chokes with an objective function of obtaining the maximum oil rate, it creates a more complex problem for the optimizer due to the presence of relatively more controllable variables (figure 4) and would need an extra optimization algorithm to assist the built in non-linear optimizer (Statoil ASA PTEC, 2010). The advantage of this method is that the only extra calculation model needed to be brought into the integrator-controller tool is the NPV calculator as all other essential considerations are met (figure 5). The partial and full wellbore description methods were used to set up models for testing.

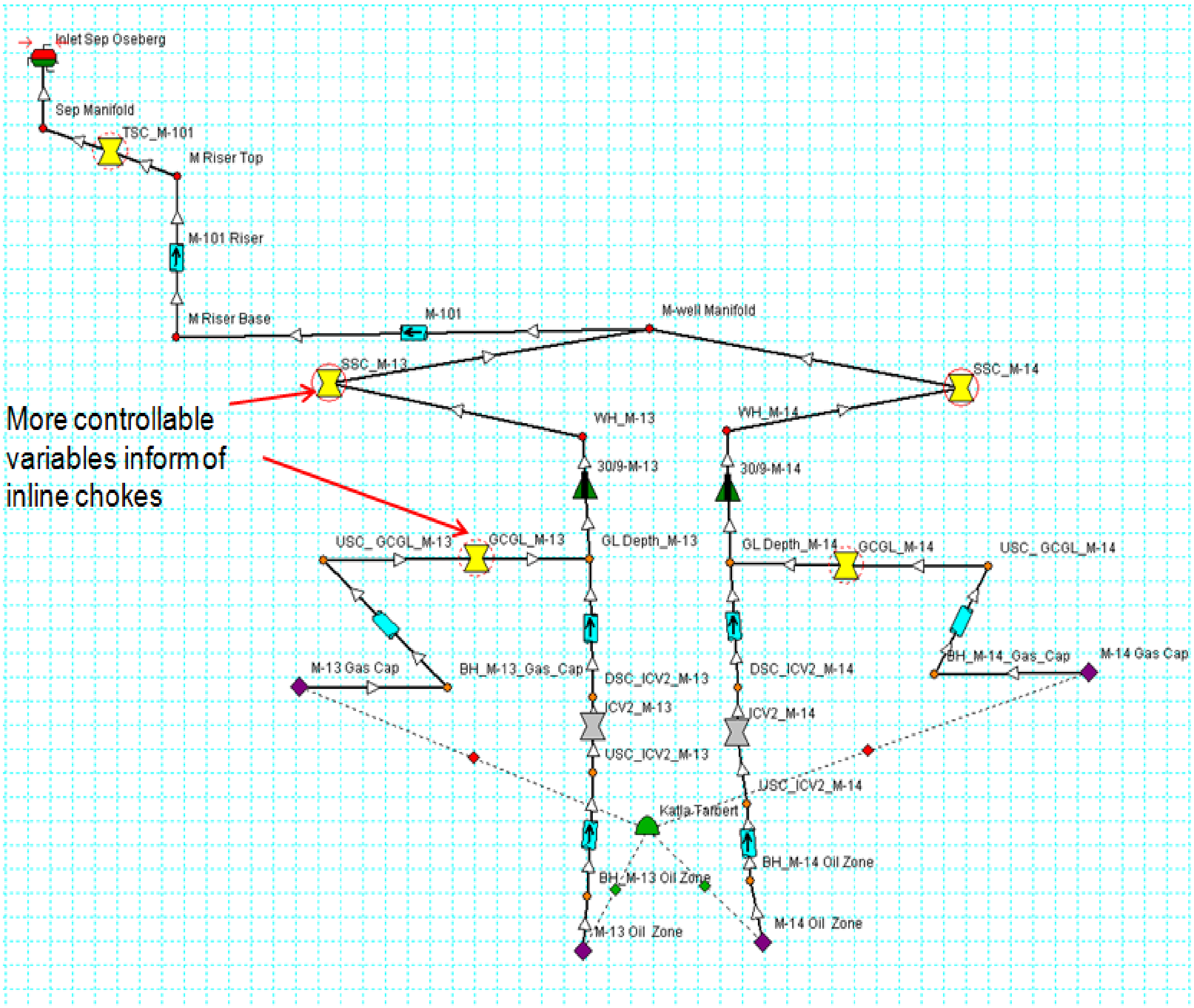

Figure 4: Partial wellbore method network model (labels defined in tables B-1, B-2 and B-3)

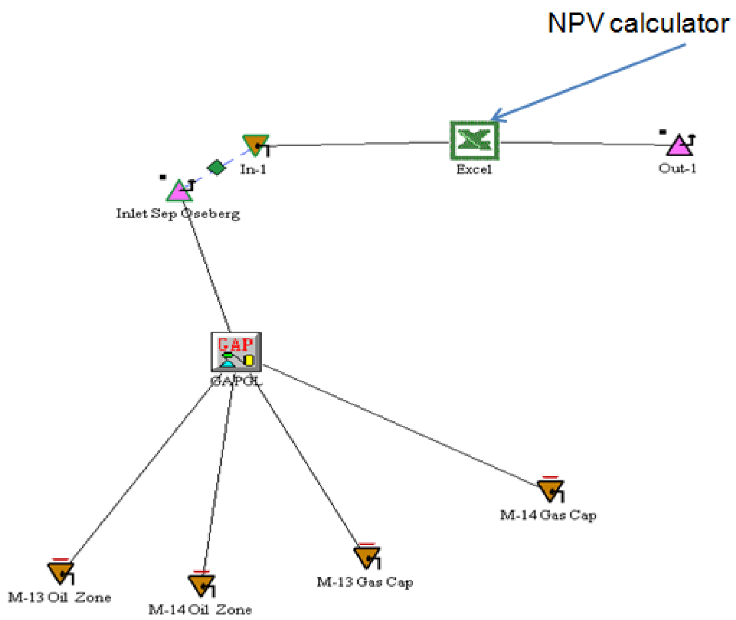

Figure 5: Partial wellbore description method on integrator-controller tool

2.2 Testing methodology on a real field case

2.2.1 Field K description

The field case K used to test the methodology is located in water depths of 95-115m, 13km south west of the nearest platform. It consists of a northern and southern segment and two main reservoir layers with different properties. The topmost layer (Heather) has average reservoir qualities but it contains mainly gas while the underlying (Tarbert) is a very good quality reservoir and contains mainly oil. The Tarbert also has a small gas cap. An important characteristic of the K field is that the two reservoir layers are separated by a pressure barrier meaning that gas can be taken from Heather without penalty to the recovery mechanism of the Tarbert (similar to the Norne case). The base case concept for the development of the field includes four subsea wells in the same subsea template. Two of these wells are horizontal subsea producers (M13 and M14) while the other two are water injectors. A test is done to see if operating the field with the GCGL methodology would give a better production profile than the base case recovery method. Network design constraints for this field are shown in table 1 (Statoil ASA, 2011).

Field Network Constraints	
Oil Rate	4000 sm3/day
Gas Rate	1Msm3/day
Liquid rate	5000sm3/day
Water injection rate	9000sm3/day
Well production efficiency	90%
Separator inlet pressure	20 bar (including topside dp)
Production line	8”
PVT Properties of Tarbert	
GOR	213.8sm3/sm3
Reservoir temperature	103.4C
Reservoir pressure	296.6 Bar
Formation volume factor	1.6818
Oil gravity	778.8Kg/sm3
Gas gravity	0.94327 Kg/sm3
Water density	1031 kg/sm3
Reservoir Parameters	
Gas oil contact (GOC)	2851m TVD MSL
Oil water contact (OWC)	2888m TVD MSL
Initial reservoir pressure at GOC	300.7 bar

Table 1: K field parameters (Statoil ASA, 2011)

2.2.2 Testing method

2.2.2.1 Setting up GCGL methodology test with tank model

The partial wellbore and full wellbore methods were used to build field models of the K field which were initially connected to reservoir tank models based on material balance (Mbal). The main reason why a tank model was used to do an initial test was because although it is simplistic as it describes the reservoir as a zero-dimensional tank (Petroleum Experts, 2010*)*, it runs ten times faster than a numerically simulated reservoir model therefore allowing for numerous runs to test if the rules set are obeyed. As expected, the partial wellbore approach method was a more difficult model to optimise due to the presence of relatively more controllable variables and therefore needed a second algorithm for controlling the GCGL valves to obtain the optimum production rate. Figure 4 shows the multiphase simulator configuration for the partial well bore approach indicating presence of controllable variables. Due to the complexity of the partial well bore approach, it was decided to concentrate on the full well bore approach (figure 6). To develop the GCGL methodology with the full wellbore approach, a model that could take out gas from the gas reservoir at the optimum gas injection rate at every time step is needed (gas ejector model). Another model describing the maximum gas injection rate at each prediction time step is also needed (verification tool). Both verification and gas ejector tools are connected to a separate Heather reservoir model (tank model initially). The verification and gas ejector tools were modelled this way as there is a known pressure barrier between the Tarbert and Heather formations. These tools were independently constructed on the multiphase flow simulator. The section of wellbore responsible for gas injection into tubing consists of gas reservoir IPR represented by the back pressure equation which is a common model for describing gas well IPR (Brill *et al*., 1999), a Olga 2P empirical multiphase pressure gradient correlation to capture the pressure loss of gas flowing through the casing annulus, a node representing pressure upstream of GCGL valve, the GCGL valve performance relationship described by a Perkins model and a second node representing the downstream pressure of GCGL valve. The Perkins model used has a flow coefficient (Cv) of 1 for simplicity. The gas ejector model was constructed as dummy gas cap gas producer wells with controllable well head chokes to ensure that the gas extraction rate from gas reservoir is similar to the optimum gas injection rate so that in case of a gas cap with pressure communication (no pressure barrier), the critical cumulative gas cap gas produced can be obtained. Diagrams describing the verification and gas ejector tools for both oil producing wells are shown in figures 7, 8 and 9.

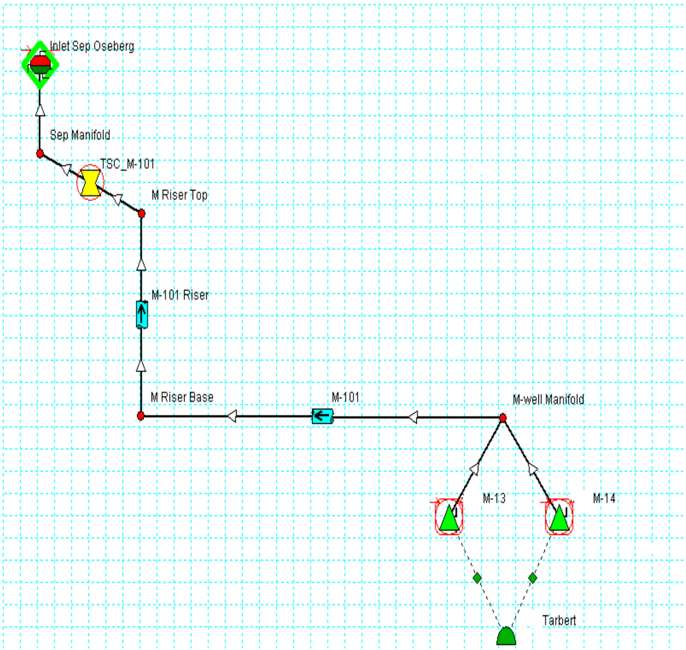

Figure 6: Full wellbore description method network (labels defined in tables B-3 and C-1)

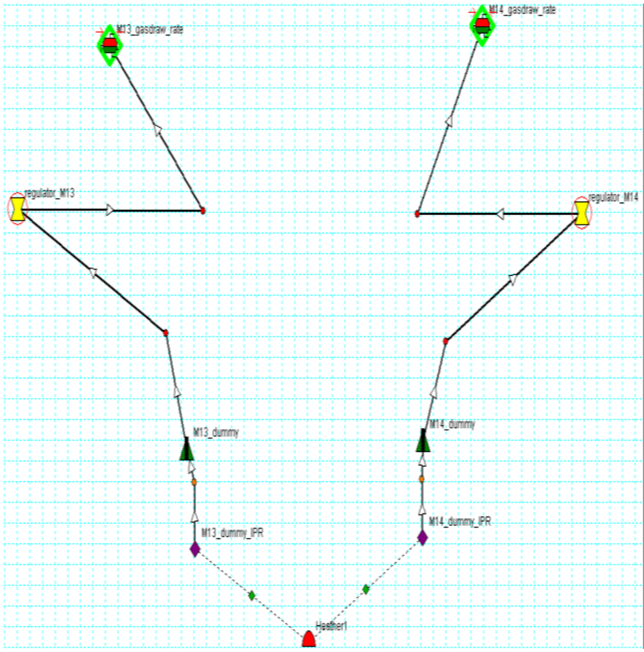

Figure 7: Gas ejector tool (labels defined in table C-2)

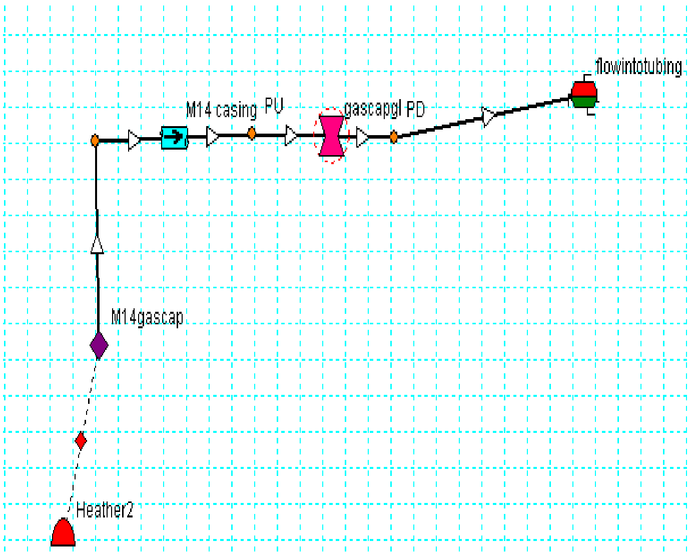

Figure 8: M14 wellbore verification tool model (labels defined in table C-3)

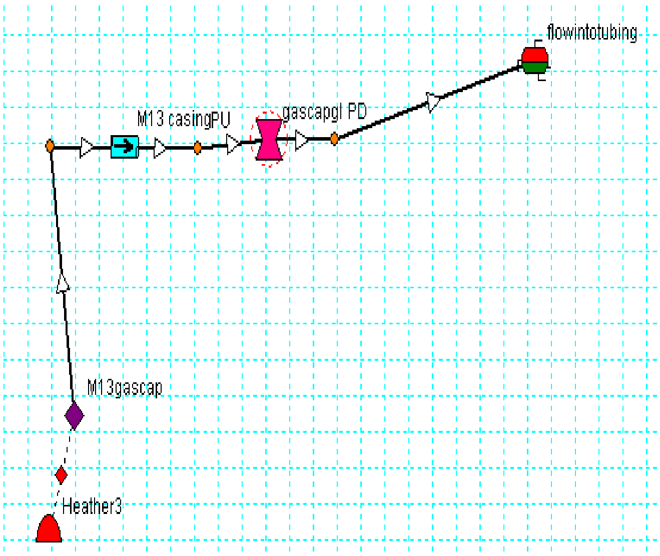

Figure 9: M13 wellbore verification tool model (labels defined in table C-4)

A simplified NPV calculator at each time step was also done to help identify benefits obtained from the GCGL system optimization. The NPV calculator was created by dividing operating cost into variable cost in $/ m^3$ and fixed costs in dollars (Petroleum Experts, 2010). The fixed cost was divided into cost of daily operation of the field including well interventions and operating plant expenses while variable cost of producing oil in $/ m^3 was obtained from the cost of carbon dioxide (CO_2) tax, nitrogen oxide (NOX) tax, oil transport and recovered reserves estimate (Statoil ASA, 2011). The cost of producing water was estimated as double the variable cost of producing oil in $/m^3 (simple assumption based on cost of handling water). The main aim of the simplified NPV tool is to give a feel of how much more profit can be gained from applying the GCGL methodology. Capital costs were ignored as the GCGL valves are also planned to be used for the production of the Heather formation after production of Tarbert oil. The table below shows the NPV calculator parameters used.

	Field K
Company Share	100%
Oil Revenue $/m^3 (oil-price.net, 2011)	621 ($98.80/barrel)
Annual discount rate	15%
Daily discount rate = (1+annual discount rate)^(1/365)-1 (Petroleum expert,2010)	0.0383%
Discount factor=(1+daily discount rate)^Number of days elapsed (Petroleum expert,2010)	
Discount factor in $ =cash flow/discount factor (Petroleum expert,2010)	
NPV=cumulative discount factor in $ (Petroleum expert,2010)	

Table 2: NPV calculator parameters for K field development plan with and without GCGL system

The integrator-controller tool was used to connect the field model to the NPV, verification and gas ejector tools. The NPV tool was set up to collect the liquid production rates from the field model to work out the NPV at every time step. At time step zero, network constraints were set. The pressure downstream of GCGL valve in the verification tool was matched to pressure of tubing at GCGL valve depth in the field model at a time step greater than zero for both wells because the verification tool was not needed to check gas injection rate initially since optimum gas injection will not be needed immediately. Before the pressures were matched at time step greater than zero, a reasonable guess for the tubing pressure at GCGL depth was made. The results of the verification tools for wells M13 and M14 are shown in Figure 10. The gas ejector tools also start at a time step greater than zero as shown in figure 11. Starting the gas ejector and verification tools at a time step greater than zero means that both tools will always be one time step behind the field model during a prediction run which although not ideal is an unavoidable artefact of this modelling technique. Consequently event driven rules were set to define a rule that will reduce the top side choke Dp to zero when production cannot be maintained at the desired oil flow rate and then start gas injection into production tubing at optimum gas injection rate (Petroleum Expert, 2010). The integrated model consisting of verification tool, gas ejector, field model and NPV are shown in the figure 12. On completion of the integrated model, a prediction run was done from the 01/01/2013 to 01/07/2015.

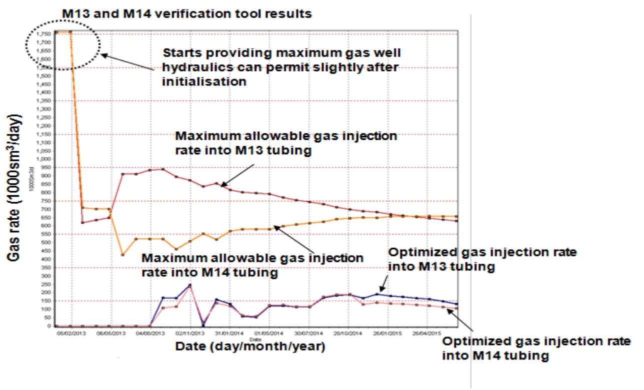

Figure 10: M13 and M14 wells verification tool results showing the optimized gas cap gas injection rate and maximum allowable gas injection rate

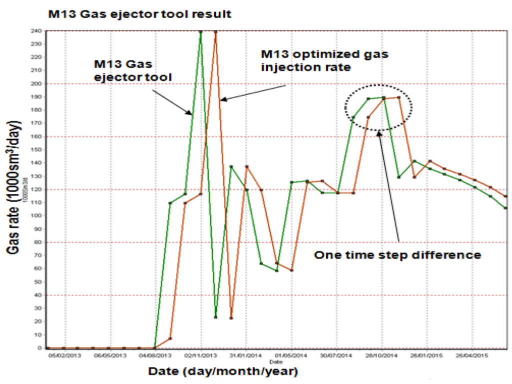

Figure 11: M13 gas ejector tool showing a time step delay between optimized gas injection rate into production tubing and gas withdrawal rate from Heather

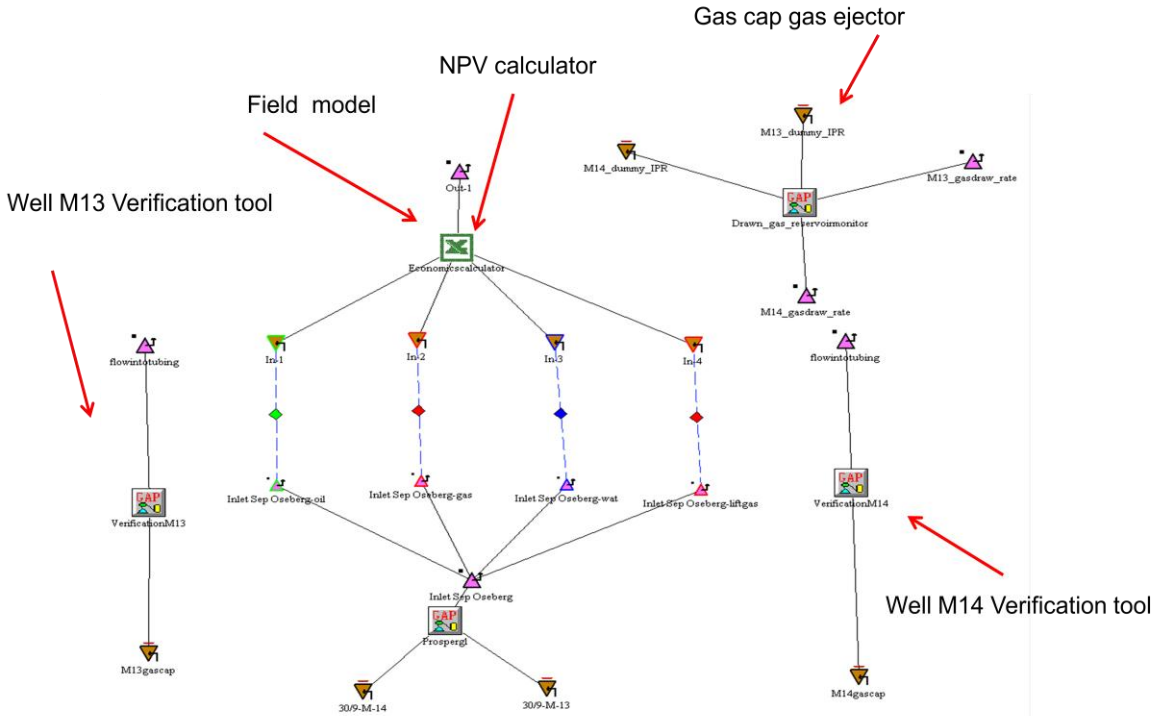

Figure 12: Full wellbore description method integrated model

2.2.2.2 GCGL methodology test with a numerically simulated reservoir

There are various methods that can be applied in modelling the reservoir-wellbore relationship. One such method is by applying the GORM used for the oil production optimization of the Troll field. The GORM does give a good description of gas coning effects in a horizontal section of a well (Hauge *et al*., 2005). The disadvantage of the GORM model is that the wellbore hydraulics has no effect on the model making it impossible to analyse different vertical lift scenarios (Mjaavatten et al., 2006). Industrial standard numerical reservoir simulators are able to capture the lifting effect of fluids from wellbore to surface by applying steady-state lift curves (VLP). Although better ways have been suggested for modelling the reservoir-well interaction by using mechanistic models due to their ability to describe dynamic effects better than steady-state lift curves (Sturm et al., 2004), the GCGL methodology was compared with a standalone numerical simulator because it is a more common technique in industry.

The tank reservoir model was replaced by a numerically simulated model of the K field reservoir to give a better description of the inflow dynamic effects (RESOLVE-ECLIPSE model). The numerical model was used to represent a more realistic inflow relationship from reservoir to the wellbore and allow comparison of production profiles with a standalone numerically simulated field model with the base case concept for development to see if GCGL methodology is beneficial. A prediction run was done from 01/01/2013 to 01/12/2019 and the field cumulative oil production and production profiles of the M13 and M14 wells are monitored for increased oil production. The prediction run was done for a longer period because it is suspected that the artificial gas lift will be needed at later stages of field life.

3.0 Simulation Results

3.1 Tank Model showing optimization effects of GCGL methodology

The first prediction run was done with the material balance based tank reservoir model of the two formations. The tank models were successfully configured to run with the applied GCGL methodology as shown by figures 13 and 14. Figures 13 and 14 shows how the optimized gas lift injection rate is started when production can no longer be sustained at a desired rate and topside choke pressure drop is at zero (fully open choke). The prediction run using the tank model produced favourable results with the GCGL methodology as shown in figures 15 to 17. Figure 15 shows an extension of maximum oil production rate of 4000sm^3/day for two months. Figure 15 also shows a section of the production profile of the k field development plan where addition of gas is not benefitial, but the GCGL system is altered to make sure the production profile of field development plan with the GCGL valve system is close to the production profile of a system without the GCGL system. There is also an addition of 90000Sm^3 of oil over the simulation period (figure 16). The extra volume of oil generates an increase in

NPV of $40 million (figure 17). The main aim was to test that the rules set were being carried out as expected.

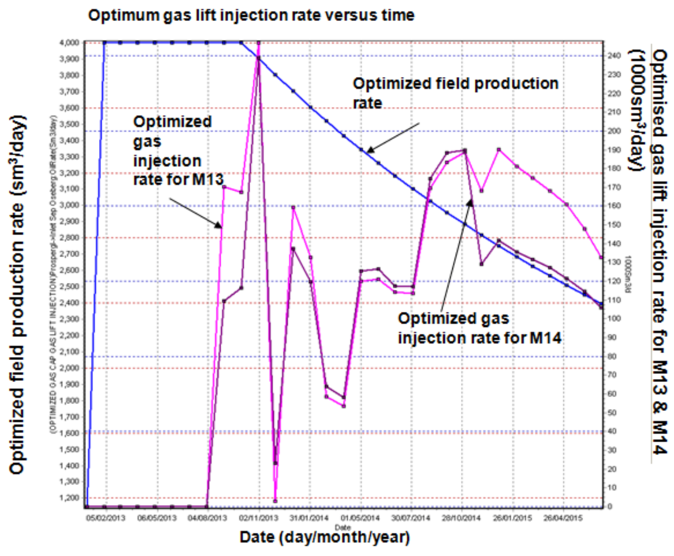

Figure 13: Optimized gas lift injection rate and optimized production rate profile

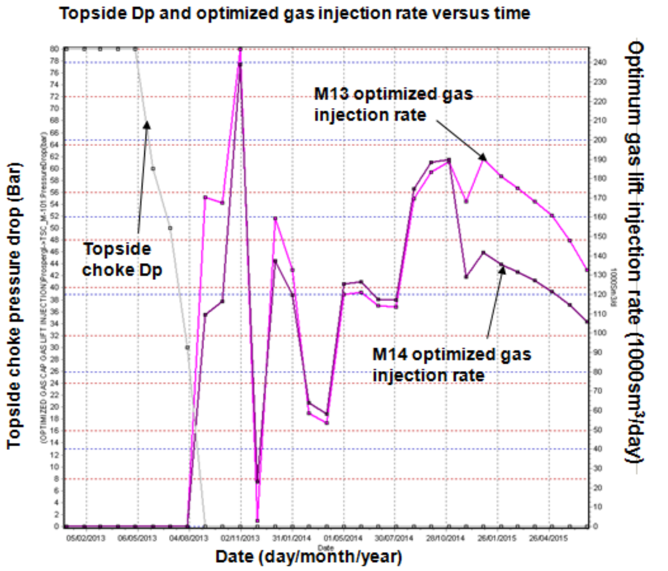

Figure 14: Topside choke pressure drop and optimized gas lift injection rate

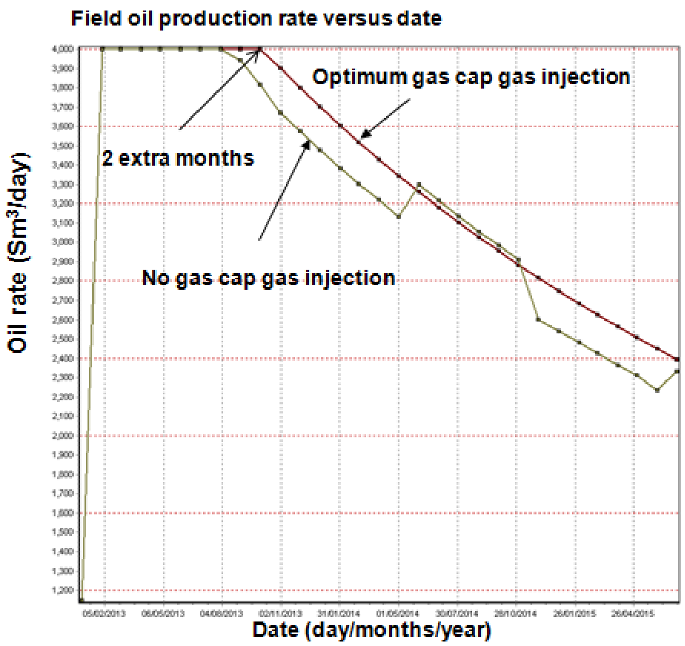

Figure 15: K field oil production rate with tank model

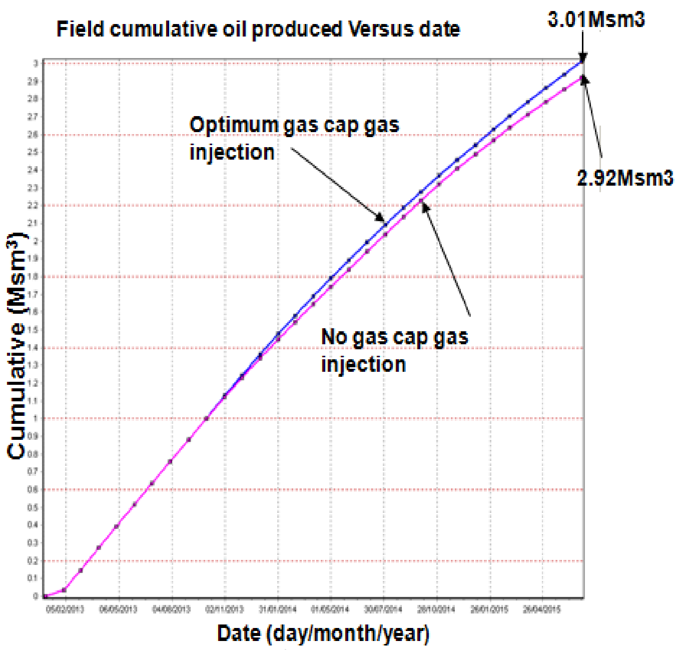

Figure 16: Cumulative oil versus time with tank model

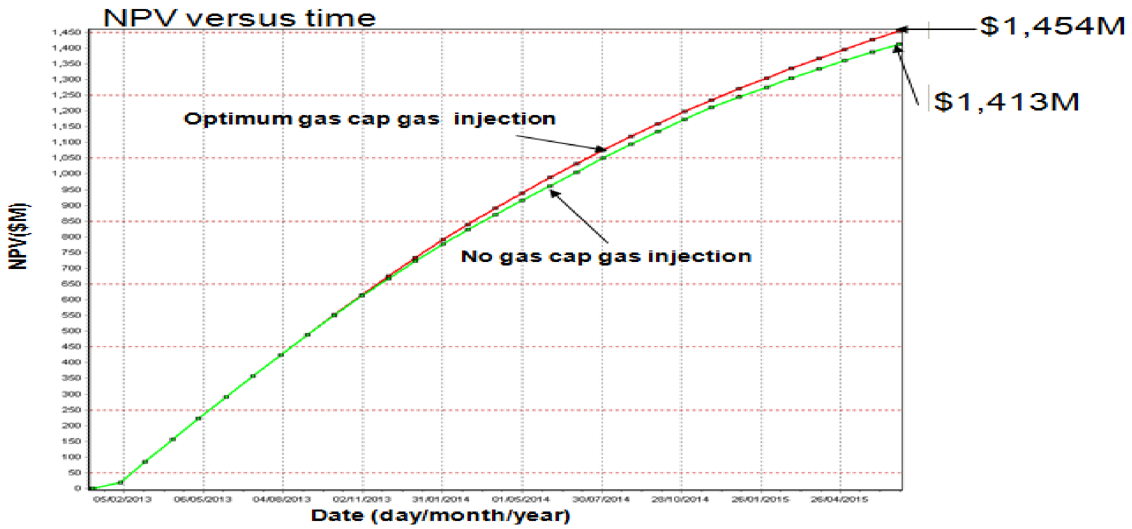

Figure 17: NPV versus time with tank model

3.2 RESOLVE-ECLIPSE field model compared to a standalone ECLIPSE field model

On comparing the simulation run results of the ECLIPSE standalone model with the RESOLVE-ECLIPSE model, it is observed from figure 18 that the case with the optimum injected gas rate produces the highest cumulative oil volume of 2.59 million sm3. The second highest cumulative oil is obtained from RESOLVE-ECLIPSE case with no gas lift which gives a cumulative oil production of 2.35 million sm^3 while the lowest cumulative oil is given by the ECLIPSE standalone model with the base case development recovery plan which gives a cumulative oil of 1.95 million sm^3.

Figure 19 also shows how the optimized gas injection rate helps to keep well M14 flowing for just over 2 extra years.

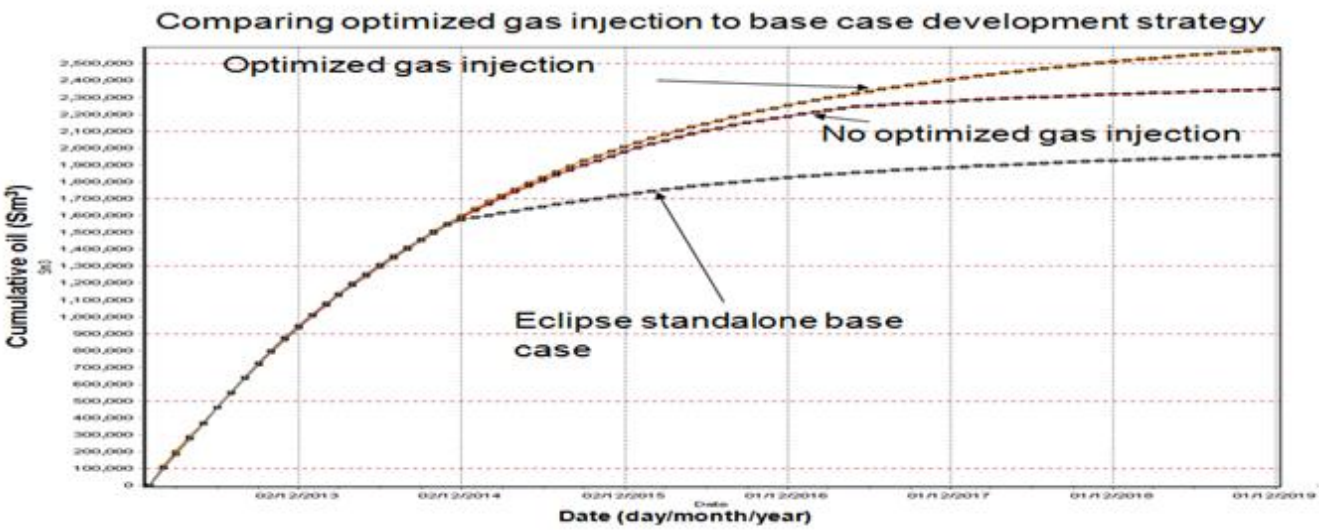

Figure 18: Cumulative oil produced from RESOLVE-ECLIPSE model and standalone ECLIPSE model

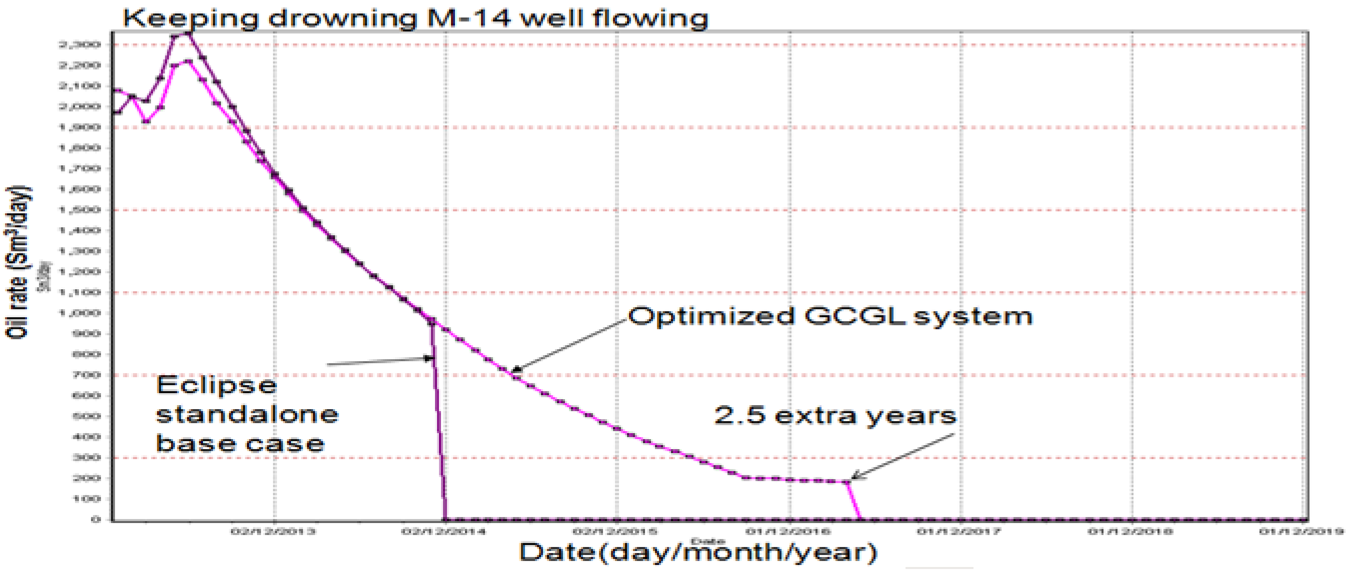

Figure 19: Production profile for well M14

4.0 Analysis

As expected, the optimum gas injection rate did give the highest production (figure 18). In figure 19, it can be observed that the gas injection is not needed by well M14 until water coning starts later on which shows the ability of the GCGL system to react to dynamic changes in reservoir condition. However to achieve these results, the field gas constraints had to be increased to 3 million sm^3/day from 1 million sm^3/day for both models because the RESOLVE-ECLIPSE model was getting unstable under gas constraints of 1million sm^3/day. It was confirmed that this was due to the way the integrator-controller software was scaling the IPR data from the ECLIPSE model.

The desired oil rate of 4000sm^3/day is impossible to achieve at a gas rate constraint of 3 million sm^3/day. The inability in obtaining the desired oil production rate meant that the rules set for the topside choke and GCGL valves were not used effectively because from the start of production, the topside choke Dp changes to zero and optimum gas lift gas injection occurs.

The model also shows how the optimizer on the specialist multiphase network model, is used to optimize oil production even without optimized gas cap gas lift injection because although there is no gas lift injection, the well head chokes are still controlled by the non-linear optimizer (figure 18).

5.0 Discussion

The results obtained from the test with the K field successfully show that the suggested GCGL modelling technique has the ability of changing important well and network controls as field conditions vary during a prediction run (figures 13 and 14) which the GCGL valve modelling technique applied on the Norne subsea field failed to do as only a specific GCGL valve configuration is determined (Al-kasim et al., 2002). The modelling technique proposed along with a separate simulation using a model with production wells in the oil zone and gas cap can easily be modified for a reservoir with a gas cap in pressure communication with the oil zone to give an engineer a good idea of the gas injection rate or cumulative gas cap gas production that would disturb a reservoir with a gas cap expansion recovery mechanism. The modification involves perforating the gas ejector tool in a connected gas cap instead of an unconnected gas cap such as the Heather. The GCGL modelling technique can also provide information on possibility of injecting gas at optimum gas injection rate (figures 10). For the development of the K field, it can assist the operator in knowing if it will be a good idea to install GCGL valves. Figure 19 suggests that although benefits of applying the GCGL system is not noticed at the early stages of field life, it will become useful later in the life of the k-field which means that this method has the ability to advice on field well and network controls at later stages of field life during the planning stages. In industry it could take to the end of field life to find out certain decisions taken were wrong.

The GCGL modelling method also effectively combines the best attributes of industry standard specialist software. From figure 18, it is observed that ECLIPSE is limited at optimizing surface facilities because all it uses are steady-state pressure gradient correlations to describe vertical lift effects from wellbore to surface and flow in production line from subsea template to platform; however, it is a powerful tool in reservoir simulation studies.

Quality check on models can also be done. For example an ECLIPSE standalone field network model can be checked against a RESOLVE-ECLIPSE model with its surface facilities modelled with a multi phase flow simulator. Achieving consistent results is a means of checking that both models are sound descriptions of the field.

There are a few areas that need improvement:

- One of such areas is the inability of the gas ejector and verification tools to start at the same time step as the field model during a prediction run because the gas ejector and verification tools need to wait for data from the main model. For example the verification tools for each well will need the main model to produce data on the tubing pressure at GCGL valve depth. A correlation that can approximately satisfy equations 1 and 2 on a spreadsheet (excel) can be used to solve this problem (similar to the NPV calculator).

- Applying a more realistic valve performance relationship is another area that needs improvement as using a valve flow coefficient of 1 does not represent choke or valve performance adequately. A Cv of 1 was assumed for simplicity. Using real life choke or valve performance relationship will give a better description of what should be expected in real life. More reliable gas valve performance relationship can be obtained by applying the API Recommended Practise 11v2 correlation (American Petroleum Institute, 2001).

- Developing a non-linear optimization algorithm for the GCGL valve of the partial wellbore approach. If the Partial wellbore approach is used, it eliminates the need for verification or gas ejector tools; however due to the presence of many controllable variables, the multiphase flow simulator non-linear optimizer was not able to find the true optimum oil production rate. To obtain this point, a separate non-linear algorithm would have to be applied. The non-linear algorithm should be able to vary the GCGL valve diameter of the producer wells until a combination of GCGL valve diameters that produce the highest oil production rate is obtained at every time step.

- Further development of NPV tool. The NPV tool will be crucial when the production profile plot does not give a clear indication on benefits of using the GCGL methodology. Doing a more detailed economic analysis for parameters used in the NPV tool will make it more realistic and can be used in making important decisions. A better NPV tool should also include the capital cost of the incurred by installing the GCGL valves.

- There is still the problem of using steady-state vertical lift curves by both the stand alone ECLIPSE model and the coupled simulated model. Applying a mechanistic model to avoid this can be advantageous in spotting certain effects that steady state lift curves will not be able to capture (Sturm et al., 2004). Steady-state lift curves tend to give wrong interpretations during unstable production conditions. An example of an unstable condition is when oil is produced from a thin oil rim (Sturm et al., 2004).

- Another area of concern is the scaling option applied by the integrator-controller tool which is the confirmed cause of the instability of the RESOLVE-ECLPSE model at certain gas constraints. Experimenting with different methods of IPR scaling options is recommended.

6.0 Conclusions

The GCGL methodology developed successfully achieved the following:

- Provides the ability to actively control the GCGL system to obtain optimum oil production by opening the GCGL valve when topside choke is fully opened and desired oil production rate cannot be obtained to let in gas at an optimized gas injection rate.

- Ability to be modified to give the amount of gas cap gas produced that can alter the recovery mechanism of a reservoir with a gas cap expansion drive.

- Checks the ability of system to introduce optimum gas injection rate.

Other applications:

- Short to long term oil production optimization of field.

- Can be used as a quality check for different field models.

7.0 Nomenclature

API	American petroleum institute
Cv	Valve flow coefficient
Dp or dp	Differential pressure
GCGL	Gas cap gas lift
GOR	Gas oil ratio
GORM	Gas oil ratio model
ICV	Inflow control valves
IPR	Inflow performance relationship
NPV	Net present value
P_D	Pressure downstream of gas cap gas lift valve
P_T	Pressure downstream of gas cap gas lift valve
Pwfg	Bottom hole flowing pressure of gas reservoir
Q_A	Gas flow rate through casing annulus
Qg	Gas flow rate
Q_T	Gas flow rate into production tubing
Q_V	Gas flow rate through gas cap gas lift valve
VLP	Vertical lift performance

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APPENDIX A: Critical literature review

Milestones in modelling of in-situ gas lift system

SPE Paper No	Year	Title	Authors	Contribution
21677	1994	Optimization of well Rates Under Gas coning Conditions	Christopher H.Urbanczyk and R.A.Wattenabrger	First to describe marginal GOR algorithm for optimization of well rates.
SPE monograph vol 17	1999	Multiphase flow in wells	James.P.Brill and Hemanta Murkajee	First to describe sensitivity analysis of gas liquid ratio with PERFORM.
74391	2002	Natural gas-lift theory and practise	S.Betancourt, K.Dahlberg, Hovde, Y.Jalali	First to attempt modelling natural gas lift by reservoir simulator to show design considerations for natural gas lift applications.
77662	2002	Remotely Controlled In-Situ Gas Lift on the Norne Subsea Field	Ferid T. Al-Kasim, Synove Tevik, Knut Arne Jakobsen, Statoil ASA, Yula Tang, SPE, Scandpower A/S, Younes Jalali, Schlumberger	First to describe Gas lift valve design with Nodal analysis and Numerical simulation on Norne subsea field.
90108	2004	Dynamic Reservoir Well Interaction	W.L.Sturm,SPE,S.P.C Belfroid,SPE,O.van Wolfswinkel,M.C.A.M.Peters,SPE,F.J.P.C.M.G.Verhelst,SPE TNO TPD,Delft,The Netherlands	First to describe modelling of dynamic relationship between well and reservoir using mechanistic models.
OTC 17111	2005	The challenge of operating and maintaining 115 subsea wells on the Troll field	J.Hauge and T.Horn,Norsk Hydro ASA	First to describe coupling of GORM and GAP for network optimization purposes on Troll field (an example of coupled simulation).
102390	2006	A model for gas coning and rate-Dependent Gas/oil Ratio in an Oil-Reservoir	Are Mjaavatten,SPE,and Robert Aasheim,Norsk Hydro ASA and Steiner Saelid and Oddvar Gronning,Prediktor a.s	First to describe the mathematical derivation of the GORM.
104202	2008	Auto, Natural, or In-Situ Gas-Lift Systems Explained	Adam Vasper. SPE, Schlumberger	First to describe determination of solution points for auto gas-lifted wells for fixed and varying gas valve upstream pressure.
120696	2009	Utilization of In-situ Gas lift system to increase production in Saudi Arabia Offshore Oil Producers	Philip Warren, Sami Logan, Makki Zubail, Abdulelah Balto, Simeon Perez, Adrian Villarreal , Oscar Becerra	First to describe determination of tubing pressure at gas injection point by solving implicit pressure balance problems.

Table A-1: Critical literature review

SPE 21677 (1994)

Optimization of Well Rates under Gas coning conditions

Authors: Christopher H. Urbanczyk, Texas A & M University, R.A. Wattenbarger, Texas A & M University

Contribution to knowledge of formulation of well rates optimization method based on marginal GOR
This paper discusses a method of optimizing a field under certain constraints.

Objective of paper:
To develop a method of optimizing well rates when wells are coning gas and field rates are constrained.

Methodology used:
This paper discusses the formulation of the marginal GOR optimization method, which suggests that under a certain gas field constraint, the marginal GOR of all wells should be equal at optimum production rate.

Conclusion reached:
Production optimization achieved by minimizing field GOR.

Comments:
Applied in the short-term optimization of Troll fields as explained by (Hauge et al., 2005).

SPE monograph volume 17 (1999)
Multiphase flow in wells

Authors: James.P.Brill and Hemanta Murkajee

Contribution to knowledge on methods of determining optimum gas liquid ratio of a well and derivation of multi phase flow pressure gradient correlations

This article discusses using sensitivity plots of liquid rate against gas liquid ratio (GLR) for determining the optimum gas liquid ratio for a well. It describes the reason for the bell shape of this sensitivity plot.

Objective of paper:
The monograph covers a number of production system topics such as

- Single-phase-flow concepts.
- Multiphase flow concepts.
- Multiphase-flow pressure-gradient prediction.
- Flow through restrictions and piping components.
- Well design and applications.

Methodology used:
The methodology of interest is the sensitivity analysis done with PERFORM to determine optimum gas liquid ratio.

Conclusion reached:

- Sensitivity analysis is a useful production optimization tool.

Comments:
This paper also gave good background knowledge on how correlations applied in multiphase simulator software are formulated.

SPE 74391 (2002)

Natural gas-lift theory and practise

Authors: S.Betancourt, Schlumberger, K.Dahlberg, Norsk Hydro, Hovde, Norsk Hydro, Y.Jalali, Schlumberger

Contribution to knowledge on conditions where natural gas lift (in-situ gas lift) can be applied and also describes using commercial black oil simulator to model a natural gas lift system

This paper discusses certain scenarios that affect applicability of natural gas lift. It shows that well position relative to gas oil contact and initial water contact (standoff) affect the need for natural gas lift. Other factors include strength of water influx and target production rate. Another point of interest is the method of natural gas system modelling applied.
.

Objective of paper:

- Using reservoir simulation of field with North Sea characteristics to show effect of standoff and target production rate on applicability of natural gas lift.

- Examination of natural gas lift design considerations for reservoirs with contiguous and non-contiguous in-situ gas reservoirs or gas cap.

- Discussions on operational experience of natural gas lift application on troll field.

Methodology used:
The methodology of interest is the method of modelling the natural gas lift which is with a commercial black oil simulator.

Conclusion reached:

- Gas lift requirements are strongly dependant on breakthrough of gas cap gas into the well for a reservoir with a contiguous gas cap.
- For a reservoir with a non contiguous gas cap, gas can be injected into tubing provided the gas zone is in hydrostatic equilibrium or higher than the pressure in the oil zone stating the need for valve adjustments with time.

Comments:
This paper describes the benefits of in-situ gas lift using a numerical reservoir model. Although realistic results are achieved there is room for improvement.

SPE 77662 (2002)

Remotely Controlled In-Situ Gas Lift on the Norne Subsea Field

Authors: Ferid T. Al-Kasim, Synove Tevik, Knut Arne Jakobsen, Statoil ASA, Yula Tang, SPE, Scandpower A/S, Younes Jalali, Schlumberger

Contribution to knowledge of previous methods that have been applied in-situ gas lift modelling:
It explains how commercial nodal analysis software and a numerical simulator were applied in modelling of an in-situ gas lift system.

Objective of paper:

- Using commercial software to design in-situ gas lift injection system.
- Applications of in-situ gas lift system on the Norne field.

Methodology used:
The methodology of interest is the application of commercial nodal analysis software and a numerical reservoir simulator in modelling of the gas lift system.

Conclusion reached:

- Determination of best in-situ gas lift gas valve design.
- Proof of potential benefits of gas lift.

Comments:
This paper comments on the modelling of a gas lift valve system through nodal analysis and numerical simulation.

SPE 90108 (2004)

Dynamic Reservoir Well Interaction

Authors: W.L.Sturm, SPE, S.P.C Belfroid, SPE, O.van Wolfswinkel, M.C.A.M.Peters, SPE, F.J.P.C.M.G.Verhelst, SPE TNO TPD, Delft, the Netherlands

Contribution to knowledge on various ways of modelling reservoir-well interaction
This paper describes the formulation of a dynamic simulation model that consists of a dynamic inflow model to portray a more realistic inflow than most dynamic well models. This model describe a more realistic fluid flow in tubing and casing than most traditional reservoir simulators because traditional reservoir simulators utilize steady state lift curves to describe well vertical lift performance.

Objective of paper:
Obtaining a dynamic reservoir-well interaction model.

Methodology used:
Using mechanistic models to obtain a dynamic well inflow model and fluid flow through vertical tubing and annulus. The dynamic inflow model comprises a radial inflow model. In the tubing, the two phase flow is modelled by means of the drift-flux model (Whalley). The annulus was modelled in a similar way to the tubing but as a single phase flow since there is only one phase present.

Conclusion reached:
The dynamic reservoir well interaction model proposed is capable of capturing occurrences which semi-steady state inflow model will miss.

Comments:
Gives an idea on ways of improving on current reservoir-well interaction modelling methods.

OTC 17111 (2005)

The challenge of operating and maintaining 115 subsea wells on the Troll field

Authors: J.Hauge and T.Horn, Norsk Hydro ASA

Contributed to knowledge of field network optimizations and modelling methods of gas lift gas system
Applied the GORM model in field production optimization. The GORM model was connected to a GAP model to assist in surface network optimization.

Objective of paper:

- This paper highlights the field experience with operation and maintenance of the Troll subsea production system.

- Explains oil production optimization model methods used on Troll.

Methodology used:
The methodology of interest applied in this paper is to increase or decrease gas rate of each well to meet the optimal marginal GOR for short-term optimisation and utilizing the GAP-GORM model to determine optimum well routing.

Conclusion reached:
Using well-simulator GORM to calculate marginal GOR for individual wells has proven to be a very useful tool for short term production optimisation on Troll. GORM is also able to be linked with the general production monitoring system. The combination of GORM and network cluster models (GAP) was also found to be promising.

Comments:
Gave a good example of how model integration can be used.

SPE 102390 (2006)

A model for gas coning and rate-Dependent Gas/oil Ratio in an Oil-Reservoir

Authors: Are Mjaavatten, SPE, and Robert Aasheim, Norsk Hydro ASA and Steiner Saelid and Oddvar Gronning, Prediktor a.s

Contribution to understanding basis of operation of specialist simulator of rate dependent GOR (GORM)
Improvements on Konieczek and Tiefnathal mathematical analysis of rate dependent GOR to form a robust simulator that captures rate dependent GOR more than traditional numerical simulators by utilizing a simplified relationship between well and reservoir.

Objective of paper:
Formulation of mathematical relationship that can accurately capture rate dependent GOR effect (basis of GORM simulator).

Methodology used:
Improved on Koniecczek and Tiefnathal work by capturing variations of fluid contact along the horizontal well length section.

Conclusion reached:

- The GORM model captures the rate dependent GOR effect adequately by capturing gas oil contact movements over a well section accurately.
- Can establish a good history match.

Comments:
This paper briefly explains how the GORM software can be used for optimization purposes due to its ability to capture a term known as marginal GOR. According the Urbanczyk and Wattenbarger, if gas constraint is the only active constraint the marginal GOR of all wells should be identical. The paper also states that, Hauge and Horn described how GORM is used in combination with the production optimisation tool GAP to plan and optimise production from Troll. In relation to this project, this tool can be used to capture the ideal GOR needed for optimum production, but since the software GORM poorly describes the well hydraulic system, it is unable to check if the optimum amount of gas can be delivered by the well hydraulic systems that are installed.

SPE 104202 (2008)

Auto, Natural, or In-Situ Gas-Lift Systems Explained

Authors: Adam Vasper. SPE, Schlumberger

Contributed to knowledge of parameters that influence wells ability to inject gas into the wellbore
Identified the relationship between the Inflow performance relationship of the gas cap reservoir (I), an equation relating gas flow rate through the casing annulus and pressure drop across annulus between down hole gas flowing pressure from gas reservoir and pressure upstream of gas lift valve (II), a flow rate versus pressure drop equation or relationship of the gas valve (III) and the pressure in the tubing (IV) as the main factors responsible for gas deliverability into production tubing. It also mentioned how the depth of installation of the gas lift valve also affects the gas lift valve functionality. A gas lift valve has the best influence on production rate at deeper depths, but this also means increase in hydrostatic pressure which then reduces the pressure difference between casing pressure gradient and tubing pressure gradient.

Objective of paper:
This paper presents the basic theory behind in-situ gas-lift and how to apply it. The components of the theory are well known and commonly used in Nodal analysis and conventional gas lift design.

Methodology used:
The methodology of interest is as follows:

I. $Qg = fn\ (Pwfg^2, Pr^2)$
II. $Q_A = fn\ (Pwfg, P_U)$
III. $Q_V = fn\ (P_U, P_D)$
IV. $Q_T = fn(P_T)$

Where P_D = pressure downstream of gas valve, P_T=pressure in tubing at gas valve depth, Pwfg=bottom hole flowing pressure of gas reservoir, Pr=average gas reservoir pressure, Qg=gas flow rate from reservoir. Q_A=gas flow rate through annulus, Q_V= gas flow rate through gas valve, Q_T=gas flow rate into tubing.
The operating point of the well is the solution to these equations where the gas rates, upstream pressure and downstream pressure to gas valve are consistent (Q refers to mass flow rate).
$Qg=Q_A=Q_V=Q_T$ and $P_D=P_T$

Conclusion reached:
The technique described can be implemented either directly through nodal analysis software or by linking nodal analysis solutions to code which handles gas flow equations.

Comments:
This paper is very important as it gives the basic theory needed for checking gas lift deliverability which is a core objective of this project.

SPE 120696 (2009)

Utilization of In-situ Gas lifts system to increase production in Saudi Arabia Offshore Oil Producers

Authors: Philip Warren, SPE, Sami Logan, SPE, Makki Zubail, SPE, Abdulelah Balto, SPE, Simeon Perez, SPE, Saudi Aramco, Adrian Villarreal, SPE, Oscar Becerra, SPE, Baker Hughes

Contributed to knowledge of modelling gas cap deliverability
Suggested another method of checking the possibility of gas injection.

Objective of paper:
The primary focus of this paper is to discuss the in-situ gas lift equipment, completion installation procedures, and field test results, operation principles utilizing the gas cap energy, production strategy and well performance using an online monitoring system, and reservoir management considerations for future installations within the field.

Methodology used:
The methodology of interest discussed in this paper is the method of minimizing the difference in solution between (3) pressure balance equations to determine the tubing injection pressure that will permit gas lift injection. The 3 pressure balance equations are as follows:

- From the oil reservoir to the gas injection point.

$$P_{inj} = P_{wfoil} - \Delta P_{Hydrostatic,oil} - \Delta P_{friction,oil} \dots \dots Equation\ A$$

- From the Gas reservoir to the gas injection point.

$$P_{inj} = P_{wfgas} - \Delta P_{Hydrostatic\ loss,\ \ gas\ annulus} - \Delta P_{friction\ loss,\ \ gas\ annulus} \dots \dots Equation\ B$$

- From Surface to the injection point.

$$P_{inj} = WHP + \Delta P_{Hydrostatic\ loss,\ \ gaseos\ colunm} + \Delta P_{friction\ loss,\ \ gaseos\ colunm} \dots \dots Equation\ c$$

Where WHP=well head pressure, *Pwfoil*=inflow performance relationship of oil zone, *Pwfgas* =inflow performance relationship of gas zone, *Pinj*=tubing pressure required for in-situ gas injection, ΔP=pressure loss factors. The fact that flow rate also has an impact on these relationships, makes solving these equations an implicit problem. The method suggested in this paper is to minimize the difference between Pinj obtained by the three relationships. An objective function set up was created to solve the problem in this paper.

Conclusion reached:
Method creates an implicit system that can only be solved by trial and error process.

Comments:
Although the methodology suggested in this paper will not be applied, it is an advantage to be aware of other methods of modelling gas deliverability into wellbore.

APPENDIX B: Partial wellbore description approach

Icon Label	Wellbore parameters	Well name
M-13 Oil Zone	Inflow relationship of oil zone	Wellbore M13
BH_M-13 Oil Zone	Bottom hole environment (pressure etc.) in oïl zone	
USC_ICV2_M-13	Upstream point of inflow control valve (ICV)	
ICV2_M-13	Inflow control valve	
DSC_ICV_M-13	Downstream point of inflow control valve	
BH_M-13 Oil Zone to USC_ICV2_M-13	Well tubing from bottom hole to upstream point of ICV	
GL Depth _M-13	Gas lift valve location	
GCGL_M-13	Gas cap gas lift valve (GCGL)	
USC_GCGL_M-13	Upstream point of GCGL valve	
M-13 Gas Cap	IPR of gas cap or gas reservoir. Can be connected or disconnected from reservoir with oil zone	
30/9-M-13	Representing rest of wellbore from gas lift valve depth to well head	
SSC_M-13	Subsea well head choke for oil producer well M13	

Table B- 1: M13 wellbore model icons definition (partial wellbore approach)

Icon Label	Wellbore parameters	Well name
M-14 Oil Zone	Inflow relationship of oil zone	Wellbore M14
BH_M-14 Oil Zone	Bottom hole environment (pressure etc.) in oïl zone	
USC_ICV2_M-14	Upstream point of inflow control valve (ICV)	
ICV2_M-14	Inflow control valve	
DSC_ICV_M-14	Downstream point of inflow control valve	
BH_M-13 Oil Zone to USC_ICV2_M-14	Well tubing from bottom hole to upstream point of ICV	
GL Depth _M-14	Gas lift valve location	
GCGL_M-14	Gas cap gas lift valve (GCGL)	
USC_GCGL_M-14	Upstream point of GCGL valve	
M-14 Gas Cap	IPR of gas cap or gas reservoir. Can be connected or disconnected from reservoir with oil zone	
30/9-M-14	Representing rest of wellbore from gas lift valve depth to well head	
SSC_M-14	Subsea well head choke for oil producer well M14	

Table B- 2: M14 wellbore model icons definition (partial wellbore approach

Icon name	Definition
Tarbert	Tarbert reservoir
M-101	Production line
M-101 Riser	Riser
TSC_M-101	Topside choke
Inlet sep oseberg	Inlet point at Oseberg platform separator
M-well Manifold	Subsea well manifold
M Riser Base	M-101 riser base
M Riser Top	M-101 riser top

Table B- 3: Subsea network and separator model icons definition

APPENDIX C: Full wellbore description

Icon Labels	Definition
M-13	Well M13
M-14	Well M14

Table C- 1: Full wellbore description model parameter definition

Icon Label	Definition
Heather	Heather gas reservoir
M13_dummy_IPR	IPR relationship of dummy gas cap gas well M13 with heather reservoir
regulator_M13	Choke to control flow rate from heather to be equal to gas injection rate into field model by M13 gas lifted oil producer well.
M13_gas_draw rate	Gas drawn from heather reservoir by dummy gas cap well M13.
M13_dummy	VLP relationship of dummy gas cap well M13.
M14_dummy	VLP relationship of dummy gas cap well M14.
regulator_M14	Choke to control flow rate from heather to be equal to gas injection rate into field model by M13 gas lifted oil producer well.
M14_gas_draw rate	Gas drawn from heather reservoir by dummy gas cap well M14.
M14_dummy_IPR	IPR relationship of dummy gas cap gas well M13 with heather reservoir

Table C- 2: Gas ejector tool model icon definition

Icon Label	Definition
Heather	Heather gas reservoir
M14gascap	M14 dummy gas cap gas well IPR relationship with heather reservoir.
M14casing	Representing multiphase pressure gradient correlation to calculate pressure gradient experienced by fluid (mainly gas) flowing through casing.
PU	Pressure upstream of gas cap gas valve.
gascapgl	Gas cap gas valve represented by Perkins relationship and set at maximum diameter (1inch).
PD	Pressure downstream of gas cap gas valve.
flowintotubing	Representing how much gas can be produced from gas reservoir into production tubing.

Table C- 3: M14 wellbore verification tool icon definition

Icon Label	
Heather	Heather gas reservoir
M13gascap	M13 dummy gas cap gas well IPR relationship with heather reservoir.
M13casing	Representing multiphase pressure gradient correlation to calculate pressure gradient experienced by fluid (mainly gas) flowing through casing.
PU	Pressure upstream of gas cap gas valve.
gascapgl	Gas cap gas valve represented by Perkins relationship and set at maximum diameter (1inch).
PD	Pressure downstream of gas cap gas valve.
flowintotubing	Representing how much gas can be produced from reservoir into production tubing.

Table C- 4: M13 wellbore verification tool icon definition