Master of Science Thesis

Optimization of well start-up

Michael Schietz

Supervised by
Univ.-Prof. Dipl.-Ing. Dr.mont. Herbert Hofstätter

MONTAN
UNIVERSITÄT
WWW.UNILEOBEN.AC.AT

University of Leoben
Chair of Petroleum Production and Processing

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AFFIDAVIT

I declare in lieu of oath, that I wrote this thesis and performed the associated research myself, using only literature cited in this volume.

Leoben, 22.09.2009

Place, date

Signature

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Abstract

This Master of Science Thesis deals with oil-well start-up and the necessity of optimizing such operations. Coupling a reservoir model with a wellbore flow model is suggested as an ideal way to capture and tame complex transient flow phenomena encountered in this production phase. Having described the approach and working principle of the chosen explicit coupling strategy, simulation and optimization results are presented and a qualitative comparison with real well start-up data is given.

Beginning with outlining current common practice in well start-up operations and demonstrating the necessity for improvement, the paper continues with an extensive description of thereby encountered flow events. The used commercial simulator software for modelling reservoir- (*SENSOR 6k*) and pipe flow (*OLGA 6 GUI*) is introduced and the respective generic model configurations are explained. The main part of this paper deals with the chosen strategy for coupling these models and the subsequent implementation using the process-integration and -optimization application *Pipe-It*. Furthermore, the importance of appropriate time-step selection is emphasized, followed by a presentation of optimized simulation results obtained from the two core strategies: fixed and variable coupled-model time-steps. Qualitative model verification, further methods for coupling, concluding remarks and recommended continuative work constitute this thesis' final section.

This project has been carried out in close cooperation with the Norwegian University of Science and Technology (*NTNU*), Petroleum Engineering Reservoir Analysts (*PERA a/s*) and the *StatoilHydro* Research Centre Trondheim as well as the respective supervisors Prof. Curtis H. Whitson and John Petter Jensen. The employed software was kindly provided by *Petrostreamz AS*, *SPT Group Norway AS* and *Coats Engineering Inc.* Valuable input came from several industry experts, while further information was taken from technical books and journals, SPE papers and the internet. All used sources were stated using the ISO 690 convention for citation, in order to give credit to the authors and make sure that continuative research can start from this paper's final state of knowledge.

Kurzzusammenfassung

Diese „Master of Science“ Arbeit beschäftigt sich mit dem Anfahren von Öl-Sonden und der Notwendigkeit einer Optimierung dieses Prozesses. Zur Bewältigung dieser Aufgabe wird die Kopplung zweier Computer-Modelle, welche den Medienstrom in der Lagerstätte bzw. dem Steigrohr erfassen, vorgeschlagen. Ein solches System ist in der Lage komplexe und dynamische Fließphänomene sowie die Interaktion von Lagerstätte und Sonde zu simulieren. Diese Arbeit beinhaltet eine detailierte Erklärung der Erstellung, Funktionsweise und Optimierung dieses explizit gekoppelten Models und diskutiert Ergebnisse und qualitative Vergleiche mit realen Felddaten.

Eingangs wird der gängige Industriestandard zur Sonden-Inbetriebnahme beschrieben und auf dessen Schwächen hingewiesen, welche eine Optimierung erforderlich machen. Anschließend werden die verwendeten Software-Pakete zur Flusssimulation in Lagerstätte (*SENSOR 6k*) und Steigrohr (*OLGA 6 GUI*) vorgestellt. Den Hauptteil der Arbeit bildet eine Abhandlung der gewählten Kopplungsstrategie und deren Umsetzung mit Hilfe der Prozessintegrationssoftware *Pipe-It*. Hierbei wird speziell die Wichtigkeit der Auswahl geeigneter Simulationsintervalle (engl: time-steps) hervor gehoben. Verschiedene Möglichkeiten zur Intervallbestimmung werden aufgezeigt und erzielte Ergebnisse, unter Verwendung zweier Methoden (fixe und variable Zeitsprünge), werden analysiert. Eine qualitative Verifizierung des erstellten gekoppelten Systems, abschließende Bemerkungen und Folgerungen sowie eine Empfehlung für weiterführende wissenschaftliche Tätigkeiten auf diesem Gebiet bilden den Schlussteil der vorliegenden Arbeit.

Das Gelingen dieses Projekts gründet maßgeblich auf der engen Zusammenarbeit mit der Norwegischen Universität für Wissenschaft und Technik (*NTNU*), Petroleum Engineering Reservoir Analysts (*PERA a/s*), dem *StatoilHydro* Forschungszentrum Trondheim sowie den jeweiligen Betreuern Prof. Curtis H. Whitson und John Petter Jensen. Die verwendete Software wurde dankenswerterweise von *Petrostreamz AS*, *SPT Group Norway AS* und *Coats Engineering Inc.* kostenlos zur Verfügung gestellt. Zahlreiche Gespräche mit Industrievertretern sowie Informationen aus Büchern, Fachzeitschriften, SPE-Artikeln und dem Internet bildeten die Wissensgrundlage bei der Erstellung dieser Arbeit, wobei sämtliche Quellen und Autoren gemäß der Zitierungskonvention ISO 690 angeführt wurden.

1 Introduction

Oil and gas wells cannot and are not desired to produce uninterruptedly for years. They have to be shut-in and subsequently restarted from time to time. Such operations can have various reasons: **a)** right after a well has been drilled and completed it is in shut-in conditions, waiting for production to commence; **b)** downhole or surface facility maintenance and reconstruction activities may require production to be shut down in order to ensure safe and efficient operations; **c)** well-tests for estimating reservoir and well performance properties comprise sequences of shut-in and start-up procedures; **d)** field management plans might schedule single wells to be run as swing producers for filling up rest capacities in platform fluid handling capacity; **e)** in largely depleted or low-permeable reservoirs the necessity of letting reservoir pressure build back up sufficiently to kick out the produced fluid and/or liquid slugs in gas wells can arise and require temporary production stops; **f)** HSE issues, e.g. hurricane warnings, could force a well to be shut in.

In all these cases, shutting in a well is not much of a difficult task – bringing it back on production might definitely be. Disturbing a resting system by relieving tubing head pressure (THP) and in effect forcing the fluid column to start moving will lead to very complex pressure, flow rate and -velocity, phase distribution and temperature phenomena. These will propagate through the tubing fluid column in a wave-like manner, interact with each other, overlay and hence grow or shrink in amplitude. Severe pressure oscillations can pose a real threat to gravel packs (GP), sand-screens but also openhole completions. Permanent changes in fluid velocities and high acceleration rates across the sandface may lead to onset of sand production due to disturbed near-wellbore formation stresses or destroy GPs by eroding it or mixing contaminated with clean gravel. The damage inflicted on a well caused by a hasty or simply inadequate start-up procedure can thereby result in permanently impaired production or even the necessity of recompleting or sidetracking the well. Especially in cases where single high-rate wells are tied back to the platform via long pipelines flow phenomena occurring during start-up can get out of hand easily and deserve careful consideration.

1.1 Industry practice and suggestions for improvement

Nowadays, the procedure of putting a well back on production is generally carried out manually. Onshore as well as offshore; standard start-up schedules or long-time experience help the people responsible in deciding which steps in rate or choke position to take, in order to perform the operation quickly and in a safe manner.

Conditions downhole can vary quite substantially from one shut-in period to another, which in many cases goes unnoticed, underestimated or misjudged by the people at the surface. Variations in initial wellbore fluid composition or rate of pressure drawdown at the tubing head can cause unexpected and unwanted events potentially harmful to the well installations and the sandface. A fully coupled reservoir-wellbore model is able to predict such phenomena and constitutes a helpful tool for planning preventive actions and designing optimal and most effective start-up procedures.

Wellbore damage is not the only concern when it comes to starting up a well: spent time and in effect money are essential factors. Such an operation takes several hours or even days. During most of the start-up period, the well-stream has to be torched or disposed, because of mud and debris contamination – leftovers from previous intervention or drilling activities – which are by no means desired in export pipelines and tankers. Having in mind the large penalty fees and CO_2 taxes due for flaring hydrocarbons and the revenues missed out on by lost production during wellbore cleanup, it makes a lot of sense to think about ways of how to speed up the operation. The solution is again a fully coupled reservoir-wellbore model in order to minimize start-up time and costs, without risking a damaged well. Thereby also the workload on platform personnel would be reduced – start-up operations commonly alert most of the platform crew on duty –, especially where wells are on cyclic production schedule.

All these problems relate to cases where the well can actually be started up. What if this is not possible? What if the shut-in reservoir pressure is not high enough to push out the waste fluid column in the tubing? A coupled model can then be run to check whether – from an economical and technological standpoint – it is better to wait some more, letting the heavy workover fluid seep down into the reservoir, effectively lowering required bottomhole flowing pressure, or whether it is best to e.g. run a kick-off string with nitrogen injection valves for assisted unloading of the well. Long story short: also shut-in events can be simulated with coupled models, providing an often yearned for decision basis.

A system, capable of independently performing well shut-in and subsequent ramp-up operations, is also able to control the well during times of normal production. This comes in handy to many companies who are currently pursuing the vision of "intelligent oil- and gas fields", where every operation is fully integrated, optimized and controlled automatically.

1.2 Modelling and optimization strategy

To simulate and analyze processes going on during a well start-up, it is essential to create a model that can handle multiphase flow in two quite different environments: porous media and pipe. Since there is no single software able to do both with sufficient accuracy, coupling of two separate applications has been investigated.

For this paper, a near-wellbore model (in *SENSOR* by *Coats Engineering Inc.*[1]) has been explicitly coupled with a multiphase pipe-flow model (in *OLGA* by *SPT Group Norway AS*[2]). The model integration was set up in *Pipe-It* (by *Petrostreamz AS*[3]), software specially designed for integrating and optimizing multi-component processes.

The basic assumption underlying the main simulation part is, that for a certain downhole flowing pressure determined by *OLGA*, *SENSOR* can accurately determine the volumes of oil, gas and water entering the wellbore. More precisely: the pipe flow model uses a desired wellhead-pressure and bottomhole inflow volumes to calculate the pressure at the downhole inflow boundary. This pressure is transmitted to the reservoir simulator, which is then able to calculate the corresponding new phase flowrates. These new rates are subsequently fed to the pipe flow model which updates the downhole flowing pressure and so on. The data transfer from one model to the other is conducted by *Pipe-It* only at the end of a time-step (*Pipe-It* time-step, PITS), which for instance might be 15 *sec*. Repeating these cycles, while an optimizer, seeking maximum surface oil-rate, controls the change in tubinghead pressure, will start-up the well as quickly as constraints on maximum property change at the in- and outflow nodes allow.

The assumption that maximum oil-rate within each PITS is resulting in the least possible overall start-up time is not entirely substantiated. The reason for this is that the optimizer does not get the "big picture" of the total operation, but only time frames in the range of seconds. Nevertheless, this concept is still doing very well in terms of overall time, but will prevent damage to the well by not allowing exceeding the range of maximum downhole rate and pressure variations.

Defining the production specific constraints is a difficult issue and depends entirely on the particular well and its affinity towards sand production or the GP quality of its completion. Also factors like perforated interval length and inclination as well as porosity and permeability of the near-wellbore zone play an important role. The boundary values chosen for this research are therefore realistic but conceptual and will need some adaption when applied to a real well case.

[1] www.coatsengineering.com
[2] www.sptgroup.com
[3] www.petrostreamz.com

2 Phenomena encountered during start-up

A well start-up operation constitutes a major disturbance to the previously resting system, which is, on a PITS basis, induced by a series of minor step-excitements (e.g. changes in THP or choke position). These changes are communicated through the produced medium from the wellhead down to the reservoir. Dynamic transient flow phenomena are characteristic for this operation. They are complex in nature and in effect very difficult to estimate. If neglected or underestimated, these events can result in severe damage or complete loss of the well. This happens not necessarily due to engineer's inexperience, but might also be caused by phenomena that simply cannot be predicted from surface without having an accurate coupled reservoir-wellbore model. Like in most technical applications, the motto here is: in order to influence the system such that goals are reached while problems are avoided, it is essential to thoroughly know what is going on and what dynamic response is to be expected for any changes made. Therefore, this chapter shall provide a description of the flow processes active in the production system during start-up above as well as below the mud-line.

2.1 Tubing flow

Pressure

Pressure waves in the tubing caused by step-like relieving THP travel through the tubing at sonic velocity, while concentration variations propagate slower, at 1 to 5 *m/s*.[4] As a response, also inflow rate at the downhole node would change, causing additional oscillations in tubing pressure distribution. The actual change of a property at a given location and time is not only governed by the propagation velocity and distance from origin of changes, but is additionally heavily influenced by interaction and superposition of the spreading waves itself.

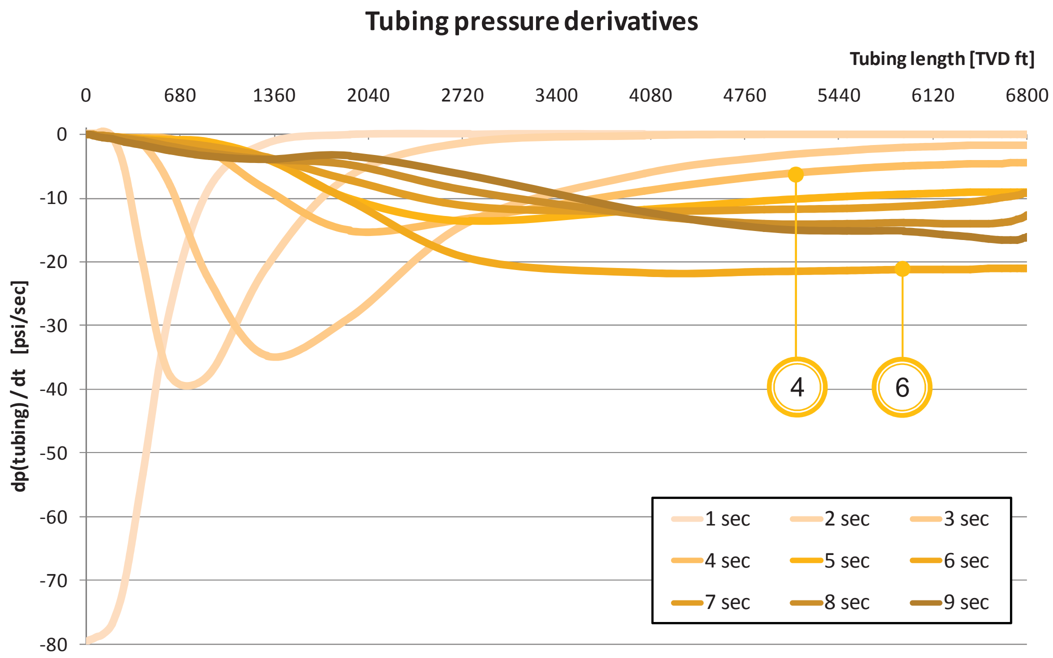

Figure 1: $dp_{(tubing)}/dt$ vs. TVD plot for sudden THP reduction

[4] Discussion with Prof. M. Golan (NTNU-IPT) on Sun, 14.06.2009

As an example, *Figure 1* above shows the development of *dp/dt* along the tubing length in PITSs of 1 *sec*. The data for this plot was retrieved from simulating a case where THP was instantaneously lowered from 730 to 650 *psia* to create a sharp pressure drop. This is of course a very unlikely scenario, but it shows clearly the wavy progression of the disturbance. The orange colour shading describes the time sequence, with the brightest line being t = 1 *sec* and the darkest one representing t = 9 *sec*.

The originally “sharp” peak in pressure drawdown is immediately dampened to half of its amplitude when travelling through the highly compressible gas containing region of the uppermost tubing part (resulting from phase segregation during shut-in). The wave would pick up speed when entering the denser oil column, where overlaying and diffusion effects cause it to vanish into a blurry and flat pressure drop. The plot shows that after 4 *sec* the pressure drawdown at the coupling point at 6800 *ft* TVD becomes noteworthy and the reservoir starts delivering fluid into the well. Up to t = 6 *sec*, bottomhole pressure (BHP) is declining at increasingly higher rates, but rising inflow rate causes BHP-decrease to slow down. Eventually, reflections and newly created pressure waves would reach the wellhead and *dTHP/dt* starts oscillating: the well enters the instable flow conditions characteristic for the early start-up phase.

These heavy pressure and rate oscillations are almost entirely encountered in and ascribable to the low-rate, multiphase tubing-flow. In porous media diffusion mechanisms act as strong dampeners and prevent emergence of large fluctuations. Phenomena encountered in this period are hard to accurately predict, but it is important for start-up operations to know and limit their order of magnitude in order to avoid damage to the production system (compare chs. 2.4 and 2.3).

Fluid velocity

Keeping an eye on fluid velocities is key in order to ensure proper wellbore cleanup quality. Also flow regime and -stability is affected by the speed at which the well-stream flows: the higher, the steadier.

Managing to attain high flowrates at an early stage of the start-up helps to get contaminated fluids out of the invaded reservoir area and the wellbore itself. Slow rate will result in large portions of the heavier water or mud slipping past the hydrocarbons streaming upwards and wellbore cleanup will take longer time, be incomplete or possibly fail at all.

On the other hand, too high flowrates will boost erosion of pipe fittings and edges in the flow-line, e.g. in sand-screens or slotted liners, reducing their resistance to burst and collapse stresses. This is especially a problem when formation fines are present in the well-stream, because they virtually result in a sand-blast eroding the pipe material.

Fluid temperature

Temperature distribution along the wellbore does not change significantly during the first minutes of the ramp-up. This is because the system is initially resting and both, fluid and tubing/annulus, have adopted the linear temperature profile of the surrounding rock. This lethargy towards heating up is caused by an effect called ‘temperature storage’ and can be neglected in steady-state flow calculations. The transients of a well start-up, however, will be affected and therefore this phenomenon is taken into account. Letting the well flow for some more time will increasingly heat subsurface installations and, hence, also the fluid surface temperature will increase.

<u>Note:</u> *An additional observation is the temperature increase towards inflow- and outflow node of the well. This is most probably non-physical behaviour and, according to SPT Group, can be attributed to the higher gas-oil ratio (GOR) at the nodes, bringing the different thermal properties of oil and gas into effect.*[5] *This model inconsistency is an early-phase problem and would fade swiftly.*

[5] (SPT Group AS, 2009 ch. ‘Thermal computations‘)

In cases where hydrate- and wax formation is to be expected, accurate temperature prediction is of high importance. Staying above the cloud-point or outside of hydrate formation conditions is critical in order to avoid precipitation of these substances, leading to blockage of downhole- and especially surface facility flow paths.

2.1.1 Wellbore cleanup

The process of retrieving contaminant fluids left in the wellbore after drilling or completion operations is called wellbore cleanup. These waste-fluids are pushed upwards by the reservoir fluids entering the well downhole. Flow phenomena during this period are clearly transient and characterized by the co-flow of reservoir fluids and non-Newtonian mud. In long deviated wells or in low-pressure reservoirs, achieving complete cleanout is especially difficult.

There is a variety of issues needed to be addressed concerning wellbore cleanout during start-up procedures:

- Estimating minimum well flow rate and overall process time required to retrieve completion- and drilling fluids
- Assess the influence of different completion designs, such as open hole sand-screens with or without inflow control devices and their effect on cleanup results
- Before drilling or well intervention: does the choice of oil- or water-based mud and variations thereof affect the cleanup process later-on?

Poor cleanup quality may result in decreased inflow from the reservoir due to higher flowing BHP and possibly partly plugging of sand-screens. Effectively, productivity of the well can be substantially decreased.[6]

2.2 Reservoir flow

Pressure
In the reservoir section, the main concern is again pressure variations. Immediate pressure drops can result in sudden saturation changes possibly resulting in emulsion blocking. But the far more likely and potent threat to the wells productivity is a purely mechanical one: drilling the well has already been a major disturbance to formation stresses in the near-wellbore region. Either that and/or additionally poor compaction can lead to weakening of the rock in the inflow section. If sharp pressure variations are encountered during a start-up operation, these instable conditions might deteriorate and result in breaking the formation. Pressure surges can fracture the rock and a sudden pore pressure relieve increases effective formation stresses which at some point become too large and the porous reservoir rock collapses. Such incidents reduce permeability and, if flow velocity in the pores is supercritical, trigger or aggravate fines- and sand production which is an extremely unfavourable situation to be in.

In this respect, mainly the spontaneity of the pressure variation is crucial. Pressure constitutes a force per unit area – in the reservoir this would be the inner pore surface. The way how rock responds to changes in force acting is a visco-elastic one. This means that the stress induced in the material is time-dependent. The so-called *Kelvin Rock Model*, shown in *Figure 2*, demonstrates this behaviour by separating elastic and viscous forces into a Hookean spring and a Newtonian dashpot respectively[7]:

[6] (Hu, et al., 2009 p. 1-2)
[7] (Hudson, et al., 1997 p. 218)

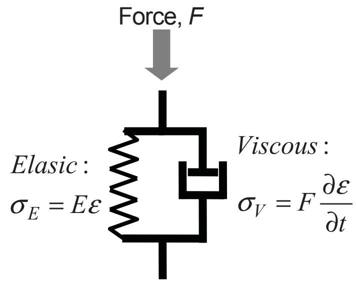

Figure 2: Kelvin visco-elastic rock model

Total stress is the sum of both parts as formulated by equation (eq.) *2.2-1*:

$$\sigma_T = \sigma_E + \sigma_V = E\varepsilon + F\frac{\partial\varepsilon}{\partial t}; \quad \text{2.2-1}$$

Rakishly spoken, the time-dependent viscous element in this setup reflects the behaviour of a car's shock absorber: when driving over a cross-drain, the shock would be fully absorbed by the dampener and cause large piston displacement in short time – large *∂ε/∂t*. When, on the other hand, the car is driven through a depression on the road, the forces acting on the dashpot are even higher due to centrifugal forces, but the displacement of the dampening piston would be less, resulting in small *∂ε/∂t*. In terms of well start-up, this means that the quicker BHP, and in effect forces acting on the rock face, changes the larger the strain per unit time and hence the stress induced in the formation is. Therefore, fast alterations in downhole pressure can result in stresses higher than the formation breakdown or lower than the collapse stress resistance and lead to unwanted material failure.

Flow velocity

Supercritical fluid flow velocities in porous media are induced by a large pressure drawdown in the near-wellbore region. Formation fines present in the pores constitute an obstacle to the flowing fluid which itself will exert a force on the particles. This force is depending on the fluid's superficial velocity, density, viscosity and the diameter of the idealized round particle. It is referred to as viscous drag force, F_d, as shown in eqs. *2.2-2* and *2.2-3*[8]:

$$F_d = \left(\frac{\pi}{8}\right)\cdot\frac{\rho C_d}{32.174}\cdot\left(\frac{D_p v_s}{12}\right)^2; \quad \text{2.2-2}$$

drag coefficients, C_d [-], are depending on the Reynolds number, *Re*, which itself relies on fluid density, ρ [lb/ft^3], superficial velocity, v_s [*ft/sec*], particle diameter, D_p [*in*], and the fluid viscosity, μ [*cp*]:

$$C_d = \begin{cases} 24/\mathrm{Re} & \\ 18.5/\mathrm{Re}^{0.6}; & \mathit{for}: \quad 2 < \mathrm{Re} \le 500; \\ 0.44 & \end{cases} \quad \begin{matrix} \mathrm{Re} \le 2 \\ \\ 500 < \mathrm{Re} \end{matrix} \quad \mathit{where}: \ \mathrm{Re} = \frac{124\rho v_s D_p}{\mu}; \quad \text{2.2-3}$$

while v_s is obtained by:

$$v_s = \frac{0.000065\cdot q}{a\phi S}; \quad \text{2.2-4}$$

In eq. *2.2-4*, q is flowrate [*bbl/d*], a is flow area [ft^2], ϕ denotes porosity [-] and S is the mobile phase saturation [-].

With flow velocity picking up, the particle will be dragged along as soon as F_d becomes larger than the inertial forces holding it in place. Core and log analysis will provide insight in the nature

[8] (Wehunt, 2006 p. 206)

of particles and surfaces in the formation pores which will then allow an approximation of maximum BHP drawdown in order to remain below critical pore flow velocity.

Productivity index
The productivity index (PI) is an important factor influencing the quality of wellbore cleanup. It denotes the ability of the reservoir to supply fluids into the wellbore for a given bottomhole pressure drawdown. Higher PI means larger fluid volumes per unit pressure are flowing into the well and effectively the contaminants present in the tubing are displaced quicker and more efficiently.

Knowing about the effects described above is very important to see which parameters need to be controlled during optimization and which do not have a noteworthy impact. In that respect, pressure is doubtless the most critical property: the coupled system is controlled with pressure, the inflow from the reservoir is governed only by pressure, the fluid behaviour is largely depending on pressure conditions, the flow performance in the tubing is heavily influenced by differential pressures etc. Temperature phenomena – even though not first-order effects – influence fluid behaviour and pressure and, hence, need to be predicted.

2.3 Completion

Completion is referred to as the installed downhole equipment enabling the reservoir fluids to enter the wellbore. It is in effect the critical link between formation and pipe and can either be an open-hole completion, where the lowest section of the well is not cased, or a cased-hole completion, comprising an assembly of tubular and equipment.[9] Transient flow phenomena can result in serious mechanical damage to the well-completion.

Tubular integrity
BHP fluctuations might at some point end up with very low pressure values, resulting in a large difference between reservoir- and wellbore pressure. This is especially troublesome in sections with lower than average permeability and hence reduced PI, which would otherwise alleviate this effect. The mechanical integrity of the perforated casing or sand-screen can be overloaded, leading to collapse of the tubular. Knowing the load capacity of the installed equipment enables the engineer to calculate maximum short-term pressure differences, defining limits not to be exceeded during start-up operations.

Flow velocity (GP completions)
In wells with GP sand-control completions strict downhole pressure management is essential during start-up operations. Most of the pressure drop in fluid flow from the reservoir into the well occurs in the close vicinity of the wellbore. In other words, the pressure drawdown per unit length, *dp*/*dr*, is reaching its maximum when the fluid enters the completion – i.e. GP, whenever present. According to Darcy's Law in its radial and differential notation (cf. eq. *2.3-1*)[10], the derivative ratio of pressure, *p* [*psi*] and length determines the flowrate, *q* [*bbl/d*], and, together with the flow area, *a* [ft^2], the fluid velocity, *v* [*ft/sec*]:

$$v_{Gdisp} > v = \frac{qB}{2\pi rh} = \left(\frac{k_{GP}}{\mu}\right)\frac{dp}{dr}\ , \quad \text{2.3-1}$$

where the middle term essentially is rate divided by the cylindrical flow area: $a = 2\pi rh$. k_{GP} [*mD*] and μ [*cp*] in the right term, denote permeability and fluid viscosity, respectively. *dp*/*dr* is the change in pressure per unit of radial distance. This denotation only holds for the simplified assumption that the GP behaves like a porous medium with uniform permeability distribution. v_{Gdisp} is defined here as the fluid flow velocity at which the gravel starts to disperse. Turbulence and buoyancy effects at velocities higher than v_{Gdisp} will lead to proppant dispersion and mixing of gravel, contaminated with formation fines, and clean grains, dramatically reducing the sand control properties of the completion and possibly even resulting in a need for replacement.

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[9] (Schlumberger Ltd., 2009)
[10] (Golan & Whitson, 1996 p. 114)

As already mentioned in the tubing-flow section above (cf. ch. *2.1*), increasing flow velocity furthermore causes worsening erosion of metal parts deflecting the fluid flow: GP completions always comprise sand screens that prevent sand and gravel from entering the wellbore. Exceeding a critical flow velocity will cause increased attrition of the screen's edges and might sooner or later result its failure to hold back the gravel.

2.4 Surface facilities

Generally speaking, transient and instable well production is in most cases problematic, inefficient and difficult to handle. This holds especially true for operating conditions in surface facilities.

Platform surface equipment like separators, flow-lines or other is secured by surge gauges, preventing over- or under-pressure as well as liquid in gas lines, improper phase levels in separators and similar. These mechanisms have to be circumvented in cases with heavily oscillating start-up rates and pressures; otherwise the safety system would prevent successful execution of the operation. Any inactive security installation is, of course, a threat to HSE and is supposed to be avoided if at all possible. Installation of equipment with high rate and pressure ratings is often economically not feasible and therefore the problem needs to be addressed on an operational level: optimization and tight control of production at the wellhead.

To avoid these issues, and to make sure not to excess handling capacities for oil, gas and water, the well-stream can be kept close to a optimal set-point by automatic controllers – i.e. changes in pressure and phase rates during start-up operations are desired to be as smooth as possible. In compliance with these efforts, THP modifications during simulations made for this research have also been predominantly gentle.

One exceptionally troublesome transient multiphase flow-phenomenon is called slugging. This condition can be witnessed during normal production, but in aggravated form during transient flow periods. Large volumes of liquid separated by gas pockets are travelling through the well, flow-line and/or platform riser (see *Figure 3*). They cause problems when arriving at the platform, because the exceptionally large volumes, accompanied by high pressure gas chambers, suddenly swamp the well-stream receiving facilities. It is an instable production condition, difficult to handle and, whenever present, needs to be addressed separately. It is, however, a crucial task of well start-up optimization to avoid slug formation in the first place.

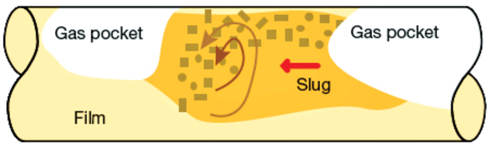

Figure 3: Liquid slug in flow-line[11]

<u>Note:</u> *The wellhead choke is the last "bastion" able to prevent dangerous pressures and volumes from entering surface facilities. The choke response-time – i.e. the period required by the servo-mechanism to accomplish any settings command received from the controller – can definitely be a limiting operational factor. A quick moving subsea wellhead-choke, regulated by a "multi-turn" actuator, can take up to 5-10 min to go from fully open to closed – ideally that is; in reality this operation might take much longer.[12] This factor needs to be considered in setting up the Pipe-It Optimizer model, in order not to presume unattainably quick THP changes.*

[11] (Havre, et al., 2000 p. 56)
[12] Discussion with Prof. M. Golan (NTNU-IPT) on Sun, 14.06.2009

2.5 Constraints limiting start-up speed

The phenomena and involved problems, afore stated in chs. *2.1* to *2.3*, call for boundaries limiting maximum and minimum THP, BHP, surface and downhole rates as well as the respective time derivatives. Obviously every well must be treated differently and therefore general constraints are hard to define. In the following, a short explanation shall be given of which boundaries have been chosen for the system set-up used for this research and why.

Bottomhole pressure and -rate
Since the bottomhole inflow node is the systems “neuralgic” point, pressure and rate constraints active there have to be considered very carefully and are generally based on geological and geophysical survey data on both, near-wellbore reservoir and completion.

In order to minimize the time-dependent viscous stress on the formation (as discussed in ch. *2.2*), downhole pressure variations must be kept within certain bounds. The maximum allowable change in BHP has been defined as ±20 *psi/min*. Maximum BHP was set to initial reservoir pressure of 3151 *psia*. In reality, pressures at the sand-face can indeed exceed shut-in BHP. This would be a result from overlaying pressure phenomena in the tubing fluid column. However, in the current model injection into the reservoir is not possible, which is why flowing BHP is not allowed to exceed its initial value. If the reservoir’s inclination towards sanding makes it necessary, a boundary for maximum drawdown is added by changing the lower boundary of the *OLGA* BHP in the *Pipe-It Optimizer* set-up from zero to the respective positive value.

The principle of viscous drag and its increase with rising flow velocities and -rates (also explained in ch. *2.2*) calls for boundaries on maximum downhole production volumes. The limit for maximum rate increase per unit time has been set to +200 *STB/d-min*. This boundary sounds rather high, but assuming a well with a bottomhole flow-diameter of 3.5 *in*, having a perforation length of 2x20 *ft*, in a two-layer reservoir with porosities of 25 and 27 *%* for interval 1 and 2, respectively, an increase of 200 *STB/d-min* would speed up the pore-fluid flow as little as 0. 0004 *m/s-min,* which is sufficiently conservative. The maximum downhole flowrate is currently defined as the target surface-rate. Should sand production prevent flowrates any higher than a certain value, this critical sanding-rate would have to be set as maximum bottomhole flow.

Surface pressure and -rate
Flow at the surface is represented by the wellhead outflow node. It should be kept as calm as possible in both, pressure and rate changes. Furthermore, constraints on maximum and minimum values have been established.

Pressure, for that matter, is limited at the lower end by the test separator pressure, assumed to be 500 psia. It does also have an upper constraint of 900 *psia*, which is mainly a precaution for irrational *Optimizer*-behaviour. Practically, this boundary does not have any impact, because the reservoir cannot sustain production at higher THP than its natural properties allow. Depending on fluid composition in the pipe and corresponding hydrostatic head, this maximum surface pressure will be between 800 and 900 *psia*. If the *Optimizer* would increase further THP, production would stop and it would have to return to lower THPs again.

The rate of change in surface pressure is constrained by a hard and a soft boundary. The former is determined by how quick the choke can be opened and closed and the latter constitutes an attempt to minimize “overreaction” of the *Optimizer*, creating unwanted flow instabilities. Assuming that the choke response time is very short, enabling it to go from 0 to 100 *%* or vice versa in only 8 *min*, and knowing that the operating pressure range is between 500 and 900 *psia*, results in a maximum THP change of ±50 *psi/min*. This is implemented as a variable boundary and hence cannot be exceeded. In contrast, violation of the soft constraint, set to ±10 *psi/min*, is possible, but rarely happens and in effect calm THP actuations are conducted.

Rates are also constrained in terms of maximum absolute and time-derivative values. The upper absolute boundary is represented by the target oil-rate, which for the present system might be defined as any oil-rate below the reservoir's maximum deliverability of ~8000 *STB/d*. A limit on surface rate increase has only been defined for oil and was decided to be +400 *bbl/d-min*. Besides these constraints, also a maximization objective has been implemented for surface oil-rate. This is the "driver" of the whole operation: maximization of surface rate at each PITS is the top priority, pushing the simulation towards minimum total start-up time.

3 Description of employed software

3.1 SENSOR 6k

SENSOR stands for “System for Efficient Simulation of Oil Recovery” and has been developed by *Coats Engineering Inc.* (founded by Dr. Keith H. Coats) for simulating 3D Black-Oil and compositional problems. It can handle single porosity, dual porosity as well as dual permeability reservoirs, includes Impes and Implicit formulations and has three linear solvers built in.[13] The program is executable on standard PCs and can be launched from DOS command-line, which makes it possible to call it from within other applications. Its superiority in terms of speed, accuracy and stability compared to peer-applications has been tested and verified in SPE (Society of Petroleum Engineers) Comparative Solution Projects and many field studies by consultants and oil companies alike.[14]

The choice of this software has turned out to be an excellent one. It has been relatively easy to get started with and allowed for gradually improving the model during in the course of the ongoing research work. Once the concept is ready to be taken to the field, this simulator enables the engineer to include state-of-the-art near-wellbore models with varying saturation-, relative permeability-, porosity distributions, eliminating the need of having to compromise the results with inaccurate reservoir flow calculations.

3.2 OLGA 6 GUI

The *OLGA* software package is used for simulating dynamics of multiphase flow in the tubing, including transient hydraulics and heat-transfer effects. It has been developed and improved over many years by *SPT Group*, which claims its software to be the market leading flow simulator for oil, gas and water in wells, pipelines and receiving facilities. As a matter of fact, it is extremely widely used and cited in research papers dealing with simulating multiphase flow, which confirms its high performance and user-friendliness.

The version used for this research is the 2009 release *OLGA 6 GUI*. For building the physical model including boundary nodes, pipes, geometry, chokes etc. the program’s graphical user interface (GUI) has been extremely useful and handling proved to be intuitive. However, for running simulations the application was launched from command-line. The input system consists of four files: general input (**.genkey*), fluid PVT data (**.tab*), flowpath geometry (**.geo*) and restart information (**.rsw*). The general input file includes all system features earlier specified in the GUI and a restart file to continue with flow conditions present at the end of the previous run. The latter is only obligatory in transient flow simulations, which is why a separate initialization run is required to create such a restart file for the first simulation time-step.

3.2.1 Flow computations[15]

How exactly *OLGA* handles computations of three-phase flow is a treasured secret of *SPT Group*. All computations are, however, based on mass-flow rates for each phase. Since the input that *OLGA* gets from *SENSOR* is in volumetric units, an equivalent mass rate is calculated using eq. *3.2.1*:

---

[13] Reduced Bandwidth Direct (D4), Orthomin preconditioned by Nested Factorization and Orthomin preconditioned by ILU with red-black and residual constraint options
[14] (Coats Engineering Inc., 2009)
[15] (SPT Group AS, 2008 p. 8)

$$m_{tot,sc} = Q_{o,sc}\left(\rho_{o,sc} + GOR \cdot \rho_{g,sc} + \frac{WCUT}{1-WCUT} \cdot \rho_{w,sc}\right); \quad \text{3.2.1}$$

$$\rightarrow m_{tot,sc} = m_{o,sc} + m_{g,sc} + m_{w,sc}$$

In-situ conditions are then calculated using the gas-mass fraction, R_s, defined in the PVT data table and inserting it in eq. *3.2.2*:

$$\begin{aligned} \Delta m_g &= (m_g + m_o) \cdot (R_{s,sc} - R_{s,resc}) \\ \rightarrow m_{g,resc} &= m_{g,sc} - \Delta m_g \qquad ; \quad \text{3.2.2} \\ \rightarrow m_{o,resc} &= m_{o,sc} + \Delta m_g \end{aligned}$$

Computation of water properties from the two-phase fluid PVT data table is left to *OLGA*, assuming that it uses values for compressibility and viscosity that fairly closely match those used in *SENSOR*. Water standard density is set to be the same in both models.

3.2.2 Thermal computations

For transient flow simulations, accurate prediction of fluid temperature distribution and heat transfer across the pipe wall play an important role when hydrate or wax formation is to be expected. *OLGA* handles thermal computations by calculating homogeneous fluid temperature and average temperature for each one of the concentric, user-specified wall layers. Resting upon the assumption that radial heat conduction is dominating the heat-transfer through the wall the heat flux is estimated using the layer-parameters previously defined by the user: thermal conductivity, specific heat capacity and density.[16]

3.3 Pipe-It 1.0

The coupling of the two simulators is entirely conducted in *Petrostreamz Pipe-It 1.0*, developed by the Norwegian company *Petrostreamz AS* (an affiliate of *PERA AS,* both founded and owned by Curtis H. Whitson). This software has been specially designed for integrated asset optimization and exploitation in the petroleum industry. Its GUI enables the user to lay out his project in different organizational layers, making it easy to understand and organize complex projects integrating many different processes and sub-processes. The objective of such an effort is to optimize the operational mode of the considered production system in order to maximize the economic value generated, while integrating any number of processes and elements that are connected to it and may affect its performance.[17]

The GUI's highly intuitive functionality and the fact that various elements and/or -groups can be run separately or collectively at will is extraordinarily helpful in setting up a project system while maintaining the overview and certainty that the different elements actually work properly.

The elements that make up a *Pipe-It* project are processes, connectors, composites and resources. Basically, processes tell Pipe-It *what* to do and the way how they are arranged and interconnected tells it *when* to do it. Resources are elements like input-, output- or DOS batch-files which are required by the processes in order to work properly. To maintain a simple and clear project structure, composites are used to group several elements into one, as shown in *Figure 11* (p. *15*), where the composite "Initialization" for instance contains all processes and resources required to initialize the *OLGA* and *SENSOR* models.

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[16] (SPT Group AS, 2009 ch. 'Thermal computations')
[17] (Petrostreamz AS, 2008)

3.3.1 Linkz and LinkzUtil

Pipe-It has a built-in feature called *Linkz* that allows the user to locate specified values in text-files which e.g. might be input or output of simulation models. Tracking down these elements is achieved by defining fixed strings in the text that do not change and the according relative position of the desired numerical value. Entering several such cross-references and information on whether *Linkz* should start looking at the top or bottom of the file ensures uniqueness of the link.

Within *Pipe-It*, these links can be addressed readily from the *Optimizer*-window and can then be read and/or overwritten. For exporting purposes, the application *LinkzUtil* is available. It is launched from a DOS batch-file and obeys certain commands, depending on whether the link is to be read or overwritten with another link or user-defined string. This utility is extremely helpful in data recording or transferring values during an *Optimizer*-run, because the *Pipe-It Optimizer* can read and overwrite variables only before or after a run, but not in between.

3.3.2 Pipe-It Optimizer

The *Pipe-It Optimizer* is a tool to load a set of input variables, perform changes on these, run the model and analyze the output in respect to predefined objectives and constraints. Subsequently the input is altered in order to further improve the solution and so on. This procedure is repeated until the solver has found a feasible solution or a minimum or maximum of an objective function. (A more detailed description of how such an optimization procedure works is given in ch. *3.3.3* below.)

There are four types of variables available to perform optimization on a *Pipe-It* project: a) VAR is an *Optimizer*-specified variable out of a user-defined range and updated before the model is run; b) AUX variables are either set by an equation, user-specified or read from file (can also be written to file) and are updated right after VAR and before the model execution; c) CON is a variable type that is either user-defined, read from file or set by equation and is updated immediately after the model run; finally d) OBJ is a user-defined variable, taken from a file or set by an equation which the *Optimizer* will try to either minimize or maximize.[18]

The user has several different solver algorithms available to choose from. In this research, only the *Nelder-Mead Simplex Reflection* solver has been used. Basically, what the *Optimizer* does is applying solver-suggested changes to VAR from one run to another in order to make sure that CON are within their predefined allowed range and in the meantime following the objective of minimizing or maximizing any given OBJ. This is done iteratively and can be stopped after some time by setting a constraint on maximum number of iterations.

To get hold of variables that are to be read from and/or written to file the *Pipe-It Optimizer* uses the application *Linkz*, described in ch. *3.3.1* above.

***Pipe-It Optimizer* GUI**
Figure 4 is a screen-shot taken from the initialization *Optimizer*-setup. The relevance of this project-part shall not matter at this point; it is only meant to provide a clear and simple example of how an optimization process is configured within *Pipe-It*.

New variables are defined by selecting a *Name*, a *Role* as well as *Upper and Lower Bounds* (cf. box **a** in figure). Depending on the respective variable role, also an *Equation*, a *Link* or both need to be defined. The link in this respect is the name of the previously defined '*Linkz*' cross-reference entry, enabling the *Optimizer* to read from and/or write to model output- or input files. In that manner, a sequence of VAR (shaded blue), AUX (green), CON (yellow) and OBJ (red) variables is introduced, constituting the optimization parameters during a subsequent solver run. Maximum number of *Iterations*, objective *Direction* and name of OBJ-type variable (*Target*) are then to be selected in box **b**. For testing purposes, icons in box **c** enable the user

[18] (Petrostreamz AS, 2008 ch. 'Pipe-It Optimizer')

to open the optimization *History*, after *Running the Model Once* or for a whole *Optimization*, in order to assess results and convergence of the procedure. Also in box **c**, the *Solver-Type* can be selected and the project's *Linkz*-database can be accessed. Depending on the chosen solver algorithm, some more settings may be required or possible; for this research's purposes, however, the ones described are more than sufficient. To maintain transparency, the *Optimizer* activity is recorded and displayed at the very bottom of the GUI.

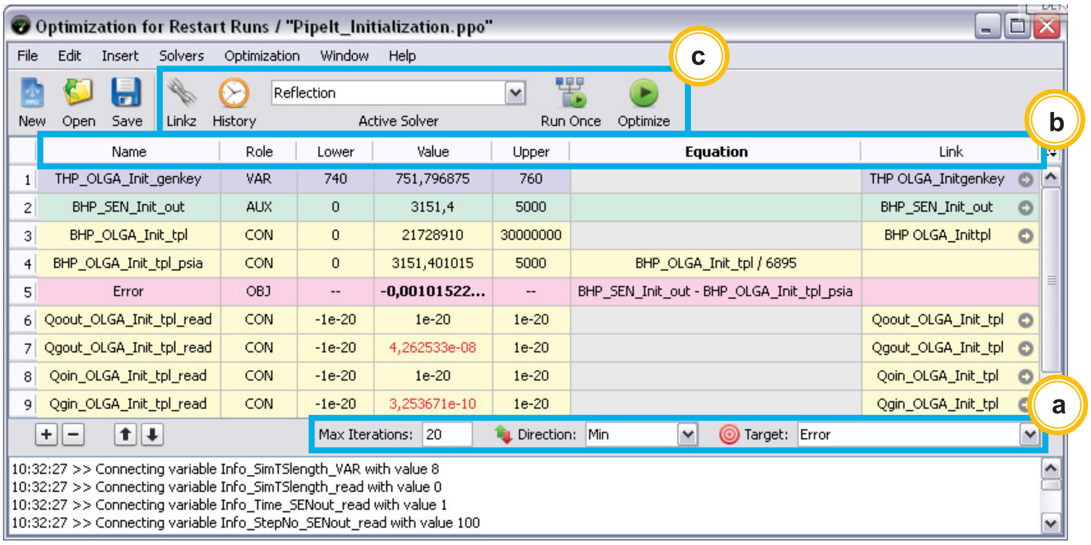

Figure 4: *Pipe-It Optimizer* GUI[19]

Pipe-Itc.exe

Launching the *Optimizer* can be done manually from the *Pipe-It Optimizer* command window shown above. However, for running simulations which include several optimization-levels or simply require frequent re-launches, calling the *Optimizer* manually each time is not practicable. Instead, an application called *Pipe-Itc.exe* is included in the software package. It is run from DOS command-line and practically corresponds to running *Pipe-It* within *Pipe-It*. The user has to specify the *Optimizer* file-name and the composite-path within which optimization should be run. Whenever this process is finished, the sub-*Pipe-It* run is terminated and the main run can continue with the process next in line.

3.3.3 Nelder-Mead Simplex Reflection Solver

The *Nelder-Mead method (NMM)* for solving nonlinear optimization problems has been developed in 1965 by J. A. Nelder and R. Mead. The *Nelder-Mead Simplex Reflection Solver* is one of several solver algorithms built in *Pipe-It* and has been used for all optimization purposes in this research.

Modus operandi

The objective of using *NMM* is to minimize an objective function in an N-dimensional space (with N being the number of variables). What it does is it creates a polytope with N+1 vertices. Then it solves the objective function for each vertex and compares these solutions against the predefined objective. The vertex giving the solution that deviates most is kicked out and a new one is defined in another location. In this manner the solver will gradually move towards the optimal solution which might be only a local one.[20]

As shown in *Figure 5*, the principle can be illustrated easily when looking at a maximization problem with two variables, *x* and *y* (N=2). The *NMM* solver would create a triangle ABC (N+1 vertices) on the parameter surface and solve the objective function *f*(*x*,*y*) for each vertex.

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[19] (Petrostreamz AS, 2009)
[20] (Bertsekas, 1995 p. 162)

In the first step, A has the smallest *f*(*x*,*y*), is therefore rejected and replaced by A' on the opposite side of the axis BC. In the same manner B' is kicked out in the next step and B'' is created. In the 4th step, the solver takes advantage of another possible action: B''' and C''' have equally poor *f(x,y)* but A''' is good, therefore it decides to extend the triangle beyond A''' to A''''. Either way, the solver algorithm's objective is to establish a sequence of triangles until the fractional convergence criterion is fulfilled. The fractional convergence tolerance is denoted as δ and describes the difference between the best (highest) and worst (lowest) objective function value *f(x,y)* for the current simplex. In mathematical terms, this is formulated by eq. *3.3-1*:

$$\delta_{current} \overset{!}{\leq} \delta_{frac.conv.} = 2\frac{|f_{best} - f_{worst}|}{|f_{best}| + |f_{worst}|} \quad \text{3.3-1}$$

Once $\delta_{current}$ is smaller than $\delta_{frac.conv.}$, the optimization has converged.[21]

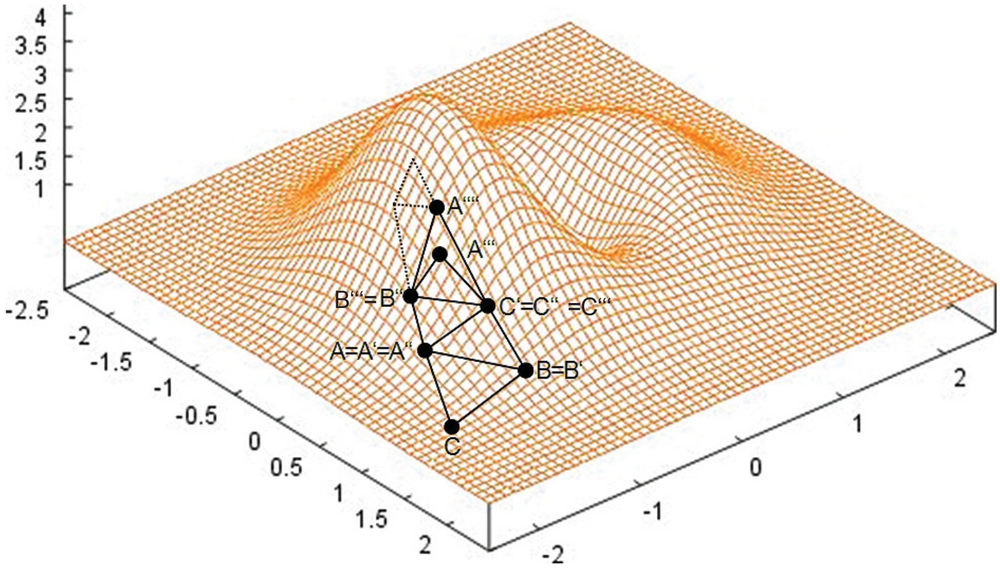

Figure 5: Nelder-Mead Simplex Solver principle[22]

Constraint weighting

Defining constraints is not only a matter of coming up with physical limits to the start-up process in whatever unit available. One needs to make sure that the *Optimizer* takes them as "serious" as they deserve. In other words: in the eye of the user comparing two pressures, first in units of *Pa* and then in *psia*, might give the same result; the *Optimizer* however, only sees absolute values and to him a deviation of 6,895 *Pa* is not the same as 1 *psia*. Checking how large the absolute deviation from the constrained region is, gives information about how severely the solver would "punish" any violation. The penalty should reflect both, deviation from and priority of the constraint.

In a later stage, when "guidance" of the optimization process is required, the issue of correct constraint weighting becomes ever more important. *Figure 6* shows the early phase of an optimized oil well start-up. While constraints on maximum change in oil-rate over time (upper) are satisfyingly met, the BHP-time derivative plot (lower) violates its boundaries considerably around PITS 40. This might be acceptable, depending on the case in question. The important aspect with this issue is being aware of it. Plots like those in *Figure 6* help avoiding long simulation runs that are mislead by too restrictive constraints on a certain property, while another one might be too loosely confined.

[21] (Lorenz, et al., 2004 p. 2)
[22] (Völker, 2002)

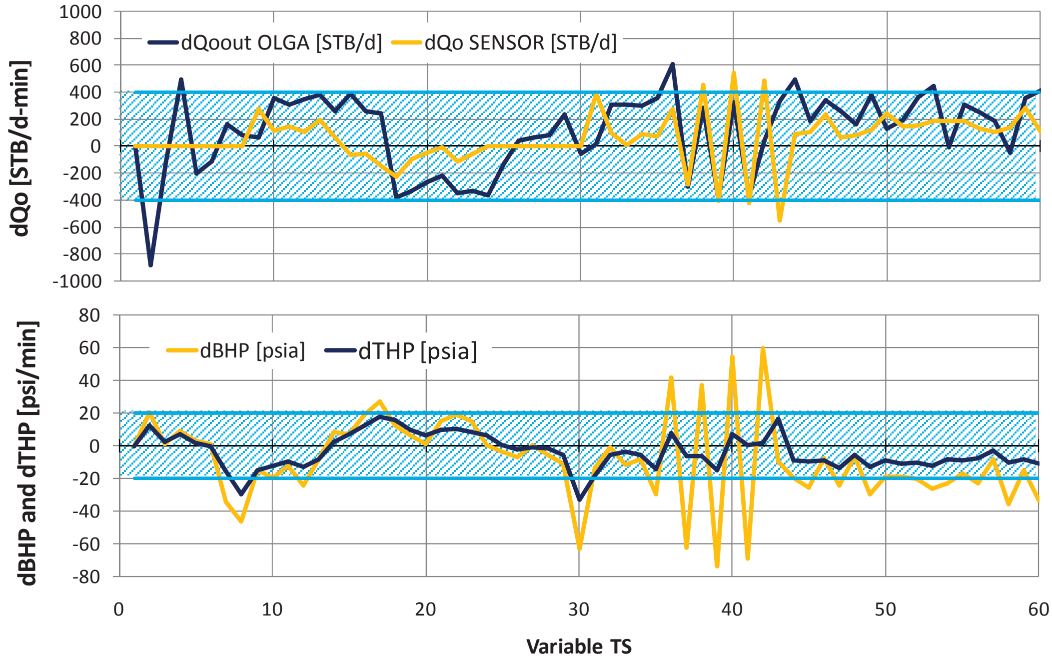

Figure 6: Oil-rate (upper) and pressure (lower) change per minute with constraints

4 Modelling

The models in use here have been set up manually and are not meant to represent any specific well nor reservoir. The objective is to create a generic yet realistic and physically correct system to investigate and simulate real-life transient flow phenomena during start-up. In the following chapter the used models for both, reservoir and wellbore, as well as efforts taken to create a fully consistent PVT data-set are described.

4.1 Near-wellbore reservoir model

The near-wellbore reservoir model created for this research comprises two hydrocarbon bearing layers of different height, permeability and porosity. The two zones initially contain undersaturated oil, bear a 100 *ft* water column and are assumed to be not communicating. The reservoir properties and schematic depiction are shown below in *Table 1* and *Figure 7*, respectively:

Property	**Layer A**	**Layer B**
formation-top	6890 *ft*	7350 *ft*
height	460 *ft*	670 *ft*
permeability, k_{xy} & k_z	300 *mD* & 100 *mD*	400 *mD* & 50 *mD*
porsity, φ	25 *%*	27 *%*

Table 1: Reservoir properties

The properties of the two reservoir sections are selected such, that they resemble those of the intervals Tilje (A) and Åre (B), found on the Mid-Norwegian continental shelf.[23] As typical for this area, the formation is assumed to be hydrostatic pressured and all numerical model regions are initialized using the saltwater gradient at the bottom of the reservoir: 8020 *ft* and 3600 *psia*. Radial gridding is used with cell radii increasing linearly towards the outer boundary (r_{outer} = 1315 *ft*). The two zones are subdivided into numerical layers of 5 and 40 *ft* thickness (layer A: 20x5 and 9x40 *ft*; layer B: 22x5 *ft* and 14x40 *ft*). Relative permeability curves have been established by the use of data characteristic for Norwegian Sea sandstone reservoirs.[24] The reservoir fluid is a Black-Oil PVT-type fluid with a bubblepoint pressure of 2000 *psia*. More information on fluid data is given in ch. *4.3* below.

Both formations are perforated in the oil-bearing top of the reservoir, with perforation heights of 20 *ft*. It is assumed that the well is completed such, that crossflow can occur as long as pressure differences exist. To imitate the pressure drop across the perforation the inter-cellular horizontal transmissibility for fluid flowing from the reservoir into the wellbore has been reduced and set to 0.2 *rb-cp / day-psi*, which acts as a downscaling factor for Darcy's law across the affected cell boundaries.

[23] (Skjaveland, et al., 1992)
[24] (Wijaya, 2006 p. 91-92)

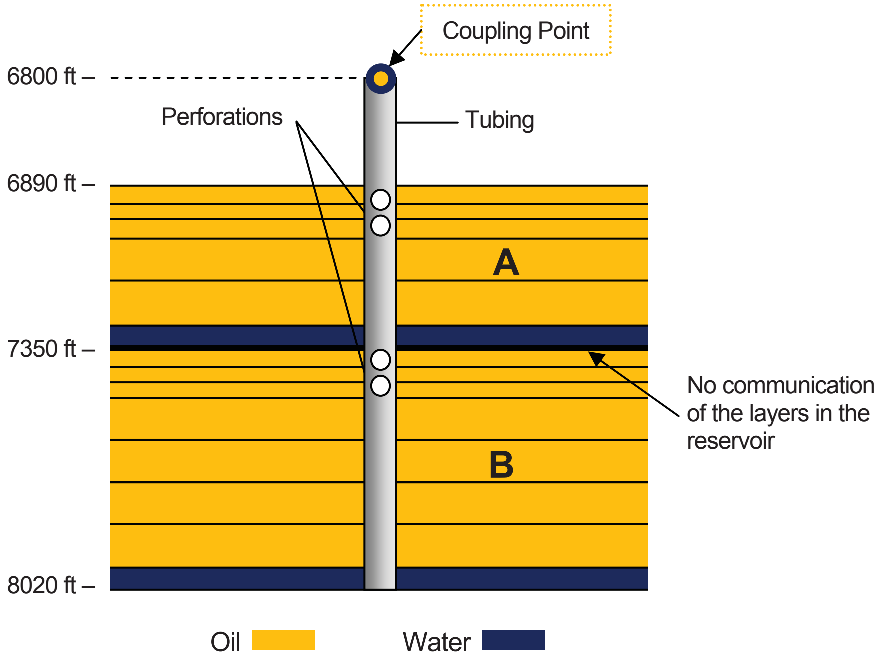

Figure 7: Reservoir model layout

The lowest part of the tubing, i.e. from 6800 *ft* to 8020 *ft* TVD, has been modelled as a column of radial grid cells within the reservoir model, using a porosity of 1.0 and permeability of roughly 2×10^9 m*D*, selected to result in a Darcy pressure drop similar to what *OLGA* would give for a liquid rate between zero and 1000 *STB/d*. This section in the production system is very sensitive. Here, crossflow and its effect on hydrocarbon recovery and phase pressure have to be captured. It has been noted, that at the direct interface between reservoir and wellbore it is more important to ensure model stability and calculation accuracy than taking pipe flow characteristics into account. Consequently, the rigorous, fully implicit coupling of neighbouring grid cells within *SENSOR* has been utilized to handle the phenomena mentioned above and to take produced fluids to the *SENSOR-OLGA* coupling point, 90 *ft* above the reservoir top.

The complete *SENSOR* input file can be viewed in *Appendix A*.

4.2 Wellbore flow model

From the coupling point at 6800 *ft* depth up to the surface, the well-stream is modelled in *OLGA*. The 3.5 *in* tubing with an inner surface-roughness of 2.5×10^{-5} *m* is discretized into 27 sections. Starting with 10 *ft* at top and bottom, the sections geometrically increase in length towards the middle of the tubing string. The multiplier is 1.45 and lies well within the *OLGA*-recommended range for the maximum neighbour-section length-ratio between 0.5 and 2.0. Additionally, there is a 28th section of 0.1 *ft* length at the very bottom, constituting the coupling overlap with *SENSOR*. It shall be noted here, that computational time increases roughly with the second order of numerical pipe section-count. On the other hand, shorter and more pipe sections improve accuracy of simulation results.[25] Depending on the application, a balance has to be found. In this regard, for coupled simulations of time spans

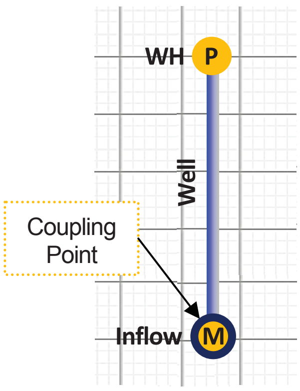

Figure 8: Schematic depiction of the *OLGA* well model

[25] (Burke, et al., 1993 p. 473)

in the order of hours or days, the number of sections would have to be reduced to speed up the process, but generally, the range given above is a reasonable criterion.

The reservoir with the chosen properties could easily sustain higher production with larger tubing (e.g. 5.0 *in*), but then the *OLGA* calculated pressure drops from one pipe section into another become very small. This causes problems in the tubing section gridded in SENSOR, because the reservoir simulator uses Darcy's law to establish flowrates and therefore it needs at least some pressure drop from cell for calculating phase-rates. The downside of the 3.5 *in* tubing is that rate peaks delivered by *SENSOR* result in even higher pressure peaks at the *OLGA* inflow node than one would encounter with a 5 *in* tubing.

To incorporate thermal radiation in the model, the required properties of pipe, annulus, casing as well as the surrounding rock were included in the order depicted in *Figure 9*. To ensure numerical stability, also here a smooth increase in formation layer thickness is necessary. To obtain good results in predicting wall heat storage effects and thermal radiation, *SPT Group* suggests a range of $0.2 \leq \frac{\delta_i}{\delta_{i-1}} \leq 5$, where δ denotes the layer thickness which itself should not exceed 30% of the layers outer radius.[26]

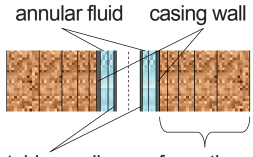

Figure 9: *OLGA* wall layers

Even though extremely simplified, the arrangement suffices for the concepts generic approach. When matching to real data, a thorough thermal property analysis for pipes, fluids and surrounding soil has to be carried out, because compromised heat-transfer calculations would make temperature predictions useless.[27] The list of chosen properties is displayed in *Table 2* below (the values reflect the range of those of several relevant SPE papers such as "*History Matching of a North Sea Flowline Startup*" by Burke et al.[28]):

Material	Thickness [in]	Heat Capacity [J/kg-C]	Thermal Conductivity [W/m-C]	Density [kg/m^3]	Expansion Coefficient [1/C]	Viscosity [cp]
tubing wall (solid)	0.3	500	50	7850	–	–
annulus (liquid)	0.8, 1	4180	0.58	900	2.46 E-5	1.04
casing wall (solid)	0.4	500	50	7850	–	–
formation (solid)	1, 1.5, 2.1, 3, 4.3	2000	2	2500	–	–

Table 2: *OLGA* wall layer property table

As a final input, boundary conditions have to be defined. Since one cannot specify both, rate and pressure, for one node at a time, the outflow node at the top is defined to be tubing-head pressure (THP) constrained and represents the control variable (CV) of the optimization process. The inflow node at the bottom of the tubing is set to be mass flow constrained, which allows the input of oil rate, GOR and watercut (WC), calculated by *SENSOR*. The possibility of introducing massflow constrained nodes is available for the first time in *OLGA 6.1* and allows for accurately defining feed rates while the program calculates the pressure at the inflow node reversely from the pressure set-point at the outflow node. (A schematic of this assembly can be viewed in *Figure 8, p. 18*) The pressure and rate conditions for the boundary nodes are updated after each single *OLGA* time-step.

Fluid temperature at the inflow node has been defined the same as reservoir temperature of 75 *°C*. Ambient temperatures have been set to 75 *°C* downhole and 15 *°C* at the surface, while values vertically in-between are calculated by linear interpolation.

(The complete *OLGA* input file can be seen in *Appendix B*.)

[26] (SPT Group AS, 2009 ch. 'Thermal computations')
[27] (Burke, et al., 1993 p. 475)
[28] (Burke, et al., 1993 p. 472)

4.3 PVT calculations

The fluid PVT data set employed in all simulations of this research is property of *SPT Group* and has been taken from a case study distributed along with the software. This simplified approach is justified by the scope of the project, which does not include extensive PVT analysis and furthermore the models do not reflect a specific real-life well, but constitute a generic system for proofing the concept.

Fluid properties in both, *OLGA* and *SENSOR*, are entered as Black-Oil data. This means the simulator is provided with basic information, enabling it to calculate or correlate overall fluid behaviour. In field applications, compositional PVT data would be supplied which on the one hand requires profound laboratory analysis of the fluids present, but on the other hand largely eliminates errors that might originate from assumptions made for the used correlations in Black-Oil PVT. According to what *Burke et al.*, using compositional fluid properties in *OLGA* simulations shows results that are "clearly superior" to those of Black-Oil PVT.[29]

It is very important to ensure consistency with fluid properties when coupling reservoir- with pipe flow models. The fluid tables in use were specially created for *OLGA* applications and therefore, input needed in reservoir simulations was not readily available and had to be derived or calculated.

Starting point was the *OLGA* fluid table given in SI units for a pressure range from 0.1 to 47 *MPa* (14.5 to 6816.8 *psia*) and temperatures from 0 to 100 *°C*. The *SENSOR*-relevant fluid properties provided are densities, density-pressure and -temperature derivatives, viscosities and gas mass-fraction. When using Black-Oil fluid tables in *SENSOR*, information on standard oil- and gas density, $\rho_{o,sc}$ and $\rho_{g,sc}$ *[lb/ft³]*, formation volume factors, $B_o(p)$ *[rb/STB]* and $B_g(p)$ *[ft³/scf]*, the solution gas/oil ratio, $R_s(p)$ *[scf/STB]*, and the solution oil/gas ratio $r_s(p)$ *[STB/scf]*, is required. The latter is set to zero by default, because no retrograde gas condensate is expected in this case.

Standard conditions

Standard conditions are defined the same in both simulators: T_{sc} = 60 *F* (15.6 *°C*) and p_{sc} = 14.7 *psia*. According to the available fluid PVT table, *OLGA* calculates standard densities for oil ($\rho_{o,sc}$), gas ($\rho_{g,sc}$) and water ($\rho_{w,sc}$), which constitute the basis for calculating data required in *SENSOR* (cf. *Table 3*). Furthermore, a constant reservoir temperature, T_{res}, of 75 *°C* has been assumed.

$\rho_{g,sc}$	0.45	kg/m^3
$\rho_{o,sc}$	846.27	kg/m^3
$\rho_{w,sc}$	998.10	kg/m^3

Table 3: Standard phase densities

Solution gas/oil ratio

In a first step, the solution gas/oil ratio, $R_s(p)$, for *SENSOR* has been calculated. Within *OLGA*, this property is estimated by using either correlations by *Standing*, *Lasater*, *Vazquez & Beggs* or *Glasø*.[30] The first one has been chosen for this particular research, to establish the *SENSOR* undersaturated R_s table. Based on California crude oils, *Standing* has developed a correlation for determination of bubble-point pressure. This equation can be rearranged and solved for the solution gas/oil ratio[31] [*scf/STB*], as shown in eq. *4.3-1* below:

$$R_s = \gamma_g \cdot \left[\frac{(0.055p + 1.4) \cdot 10^{0.0125\gamma_{API}}}{10^{0.00091T}} \right]^{1.205} \quad . \qquad 4.3\text{-}1$$

[29] (Burke, et al., 1993 p. 475)
[30] (SPT Group AS, 2009 ch. 'Black Oil')
[31] (Whitson, et al., 2000 p. 30)

Thereby, the specific gravity of gas is $\gamma_g = \frac{\rho_{g,sc}}{\rho_{air,sc}} = 0.37$ and API-gravity of the fluid is $\gamma_{API} = \frac{141.5}{\gamma_o} - 131.5 = 35.39$, where the specific oil-gravity is $\gamma_o = \frac{\rho_{o,sc}}{\rho_{w,sc}} = 0.85$.[32] Used reference densities for water and are: $\rho_{w,sc}$ = 998.10 *kg/m*^{3} and $\rho_{air,sc}$ = 1.22 *kg/m*^{3}. Temperature, *T*, and pressure, *p*, are inserted in [°*F*] and [*psia*], respectively. The obtained *SENSOR* R_s table values increase from 0 *scf/STB*, at standard-conditions up to 352.4 *scf/STB* at the bubble-point and remain constant beyond this pressure.

Formation volume factor (FVF)
FVFs are calculated in the second step. *OLGA* derives phase densities from previously calculated B_o and B_g.[33] Since ρ_o and ρ_g are given by the *OLGA* PVT tables, B_o and B_g for *SENSOR* are calculated using *OLGA*'s reverse approach:

OLGA estimates B_g by using eq. *4.3-2*, with *Z*-factors being based on equations presented by *Hall & Yarborough* and fitted to the *Standing-Katz Chart*[34]:

$$B_g(p) = \left(\frac{p_{sc}}{T_{sc}}\right)\frac{ZT}{p}; \quad \text{4.3-2}$$

Then, the simulator calculates gas densities with $\rho_g(p) = \frac{\rho_{g,sc}}{B_g(p)}$. To get B_g for our purposes, the equation is simply rearranged to the form of eq. *4.3-3* below:

$$B_g(p) = \frac{\rho_{g,sc}}{\rho_g(p)}. \quad \text{4.3-3}$$

Saturated ρ_o is derived from the definition of oil density in Black-Oil PVT[35] which is also used in *OLGA* (cf. eq. *4.3-4*):

$$\rho_o(p) = \frac{62.4\gamma_o + 0.0136\gamma_g \cdot R_s(p)}{B_o(p)}, \quad \text{4.3-4}$$

where γ_o and γ_g are used as defined in section '*Solution gas/oil ratio*' above. In order to get B_o for *SENSOR*, eq. *4.3-4* is regrouped to eq. *4.3-5*:

$$B_o(p) = \frac{62.4\gamma_o + 0.0136\gamma_g \cdot R_s(p)}{\rho_o(p)}. \quad \text{4.3-5}$$

Viscosity
In the third step pressure-dependent phase viscosities, μ_o and μ_g, have to be transformed into a *SENSOR* input. These values can be readily taken from the *OLGA* PVT file and only have to be regrouped and unit-converted.

Now, all required PVT data is available and contained in the *SENSOR* input-file. Possible inconsistencies and numerical instabilities due to deviating fluid definitions in the models are thereby eliminated. *OLGA* would not accept any rate at any given pressure to enter at the inflow node, but only an amount that complies with the PVT data-set that it is using. Therefore, the level of consistency can be checked by comparing the phase rates delivered by *SENSOR* to those actually entering the *OLGA* tubing at the coupling point. In case they are found to be deviating, the calculations made for the reservoir PVT need to be reconsidered.

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[32] (Whitson, et al., 2000 p. 20)
[33] (SPT Group AS, 2009 ch. 'Black Oil')
[34] (Whitson, et al., 2000 p. 23)
[35] (Whitson, et al., 2000 p. 30)

5 Coupling strategy and implementation

The coupling approach chosen for this research work is an explicit one. This means, that reservoir and wellbore flow simulator are connected to each other only at one specified point. Phase rates are transferred from *SENSOR* to *OLGA* which in turn provides downhole pressure conditions. The data stream is updated after a certain predefined PITS length.

5.1 Coupling strategy

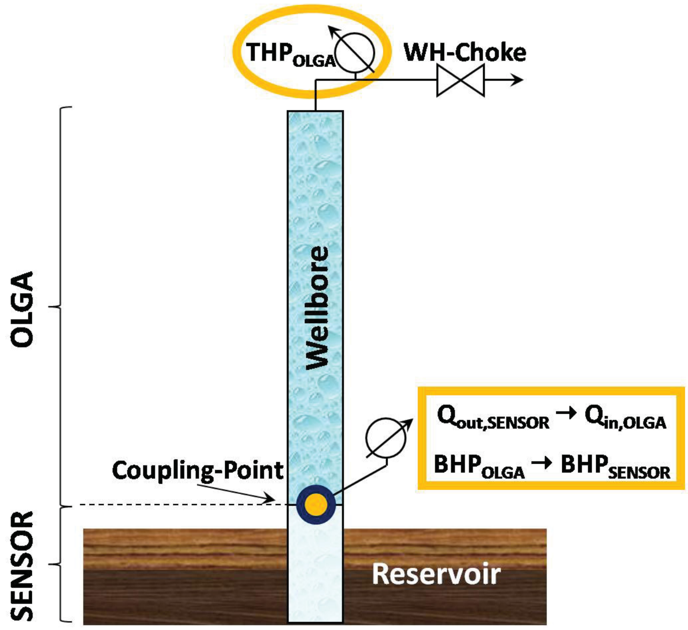

Figure 10: Set-up of the coupled system

When looking at *Figure 10* above, it becomes obvious that the basic principle of how the reservoir model is connected to the pipe-flow model is as simple as it can possibly be. Quite a few companies have already put a lot of effort to couple those two models, but with different strategies and unfortunately also limited success. *OLGA ROCX* by *SPT Group* is for instance a very ambitious attempt to create a system capable of capturing transient reservoir-wellbore interactions. What the experts at *SPT Group* did was creating a communication point for every single perforation. This approach connects the two systems at the physically most sensitive location with the highest complexity of flow phenomena and each perforation point bears a possible source for inconsistencies or numerical deviations. For those reasons, and possibly in some applications also due to weaker reservoir simulator performance, the obtained results are not yet 100 percent satisfactory but probably will be in the future.

For the research at hand, the coupling as such has been limited to only one point – namely 90 *ft* above top of reservoir. Everything happening in the tubing below is handled within the reservoir simulator. Simulation results as well as discussions with thesis supervisors Prof. Whitson and Jensen, and at a later stage also with representatives of *SPT Group* and *BP*, affirmed, that this approach is an efficient and robust possibility to solve the problem. It is hard, if not impossible, to estimate what exactly is happening at sandface, which is why it is important to capture first order tubing hydraulic effects (basically gravity) in a quick and accurate manner. According to Prof. Whitson, *SENSOR* is able to achieve this task. Its internal fluid handling procedure is fully implicit and runs a lot faster than *OLGA*'s. To also capture second order friction effects, tuning tubing "permeability" helps to approximate the pressure drop to what real pipe-flow would give.[36]

The coupled model is then controlled only by THP. If needed, this THP along with the constant choke downstream-pressure can be directly related to wellhead choke opening via the respective empirical choke-equation. As shown in *Figure 10*, the fluid volumes entering the well downhole together with the current THP enable *OLGA* to calculate an equilibrium BHP at the coupling point. Changing THP will inevitably result in a different BHP and in effect also changed inflow from the reservoir. In this manner, THP is reduced in small steps while *OLGA* and *SENSOR* constantly calculate BHP and reservoir rates for current conditions until the well start-up is completed.

Dynamic interaction of reservoir and wellbore is essentially pinned down to BHP and inflow rates affecting each other. The coupled model constantly provides us with information on these properties, giving us the opportunity to react to unwanted developments – i.e. optimizing the start-up operation.

5.2 Implementation in *Pipe-It*

Coupling two numerical processes means establishing a system that allows passing information from one to the other and back again as well as running the actual models whenever necessary. In our case, *OLGA* and *SENSOR* constitute these numerical processes, while *Pipe-It* provides us with the required tools for transferring data, running the models and performing optimization. Not surprisingly, a substantial amount of logical thinking as well as trial and error is required to set up a totally reliable system.

A multilevel project has been developed which is capable of carrying out optimized runs of a coupled reservoir-wellbore model. In the following paragraphs, a detailed description of the project's different levels and components shall be given.

5.2.1 Project top level

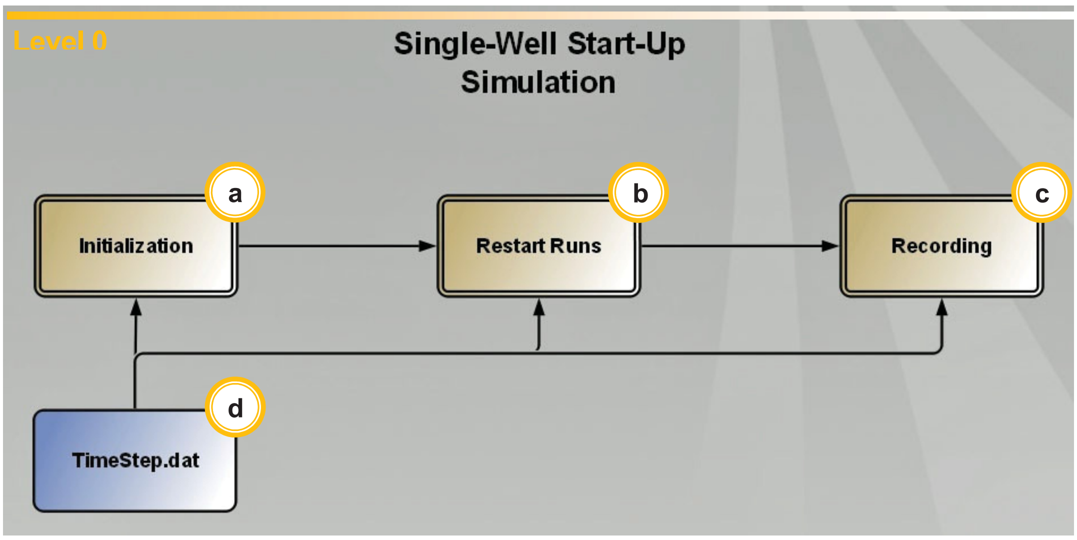

Figure 11: Project top level layout[37]

[36] Discussion with Prof. C. Whitson on several occasions
[37] (Petrostreamz AS, 2009)

Figure 11 shows a schematic of the integrated model, consisting of three main parts: **a)** '*Initialization*' of the *SENSOR* and *OLGA* models, **b)** a composite containing '*Restart Runs*', which comprises the main simulation and optimization processes, including several sub-levels and varying in configuration depending on the chosen strategy, and **c)** '*Recording*' and visualization of the simulation results for further investigation. The file **d)** '*TimeStep.dat*' is the coordination file and is called from within all three composites. It enables *Pipe-It* to always keep track of current time- and step information for *OLGA* and *SENSOR*.

5.2.2 Composite 'Initialization'

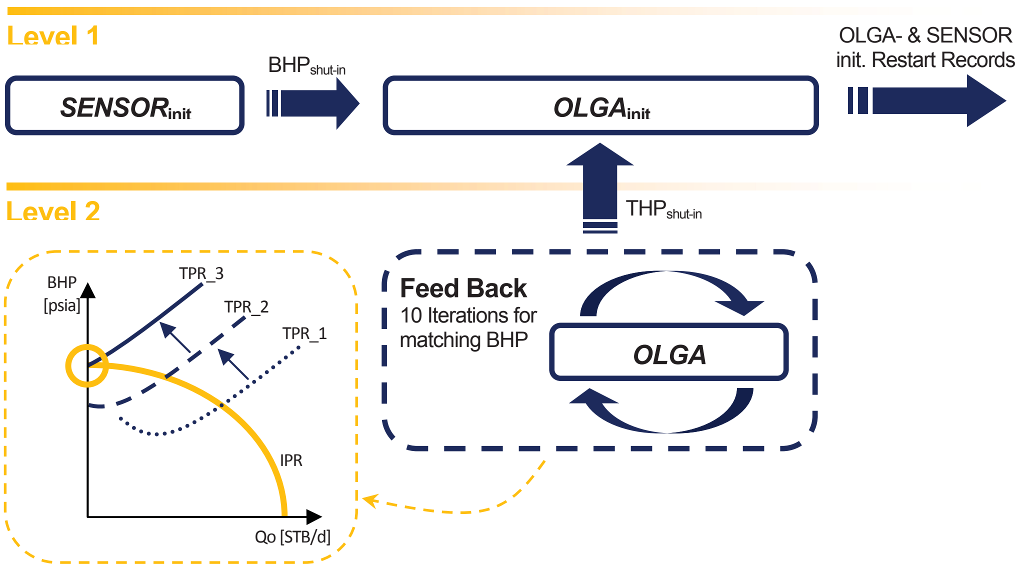

Figure 12: Working principle of composite "Initialization"

The necessity of initializing *SENSOR* and *OLGA* will be discussed in more detail in ch. *6.1* below and shall be taken for granted at this stage. In *Pipe-It*, the model initialization was implemented by using the arrangement shown in *Figure 12*: *SENSOR* is run for a simulation time of 1 day at zero rates before the initial restart record is written to file. This data-set includes all geometrical and physical properties of the near-wellbore reservoir model which henceforth cannot be changed anymore and in effect will also not be included in future *SENSOR* input files. The most important property retrieved from the zero-rate *SENSOR* run is the shut-in BHP. It is measured at mid-cell of the top-most reservoir grid-block, which happens to be the coupling cell overlapping with *OLGA*.

<u>Note:</u> *Even though unnecessarily long, a run length of 1 day is convenient because SENSOR requires time input in days and in doing so, initialization will only add "1." to the restart-time which for start-up runs will only increase in the range of forth-order decimals.*

Since the *OLGA* model is pressure controlled only at the wellhead, we have to iteratively determine the zero-rate THP that results in an inflow-node pressure matching the *SENSOR*-BHP. This bears comparison with identifying the THP that results in a tubing performance relationship (TPR) curve intersecting the IPR curve exactly at the zero-rate inflow pressure. This procedure is schematically described in the orange insert-box of *Figure 12*, where the THP giving curve *'TPR_1'* would be gradually increased by the *Pipe-It Optimizer* until the best-fit BHP is obtained with '*TPR_3*'. In practice, the *Pipe-It 'Feed Back' Optimizer* in *Level 2* initiates several 10-hour *OLGA* runs with ever changing THP values. The reflection solver would improve its THP choice after each single run until it finally succeeds in matching the *OLGA* BHP with the shut-in *SENSOR* BHP. The best fit solution will then be used in *Level 1* to write the initial *OLGA* restart-file and generate the first input data-set for both models in the main coupled runs, containing information on initial pressures, time and rates (= 0 *STB/d* etc.).

Note: OLGA uses a steady-state pre-processor that requires either a restart-file or non-zero inflow rate at simulation-start. As we don't have the former and actually don't want the latter, a little trick is required: running OLGA for 1 sec with a standard-flowrate of 1 STB/d followed by a 10 h run with 0 flowrates circumvents this problem. Effectively, the whole tubing is initialized entirely oil-filled while subsequently the system is given enough time to "recover" from the 1 sec rate-excitement and finally develop static no-flow conditions.

The reason for choosing an iterative procedure to determine THP in the first place lies in the nature of the *OLGA* well model itself. As can be seen in *Figure 8* (p. 3), the inflow node at the bottom is massflow constrained, while the outflow node at the tubinghead is pressure controlled. For determining shut-in THP in one single run, one would have to enforce a fixed BHP equal to the reservoir pressure and then determine the associated THP. This system configuration would then be written to the restart file. Since the start-up simulation requires pressure control at the tubinghead one would have to switch the node properties and hence cause an unwanted discontinuity in the very sensitive beginning of the simulation.

Unfortunately, the optimization procedure here is occasionally trapped by local minima and therefore it is recommendable to check whether the resulting THP does actually give the correct BHP for zero flowrates. *Simulated annealing* is an effective way of solving this problem. This procedure basically imitates the movement of metal atoms during cooling of a part, which are able to temporarily assume higher energetic positions, only to be able to reach one with even lower energy than the previous one. In other words: this algorithm is looking for a minimum, but on its way down it allows increasing values every now and then, effectively enabling it to avoid local minima.[38] Having done that, good starting values and narrow boundaries for THP can be chosen, in order to find the best possible solution in a second attempt.

5.2.3 Composite 'Restart Runs'

A closer look shall be taken at composite '*Restart Runs*', labelled with letter b) in *Figure 11*. As already indicated, this is the main simulation part of the *Pipe-It* project. It is organized in discrete PITS (that are entirely independent from the intervals chosen in *SENSOR* or *OLGA*) within which several optimization- and one simulation run are conducted. Its functionality is split into two levels with the '*Head Master*', being the simulation level, and the '*Feedback Loop*', constituting the optimization level.

For each PITS a new THP needs to be defined in order to get the well started up. As illustrated by *Figure 13*, at the beginning of '*PITS 1*', the *Feedback Loop* defines this new '*THP 1*' and only then the *Head Master* will run the coupled model for the period of '*PITS 1*', using the given '*THP 1*'. Having done that, the *Feedback Optimizer* will come up with '*THP 2*', before *Head Master* is running '*PITS 2*' on this very THP, and so on.

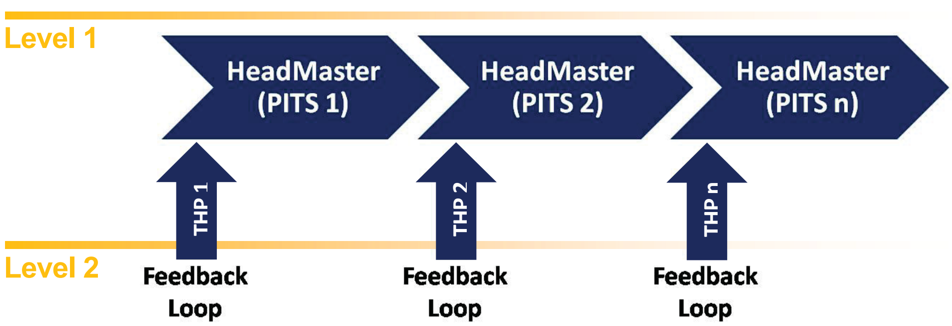

Figure 13: Simulation sequence in composite "Restart Runs"

[38] (Eberl, 1995)

The basic principle of how the simulation process is organized within one PITS is shown in *Figure 14* below. The solid box *Head Master* represents the main simulation line in *Level 1*. The *Optimizer* controlling this composite keeps the coupled model running, handles information on current time and PITS and ensures consistent system data recording. *Level 2* is the *Feedback Loop* which is always one and a half PITS ahead of the *Head Master*, in order to make sure that chosen THP changes do not cause any unwanted effects later-on in the main simulation. In other words, using the model conditions at the end of the previous *Head Master* run, the *Nelder-Mead Simplex Solver* iteratively determines the optimal change in THP for the next PITS. This optimization is subject to constraints on maximum *OLGA* surface gas rate, change in *OLGA* BHP and change in *SENSOR* oil-rate. To keep the optimization on the edge in terms of total start-up time, the objective function entered is to maximize *OLGA* surface oil rate within each PITS.

After the *Feedback Optimizer* has converged and a decision has been made, the THP settings information is passed on upwards to *Level 1* – the *Head Master* – which then takes the simulation one step ahead, before consulting *Feedback* again in the next PITS. This procedure is repeated several hundred times until the pre-defined final steady-state production characteristics are fulfilled.

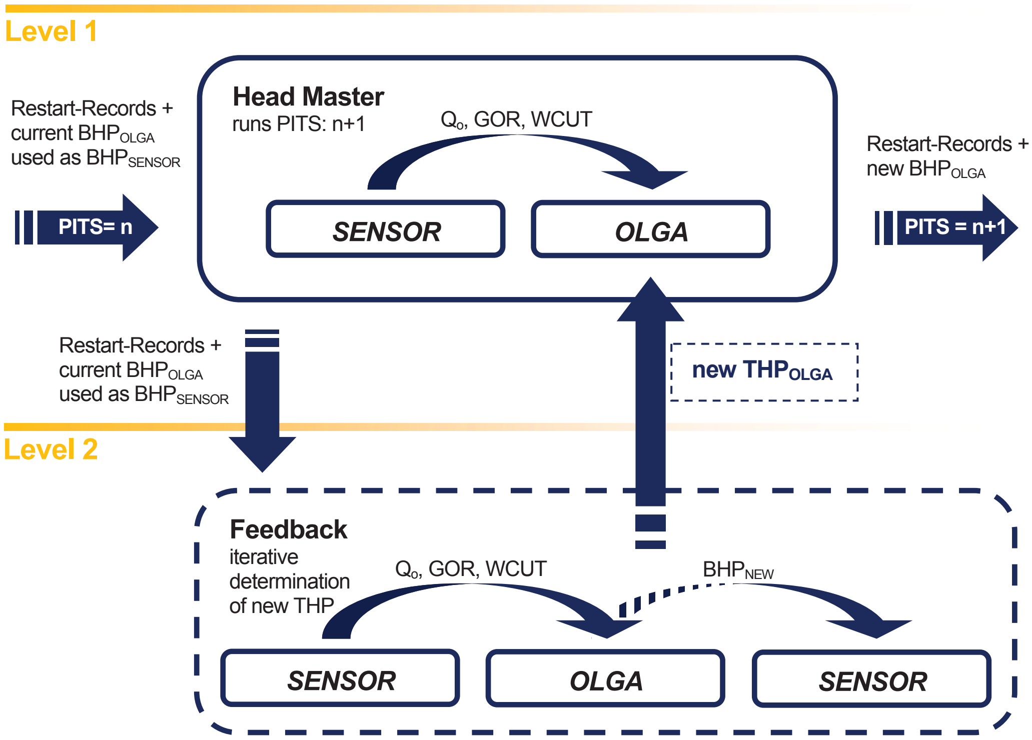

Figure 14: Working principle of composite "Restart Runs"

Implementation in *Pipe-It*

This concept's implementation in *Pipe-It* has been done the following: as the first action in *Feedback*, *SENSOR* is launched using the restart-file and *OLGA* BHP provided by the last PITS. Its output will contain the rates for oil, gas and water that the reservoir can sustain for the given BHP. These volumes constitute the input for *OLGA* and remain unchanged throughout the optimization of the current PITS. What will be changed though is the THP. The *Feedback* reflection solver would apply a certain change to the current THP, then run *OLGA* and subsequently *SENSOR* to see how the new pressure affects the producing system. Given the constraints on rate and pressure changes and the objective of maximizing surface Q_o it might or might not reconsider its choice of THP. As soon as a sufficiently good solution is found or after a maximum of ten iterations, the *Optimizer* will restore the best solution and transfer the input THP to the *Head Master*. Confident that this is the best possible new THP setting, the *Head Master Optimizer* will run *SENSOR* and *OLGA* for the current main-simulation PITS, using the exact same restart information that *Feedback* has been using. After that a batch-file for recording current production data is launched and finally the file *TimeStep.dat* is updated which will then contain model start- and end-times for the next run.

Note: *Within the feedback loop and especially with short PITS and little SENSOR run-time,* OLGA *is executed in very short intervals. This frequently causes problems with the* OLGA *'License Handler' application which apparently takes some time (>3* sec*) to reinitialize. If the available time is to short, the license verification for one of OLGA's components would fail and cause the Pipe-It run to terminate due to an error. Most of the time, the simulation can immediately be manually continued, because the Feedback Loop does neither write time nor restart-records. If, for whatever reason, this failure occurs during a Head Master OLGA run, the model has to be run again from the beginning. This necessity will reveal itself rather quickly, because corrupted time- and/or step information in SENSOR results in failure of the Pipe-It model during the next PITS.*

Data handling and transfer

At the beginning or at the very end of each *Optimizer* run, variables are read from and written to file only by the *Optimizer*. In cases where data needs to be transferred or updated while the *Optimizer* is busy, *LinkzUtil* is to be launched from a DOS batch-file. This application, however, does not allow for any arithmetic operations such as unit conversions. If this is needed anyway – e.g. in the *Feedback Loop* for transferring *OLGA* BHP (*Pa*) to *SENSOR* pressure input (*psia*) – a process scripter has to be introduced for running a *Pipe-Itc Optimizer* to take care of the unit conversion and subsequent handover of the corresponding values.

One might argue that checking *SENSOR* rates in the *Feedback Loop* by re-running it after the *OLGA* model is superfluous, because *OLGA* already determines a BHP which fairly linearly relates to the *SENSOR* rate response and could be compared against a BHP constraint. This is true only for simple, undersaturated reservoir conditions. In more complex situations, with gas, water and maybe even drilling- or completion fluids present, assumptions for simple IPR do not hold and the necessity arises to check the actual rate-change for a given new *OLGA* BHP, in order to provide the *Optimizer* with accurate information about the effects of its decisions.

5.2.4 Composite 'Recording'

The composite *Recording* is responsible for fetching the tab-delimited text-file that contains the end-of-step information of each PITS and automatically opening it in a prepared *MS Excel* workbook which would then display graphs for *SENSOR* and *OLGA* output vs. PITS (cf. *Figure 15*).

The data recording as such is actually done in *Level 1* of composite *Restart Runs*: at the very end of each PITS, after the coupled model has been executed. *LinksUtil* fetches specified values from *SENSOR* and *OLGA* output and writes them in tab-delimited form to a preliminary record file. A DOS-command will then append this information to the main recordings file, already containing information from all previous PITS.

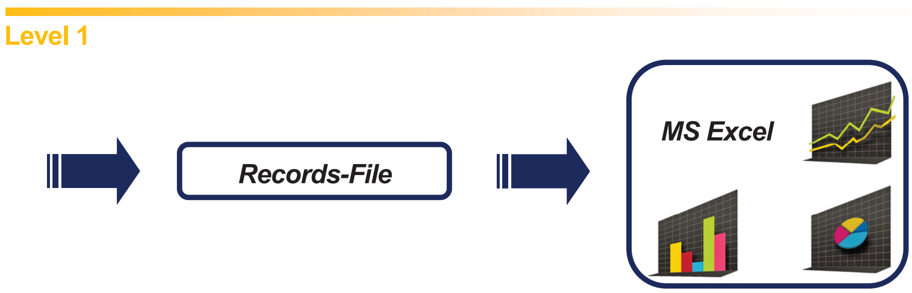

Figure 15: Working principle of composite "Recording"

5.2.5 TimeStep.dat

The text-file *TimeStep.dat* contains information on current simulation time and PITS number, end-time of the next PITS, PITS length and current number of recordings file entries. It is very important to closely keep track of time and step information throughout the simulation in order to make sure that always correct restart-file entries are read. Giving a wrong reference time would cause *OLGA* to load the closest matching entry. In *SENSOR*, however, giving an end-time lower than current restart-time or a *SENSOR*-step-number other than the one in the restart-file would immediately terminate the application and in effect the whole coupled *Pipe-It* run. The data in *TimeStep.dat* is read and written to by the *Head Master Optimizer* using *LinkzUtil*, and constantly kept up-to-date. Also *Feedback* would read current end-of-PITS information from this file but is not allowed to change them.

Furthermore, the initialization *Optimizer* iterating on the *OLGA* shut-in THP is getting information on how long to run the model from *TimeStep.dat* and final steady-state production conditions for rate and/or pressure are also contained there and retrieved by the *Head Master Optimizer*.

An example of how *TimeStep.dat* looks like during a simulation can be viewed in Appendix C.

6 Initial and final conditions

In order to make different coupling strategies comparable, fixed simulation start- and end points have been defined – i.e. initial conditions, with the coupled system at rest (neglecting inevitable interlayer crossflow in the reservoir section), and final conditions, for the point in time when the start-up has been successfully conducted.

In *Appendix D*, a detailed description of flow events during shut-in and corresponding initial reservoir pressure conditions is given for different assumptions on phases present the tubing prior to the well start-up. Examining the effects of the tubing being initially filled with oil or water only has shown that such a system is out of balance. This results in ongoing wellbore-reservoir interaction even though the well is shut-in at the surface. Depending on the severity of the initial imbalances as well as the ease of communication across the perforated interval (given by the *kh*-product), the system will largely stabilize after a couple of days. "Largely stabilized" conditions are referred to here as when counter-directional flow of phases at the tubing cross-section right above reservoir top has completely ceased. This means that in a case with tubing initially filled with water, oil would have displaced the water column back into the reservoir to an extent where the hydrocarbon-water contact has dropped below the point in question. In this research, this very tubing cross-section has been defined at a TVD of 6800 *ft* – namely the *SENSOR*-*OLGA* coupling point at 90 *ft* above the reservoir top – and will hereafter be referred to as the coupling point.

It is extremely important to make sure that the system is actually at rest before starting the coupled model run. Otherwise, additional physical instabilities could hardly be distinguished from numerical ones and in order to retain useful results, the latter need to be largely eliminated.

6.1 Initial conditions for *SENSOR* and *OLGA*

Initialization of the models is done separately. The reservoir model is run in a shut-in manner before writing a restart record and retrieving the initial shut-in bottomhole pressure (BHP). In an elementary all-oil case with zero water, BHP measured at a depth of 6800 *ft* TVD amounts to 3151 *psia*. To establish desired static conditions, the *OLGA* THP is then selected such that a shut-in initialization run results in the same BHP earlier provided by *SENSOR*. Subsequently, the initial *OLGA* restart-file is written, containing information on pressure, phase- and temperature distributions. The obtained restart-files constitute the basis of all simulation runs, no matter what strategy is used. Considering again an all-oil case with no water fraction, a shut-in THP of 751.8 *psia* is determined to set off the difference between initial reservoir pressure and hydrostatic tubing pressure. In *Figure 16* to the right, initial tubing pressure conditions are plotted over true vertical depth (TVD). It must be noted, that after real-life drilling, completion or well-intervention operations, the pipe is not likely filled with one phase only, but rather a sequence of e.g. diesel, brine, mud, special pills etc.

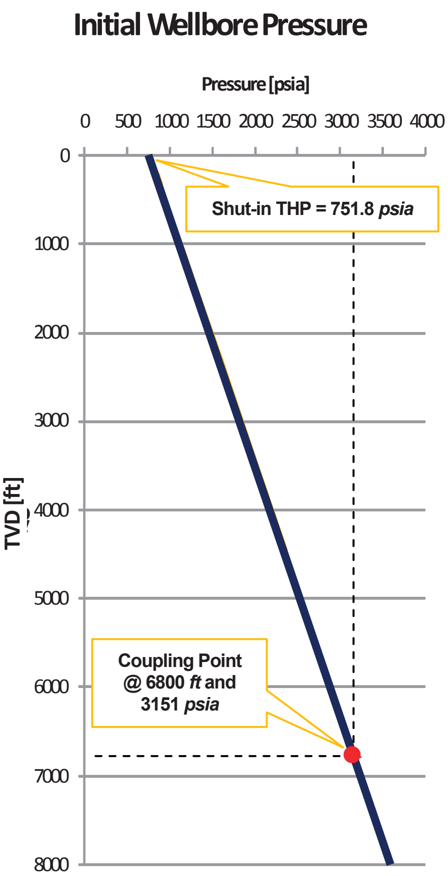

Figure 16: Tubing pressure vs. depth plot for initial conditions

Depending on the phase distribution initially present in the tubing fluid column, the OLGA model would return shut-in THP values that vary widely from the 751.8 *psia*, retrieved for the all-oil case. When producing oil with moderate GOR at low rates, pipe flow friction losses can possibly be smaller than the loss in hydrostatic head due to the presence of gas in the tubing. Producing THP may in effect be even higher than the initial shut-in THP. This observation might sound startling, but has been tested and verified in many simulation runs. In start-up optimization runs, producing THP at times climb beyond 900 *psia*. With increasing flowrate, gas will take ever more pipe-volume. Above inflow rates of more than approximately 5000 *STB/d*, friction starts to dominate over decreasing hydrostatics and the difference between flowing BHP and THP has reached its minimum.

<u>Note:</u> *For zero-rate initialization of the OLGA model, a short period of minimal flow is required in order to launch the steady-state pre-processor. This is currently implemented as 1 sec of 1 STB/d oil-rate at the bottomhole inflow node. If OLGA was to be initialized with a specific amount of water or gas present in the tubing, the time of 1 sec will not be long enough and will have to be increased in the input-file. Exactly how long this flow period will have to be, before the well is shut-in, and what fluid composition is required to achieve – say, a 4000 ft water column – cannot be determined up-front. Trial and error in OLGA will be necessary to establish the input values for automatic initialization in Pipe-It.*

Taking the created initial restart files into the fully coupled model run reveals that the system is indeed at rest. Obviously this is only valid when THP is kept constant at its shut-in value and *SENSOR* continues to deliver zero rates. Plotting rates for oil and gas flowing out at the wellhead shows, that, in strict numerical terms, the *OLGA* model is slightly active even though node pressures do not change. This can be contributed to the fact that shut-in THP has been determined iteratively and is therefore not 100 *%* correct. The two peaks in surface rate are believed to be numerical instabilities in OLGA, stemming from compressibility or thermal calculations. However, *Figure 17* illustrates that the amounts of oil and gas crossing the boundary at the tubinghead are generally well below 0.005 *STB/d* and 0.001 *Mscf/d*, respectively, which can be neglected with clean conscience. Even if shut-in THP where exact, there would still be some flow occurring. This is due to the fact that not a choke, but a pressure boundary is shutting in the well.

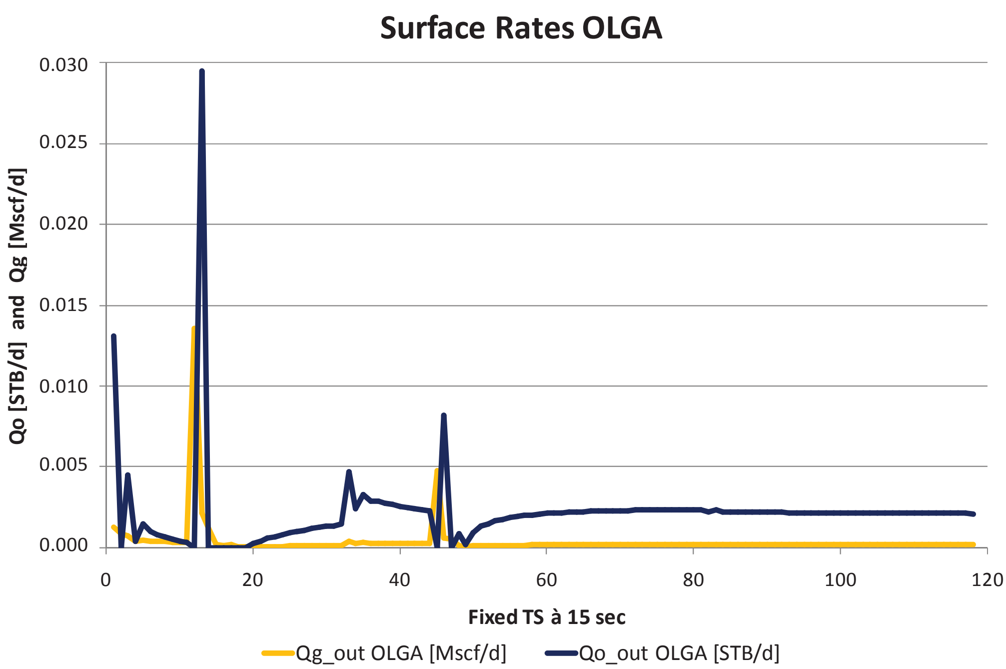

Figure 17: *OLGA* rate plot for shut-in coupled model run (30 *min*)

6.2 End-of-start-up (steady-state production)

This set of data defines anticipated conditions at simulation end. Normally, a desired target liquid- or gas rate is defined as primary final condition. Alternatively, also a favoured THP could be set, but this is rather uncommon, as are GOR or GLR targets, for wells desired to fill up rest-capacities in platform gas or water handling. Reaching these conditions once is not accurate enough to define simulation end. Superimposing waves create spikes in fluid pressure and wellbore storage effects might temporarily give a rate equal to Q_{target} even though steady-state production has not been reached yet. To avoid being misled, *Optimizer* limits have been defined for both, target rate and pressure oscillations for the nodes at the tubinghead and the coupling point. Once these constraints are fulfilled, the start-up is fully conducted and the total time for the operation can be recorded for performance evaluation.

Figure 18 shows a plot of rate-time derivatives. Here it becomes obvious, that, even though rate change quickly establishes a largely constant low positive value, the time until *dQ/dt* reaches near-zero values is considerably longer. This is especially true for late start-up phase *SENSOR* oil-rates which continue to grow with slowly decreasing pace. (The sudden drop in *dQoout OLGA* at approximately 30 *min* is caused by the surface rate hitting its maximum allowed volume and is henceforth kept constant by the *Optimizer*.)

To capture this during simulations, it has been decided that a *dQ/dt* for inflow and outflow rate growth must be below 2.5 *STB/d* within a time-span of 1 *min*, which is very low considering *SENSOR*'s field-unit output accuracy of 1 decimal digit. In the course of the start-up, wellbore storage effects will decay rapidly at the end-of-start-up and finally, the amount of liquid entering the well would not exactly match the one flowing out through the wellhead, but – depending on compositional changes due to relieved pressure – is supposed to be fairly similar. That is why a further condition has been defined: the maximum rate difference during steady-state production must not exceed ±50 *STB/d*. Furthermore, in terms of pressure, the maximum *dp/dt* must not exceed 1 *psia/min* for both, BHP and THP, in order to classify for steady-state production.

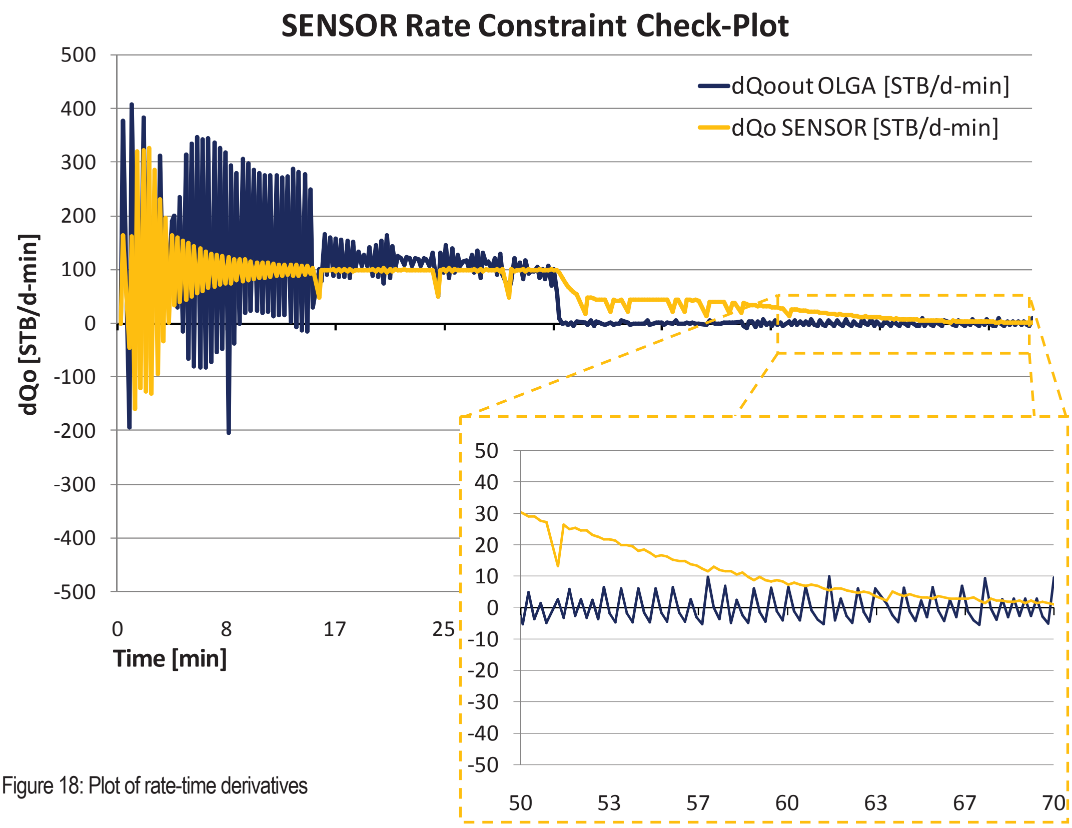

Figure 18: Plot of rate-time derivatives

All end-of-start-up constraints for rate, pressure and the respective time derivatives are treated within the *Head Master Optimizer* and as soon as a feasible solution – i.e. all constraints are met – is found, the *Optimizer* will bring the coupled model run to an end and the well start-up is successfully completed. There is, however, a limit of maximum *Head Master* iterations of 5000 in order to rule out pointless long runs without any hope of actually being able to get the well back on stream.

Depending on the application or simulated scenario, different decisions for final conditions would be chosen. For this research, both, target rate as well as -THP, cases have been run. The deviation of this target from the initial conditions largely determines total start-up time and in effect simulation duration. For instance, a case with a target of 7200 *STB/d* in oil-rate or analogical a THP of 650 *psia*, takes six to seven hours to simulate on a 1.73 *GHz* computer. This is rather long for testing different *Optimizer* settings and strategies, which is why mostly shorter runs of four hours have been simulated, with a final steady-state production rate of 3000 *STB/d* only.

7 Optimization using pre-defined fixed PITS-length

This chapter presents approach to and result of using fixed PITS in optimizing coupled model start-up runs. A base-case with linear THP drawdown is constructed, before the topic of optimization is entered, explaining how this is achieved and what benefits can be expected of it.

7.1 PITS selection

The optimization in the strategy at hand is solely relying on PITS-end information for rate, pressure and the respective time-derivatives. Therefore, the selected step interval length bears heavy influence on the outcome of the simulation, because it determines what the *Optimizer* gets to “see” and what it bases its decisions on. The conclusion *Pipe-It* makes from the simulation output might therefore be entirely wrong and can result in the generation of additional, numerically caused oscillations and/or amplify encountered physical instabilities.

As has been stressed before, the system is regulated by changing THP which is done in step-like excitements at the beginning of each new PITS. These changes in pressure may be relatively small from step to step, yet they are sharp and hence represent a shock to the system. Pressure waves are initiated, travel through the tubing fluid column and manifest themselves in all kinds of complex phenomena (cf. ch. 2). Step-end information is only retrieved at the tubinghead- and the bottomhole inflow node. Due to the aforementioned pressure fluctuations, the PITS length determines whether the output used for the *Optimizer*-reflection shows e.g. a pressure peak or a through. *Figure 19* shows a plot of pressure-time derivatives at both, inflow and outflow node, after a single 10 *psia* negative step in THP. As expected, the BHP response is clearly time-delayed by a little over 6 *sec*. However, the main focus here should be laid on the fact that using fixed PITS lengths of either 6, 12 or 20 *sec* will determine whether the solver retrieves BHP value a, b or c and, needless to say, this will strongly influence its decision for the next PITS’ THP.

Selecting an appropriate PITS length is therefore critical and as a first concept, fixed interval lengths have been employed during optimization. The step-length has to be determined manually before simulations start. This could be achieved a) empirically, by running several simulations with varying step-intervals and checking which one gives satisfactory solutions, or b) by placing an *Optimizer* loop within the initialization composite that runs test simulations and determines the PITS length causing the least numerical instabilities. PITS would then be kept constant for the whole simulation run.

<u>Note:</u> *A general distinction between physical and numerical instabilities is difficult. An increase with time, though, is a strong hint towards the latter. Also persistent rate fluctuations without any tendency up or down has proved to be an indication of improper PITS selection and often results in the inability of the Optimizer to start-up the well at all.*[39]

A “good” interval-length is generally referred to here as one that shows as little oscillation in rate and pressure as possible. In *Figure 19*, for example, value b) and consequently a PITS length of 12 *sec* would be used:

[39] Discussion with Prof. C. Whitson

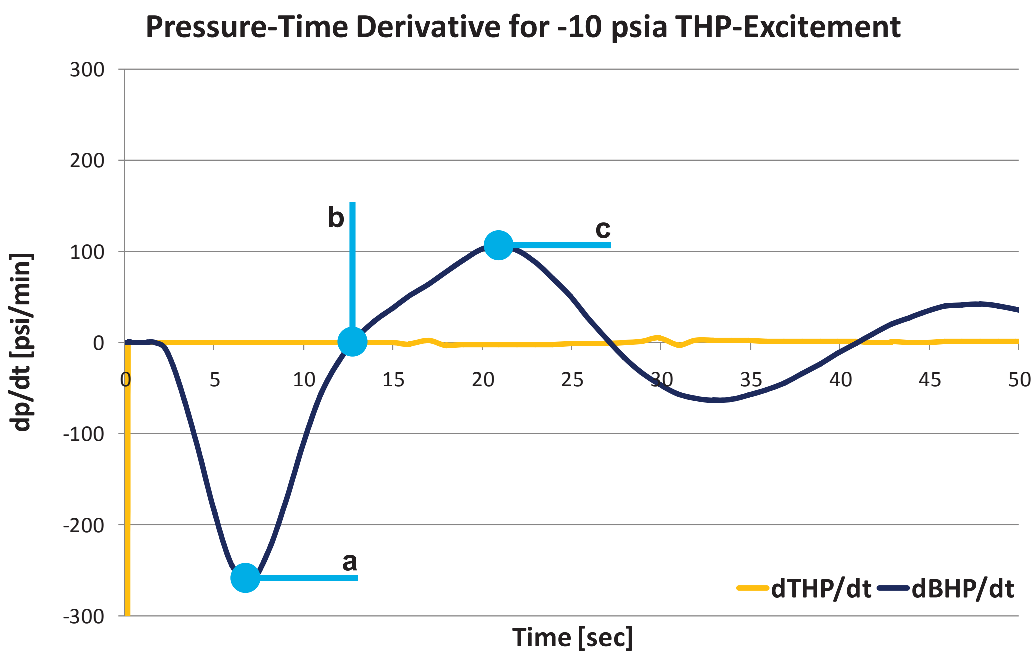

Figure 19: Pressure-time derivative plot during early-phase start-up (-10 *psia* THP excitement)

Unfortunately, the chosen 12 *sec* PITS will not perform equally well throughout the whole start-up simulation. In the final phase of the simulation run (as can be seen in *Figure 20*), the end-of-step information for the same -10 *psia* excitement using a 12 *sec* PITS will result in peak-values instead of the desired average. The late-stage step-length should therefore rather be 15 or 20 *sec*. Apparently, each system has its own preferred oscillation-frequency, dictating the wave-length of pressure- and rate peaks following a THP excitement. This preferred wavelength is then changing as pressure, rates and well-stream composition change. Interestingly, THP changes in a system having already high flow-rates result in instable rate swelling rather than real oscillations (cf. *Figure 20*).

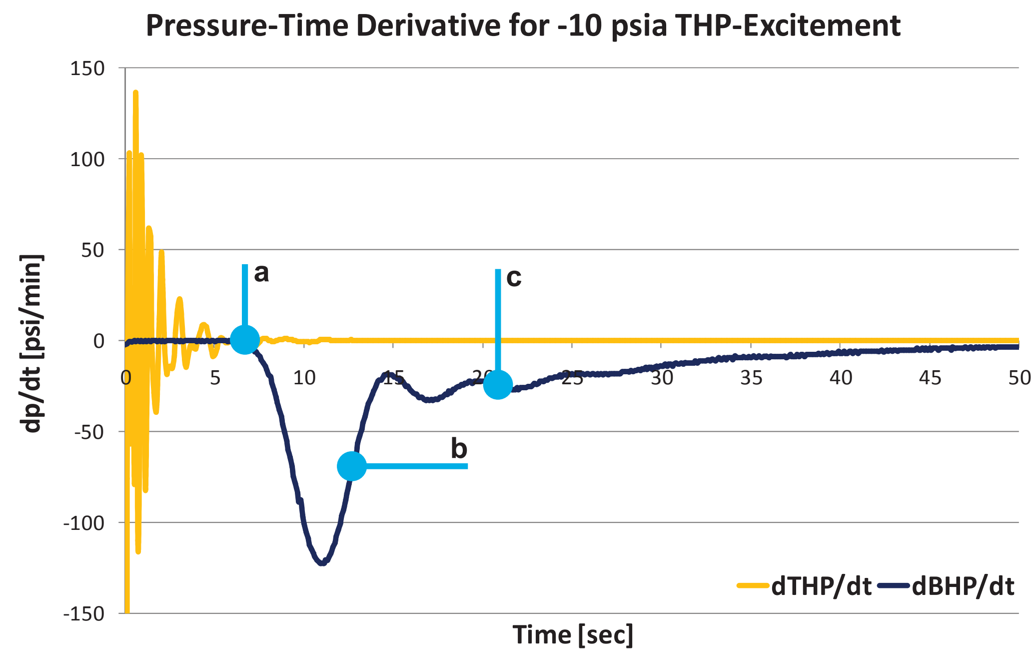

Figure 20: Pressure-time derivative plot during late-phase start-up (-10 *psia* THP excitement)

The early-phase of a well start-up has shown to be especially sensitive to changes in THP and, if not smoothly conducted, will respond with large amplitude BHP oscillations that causing alternating production and injection at the sandface and occasionally even get out of hand. For that reason, a PITS of 13 *sec* has been chosen: it fits very well for the early period and starts to deviate from the optimum only when well has already developed strong and relatively stable flow which is not as easily distracted anymore. This PITS-length has been determined iteratively and will certainly have to be modified if changes are made to any major component of the system.

Choosing too short PITS in the beginning creates an additional problem: Relieving THP at the surface will send an anti-pressure wave down the fluid column. Depending on the fluid composition in the tubing, it will take between 3 and 7 *sec* before reaching the coupling point where the reservoir “feels” the change. *Figure 19* shows that the initially oil-filled tubing has a shorter “reservoir-response time” than the one during near-steady-state production in *Figure 20*. This can be pinned down to the reduction of well-stream density due to the formation of gas as pressure decreases. If, supposedly, a 1 *sec* PITS was chosen, the *Optimizer* would select a ∆THP that it deems right, but there’s no way it can actually know the impact of its decision, since the reservoir would not respond before at least 4 *sec* later and the *Optimizer* is only provided with pressure and rate information from the top- and bottom node and not in between. The time-lag between action and reaction is natural and there is nothing one can do about it except keeping it in mind when selecting PITS length.

7.2 Base case – linear ramp-up

In order to establish a base case, the simplest possible control strategy has been employed: linear THP drawdown with neither optimization nor response to constraint violations. The aim of this is to show the benefit of running lengthy simulations, determining optimal THP settings for each time-step, instead of just ramping up the well with a somewhat conservative pressure drawdown that does not cause dangerous downhole rate and pressure variations.

If, however, a linear THP drawdown is the favoured manner to start the well, then the coupled model at hand is an ideal tool to assess the induced BHP and inflow rate variations and to estimate the maximum rate of THP decline in order not to endanger the completion or near-wellbore reservoir.

Another benefit from establishing a simple scenario like this one is the ability to reflect on likely start-up phenomena and to find out which of these have to be curbed by setting constraints for the *Optimizer*. Furthermore, one gets a feeling about how long the well might take before developing steady-state flow conditions and what rate it can deliver once having reached those.

7.2.1 Starting conditions and simulation

Shut-in THP determined from model initialization with an entirely oil-filled tubing has been found to be 752 *psia*. The desired final surface oil-rate was 4000 *STB/d*, which can be sustained by the present system at a THP of 735 *psia*. The constant enforced slope of surface pressure was -0.25 *psi/min*, resulting in a time needed to take THP down to its target value of 68 *min*. About 20 *min* later, surface oil-rate reached its desired value of 4000 *STB/d*, while the inflow at the bottom-hole node continued to grow for another 20 *min*. The total start-up time was in effect 108 *min*.

7.2.2 Observations

Both, pressures and rates, remain well within tolerable regions. (For more details in terms of which ranges have been deemed “tolerable”, please refer to ch. *7.3* below.) This behaviour can be entirely contributed to the selected THP step height of -0.25 *psi/min*, which is extremely small and does not cause much of a disturbance in the producing system. Nevertheless, it has shown that BHP variations are smooth but at substantially higher with -12 *psi/min*. This value is tolerable but shows clearly that change in THP is completely independent from the one in BHP. Maximum values in inflow and outflow rate increase are a little over 100 *STB/d-min* which is again okay.

Consequently, THP drawdown could be a bit quicker, e.g. 0.3 *psi/min*, in order to push the system to its limits and achieve maximum allowable drop in BHP. Nevertheless, this boundary would only be hit once at approximately one hour after simulation start. This is not likely optimal in terms of minimizing total start-up time; keeping the process close to but beyond the lower pressure-change and upper rate-change constraints is the objective that needs to be achieved in order to start the well up as quickly and safely as possible.

The project in Pipe-It has been constructed such, that the start-up process can be directed towards the aforementioned objectives by the use of a reflection solver algorithm.

7.3 Optimization using fixed PITS

Level 2 of *Pipe-It* project composite *Restart Runs* is responsible for determining the change in THP on a PITS basis, while sticking to constraints and objectives (cf. ch. *5.2.3*).

The CV-“steering wheel” of the coupled model is the change in THP and the “captain” iteratively determining how much exactly to “turn the wheel” is the *Nelder-Mead Simplex Reflection* solver run by *Pipe-It*:

***Optimizer* working principle within each PITS**
The first action taken by the *Level 2 Optimizer* is the definition of a the VAR-type variable ‘∆THP’. Then it get all the information required for running *SENSOR* and *OLGA* for this very PITS (loading AUX-type variables): current time and step, end-of-step pressures, rates and composition from the previous PITS. Having done that, *Pipe-It* will start executing all processes subject to this *Optimizer* – which in our case is *SENSOR*, *OLGA* and then again *SENSOR*. Subsequently, all relevant output information (CON- and OBJ-type variables) is loaded from the models; i.e. SENSOR-rate and –BHP as well as OLGA surface and downhole rates and pressures. This data provides the decision basis for the *Optimizer*’s next ‘∆THP’.

This procedure is repeated over and over again with ever changing ‘∆THP’ until all constraint- and objective functions are satisfied. In case the solver is mislead and/or is not able to converge within a reasonable time, it is stopped after 20 iterations and the best fit solution is retrieved to carry on. No matter whether the convergence is on constraints or on maximum iterations, the best ‘∆THP’ setting is returned to Level 1 and used for the current main-simulation PITS.

Level 1 is furthermore controlled by the *Head Master Optimizer* which retrieves rate and pressure information at the end of each *Head Master* PITS and checks whether steady-state production conditions are already fulfilled.

Constraints
The chosen production-specific constraints are: [$30 < Q_{o,surface} < 10900$ *STB/d*], [$0.003 < Q_{g,surface} < 170$ *MMscf/d*] and for downhole rate change in order not to risk onset of sand production: [$-10 \leq \Delta Q_{o,SENSOR} < +200$ *STB/d-min*]. For securing completion integrity, a limit on maximum downhole pressure oscillations has been set at [$\Delta BHP_{OLGA} < \pm 20$ *psi/min*].

Note: *Boundaries for maximum GOR are not practicable during the first period of the start-up, because for near-zero oil rates, GOR often rises to values in the order of 10x6 scf/STB. This would overemphasize the error on the GOR constraint in the optimization and lead to an irrational and abrupt increase in THP, causing additional physical and also numerical oscillations in BHP and inflow rates.*

To avoid large liquid slugs flooding the test-separator, a limit on maximum increase in surface oil rate has been implemented: [$-10 \leq \Delta Q_{o,OLGA} < +400$ *STB/d-min*] and in order not to fall below the required surface facility pressure THP has to meet the condition: [$THP_{OLGA} > 650$ *psia*]

Additional constraints were required to ensure model stability: The CV range has been defined as [$\Delta THP_{OLGA} < \pm 50$ *psi/min*], while a soft constraint was set as low as [$\Delta THP_{OLGA} < \pm 10$ *psi/min*] in order to keep control activity at the tubinghead low.

Graphical output

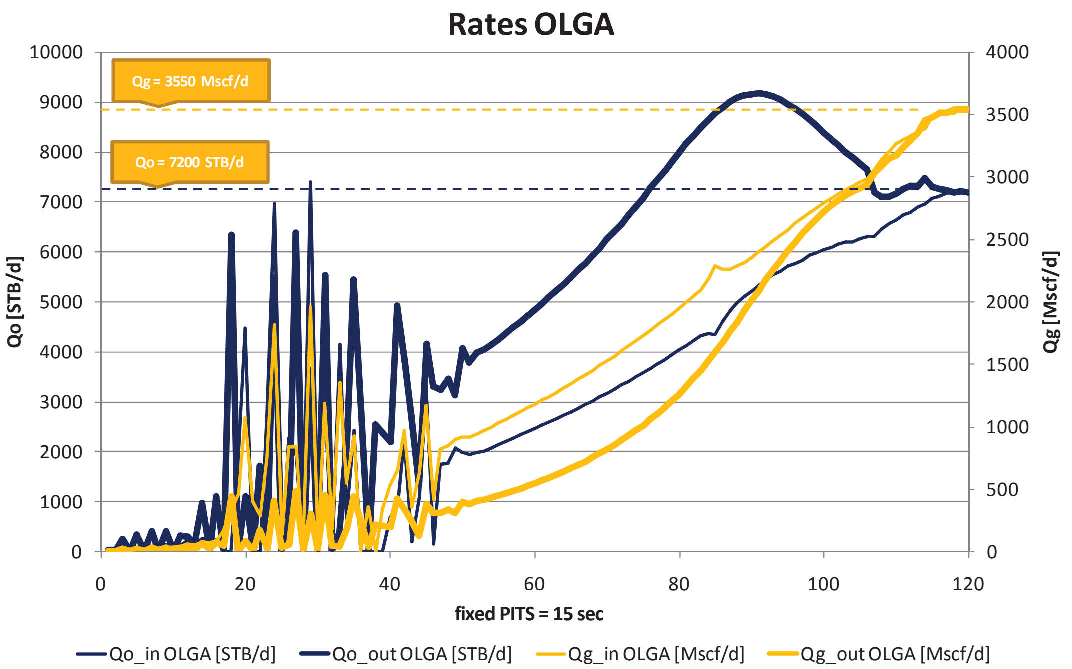

Figure 21: Rate vs. step plot for optimized all-oil/no WC run using fixed PITS

Running a simulation subject to the afore-mentioned constraints and objectives, the result looks like displayed in *Figure 21*. The target-rate in this run was set to 7200 *STB/d* and has been reached after 120 PITS or 30 *min*. The blue lines represent oil-rate in *STB/d* (bold for surface- and thin for downhole rates) and the orange graphs are the corresponding gas-rates, displayed on the secondary axis in *Mscf/d*.

Figure 22 below depicts BHP along with the optimized THP. The sharp edge in BHP at PITS 105 (~25 *min*) is the point in time when wellbore storage effects have almost entirely decayed and the *Optimizer* realizes that a sharp THP-reduction is needed in order to maintain maximization of surface oil-rate. When the *Optimizer* reaches 650 *psia*, which is assumed to be the test-separator pressure, THP cannot be taken down any further and soon hereafter the maximum reservoir flowrate is reached at 7200 *STB/d*.

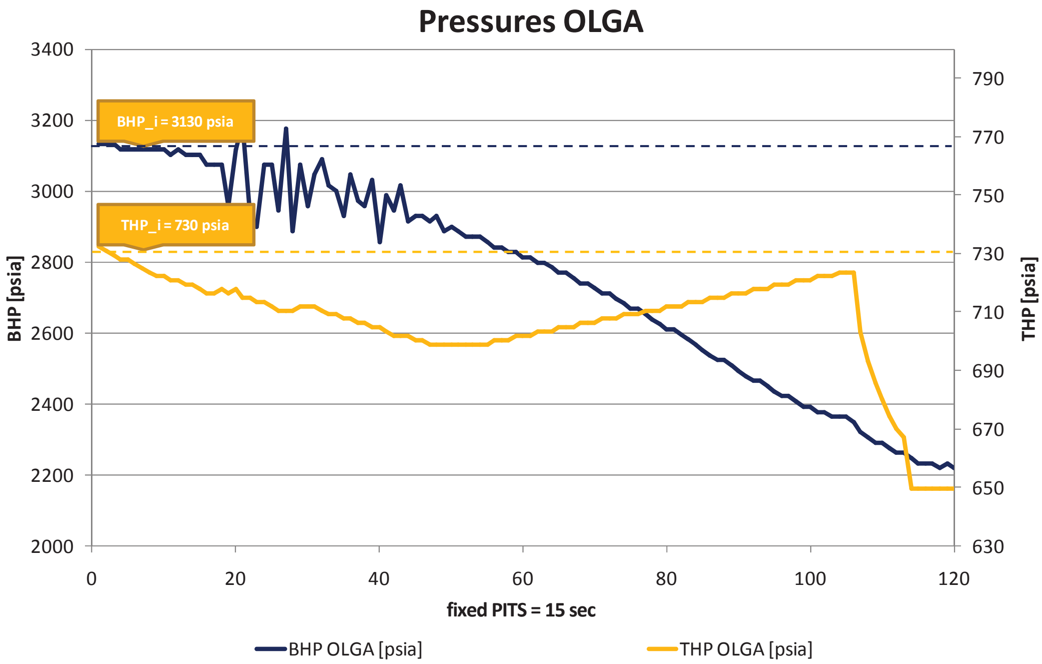

Figure 22: Pressure vs. step plot for optimized all-oil/no WC run using fixed PITS

There is a short interval around PITS 25 where *OLGA* BHP peaks above *SENSOR* reservoir pressure. In these periods, injection would occur, but in the present version of the coupled model, this behaviour cannot yet be simulated.

7.4 Observations from optimized run

Early-phase oscillations
As already mentioned before, the early-phase start-up interval from PITS 20 (~5 *min*) until PITS 50 (~15 *min*) is the most critical period in the whole operation. During this time the well literally comes to life and it does so with heavily oscillating pressures and in effect rates, both at the surface and downhole.

The severity of rate fluctuations is this period is very unsettling and it has been found that they represent physical instabilities, numerically amplified by improper *Optimizer* response.[40] A way of getting rid of those superimposed numerical oscillations is to further improve PITS length selection in a way that end-of-step information is showing averages rather that spikes. This will in effect reduce the *Optimizer*'s hefty response.

(For further information on the issue of selecting PITS length cf. ch. *8.3*.)

Model run stability
Pressure phenomena encountered at the beginning can also be detrimental to the simulation run itself: the oscillations can quickly increase and BHP might reach values larger than 6800 *psi* (47 *MPa*) which is beyond the *OLGA* fluid PVT table, used for this research. Since *OLGA* cannot extrapolate the fluids behaviour to such extreme conditions, the application reports an error and terminates itself. This situation would also cause the coupled *Pipe-It* run to fail, even though it might only happen during a single *Optimizer*-iteration and would not represent an actual simulation step. Therefore, setting a constraint on maximum BHP is not helpful. If such a problem occurs during simulation and the engineer is certain that it reflects the well's physical behaviour, he would have no other option than getting PVT data for a larger pressure range. For the research at hand, one option would have between to manually extend the PVT table, but

[40] Discussion with Prof. C. Whitson and J. Jensen (NTNU-IPT) on Wed, 03.06.2009

there was a risk that the possibly unrealistic assumptions made would have a negative effect on simulation results. To avoid this, the transmissibility of the *SENSOR* grid-blocks representing the two perforated intervals, T_{perf}, has been limited to 0.2 *rb-cp/d-psi*. A physical justification for this is wellbore damage (i.e. near-wellbore skin) induced by drilling- or previous workover activities. The reservoirs deliverability is thereby reduced and it cannot supply fluids quickly enough to generate inflow-pressure peaks higher than 6800 *psia*.

Constraint weighting

During the first *Optimizer*-runs on a new set of constraints, it is recommendable to closely watch the models behaviour. Boundaries intended to be “soft” might be fulfilled at all times, while a constraint essential to operation safety might be continuously violated. If such events are detected, multiplying the constraint function with an empirically determined value will lead to larger absolute violation values and hence get more intention by the *Optimizer*.

While pressure variations in *Figure 21* are – apart from four spikes – in a tolerable range, *Figure 22* clearly shows that rate behaviour is not. A possible reason for this is too loose constraint handling and consequently the weighting was adjusted. Change per unit time in *OLGA* BHP and *SENSOR* oil-rate was multiplied by 100 and 10, respectively, in order to force *Pipe-It* to quit crossing their bounds – successfully as subsequent runs showed.

Experience has shown that introducing too high violation penalties will likely increase the number of required iterations, if a constraint is hard to meet, and in effect total simulation time. Also, an increase in violation punishment does not necessarily help in all cases: in the current set-up, the *Optimizer* is forced to converge after a maximum of 20 iteration runs. Unfortunate step-length selection and/or instable production conditions might in some cases prevent convergence on constraints, even though maximum iterations number was set to, say, 100. This would of course boost CPU time. If the *Optimizer* shows inability to find good solutions within reasonable time and further constraint tightening measures do not help, one has to go find other solutions. Since this problem has been encountered on many occasions, the project set-up has been adapted to variable time stepping, which is treated in detail in the course of the next chapter.

Comparison to base case

As for obeying constraints on rate and pressure, both runs did surprisingly well. This proofs that optimization of the coupled model is able to steer the system within certain bounds. The linear ramp-up case, however, only remained within these constraints due to the predefined small step-change for THP which does not stir the system too much, but results in long total start-up time. The optimized run, on the other hand, was more than three times faster, taking only 30 *min*, compared to the base case’s 108 *min*.

<u>Note:</u> *Both time-spans are not accomplishable in real-life, but only with a system as simple as the one dealt with here which is fine since the concept is to be proven on a generic model.*

Both runs had the same starting and final conditions and optimization took the well from the former to the latter substantially quicker than mere linear start-up, and still achieved excellent constraint adherence (using updated weighting). Consequently, running optimization on a coupled model for start-up operations does a great job in terms of cutting total required time while being aware and in control of critical parameters at the surface and downhole!

8 Optimization using variable PITS-length

As indicated in the reflection on fixed PITS selection of ch. *7.1*, this property bears a large impact on the outcome of the simulation – it can even prevent the model from being started up at all. Relying on manually defined and constant PITS can therefore lead to wrong solver-assumptions and simulation results.

The logical conclusion to this is that selecting an appropriate interval length for each PITS, depending on the severity of changes the system is currently going through, would minimize the risk of obtaining accuracy deviations caused only by varying quality of chosen PITS length. In other words, this means to tell *Pipe-It* when to look for the PITS-end information it would base its current optimization decision on.

In cases where the output function is oscillating, this concept is more resistant towards overreaction to peaks in e.g. *SENSOR* oil-rate. It must be emphasised that physical oscillations do not vanish just because of variable PITS selection! They are still occurring, but remain undetected by the *Optimizer*. This is a compromise one can be willing to take, since also fixed PITS has limited resolution of output data and only captures extremes that coincidentally occur at the end of a simulation-interval. Variable time stepping lets *Pipe-It* “see” only average values, but allows it to detect and follow medium-term (i.e. a couple of PITS) trends.

8.1 Changes to the existing system

The optimization of PITS length has been implemented on a restart iteration basis, i.e. in *Level 2* of the composite *Restart Runs*. The constraints to which step selection is subject are the same as those chosen for determining the appropriate THP change. The criterion is therefore based on maximum change of input variables and in effect employs a method very similar to the one *SENSOR* does by default. As expected, the newly added second CV is not entirely independent from delta-THP, which impedes optimization to some extent. Therefore, the number of allowed iterations has been increased to 30. Analyzing required iterations during a whole start-up simulation showed that also 30 is a too low number, because the *Optimizer* would exclusively converge on maximum iterations – not a single time below that. But it also showed that results obtained are very good in terms of constraint adherence and allowing more runs per PITS would extend total simulation time substantially, without gaining much in result quality.

<u>Note:</u> *OLGA selects its internal time-step somewhat different from SENSOR. Not a change-type criterion is setting maximum step length, but the so-called “Courant-Friedrich-Levy“ criterion, which is basically limiting maximum time-step to the time a fluid particle requires for transiting a numerical pipe section.[41] As a result of this concept, OLGA runs increase substantially in time when flowrates and -velocities pick up. If the user wishes to do so, there is in both simulators a possibility to enforce fixed time-step lengths or to limit maximum and minimum step intervals.*

The upper limit for PITS in the early start-up phase has been set to 20 *sec*, in order not to get a too blurry picture of the transient events and the lower one is determined to be 5 *sec*, to ensure that the change in THP can show its effect at the coupling point. Simulations have shown that *Pipe-It* would not choose PITS smaller than 10 *sec* and, if allowed to do so, also not larger than 20 *sec*. Due to the fact that the system’s agitation caused by step-like THP-adjustments is most severe in the subsequent first seconds, *Pipe-It* would seek to avoid those by choosing PITS larger than 10 *sec*.

[41] (SPT Group AS, 2009 ch. ‚Numerics‘)

This new way of setting step intervals is taking most of the burden away from the *Head Master Optimizer* and shifts it to the one controlling the *Restart Loop*. This is necessary, since the same PITS length determined as best fit in the *Restart Loop* has to be employed on *Level 1* as well. Previously, the *Head Master* would read time information as an AUX-type variable at the beginning of each step and only then consult *Level 2* for its optimization. Since this optimization newly also comprises PITS changes, which take place only after the *Head Master* has already read and updated time in the main simulation input files, time will have to be handled entirely in *Level 2*. Consequently, the *Head Master* will no longer read current time- and step data at the beginning of a new PITS, but will be handed it from *Level 2* along with information on new THP settings. The only properties remaining in control of *Level 1* are end of start-up criteria on rate and pressure, including the corresponding constraints on time derivatives and updating *TimeStep.dat* after each main-run PITS.

The results obtained from this approach are a lot smoother than those with fixed PITS and sharp rate spikes in whatever direction are largely eliminated. Comparing *Figure 21* and *Figure* 22
(p. 37 et seqq.) using fixed PITS with *Figure 23* and *Figure* 24, respectively, below, gives a clear impression of the benefits coming along with variable PITS. (It must be pointed out in this context, that target rate for the variable step run has been reduced from 7200 *STB/d* to only 4000 *STB/d*. This does not affect results obtained from the early-phase simulation, which is the period we want to focus on.)

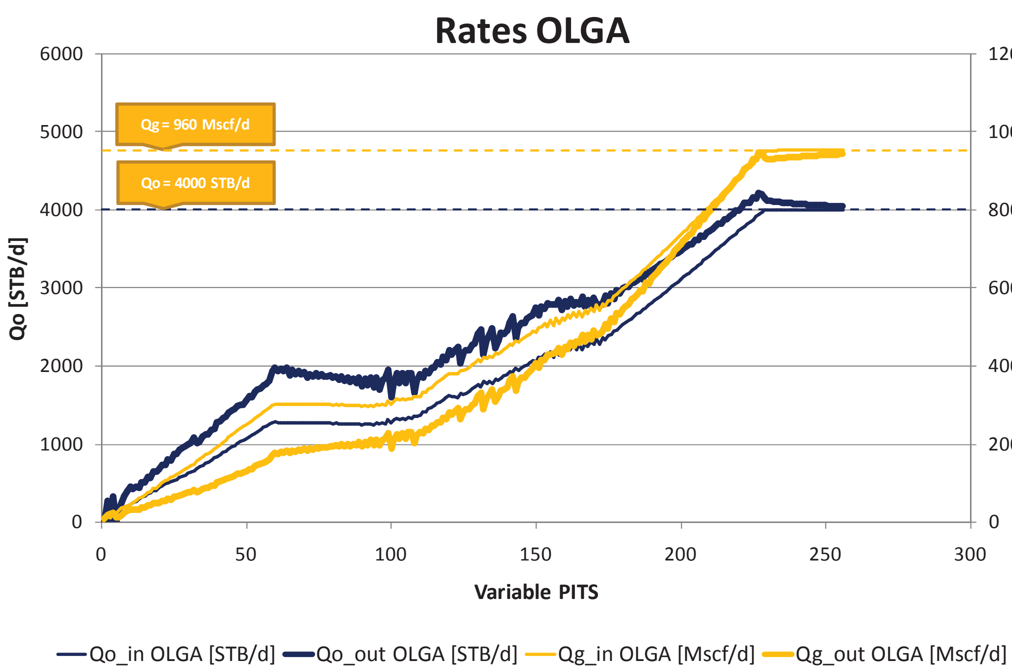

Figure 23: Rate vs. step plot for optimized all-oil/no WC run using variable PITS

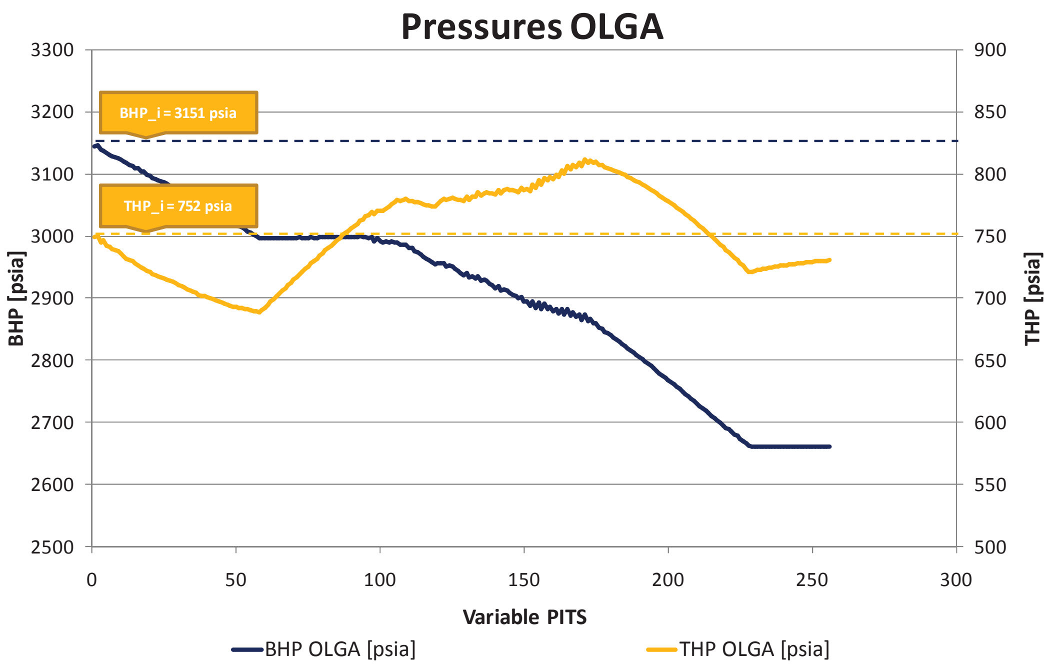

Figure 24: Pressure vs. step plot for optimized all-oil/no WC run using variable PITS

8.2 Observations

PITS length

The rate plot gives a very good example of the impact PITS selection bears on THP control: unlike in *Figure 21*, large oscillations – i.e. physical instabilities, numerically amplified – are entirely absent in *Figure 23.* There are, however, two intervals where the otherwise stable growth in flowrates comes to a sudden halt or shows fluctuating behaviour: PITS 60-105 and 150-170. (To enhance clarity, these sections have been shadowed in the upcoming plots.) There is no obvious explanation to that when looking merely at downhole- and surface constraints in rate and pressure. The only striking observation is that exactly during these periods, PITS solution seems to be trapped at 20 *sec* (cf. *Figure 25*). This results in virtually fixed PITS interval length in a position returning near-peak – and definitely positive – rate and pressure values. Letting the solver move towards smaller PITS will bring the output even closer to the peak which is undesirable. Therefore, PITS is “locked” at 20 *sec* and the solver keeps THP change in positive realm, causing the stagnation and sometimes cutback in oil-rate. Consequently, maximum PITS length has been reduced to 19 *sec* to avoid this problem, which has shown to be an effective measure.

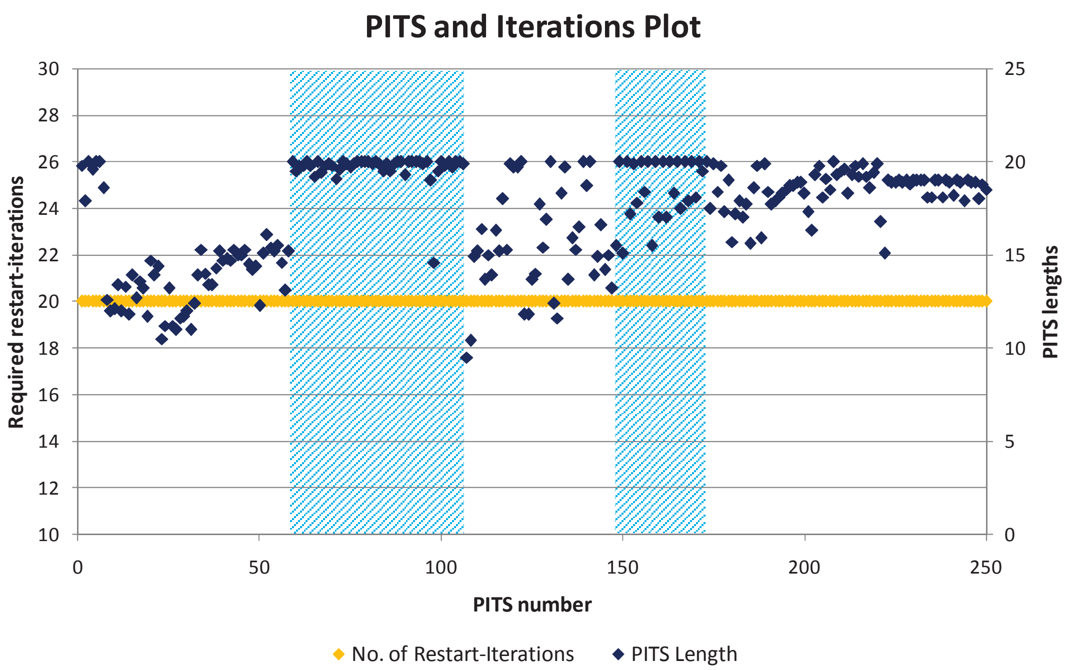

Figure 25: PITS and iteration-count plot for Restart runs

In the other periods, when PITS selection is actually "active", letting the concept to show its full advantage and achieving high start-up efficiency. Selected PITS length was in the range from 10 to 15 *sec* in the first minutes and would end up between 15 and 20 *sec* towards the operation end. This is proof of the assumption that using fixed PITS length while obtaining equally good results throughout the whole simulation run is not achievable. Variable and *Optimizer*-controlled time-stepping is the only solution to this problem and has therefore been employed henceforth.

<u>Note:</u> *The only question mark remaining lingers on the objective for PITS optimization. As mentioned, currently those set up for determining optimum change in THP are applied, which is a concept that might need some adjustment or possibly even replacement.*

Constraints

Pressure boundaries have hardly ever been violated – besides during the second "PITS-locked" period after step number 150, where strong variations in THP and in effect BHP and rate have been recorded. Nevertheless, ∆THP has hardly ever exceeded its predetermined range of ±10 *psi* (cf. *Figure 26*). Therefore, a further increase in penalties for violating ∆BHP constraints was necessary, resulting in heavier ∆THP-agitation. Allowing more iteration in the *Restart Loop* will also give better results in terms of obeying ∆BHP bounds. It is strongly advised to take such measures in order to curb ∆BHP spikes – this is the property controlling inflow variations at the sand-face, which are, besides ∆BHP as such, the main source for problems during well start-up.

Rate-wise, there are a few large spikes in surface oil-rate between PITS 100 and 150, without any preceding irrational THP change that would justify these (cf. *Figure 27*). An explanation could be physical instabilities in the model which *Pipe-It* was not able to compensate, due to limited allowed iterations. Also the fact that constraints in downhole rates are backed-up by harsher penalties, than those at the surface, has contributed to letting these runaway values emerge: the *Optimizer* would not induce sharp inflow increases to make up for outflow cutbacks. Increasing constraint-violation punishment for surface oil has not been implemented as a remedy for those spikes. By doing so, one would inevitably reduce priority of downhole constraints which is clearly unwanted. For now, no specific counter-measures have been taken to reduce those few rate peaks, because they have always been preceded by even sharper drops in rate and constitute not an actual jump but more a one-time variation and are not likely to pose a security risk.

Generally, both, surface and downhole flowrates, have been kept almost entirely within the desired positive terrain which has been set rather conservatively, as discussed in ch. *2.5*. During the “PITS-locked” phases however, rates jumped below the bottom boundary quite frequently – a result of the bad choice in PITS which caused faulty ΔTHP decisions.

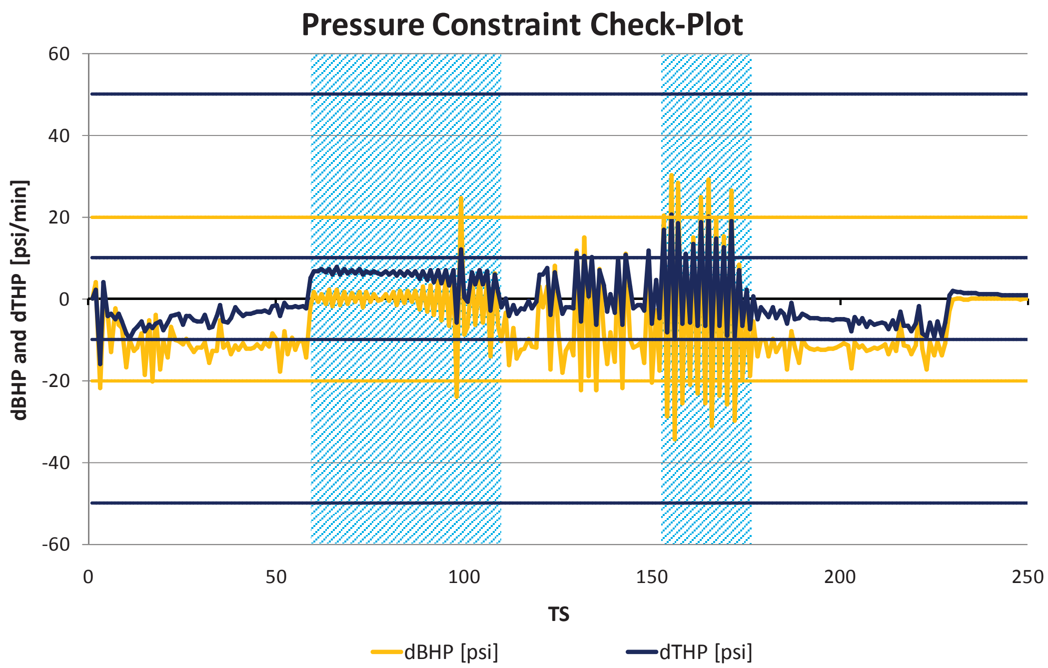

Figure 26: Pressure constraint plot for variable PITS run

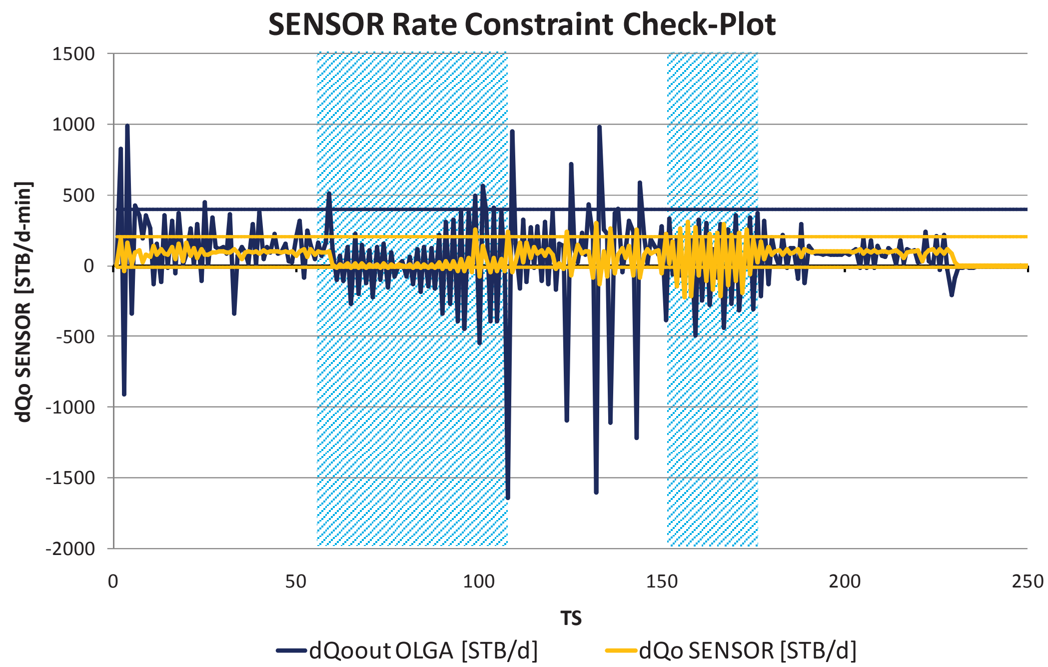

Figure 27: Rate constraint plot for variable PITS run

Total start-up time

The time required for bringing the well back on production has been 75 *min*. This is a very competitive result considering the trouble *Pipe-It* had within the “PITS-locked” phases and hence loosing approximately 10 *min*. On the other hand, the target-rate is 4000 *STB/d* which is only half of what the reservoir could sustain with the given well configuration at minimum THP of 500 *psia*.

Comparing to real-life start-up times of sometimes five, ten, twenty hours, the result obtained from the coupled model is nowhere near that. The reason for that is three-fold: a) the system we are looking at is as simple as it can possibly be and so are the occurring phenomena and their interaction. Having inclined or horizontal production intervals, long surface flow-lines or high GOR will substantially prolong total simulated start-up time.[42] (Such characteristics can be later-on included in the model, without much further effort.) b) In real-life systems having a known sensitivity towards sand-production, the start-up operation must be conducted very slow and cautious, because the engineer does not know what is going on downhole. Therefore, more time than needed is taken, in order to be on the safe side. c) Last but not least, the objective of bringing a well back on production in the first place, by using a coupled reservoir-wellbore model, was reducing total start-up time.

Simulation-time

Simulation-time, on the other hand, is a whole lot of a different story: when using variable PITS in combination with a surface-oil maximization-objective, full utilization of allowed iteration in the *Restart Loop* results in a CPU runtime of six to eight hours, which is clearly rather long. Given the current system set-up, options to speed up the process are limited. Less iteration would compromise the result-quality; a more powerful CPU to run on is definitely an option; so is a change in the optimization structure to allow separate determination of PITS which could also bring down total simulation runtime. As an attempt in this direction, a concept of replacing the objective function with a combination of inequality constraints has been tested – with success, as discussed in section ‘Simulation efficiency’ below.

Production overshooting

The problem of production overshooting is an especially big issue when starting-up high-rate wells. The whole well-stream is piped through the test-separator and then through disposal facilities. The maximum phase rates this system can take determine the highest allowable production overshot. However, the limit will be set lower, because this phenomenon occurs in the last phase of the start-up operation, when wellbore clean-out has – hopefully – been successfully conducted and hence every barrel of oil produced too much here is essentially wasted money. Nevertheless, one will allow exceeding Q_{target} to some extent, because this course of action will lead to quicker late-phase increase in downhole inflow-rates, which are generally behind outflow during start-up, and hence will result in shorter required total start-up time.

[42] Discussion with Prof. C. Whitson and Prof. M. Golan (NTNU-IPT) on Fri, 12.06.2009

An extreme example of banning production overshooting is shown in *Figure 28*:

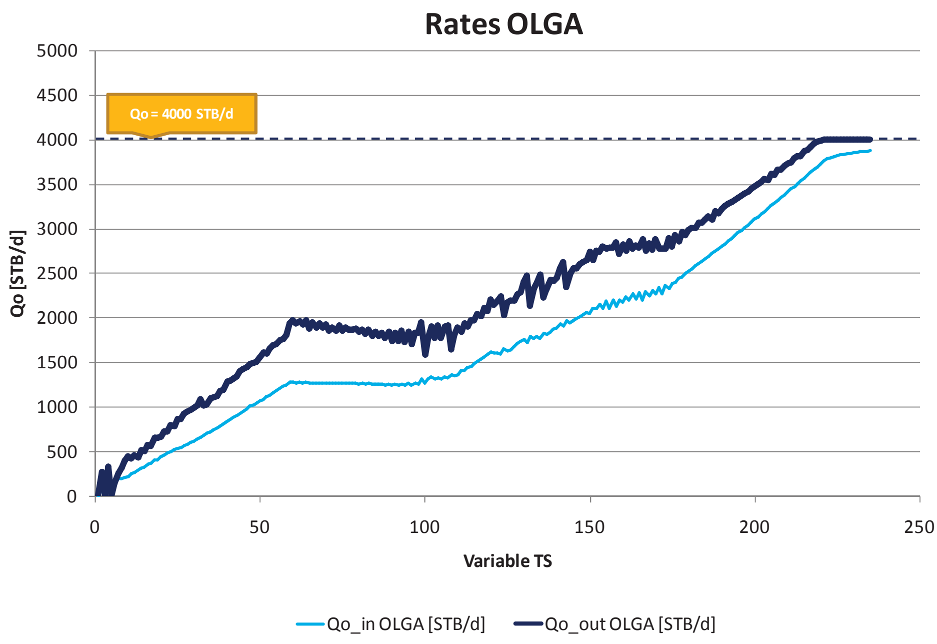

Figure 28: Downhole- and surface oil-rates with no production-overshooting

In this case, exceeding target surface oil-rate of 4000 *STB/d* has been entirely prohibited by introducing a large penalty. It shows that in the last phase, once surface rate has reached its target, considerable time is spent on waiting for the reservoir to pick up. As already mentioned, a compromise has to be made between lost production and total start-up time. Practically at this stage, the operation can be considered as accomplished, since volumes entering the platform facilities will not change anymore. However, there will be ongoing adjustment in THP required before inflow from the reservoir has reached its final constant rate. In order to enable *Pipe-It* to sufficiently curb surface rate and overshot it must be given an appropriate range in ΔTHP that it can exhaust.

The optimum in terms of minimizing lost production has to be determined separately and can later-on be implemented in this project by setting soft constraint on Q_{target} and a hard one on maximum overshot. Determination of this balance is facilitated by having a coupled model, which helps in optimizing allowed overshot with respect to total start-up time and “lost” well-stream.

In cases where the wellbore cleanup is completed and the well is put online before reaching its desired target oil-rate, balancing overshot and start-up time will not be an issue and consequently the allowed excess in surface rate will be zero.[43]

Simulation efficiency

The optimization approach chosen here is quite time consuming, because each single PITS has to be simulated up to 20 times. There are, however, several ways to improve simulation efficiency and bring down total runtime. In the following, a short reflection on these possibilities shall be given.

– **With short time-steps**, transferring and writing data to file makes up for the biggest portion of total simulation time. It is rather difficult, though, to speed up these processes without compromising on the amount of recorded data. It is a matter of how quick *LinkzUtil* works which lies in the hands of the developer of *Pipe-It*, who already has been and still is improving the application. The number of values transferred from

[43] Discussion with Prof. C. Whitson and Prof. M. Golan (NTNU-IPT) on Fri, 12.06.2009

SENSOR to *OLGA* and vice versa is vital to the coupling procedure and cannot be further reduced.

– **As PITS length increases**, the above-mentioned procedures become less significant. *SENSOR* and especially *OLGA* take increasingly more run-time with longer PITS. Here, economisation mainly aims at cutting model complexity. Lowering the number of active reservoir grid-blocks as well as tubing sections and wall layers in the pipe-model will lead to shorter run-times. As mentioned before, such actions compromise the simulation result accuracy and have to be undertaken with care. Using simplified models only in the restart runs would also help to raise efficiency. Unfortunately, both, *OLGA* and *SENSOR*, do not allow system properties different from those in the restart-file. In the coupling strategy discussed here, this would have to be the case and therefore the same model set-up has to be employed for *Restart*- and *Head Master* Runs.

– The **optimization procedure** also leaves some space for time reduction: e.g. lowering the number of maximum iterations of restart runs and implementing a way of increasing PITS length to 60 *sec* or more once stable flow conditions are established.

  Using constraints as “pseudo-objectives”, like setting unreachably high lower constraints for Q_o, will cause the *Optimizer* to always exhaust the maximum allowed number of iterations, which will significantly increase total simulation duration. Selecting constraints that curb irrational oscillations is inevitable in the early start-up phase and the *Optimizer* will have to try hard in order to stay within these constraints. They shall, however, be selected such that they can be fulfilled with few iteration once in the stable-flow phase. A wisely chosen number of maximum iterations for the restart runs can be determined by checking whether the optimization is mostly within the constraints and iterations generally do not exhaust this maximum number. If they do and results are still not satisfactory, the *Optimizer* might need some more trials and more iteration should be allowed (but apparently this does not always help).

In order to find the appropriate balance between short run-time and sufficient accuracy, sensitivity analysis, trial and error and, to some extent, experience of the user are required.

8.3 Concluding remarks on PITS selection

Both approaches for choosing step-length incorporate certain flaws, which leads to the conclusion that this topic needs some more consideration. It is undisputed, that the simulation and, above all, optimization results are not to be compromised by a wrong PITS-selection method. Creating a mechanism that combines only the virtues of both strategies seems to be the optimum solution.

Using fixed PITS requires less CPU power and hence reduces total simulation time. Nevertheless, this method requires several trial-and-error runs in order to find out what step-length is best, and even then production conditions might change such that numerically amplified oscillations get out of hand and prevent the *Optimizer* from starting up the well. A variable PITS selection, however, has the big disadvantage of showing only trends and veiling peak values. This can be dangerous and may lead to wrong assumptions. The good thing about this strategy is its convergence stability (accompanied by increased total simulation time) and the possibility of implementing a single objective that continuously underlies determination of PITS. The nature of this objective so far has been to stick to limits on maximum allowable change in output parameters.

It is important to create a fully automated and robust mechanism for selecting PITS length:

a) Variable PITS with separate peak-detection
The currently employed concept of selecting PITS variable on a *Feedback*-iteration basis is maintained, while *OLGA*-output, based on its internal step-length, is checked for outstandingly high or low values. Thereby, convergence stability is maintained, while extremes are made visible and can be incorporated in the solver reflection process. The objective in respect to what is an “optimum” step-length is still limited change in output-parameters from one PITS to another.

b) Variable PITS from one ‘Head Master’ step to the next, but fixed within
To also tackle the problem of excessive total simulation time, one can implement a mechanism capable of separately determining optimum PITS length at the beginning of each *Feedback Loop* iteration series. This PITS is then to be kept constant for each of the upcoming iterations. Only when the *Head Master* has taken the simulation one step ahead, PITS length would be re-evaluated. This second approach requires quite some work reconstructing the current *Pipe-It* project, but enables the user to define an objective for seeking the best PITS, different from the one used for determining optimum delta-THP. Consequently, the aforementioned “peak-detection” process could be replaced by selecting a PITS length that gives the maximum change in output parameters for a given input excitement. Step-lengths would then be mostly in the range of 5-10 *sec*, which is rather short and result in a relatively high “*Pipe-It* overhead” portion in simulation time. Instead, it is recommendable to simply take out the part solving for optimum PITS by running a three-iteration test-run, e.g. with a theoretic delta-THP excitement of -5 *psi*. This would determine the producing system’s mentioned preferred frequency and hence constantly give an optimized PITS.

Note: *Maximum allowed iteration as little as three in the PITS-step is justifiable, because the Pipe-It Optimizer would look for values close to the previous run’s optimum and the best step-length does only change very little from step to step.*

After PITS length has been established, the *Feedback-Loop* can proceed to business as usual and iteratively determine the optimum delta-THP, using the same PITS throughout the whole sequence (cf. *Figure 29*):

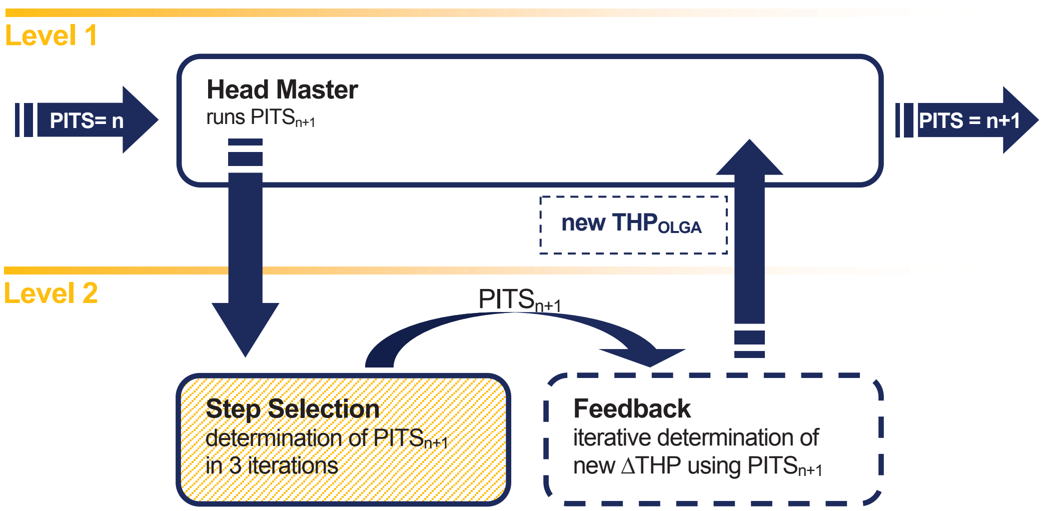

Figure 29: Concept of separate PITS selection within composite “Restart Runs”

Method **a)** basically improves the concept of variable PITS selection and still requires heavy CPU-usage, while approach **b)** combines the virtues of fixed and variable time-stepping, runs quick but requires a new *Restart-Loop* setup. Both methods would perform better than strictly using fixed or variable stepping, but the fact that in **a)** variables delta-THP and PITS are run in one optimization operation and are obviously interdependent, leads to a clear recommendation of PITS selection-strategy **b)**.

9 Verification of results

Verification of obtained simulation results is one of the most important aspects of any research work and, hence, also with this one. Even though strictly generic, the applicability of the system presented here relies on the proven physicality of the coupled model.

With processes as dynamic and complex as well start-up, the amount of work required for proper verification is especially large and there is no doubt that the greater part still remains to be done. For the time being, a qualitative comparison of simulation results with real production data has been carried out and the obtained pleasing results clearly indicate the model's capability for simulated optimization of well start-up operations. As a side-effect, this analysis provided a good feeling about the dimensions and ranges of certain parameters and in effect helped with defining reasonable constraints for optimization runs.

9.1 Real field data

Four oil wells from a Norwegian Sea production platform operated by *StatoilHydro ASA* have been selected. Available rate and pressure data was thereby of particular interest. All wells are strong oil producers with low WC and GOR. The set of data has been kindly provided by *StatoilHydro ASA* – for corporate non-disclosure reasons, any reference to it made in this paper has been scaled and units have been removed. Behaviour of the four wells during start-up was fairly similar and hence only one well was used for graphical demonstration in *Figure 30-Figure* 32:

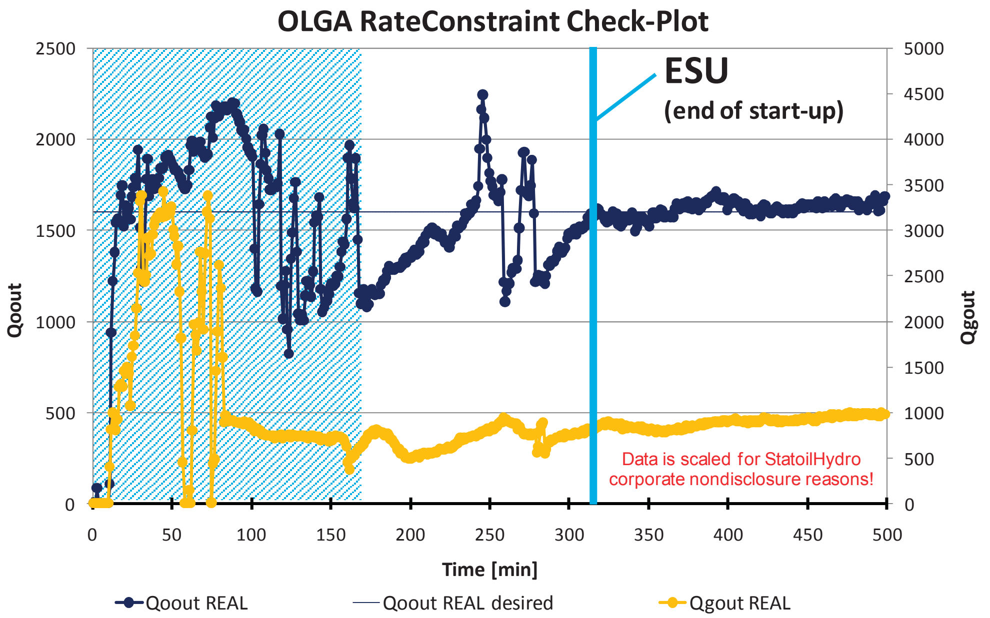

Figure 30: Real reference well data – surface rates vs. time

When looking at surface oil- and gas rates during start-up (as shown in *Figure 30* above), it becomes obvious that early phase flow is indeed instable and jumpy. This finding confirms what has been revealed in simulations using fixed PITS (cf. ch. *7.3*). Required control activity is highest in this most sensitive start-up phase and heavy oscillations only vanish after almost three hours (light-blue shading). In the subsequent data sections (from 170-250 *min* as well as 270-320 *min*) a steady rate increase has been achieved – again going hand in hand with simulation results, where flow has been found to stabilize in the second half of the operation.

End of start-up (ESU) has been reached after 5.3 hours, which is substantially longer than the time required for running the coupled model. However, this discrepancy results from the fact that well geometry is much more complicated in the reference well than the one in the simplified model which has a strong impact on total start-up time. From an operational standpoint, rate increase in the beginning was too sharp, resulting in early and severe production overshooting (>25 % above target rate) and also worsening flow instabilities, requiring longer time to calm down and effectively delaying ESU. Besides that, one major objective of optimization is to reduce total start-up time anyway.

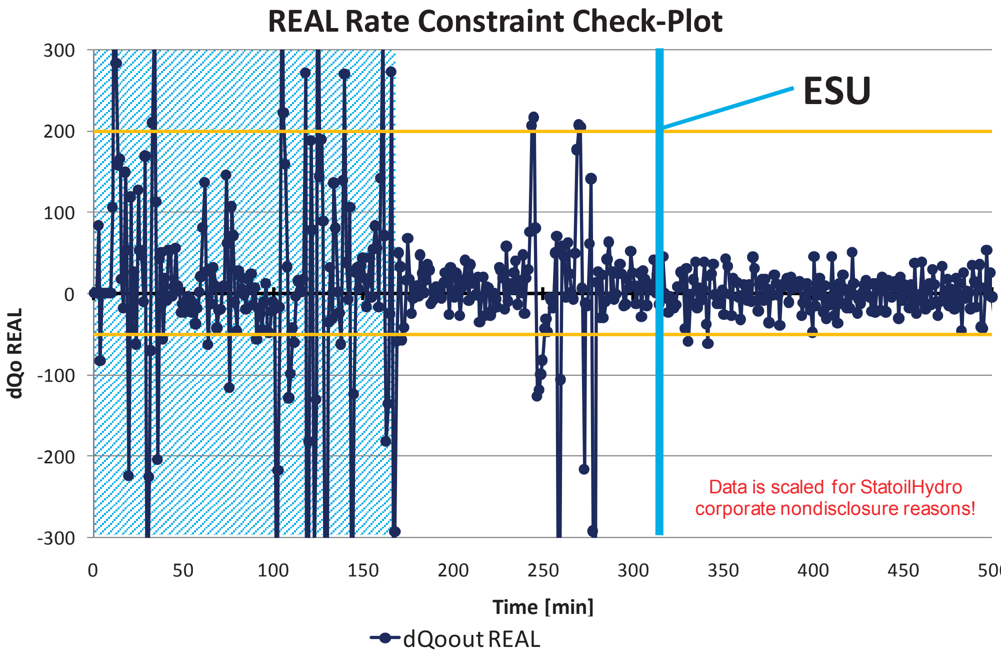

Figure 31: Real reference well data – surface oil rate time-derivative vs. time

Further analysis on surface oil-rate is possible when plotting rate changes per unit time over time (cf. *Figure 31*). Absolute change in flowrate from one measurement to the next is revealed in this depiction, showing large fluctuations in the beginning and especially from 100-170 *min*.

The boundaries for maximum and minimum values in rate change used in optimized simulation runs are marked by orange lines. It shows that the operation has been maintained largely within these limits. Nevertheless, one outlier alone can already cause severe problems and optimization in *Pipe-It* is capable of preventing this. Setting a more stringent constraint on maximum rate-increase (e.g. +100 [*volume/time*]) will further increase the necessity of a computer model. While positive spikes can potentially damage surface equipment, negative ones indicate a temporary production decrease and, if occurring regularly, oppose the objective of consequent rate growth during start-up and lead to unnecessarily long total operation time.

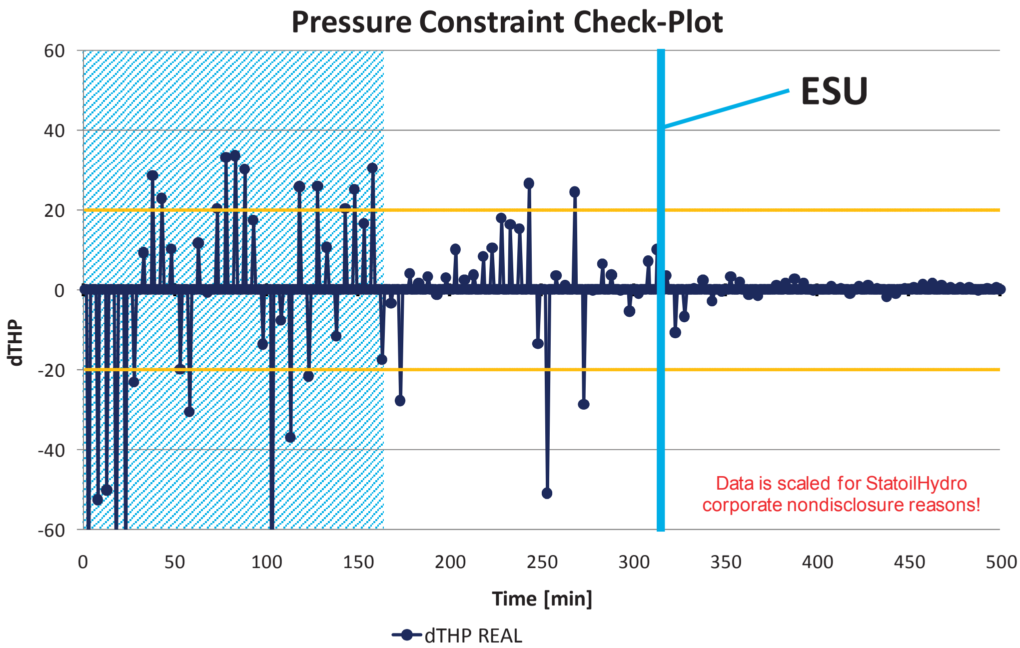

Figure 32: Real reference well data – THP time-derivative vs. time

An analysis of tubing head control activity – i.e. change in THP per unit time (cf. *Figure 32*) – reveals that boundaries for the respective *Pipe-It Optimizer* VAR-type variable (orange lines) have been chosen appropriately. Violations would have occurred mostly in the beginning which is likely a result of a too impetuous first wellhead choke excitement and could have been avoided by planning the operation with a good coupled reservoir-wellbore flow model.

As already mentioned above, a verification process as superficial as this one is not sufficient for being able to take the concept to the field. Both, available time and scope of this project prevented the author to do more work on this extraordinarily important subject. What can be concluded from a qualitative data comparison is, however, that the coupling approach suggested in this paper is capable of simulating well start-up scenarios and yielding realistic results. The main objective of the project's first stage as presented is hereby proved: coupling a reservoir- with a wellbore model can be done and *Pipe-It* is a software package capable of doing it.

What remains to be done in terms of model testing is a thorough quantitative comparison with good field data. For that matter, the *SENSOR* and *OLGA* models need to be accurately adapted to and separately tested against the real-life system in question. Only then, the coupled model can be compared with well-test data from this reference well, involving real rates, pressures and temperatures for surface and downhole. Possible flaws of the coupling strategy can then be revealed and eliminated.

10 Further methods for coupling and control

In practical applications, simulation speed is a critical issue: for research purposes it might not matter if 1 *min* real-time requires 10 *min* to simulate – in the field, however, it certainly does. Even though for model construction and verification a system that actually runs both, *SENSOR* and *OLGA*, will most likely be required, there are still other possibilities of constructing a model that can then be used by a model-predictive controller (MPC) or an engineer designing start-up schedules. "Model coupling" does not necessarily mean that both models have to be executed during each time-step. One can also use one of the models to create tables accurately reflecting their behaviour and use those as an input for the remaining simulator. Furthermore, there are concepts that actually do run both models, but use an entirely different optimization approach.

In the following, ideas of further concepts to achieve prediction of well start-up behaviour and optimizing this procedure shall be discussed.

10.1 Control with *SENSOR* BHP

Currently, the coupled model is optimized by changing THP-setting. During a discussion with Prof. Whitson at the NTNU Petroleum Institute, he pointed out that control could be taken from the surface to the sand-face[44], i.e. replacing delta-THP with delta-BHP as the CV. This approach is in contrast to what can be done in field applications, where direct manipulation of BHP is hardly ever possible (except when inflow control devices are installed), but constitutes a viable method for setting up optimized start-up schedules. Delta-THP is obtained from the optimization as a "controlled" output variable and can be used subsequently for establishing choke-opening schedules for well start-up.

Normally, downhole conditions pose the biggest obstacles in start-up operations and hence define limits to maximum rate-increase and also incorporate the largest potential for severe problems. This concept makes it easier to push the limits in terms of maximum start-up speed, while largely excluding the possibility of violating constraints on BHP-change: the *Pipe-It Optimizer* would not allow changes on BHP greater than predefined limits, while inflow-rate and -velocity fairly linearly relate to pressure and hence becomes easily controllable. On the flip-side, maintaining surface fluid quantities as well as THP fluctuations within facility capabilities will become more difficult. Nevertheless, fluctuation tolerance is mostly larger at the surface and can also be artificially increased if needed, which is not possible with e.g. formation fracture resistance.

Implementing this concept in *OLGA* will require some mayor changes because the whole *Pipe-It* project is currently built on the assumption of having a massflow-constrained node at the bottom and not a pressure node. As one cannot have both at the same location, also the wellhead node must be changed. Inevitably, this would take out the system's capability of capturing wellbore-storage effects: the phase volumes provided by the reservoir simulator can now be delivered to *OLGA* only as desired outflow at the surface, which neglects occurring rate variations from in- and outflow. In cases where gas part of the well-stream, a compromise like that can have a large influence on result accuracy, which needs to be estimated to find out whether one can tolerate it or not. Generally one can expect to have no trouble in all-oil applications, while wellbore storage effects are likely to become more evident with increasing GOR. They constitute an important transient phenomenon and when occurring should – if at all possible – be captured in order to maintain the models usefulness.

[44] Discussion with Prof. C. Whitson (NTNU-IPT) on Wed, 03.06.2009

<u>Note:</u> *Having the SENSOR model run on rate-control – instead of BHP, as it is currently done – can help to reduce the negative impact of neglected inflow-outflow difference: the model-sequence within the 'Restart Loop' is first SENSOR then OLGA and then again SENSOR. Maintaining this structure, the first SENSOR run is using a target oil-rate equal to the previous PITS' OLGA inflow-rate and an unreachably low target BHP.*

10.2 Predefined pressure or rate function

This concept takes out the necessity of running restart-iterations on a PITS basis. The only thing required is a general idea of how THP, BHP, inflow- or outflow rate is desired to develop over the course of a well start-up. This trend-curve can then be expressed by a mathematical function, comprising a set of tuning parameters *A, B, C...* . These parameters would serve as CVs during the optimization and remain constant during a complete start-up simulation run. An *Optimizer* loop positioned on top of the *Head Master* is in charge of updating the CV-parameters in order to meet the given constraints and objectives. Also an active control on total start-up time becomes possible with an approach like this, which can be implemented as a further variable, similar as in the fixed PITS concept described in ch. *7.3* above, or as an OBJ-type variable in *Pipe-It* with the objective of minimization. Either way, finding the minimum required total start-up time will have to be conducted with a fixed total number of PITS, while the length of these is defined as a variable.

The time and effort required to adapt the system to this new strategy is, however, tremendous and compares to creating an entirely new project. The reason for that is the necessity of an application that can scan a whole start-up record data-set for constraint violations. If this is achieved, however, still a lot of restart-iteration will be required if several parameters are used for tuning. Simpler functions may yield results quickly, but in these cases, the optimum is likely to be limited to short "bottleneck" periods and during the rest of the time the well would be operated too conservatively.

Nevertheless, simple mathematical expressions could very well be used for splitting the whole start-up operation into e.g. ten or hundred time periods, while optimization within these is treated separately in one piece. Those time-intervals compare to super-PITS, comprising many normal PITS, and the more of those super-PITS are chosen, the closer the obtained solution will reflect the optimum, while the fewer tuning variables are used, the quicker the *Optimizer* will converge.

Examples for simple pressure and rate functions
When using tuning of mathematical functions as an optimization strategy, it is advisable to do that for parameters active rather close to critical system properties. In other words, BHP and inflow rate would be used instead of THP and surface-oil, respectively, in order to increase the probability of the *Optimizer* to converge on constraints. As previously indicated in ch. *10.1*, enforcing BHP at the bottomhole inflow-node requires compromises, due to an inability of capturing wellbore storage effects. In cases where this is not an option, BHP-functions may as well be used for describing THP, while granting *Pipe-It Optimizer* additional iteration leeway.

The first option here is to use simple, single-parametrical functions. *Figure 33* gives four examples of such models with **a)** being a linear, **b)** an exponential and **c)** as well as **d)** monomial BHP- (or THP-) function:

a) $BHP = BHP_{shutin} - A * t$

b) $BHP = BHP_{shutin} - A * t^2$ 10.2-1

c) $BHP = BHP_{shutin} - A * t^4$

d) $BHP = BHP_{shutin} * \exp(-A * t)$

Eq. *10.2-1* **c)** and **d)** are especially suitable for modelling pressure because they generate little change in the beginning – the unstable early start-up phase – and pick up speed later-on when flow conditions become increasingly stable. Even though *Figure 33* shows examples for BHP models, the same equations with little modification can be used for inflow- (and if desired outflow-) rates as well.

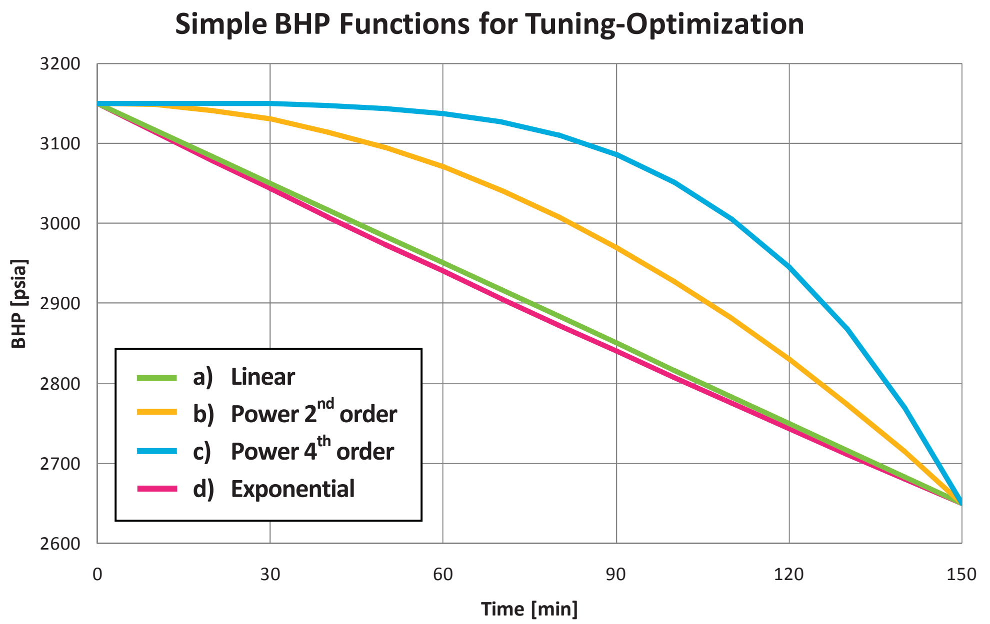

Figure 33: Single-parametrical functions for model tuning optimization

When it comes to simple functions describing flow rate, a substantial increase from zero to target production of some thousand *STB/d* has to be bridged. Exponential and power functions of 3rd or higher order are not applicable, because they create a slope too steep towards the end. Therefore, equations ***a)*** and in some cases ***b)*** of list eq. *10.2-1* can be applied.

Examples for complex pressure and rate functions
Figure 34 shows a typical example of BHP behaviour during an optimized start-up operation, capable of taking our generic well from zero to 4000 *STB/d* surface oil in five hours:

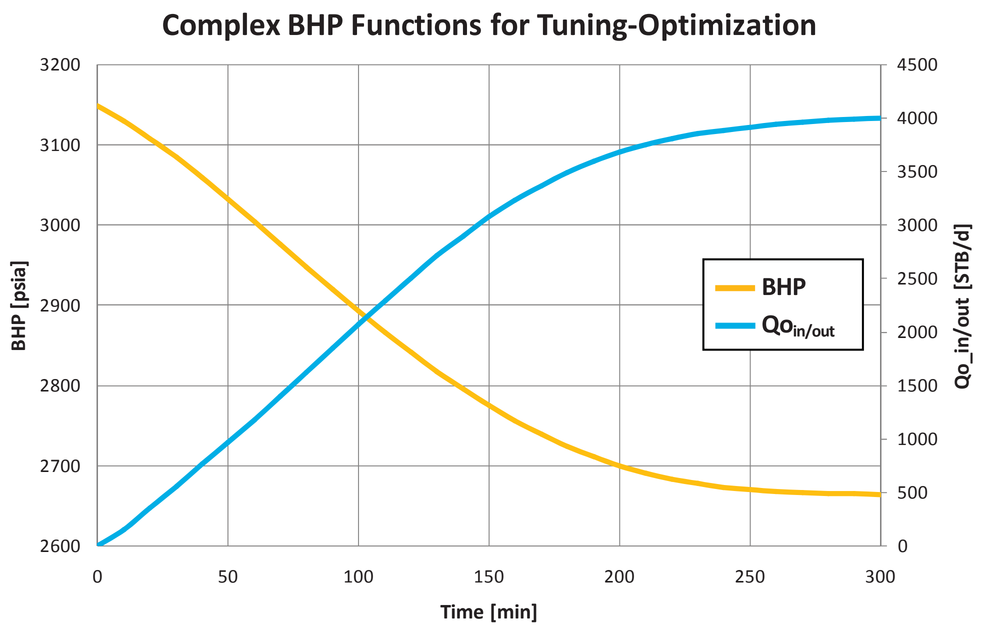

Figure 34: Multi-parametrical functions for model tuning optimization

Functions for both, BHP and $Qo_{in/out}$ have been established and operate with four parameters, constituting the CVs required for the *Pipe-It* optimization. Also equations for THP are included, which are similar to those for BHP, but also have the ability to increase during one period within the second half of the start-up (cf. *Table 4*).

Name	Function	Parameters
Magnetic Saturation with Offset	$THP = A * t * (1 + B * \exp(C * t)) + D$	A = -7.8092 E-02 B = 4.2807 E+01 C = -1.5274 E-02 D = 7.6994 E+02
Sigmoid A with Linear Growth and Offset	$THP = \frac{C * t}{1 + \exp(-A(t - B))} * D$	A = -3.9084 E-02 B = 1.2053 E+02 C = -8.5979 E-01 D = 7.3752 E+02
Weibull	$BHP = A - B * \exp(-C * t^D)$	A = 2.6504 E+03 B = -4.8628 E+02 C = 4.0920 E-04 D = 1.6205 E+00
Double Langmuir Probe Characteristic with Offset	$BHP = A * (\tanh(B * t + C)) + D$	A = 3.0244 E+02 B = -9.6171 E-03 C = 7.5812 E-01 D = 2.9523 E+03
Sigimond B	$Qo_{in/out} = \frac{A}{1 + \exp\left(\frac{-(t - B)}{C}\right)}$	A = 3.9420 E+03 B = 5.5150 E+01 C = 1.0447 E+01
Gompertz	$Qo_{in/out} = A * \exp(-\exp(B - C * t))$	A = 4.0001 E+03 B = 3.0876 E+00 C = 6.3632 E-02

Table 4: Multi-parametrical functions for model tuning optimization[45]

The functions for THP, BHP, inflow- and outflow oil-rate, shown in *Table 4* above, are mere suggestions and can be replaced by whatever fits the user's objectives best (e.g. by polynomials with four or five coefficients). One must keep in mind that multi-parametrical mathematical expressions tend to be sensitive towards changing parameters. Therefore, the *Pipe-It Optimizer* will require some "guidance" by providing it with information on order of magnitude as well as algebraic sign for each parameter to speed up the process. The parameters entered in *Table 4* are mere suggestions and have been retrieved by tuning the respective function in order to fit a set of data retrieved from a conventionally coupled model run.

Furthermore, it must be stated, that even though the concept of optimizing a coupled *SENSOR-OLGA* start-up by parameter tuning looks very promising, it has not been tested in practice and its implementation might very well prove to be tricky.

[45] (ZunZun.com (Python Equations Google Code Repository), 2009)

10.3 Substituting one model by VLP or IPR tables

10.3.1 OLGA VLP

The main objective of coupling reservoir- and well models for optimizing start-up operations is to capture the dynamic interactions of the two systems. As discussion of flow events encountered during this stage has demonstrated (cf. ch. *2.1, p. 3*), pipe-flow is succumbed to the heaviest of transient phenomena. It is therefore against the project's objective to substitute this element with a concept that has been designed for describing steady-state flow conditions. The benefits of using VLP tables instead of *OLGA* in terms of overall simulation time would be substantial, but obtained results would differ widely from reality, leading to wrong assumptions and failure of the optimization. For these reasons it is strongly recommended to stick to running *OLGA*.

10.3.2 SENSOR IPR

In all-oil cases where reservoir transients – e.g. like inter-layer crossflow – can be neglected, exchanging the *SENSOR* reservoir model with an IPR table that *OLGA* can read from is a possibility to improve run time efficiency of the coupled model. Considering a saturated oil-well start-up with a bubblepoint pressure of 2000 *psia* and neglectable WC, the reservoir inflow performance curve looks similar to the one depicted in *Figure 35* below. It shows a plot of oil-rate vs. BHP drawdown for the reservoir model during a coupled run, where GOR is constant and WC is zero throughout the whole operation. It shows that BHP for the desired rate of 4000 *STB/d* is 2670 *psia* is still well within the undersaturated region, meaning that linear IPR behaviour can be assumed. Whenever BHP falls below bubblepoint pressure, either *Vogel*- or *Fetkovich* IPR prediction methods need to be applied, depending on rate and predominant phase produced by the examined well.

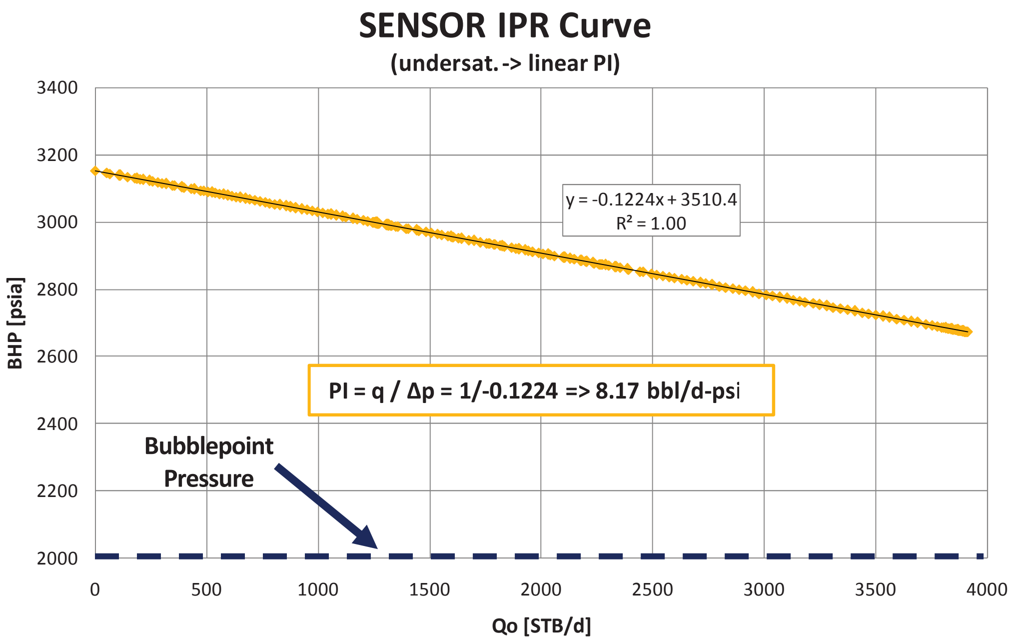

Figure 35: Undersaturated IPR plot for SENSOR during start-up

Applicability of steady-state IPR during start-up scenarios requires thorough validation and can only be applied if deviation of inflow data from the developed IPR curve is near zero. (To verify the obtained results, it is recommended to run a fully coupled model in order to create a reference data-set.) In cases where those assumptions hold, IPR data retrieved from the reservoir model can be reformatted to *OLGA* input. This method will speed up start-up simulations substantially by reducing the *Pipe-It* overhead of transferring data back and forth between the models and by not having to run *SENSOR*. However, transient reservoir-behaviour is not included at all with this approach. It has to be noted though, that after well interventions, with mud and/or water being left behind in the well and near-wellbore reservoir, in producers subject to gas coning or simply wells producing from saturated reservoirs or having notable WC, the simplifications required for employing oil-IPR curves cannot be sustained and would lead to wrong results. A means of capturing multiphase flow is to create separate IPR data for oil, gas and water – reservoir flow dynamics, however, remain still concealed.

PITS-IPR table

Discussing the issue of replacing *SENSOR* with IPR data, Dr. Keith Coats, Brian Coats and Prof. Whitson, came up with the idea of establishing a new IPR table for each PITS.[46] In doing so, *SENSOR* would not be entirely replaced, but only one run per PITS would be required – instead of up to 20 times before and 20 times after *OLGA* – which gives us the chance of capturing transient reservoir behaviour.

At the beginning of each PITS, *SENSOR* would be launched within the *Restart-Loop* Level to create an IPR table for each phase, i.e. oil-, gas- and water. The flowing BHP range needed can be approximately limited to the previous PITS's value ±100 *psi*. Subsequently, *Pipe-It* will read the resulting four-column IPR table (BHP and three phase-rates) and hand it to *OLGA*. Using different THP values, *Pipe-It* can now run its restart iterations of *Level 2* while *OLGA* is able to retrieve inflow rates for any BHP it calculates readily from the established IPR table, making a re-run of *SENSOR* completely superfluous.

It is expected that with this concept numerical oscillations resulting from the coupling itself will vanish entirely and consequently also the PITS length debate becomes irrelevant. Therefore, among all suggestions about alternatives to explicit model coupling, this concept is believed to comprise the largest potential in terms of bringing down total simulation time while even improving simulation results.

Note: Observations show that transient reservoir behaviour is mainly occurring in the early start-up phase, where fluid contamination is still present and BHP instabilities are most severe. Towards the operation-end, inflow behaviour will stabilize and the same IPR curve could possibly be employed for some ten, twenty PITS, further improving the concept's benefits.

10.4 Replace OBJ by a combination of CON-conditions

Total simulation runtime largely depends on average number of restart-iterations per PITS. Having an *Optimizer* setup comprising a maximization objective for surface oil-rate requires the definition of an OBJ-type variable with a target of maximizing this value in each iteration sequence. This goal is defined rather loosely and leads to a situation where, even if all constraints would be fulfilled after e.g. five iterations, *Pipe-It* would keep on looking for solutions with even larger OBJ-values – i.e. larger oil-outflow from the *OLGA* model. Consequently, the solver would hardly ever converge before it reaches maximum allowable number of iterations. Admittedly, the quality of the solution is improving with the number of trials, but this comes with unreasonably high CPU-time.

Replacing OBJ- with CON-conditions allows the *Optimizer* to converge quicker and on constraints rather than on maximum number of iterations. In practice, this is implemented by introducing a CON-type variable that closely defines the desired growth rate for surface-oil, while the optimization target is changed from 'Maximize' to 'Find feasible solution'. (If needed, please cf. *Figure 4, p. 14* for better understanding.)

As tests have shown, this modification of the *Optimizer* structure bears large potential to bring down total runtime. Depending on how ambitious rate-growth goals are defined, the solver may converge continuously after low single-digit iteration, making simulations twice as fast or quicker.

[46] E-Mail correspondece from Dr. K. Coats, B. Coats and Prof. C. Whitson on Sun, 21.06.2009

11 Concept-application areas

The primary objective for building a coupled reservoir-wellbore system has been optimization of well start-up operations. Having confidence in the model's ability to efficiently handle the occurring transient flow conditions, the system can also be employed in a variety of other applications and "sub-applications" that are dominated by dynamic and complex fluid flow phenomena as well as interaction between reservoir and wellbore.

11.1 Transient flow conditions

Transient flow is occurring only during a relatively short period after major production parameters have been changed. In this respect, start-up and shut-down of a well is the gravest thinkable interference, resulting in highly dynamic and complex flow phenomena. In between, the well might be succumbed to sudden operational changes in e.g. THP or surface rate, while the likeliness of damaging the production system is thereby small, because flow has previously established steady-state conditions and is not easily destabilized. This is why it makes sense to focus on the "extreme" situation of start-up – being able to handle that, the system becomes applicable to a wide range of tasks:

Well start-up
Flow during well start-up is characterized by a combination of several transient events. As discussed extensively throughout this paper, the operation can be optimized comprehensively by controlling pressures and rates at two specified points in the coupled model (i.e. the coupling point and the wellhead), without addressing each of the sub-problems separately.

If, however, a closer look must be taken at certain process, the coupled system provides the dynamic boundary conditions.

Wellbore cleanup
This would be a first example for a sub-event, taking place during start-up of a well. The efficiency of retrieving drilling-, workover-, completion- or kill-fluids from the wellbore is of utmost importance to the production engineer. When running a coupled-model start-up simulation, a detailed analysis of the cleanout process is possible and helps to determine minimum inflow rates from the reservoir, evaluate the cleanout quality over time, find out whether the reservoir is actually able to "push" out the heavy waste-fluid and if not, evaluate possible artificial assistance methods like downhole nitrogen injection or pumping.

Near-wellbore reservoir cleanup
Not only the wellbore, but also the reservoir in its vicinity may be contaminated with unwanted waste substances before start-up. Obviously it is also important to push out these fluids and potentially formed emulsions to ensure best possible post-start-up reservoir performance. Also in this respect, a coupled model is needed for detailed analysis of the cleaning process under dynamic flow conditions.

Well shut-in flow events
In cases where the shut-in reservoir pressure is less than the bottomhole fluid pressure exerted by e.g. heavy workover fluid, running a coupled model for shut-in conditions allows determination of required time to let the waste fluid seep down into the reservoir, allowing the wellbore to gradually fill with lighter gas and oil. The simulation will show whether the bottomhole pressure can be lowered far enough only by waiting, to make start-up of the well possible without artificial lift. Thereby, the coupled model run helps in making an economic decision on whether to continue waiting or to immediately apply artificial start-up assistance. (*Appendix D* provides further information on this topic.)

Completion design
Transient flow events usually result in abnormal strain of the subsurface equipment. When designing new completions or evaluating changes to existing installations, a coupled model is suited for running various worst-case scenarios in order to ensure the tool's integrity under any condition likely to occur during production. Lacking such a model, certain events might be overlooked or simply underestimated, resulting in premature completion damage or failure and consequently expensive repair work or loss of the well.

Flow-line start-up
Flow-lines connecting single wells with production platforms or gathering manifolds can be several kilometres long, large in diameter, follow a bumpy route and may also comprise vertical risers. Transient flow events during start-up of such a flow-line are especially intense and their interaction with both, wellbore and reservoir, can be tight and potentially harmful. In such cases it makes a lot of sense to model the wellbore and the surface flow-line in *OLGA* and run it coupled to a *SENSOR* reservoir model. In the same manner, other surface facilities (e.g. separators or slug-catchers) can be modelled and simulations run with the coupled downhole production system, even though their ability to influence the reservoir inflow or even cause permanent damage to it is limited, compared to long surface pipelines or the wellbore itself, due to their small volumes.

Surface facility design
Even though flow dynamics in e.g. a separator will not likely provoke instabilities in the reservoir, the vice-versa case deserves more attention: similar to what has been discussed in paragraph "*Completion design*" above, also surface installations need to withstand various extreme production conditions. A coupled reservoir-wellbore model can thereby aid in estimating the consequences of transient flow at the wellhead, enabling the engineers to design the 1st stage surface equipment accordingly.

Well-test design
Well-tests are essentially operations comprising a sequence of shut-ins and start-ups, intended to recover information on reservoir properties. The required test-string, comprising expensive tools for fluid sampling and gauging pressures, temperatures, rates etc., as well as the execution time and work needed make well-testing an expensive undertaking. Detailed preliminary planning is therefore important to ensure a quick and safe operation. Coupled reservoir-wellbore models constitute a great tool for designing such well-tests. Accurate information about the reservoir might not yet be available in the planning stage, but good estimates are sufficient to establish a *SENSOR* model and run a coupled simulation for dimensioning the test-string and optimizing the operational sequence.

11.2 Steady-state flow conditions

Steady-state flow is easier to understand and describe than complex transients. A model capable of simulating the latter is likely to also handle the former. End of start-up is characterized by steady-state flow and the current coupled system has done an excellent job in describing this operational phase. However, the CPU load required for the coupling is thereby not justifiable, because running the models separately will return the same result only a lot quicker. Consequently, the coupled model is indeed capable of simulating steady-state flow in reservoir and wellbore but using uncoupled numerical models instead is more efficient.

11.3 The “intelligent field” concept

In an environment of declining production volumes and ever scarcer new recoveries, improving efficiency and optimizing operations is often the only way of maintaining field output or curbing its decline. Processes making up the petroleum production chain are complex, often overlapping and interacting and therefore an overall optimization attempt must inevitably be applied at the organisational top level. As mentioned in the “*Introduction*” to this paper, many oil- and gas companies are putting large effort into creating computer models of production systems and entire fields to allow fully integrated process optimization. A coupled reservoir-wellbore model would thereby constitute the first and most influential part of such a system. Several such models closely connected to processes surface facility can then be simulated to obtain optimum operating conditions such as e.g. maximum NPV, maximum condensate rate or minimum required injection gas volumes.

12 Summary and conclusions

From the beginning on it was not quite clear what can be expected of the project. But the picture quickly became clearer once the system started to assume shape in *Pipe-It* and challenges and tasks continued to emerge along the way. Hence, the whole thesis work was a conclusion in a sense. Nevertheless, there are major findings that need to be given a concluding mention:

- The main finding certainly was the actual possibility of taking two commercial numerical simulators – i.e. *SENSOR* and *OLGA* –, creating self-contained flow models for reservoir and wellbore, and coupling them within *Pipe-It* to permit operational simulation and optimization. This provides us with a wide range of possibilities because the models – since self-contained – can be changed and updated at will, while *Pipe-It* would still be able to run and optimize the coupled simulation. In this respect, a high degree of variability and/or detailedness can be achieved, making the tool widely applicable for simulating transient flow events. *Pipe-It* and its developers deserve most of the credit on that behalf, because it is user-friendly, impartially runs any process and furthermore sets virtually no limits in terms of project structure and complexity.
- Qualitative comparison with real field data showed that, even though highly dynamic and affected by reservoir-wellbore interaction, the complex flow phenomena during well start-up can be simulated in the coupled system, while obtained results are realistic. Nevertheless, thorough further testing and verification will be necessary.
- From a coupling strategic standpoint, the decision to model the wellbore section below top of reservoir within *SENSOR* has turned out to work very well and runs orders of magnitude faster than what *OLGA* could achieve. This concept was not entirely new, but has been tested previously by Prof. Whitson and his colleagues at PERA on cases where the whole tubing string was gridded in the reservoir model. The novelty thereby is that it proved its applicability to transient flow problems, reduces the number required coupling interfaces to a single point, and makes the process structure clear and simple while returning satisfactory result accuracy (also refer to ch. *4.1, p. 17* and ch. *5.1, p. 22*).
- Regarding time-stepping within the coupled *Pipe-It* model, the length of these PITS has shown to have an unexpectedly large impact on simulation results. Determination of appropriate interval sizes is therefore of utmost importance, since this is a mere numerical quantity which can only have negative or no impact on simulation results (the former is to be preferred).
- Constraints, objectives and combinations thereof have shown to not only determine the simulation's outcome but also its progress. In other words, variables defined in the *Pipe-It Optimizer* structure should most importantly reflect physical upper and lower limits of the start-up procedure, but they also constitute a useful tool to "steer" the optimization process. Having too many or mutually exclusive constraints can thereby have a negative effect on the outcome.
- The relevance of this topic throughout the industry is substantial, which is why operators like *StatoilHydro* and *BP*, service companies like *SPT Group* and *PERA* as well as university faculties like *NTNU IPT* are addressing it. Optimizing well start-up operations can prevent severe damage to the well and boost efficiency and revenues. The subject is therefore as important as it is interesting and the large amount of work still needed to be done is definitely worth the effort.

13 Recommendations for further work

13.1 Model verification

The first continuation step will be marked by further verification of the coupled model. A generic model that returns results looking promising in a qualitative comparison is good for proving the concept, but confidentiality in its detailed accuracy can only be obtained from a real-life test case.

Field testing
A well-test must be carried out in a vertical well with little GOR and WC in order to obtain quality data on downhole- and surface rates, pressure and temperature. The models in *SENSOR* and *OLGA* must then be fitted separately to the real conditions downhole. Running a simulation following the THP schedule obtained from the well-test, without any optimization attempts, must then return rates and pressures at both nodes matching the previously obtained field data. Having achieved that, further tests can be run on cases with different well-stream compositions, reservoir properties or well geometries to ensure maximum confidentiality in the tool's performance.

Uncoupled testing in *SENSOR*
For preliminary testing, a *SENSOR* reservoir model can be established, including the whole tubing string as a highly permeable grid cell column with the same discretization as the wellbore model in *OLGA.* This model is then run to check whether the same results as in the coupled model can be achieved.

Note: *SENSOR calculates pressure drops from one cell to another by employing Darcy's law, meaning that it is linearly dependent on the flowrate. To be able to compare the results to those obtained from OLGA – which uses non-linear pipe-flow equations –, tubing-cell "permeabilities" must be tuned to give the same overall pressure drop for various flowrates in SENSOR that what OLGA would calculate.*

These efforts are justified by the fact that the reservoir simulator provides fully implicitly coupled intercellular flow, which is more accurate than the explicit coupling of *OLGA* and *SENSOR*. This is not intended to show *SENSOR*'s ability to simulate pipe-flow – which it can only approximate to a certain degree of accuracy –, but to rule out any severe numerical error caused in the coupling-point, which otherwise might accumulate over time and spoil simulation results unnoticed.

13.2 Model improvement

Both, the *OLGA* well and the *SENSOR* near-wellbore model have a lot of space for improvement.

OLGA
Currently, a simple mono-diameter vertical well is used, without any flow restrictions whatsoever. One might consider having an inclined section above the coupling point to study how this might affect wellbore cleanout. Also a more complicated tubing strings with several tapers and/or flow restrictions, including surface flow-lines and platform-risers can be implemented for capturing phenomena like slugging, hydrate formation and unloading of gas-wells. *OLGA* also enables the user to include gas-lift and for studying assisted start-up operations.

SENSOR
The reservoir model can be further improved by including skin, elevated near-wellbore water saturation, the possibility of injection in cases where *OLGA* BHP exceeds *SENSOR* top reservoir pressure (i.e. $BHP_{OLGA} > THP_{SENSOR}$) etc. Apart from that, more dominant reservoir crossflow activity, a larger number of communicating and non-communicating reservoir layers or different formation pressures can be simulated. Reservoir properties can be improved either by parameter tuning to fit well-test data or – whenever available – by using core- and log-data.

Generally speaking, both models will have to be modified substantially before testing against real cases. The main system features to do that are already available in the models and need only be changed, but there will certainly be some aspects that are not yet included.

Pipe-It
As discussion in ch. *10 (p. 53 et seq.)* has revealed, there is many possible ways of how to further improve the current *Pipe-It* project. All these changes in coupling strategy will result in reconstruction of the existing *Pipe-It* system or may even require its replacement. A suggestion looking especially promising is partly replacing *SENSOR* by IPR tables (cf. ch. *10.3.2, p. 57*). It is strongly recommended to investigate the potential of this strategy.

There are, however, some changes not related to the strategy as such, but rather present amendments to the existing project: making injection possible in the *SENSOR* model (as stated above) to also enable counter-current flow of water or changing THP excitements in *OLGA* from step-like to smooth linear in order to reduce the “shock” after each PITS are but two of many thinkable ways to improve the model. (Please also cf. chs. *13.3*-*13.6* below for further suggestions of how to improve the *Pipe-It* project.)

13.3 Number of maximum iterations

In simulations done so far, the restart optimization seldom converges on fulfilled constraints, but mostly by maximum number of iterations. This is not exactly ideal, because compromises have to be made and the best solution – even if possibly violating constraints – is continued with. The reason for setting maximum iteration limits of 15 for fixed PITS and 20 for variable PITS is simply limited CPU power. Having a 4.0 *GHz* processor or faster would allow the user to set the iteration limit higher, which would make convergence on constraints possible in most PITS.

13.4 Implementation of suggestions for PITS selection

In ch. *8.3 (p. 47)*, two possible approaches are discussed, addressing the influence of PITS selection on simulation results: **a)** *Variable PITS with separate peak-detection* and **b)** *Variable PITS from one Head Master step to the next, but fixed within*; both suggestions mainly affect the *Pipe-It* project, while option b) is the favoured option and should be implemented first.

13.5 Staggered constraint structure

Constraint boundaries used in the *Pipe-It Optimizer* may be varied over the course of the simulation. The results can thereby be pushed closer to the optimum, while also simulation time can be substantially decreased. The set of boundaries must be defined in a text-file, which can be read from by the *Pipe-It Optimizer* at specified points in time by using ‘*Linkz*’.

13.6 Compositional fluid PVT

Both *OLGA* and *SENSOR* allow for compositional tracking. Using this feature together with compositional fluid PVT data will give more accurate information about local phase distribution changes and its effect on the start-up process. Furthermore, inaccuracies arising from interpolation of Black-Oil data can largely be eliminated when using compositional fluids.

Technical nomenclature

Δ	–	indicates differential values for pressures, rates etc.
BHP	–	bottomhole pressure
CV	–	control variable
FVF	–	formation volume factors
GLR	–	gas-liquid ratio
GOR	–	gas-oil ratio
GP	–	gravel pack
GUI	–	graphical user interface
HWC	–	hydrocarbon-water contact
IPR	–	inflow performance relationship
o, g and w	–	subscripts for phases oil, gas and water
p	–	pressure
PI	–	productivity index
PITS	–	*Pipe-It* time-step
PVT	–	pressure-volume-temperature
STB	–	stock-tank barrel
T	–	temperature
THP	–	tubinghead pressure
TPR	–	tubing performance relationship
TS	–	time-step
TVD	–	true vertical depth
VLP	–	vertical lift performance
WC	–	watercut
WOC	–	water-oil contact
γ	–	specific weight
μ	–	viscosity
ρ	–	density

Abbreviations

cf.	–	confer
ch., chs.	–	chapter, chapters
CPU	–	central processing unit
e.g.	–	lat: exempli gratia (eng: for example)
eq., eqs.	–	equation, equations
et al.	–	lat: et alii (eng: and others)
et seq., et seqq.	–	lat: et sequens (eng: and the following)
HSE	–	health, safety and environment
i.e.	–	lat: id est (eng: that is)
SENSOR	–	system for efficient simulation of oil recovery
SI units	–	Système International d'Unités
SPE	–	Society of Petroleum Engineers

SI metric unit conversions

bar	x 100,000	= Pa
bbl	x 0.158987	= m^3
bbl/d	x 1/543,396	= m^3/s
cp	x 0.001	= $N\text{-}s/m^2$
F	(F – 32)/1.8	= °C
ft	x 0.3048	= m
ft^3, cuf	x 0.0283169	= m^3
in	x 0.0254	= m
lb, lbm	x 0.453593	= kg
lb/ft^3, lbm/ft^3	x 16.0185	= kg/m^3
psi, psia, psig	x 6894.757	= Pa
scf/STB	x 0.17811	= m^3/m^3

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Appendix A *SENSOR* input file

```
TITLE

-------------------------------------------------------------------------------------------

        Radial 3-Phase Model with WOC in Tbg @ 100ft (pipe practically filled w\ water)

        2 Reservoir Zones (Tilje & Aare) are devided into 22 and 29 Layers.
        Tbg in the Reseervoir section + 2 Gridcells is modeled with SENSOR.
        The Pressure at this point is determined by OLGA and returned after each step:
        SENSOR then delivers the phase rates accordingly.

        Radial Gridding is used: 26 radial   1 angular   67 in z-direction

-------------------------------------------------------------------------------------------

ENDTITLE


GRID   26  1  67
RUN
CPU
IMPLICIT

C -----------------------------------------------------------------------------------------
C RADIAL GRIDDING
C -----------------------------------------------------------------------------------------

RADIAL
3               ! read nx rbi
0   1315        ! Tbg_ID = 3 1/2 in

C rbi:   Multiplicator for geometrical Radius-Increase = 1.439470464
0            0.145833333  0.209922775  0.302177635  0.43497578   0.626134788  0.901302534
1.297398376  1.867566642  2.68830702   3.869738553  5.570374349  8.018389346  11.54223463
16.61470583  23.91637831  34.42692018  49.55653475  71.33516805  102.6848674  147.8118337
212.7707688  306.2772373  440.8770367  634.6294725  913.530381

360             ! dely(j) = deltheta [degrees]


C -----------------------------------------------------------------------------------------
C DEPTH  -> Layer thickness definition
C -----------------------------------------------------------------------------------------

DEPTH CON
6799.9

THICKNESS ZVAR
    0.1      90.0       ! SENSOR-Tbg part reaches 90.1 ft above top of Tilje
 20*5.0    9*40.0       ! Fmt gross thicknesses: Tilje = 460 ft (29 cells) and
 22*5.0   14*40.0       !                         Aare  = 670 ft (36 cells)

                        ! OLGA-Wellmodel reaches to 6800 ft (Depth of Fluid handover)
                        ! In effect there is an overlap of 0.1 ft for acurate mid-cell
                        ! pressure and rate calculation!!


C -----------------------------------------------------------------------------------------
C PVT DATA
C -----------------------------------------------------------------------------------------

C Bw = Bwi(1-cw(p-pref)); cw = water compressibility; denw = water density
C at std T&P (sp. gr. or lb/ft3); dw = (denw/Bwi)(1+cw(p-pref)) lb/ft3;
C PV = PVbase(1+cf(p-pbase)); entered pv (or porosity) PVbase; PVinit is measured
C at pinit by default unless
C POROSBASE >pbase< is entered (pbase then is the
C pressure at which PVinit has been measured!)

C      Bwi      cw         denw      visw   cf         pref
C      rb/stb   1/psi      lb/ft3    cp     1/psi      psia
```

```
MISC   1.03     3.406E-6   62.3096   0.38   4.702E-6   3709.   ! -> Source: Geir Frode Kvilaas


PVTBO          ! NOPRINT

C         deno      deng          coil       ! cvoil      (= oil- & gas surface density, oil-
C                                                          compressib., oil viscosity coeff.)
C         lb/ft3    lb/ft3
DENSITY   52.8306   0.0904694     6.34E-06   ! 9.02E-5    ! values are taken from OLGA PVT data

PRESSURES   4   8   PSIG
 0.   710.66   1725.89   2741.12   3756.35   4771.57   5786.80   6802.03

C SATURATED PVTBO Table
C  psig      rb/stb         rb/scf         scf/stb     cp       cp
   PSAT      BO             BG             RS          VISO     VISG
   2741.12   1.107044025    0.000529818    352.39854   0.1290   0.0196
   1725.89   1.071705908    0.000868648    203.86190   0.1330   0.0159
   710.66    1.03556887     0.002168089    72.71726    0.1380   0.0135
   0         1.022513859    0.06154036     0.000000    0.1380   0.0135


C UNDERSATURATED PVTBO Table
C  psig      rb/scf         cp
   P         BG             VISG
   6802.03   0.000132674    0.039
   5786.80   0.000160648    0.036
   4771.57   0.000263166    0.0361
   3756.35   0.00037737     0.025

PRINTKR 0


C ---------------------------------------------------------------------------------------
C ROCK TYPES: 1 = tubing ; 2 = reservoir       // Grid Block Properties are entered as Arrays!
C
C                                              // MOD sets rocktype for layers i to other than
C                                              // the type defined globally with CON
C ---------------------------------------------------------------------------------------

ROCKTYPE CON
1
MOD
 2 26 1 1  3 67 = 2


C ---------------------------------------------------------------------------------------
C DEFINITION OF REGIONS: 1 = tubing ; 2 = Tilje ; 3 = Aare
C ---------------------------------------------------------------------------------------

REGION CON
1
MOD
 2 26 1 1  3 31 = 2
 2 26 1 1 32 67 = 3


C ---------------------------------------------------------------------------------------
C Tubing "relative permeability"
C ---------------------------------------------------------------------------------------

KRANALYTICAL 1
 0.0  0.0  0.0  0.0     ! Swc        Sorw      Sorg      Sgc
 1.0  1.0  1.0          ! krw(Sorw)  krg(Swc)  kro(Swc)
 1.0  1.0  1.0  1.0     ! nw         now       ng        nog
```

```
C Explanation of abbreviations

C Swc   connate water saturation
C Sorw  residual oil saturation to water
C Sorg  residual oil saturation to gas
C Sgc   critical gas saturation
C krwro relative permeability of water at Sw=1-Sorw, Sg=0
C krgro relative permeability of gas at Sw=Swc, So=Sorg
C krocw relative permeability of oil at Sw=Swc, Sg=0
C nw    exponent for krw curve  |
C now   exponent for krow curve |-> influence curvature of KR-curves (fit to Zein's data)
C ng    exponent for krg curve  |
C nog   exponent for krog curve |


C ---------------------------------------------------------------------------------------
C ROCK    <- Source: Zein Wijaya, 2006
C ---------------------------------------------------------------------------------------

KRANALYTICAL 2
 0.18  0.02  0.2  0.05  ! Swc        Sorw      Sorg      Sgc
 0.98  0.75  1.0        ! krw(Sorw)  krg(Swc)  kro(Swc)
 5.0   4.0   1.8  2.8   ! nw         now       ng        nog

KRANALYTICAL 3
 0.18  0.02  0.2  0.05
 0.98  0.75  1.0
 5.0   4.0   1.8  2.8


C ---------------------------------------------------------------------------------------
C PERMEABILITY          <- values obtained or estimated from SPOR Monograph
C                       (used 10 times the k_min for each layer)
C ---------------------------------------------------------------------------------------

KX CON          ! fitted by: KX = 2,211211E+12 * Q_liq^(- 1,023924)

1993901729      ! match to Olga Tubing dp for 0 - 1000 STBLIQ

MOD
 2 26 1 1  3 31 = 300           ! Tilje
 2 26 1 1 32 67 = 400           ! Aare

KY EQUALS KX

KZ EQUALS KX
MOD
 2 26 1 1  3 30 = 100           ! Tilje (k_v/k_h = 0.5)
 2 26 1 1 32 67 =  50           ! Aare (k_v/k_h = 0.1)

 2 26 1 1 31 31 =   0           ! make layers non-communicating (KZ = 0 is tighter than TZ =
0!!)

TZMAX 1000                      ! limit maximum TZ to improve run stability when using impes
formulation
TRMINUS


C ---------------------------------------------------------------------------------------
C POROSITY                              <- values obtained or estimated from SPOR Monograph
C ---------------------------------------------------------------------------------------

POROS CON
1
MOD
 2 26 1 1  3 31 = 0.25          ! Tilje
 2 26 1 1 32 67 = 0.27          ! Aare
 2 26 1 1  1  2 = 0.0           ! deactivate outside-tubing cells above Top of Reservoir
```

```
C -------------------------------------------------------------------------------------------
C Assigning grid blocks to the 3 initialization regions; 1 = tubing ; 2 = Tilje ; 3 = Aare
C -------------------------------------------------------------------------------------------

INITREG CON
 1
MOD
 2 26 1 1  3 31 = 2
 2 26 1 1 32 67 = 3


INITIAL 1
 DEPTH  PSATBP
 6799.9 2000

 ZINIT  8020.   ! [ft]
 PINIT  3600.   ! [psia]
 C HWC  6800.   ! [ft]


INITIAL 2
 DEPTH  PSATBP
 6890   2000

 ZINIT  8020.   ! [ft]
 PINIT  3600.   ! [psia]
 C HWC  7250.   ! [ft]


INITIAL 3
 DEPTH  PSATBP
 7350   2000

 ZINIT  8020.   ! [ft]
 PINIT  3600.   ! [psia]
 C HWC  7920.   ! [ft]

ENDINIT


MODIFY TX
 2  2   1 1    7 31 = 0         ! limits perforated interval to
 2  2   1 1   36 67 = 0         ! 20 ft at the top of each interval

 2  3   1 1    3  8 = .2        ! limits T_perf
 2  3   1 1   32 37 = .2


C -------------------------------------------------------------------------------------------
C Define Well A1
C -------------------------------------------------------------------------------------------

WELL
       I   J   K   RW        PI
  A1   1   1   1   .145833   1000

WELLTYPE
  A1  STBOIL            ! oil producer in stboil/d
```

```
C ----------------------------------------------------------------------------------------
C Output Control Section
C ----------------------------------------------------------------------------------------

WINDOWS
   1   1 1   1 1   1 1   XZY  ! Coupling Point

MAPSPRINT 1 P

MAPSFILEFREQ  -1        ! -> Mapsfile Printout
MAPSFREQ      0         ! -> Maps Printout: Print only at times entered
STEPFREQ      1         ! -> Timestep Table
WELLFREQ      1         ! -> Well Table
SUMFREQ       -1        ! -> EndOfRun Summary (every timestep)
PRINTZERO     -1        ! -> To include zero rate lines
PRINTREG      -1        ! -> Region table printout (insert # of regions to be plotted)


C ----------------------------------------------------------------------------------------
C Pressure/Rate Schedule
C ----------------------------------------------------------------------------------------

RATE
 A1 100 STBOIL

BHP
A1 500

RESTART
TIME   1   .01

END
```

Appendix B *OLGA* input file

```
!*******************************************************************************
!        CASE
!*******************************************************************************
CASE AUTHOR="MSchietz", DATE="08.04.2009", PROJECT="MSc Thesis", TITLE="Single Well S.U."
INTEGRATION ENDTIME=36051.2063 s, MAXDT=10 s, MINDT=0.001 s, STARTTIME=36046.2063 s,\
DTSTART=0.001 s
FILES PVTFILE="./OLGA_FluidTable.tab"
OPTIONS TEMPERATURE=OFF, STEADYSTATE=ON, FLASHMODEL=HYDROCARBON, DEBUG=OFF
OUTPUT DTOUT=1 s
TREND DTPLOT=5 s
PROFILE DTPLOT=1 s
RESTART WRITE=OVERWRITE, WRITEFORMAT=BINARY, READFILE=ON, FILE="./OLGA_HeadMasterRun.rsw",\
READTIME=36046.2063 s

!*******************************************************************************
!        LIBRARY
!*******************************************************************************
MATERIAL LABEL="Annulus", CAPACITY=4180 J/kg-C, CONDUCTIVITY=0.58 W/m-C, DENSITY=900 kg/m3,\
   TYPE=FLUID, EXPANSION=2.46e-005 1/C, VISCOSITY=1.04 CP
MATERIAL LABEL="Formation", CAPACITY=2000 J/kg-C, CONDUCTIVITY=2 W/m-C, DENSITY=2500 kg/m3
MATERIAL LABEL="Tubing", CAPACITY=500 J/kg-C, CONDUCTIVITY=50 W/m-C, DENSITY=7850 kg/m3
MATERIAL LABEL="Casing", CAPACITY=500 J/kg-C, CONDUCTIVITY=50 W/m-C, DENSITY=7850 kg/m3
WALL LABEL="WALL_Tubing", THICKNESS=(0.3, 0.8, 1, 0.4, 1, 1.5, 2.1, 3, 4.3) in,
MATERIAL=("Tubing",\
   "Annulus", "Annulus", "Casing", "Formation", "Formation", "Formation", "Formation",
"Formation")

!*******************************************************************************
!        FLOWPATH
!*******************************************************************************
NETWORKCOMPONENT TYPE=FLOWPATH, TAG=FLOWPATH_0
 PARAMETERS LABEL="Well"
 BRANCH GEOMETRY="OLGA_Sim", INIFLOWDIR=POSITIVE, FLUID="1"
 GEOMETRY XSTART=0 M, YSTART=-6800 ft, ZSTART=0 M, LABEL="OLGA_Sim"
 PIPE ROUGHNESS=2.5E-05 M, LABEL="Well", WALL="WALL_Tubing", NSEGMENT=28, LSEGMENT=(0.1,\
   9.9, 14.510007, 21.039993, 30.520013, 44.270013, 64.209974, 93.140092, 135.10007,\
   195.95997, 284.25, 412.30971, 598.06102, 867.49016, 1258.2808, 867.49016, 598.06102,\
   412.30971, 284.25, 195.95997, 135.10007, 93.140092, 64.209974, 44.270013, 30.520013,\
   21.039993, 14.510007, 10) ft, XEND=0 M, YEND=0 M, DIAMETER=3.5 in
 HEATTRANSFER PIPE="Well", INTERPOLATION=VERTICAL, HOUTEROPTION=WATER, INTAMBIENT=75 C,\
OUTTAMBIENT=15 C
 OUTPUTDATA VARIABLE=(GG, GL, PT, ROG, ROHL, ROL, ROWT, STDROG, STDROHL, STDROWT, VISG,\
   VISHLTAB, VISWTTAB)
 TRENDDATA VARIABLE=(PT, QGST, QOST, WCST, GORST), PIPE="Well", SECTION=(1, 28)
 PROFILEDATA VARIABLE=(AL, HOL, HOLHL, HOLWT, PT, QG, QLT, TM)
ENDNETWORKCOMPONENT

!*******************************************************************************
!        NODE
!*******************************************************************************
NETWORKCOMPONENT TYPE=NODE, TAG=NODE_0
 PARAMETERS LABEL="Inflow", TYPE=MASSFLOW, Y=-6800 ft, LINE="NO", FLUID="1",\
STDFLOWRATE=0.1 STB/d, PHASE=OIL, GOR=237.9 scf/STB, WATERCUT=0.000 %, TEMPERATURE=75 C,\
 PRESSURE=3151.4 psia
ENDNETWORKCOMPONENT

NETWORKCOMPONENT TYPE=NODE, TAG=NODE_1
 PARAMETERS LABEL="WH", TYPE=PRESSURE, FLUID="1", GOR=-1 scf/STB, WATERCUT=0,\
 TEMPERATURE=25 C, PRESSURE=751.796875 psia
ENDNETWORKCOMPONENT

!*******************************************************************************
!        CONNECTIONS
!*******************************************************************************
CONNECTION TERMINALS = (FLOWPATH_0 INLET, NODE_0 FLOWTERM_1)
CONNECTION TERMINALS = (FLOWPATH_0 OUTLET, NODE_1 FLOWTERM_1)

ENDCASE
```

Appendix C TimeStep.dat

```
        !! This file stores information on current !!
        !!   time-step number in SENSOR and OLGA   !!


SENSOR:

Info_StepNo_SENdat      100     [steps]
Info_Time_SENdat        1.0     [d]

Info_StepNo_SENout      100     [steps]
Info_Time_SENout        1.0     [d]



OLGA:

Info_Tstart_OLGAgenkey  0               [sec]
Info_Tend_OLGAgenkey    36046.2063      [sec]
Info_TRestart_OLGAout   36046.2063      [sec]




SIMULATION:

Info_SimTend            100     [sec]
Info_SimTcurrent        0       [sec]
Info_SimTSlength        5       [sec]
Info_SimTSno            0       [steps]

Info_RestartIterations  -1      [it.]

Info_OLGA_InitTend      10      [h]
RecordEntry             2159    [-]

Steady-State THP        650     [psia]
Steady-State Qoout      4000    [STB/d]

end
```

Appendix D Initial reservoir pressure considerations

It is important to realize that even though a well might be shut-in at the surface, it may still be quite active downhole. The conditions at the moment of closing the wellhead-choke basically constitute a snapshot of the dynamic pressure and saturation distribution during production. Even though in dynamic equilibrium before shut-in, these conditions will be severely out of static balance during shut-in. Fluids will continue to move and local saturations and pressures will change as long as any imbalances exist.

To better understand the behaviour of the reservoir model as such and for capturing processes occurring during shut-in periods, a thorough analysis of the initialization effects and communication between layers has been performed. For this purpose, four cases have been assumed and simulated: **a)** undersaturated reservoir with tubing initially filled entirely with oil, **b)** undersaturated reservoir with initially filled with water up to a depth of 1000 ft, **c)** undersaturated reservoir where the well has been shut in after ten years of partly cyclic production and **d)** saturated reservoir with initially filled with water up to a depth of 1000 ft.

a) Tubing initially filled with oil (undersaturated reservoir)
The tubing is initially completely filled with oil. As shown in *Figure 36,* there is a pressure overbalance across the perforations. This is imposed by the lower density of oil inside the tubing, compared to sea-water gradient pressured formation fluids.

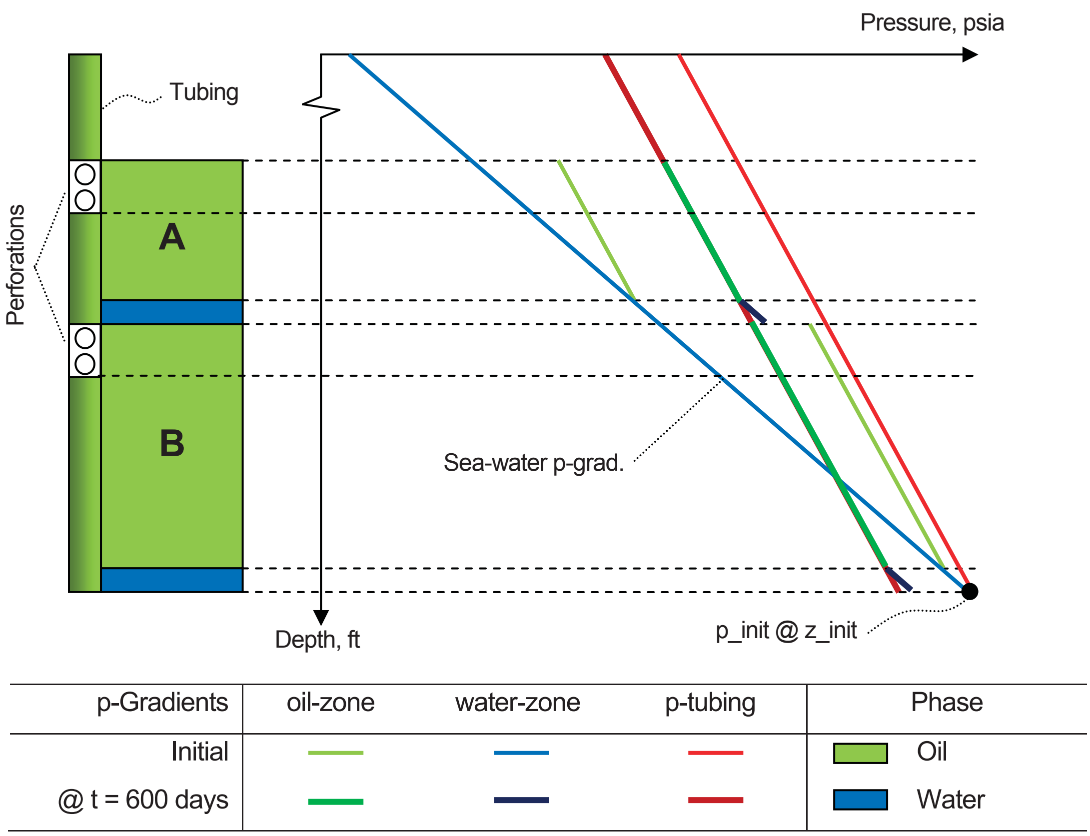


Figure 36: P-gradients for initially oil-filled tubing (undersaturated reservoir)

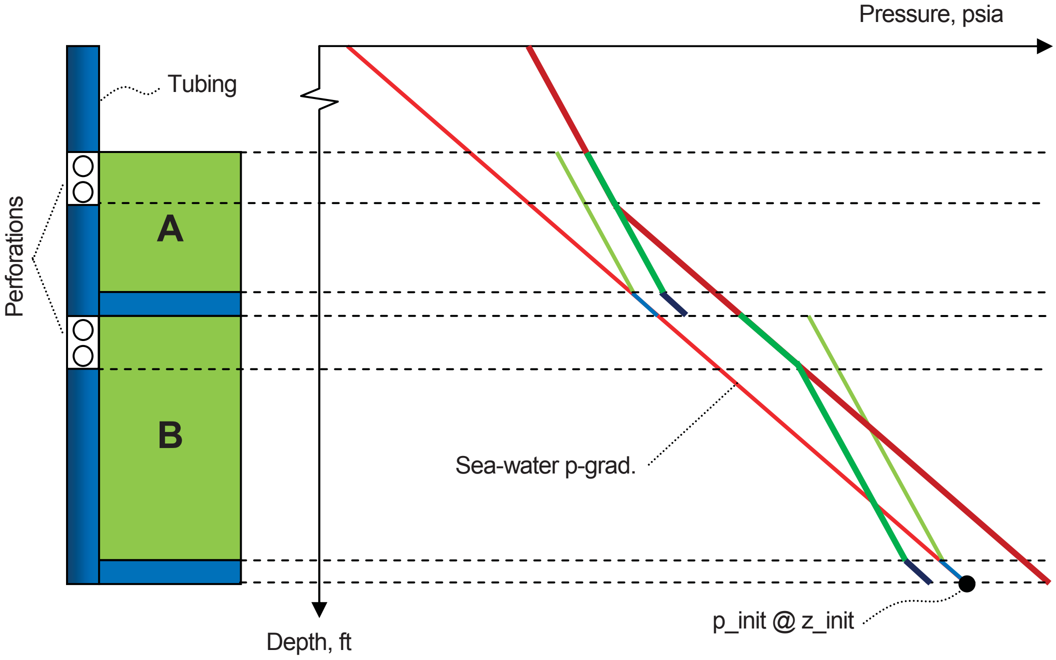
The initial reservoir pressure conditions are governed by the hydrostatic sea-water gradient, represented by the light blue line, while the steeper light green lines represent the pressure gradient in the oil-bearing zones. The light and dark red lines indicate the initial and stabilized pressure gradient, respectively, inside the tubing oil column. The conditions at hand present an unbalanced system and therefore pressures will change once the well is perforated and shut in.

The short-term effects cause the pressure inside the tubing to drop to a level between the two formation pressure gradients. After t = 5 *sec*, the tubing pressure has reached a temporary equilibrium (dark-red line). The exact position of the stabilized tubing gradient is dependent on the permeability and interval length of the two zones. It will lie closer to the gradient of the larger kh-layer – in this case zone B. Apparently, the exact position is linearly depending on the *kh*-ratio, i.e. $p_A + (p_B - p_A)*(kh_A/kh_B)$.

After these immediate tubing pressure change effects are completed, crossflow becomes the dominating phenomenon. It occurs comparatively slow – it takes 600 days until pressures in the two formations reach a common gradient. The dark-coloured lines in *Figure 36* represent the bright-coloured initial gradients, once crossflow has stopped and pressure equilibrium is reached.

The conclusion of these observations is that in the first seconds after start-up the tubing pressure distribution and hence inflow performance will be affected by the zonal pressure difference. For that reason these effects need to be taken into account. Furthermore, it has to be noticed that even though the well might be shut in, the system is in motion (if crossflow is allowed and has not reached p-equilibrium).

b) Tubing initially filled with water up to 1000 ft TVD (undersaturated reservoir)
The WOC inside the tubing is initially located at 1000 *ft* TVD. As in case **a)**, the reservoir pressure is initially sea-water hydrostatic. What is different though is the position of the initial tubing pressure gradient, which is in this case lower than the formation pressure at the perforations and therefore a severely underbalanced situation is encountered (cf. *Figure 37*):



p-Gradients	oil-zone	water-zone	p-tubing	Phase
Initial				Oil
@ t = 19 days				Water

Figure 37: P-gradients for WOC inside tubing at 1000 ft TVD (undersaturated reservoir)

After simulation start, the tubing pressure gradient increases immediately (t<10 sec) until it overruns the gradient of the upper zone and stops right below the one of the lower zone.

Oil from the lower zone starts bubbling through the water column and accumulates at the top of the well. Gradually, the water column in the tubing is displaced downwards, seeping into the top zone. It shows that water-injection occurs only in the upper zone, because there is a slight pressure underbalance across the lower perforations and initially quite the opposite across the upper ones.

After 19 days, the WOC will have dropped below the top perforated interval, i.e. ~7000 *ft* TVD. From that time on, the fluid movement is only governed by the reservoir pressure difference between lower and upper zone.

It has to be noticed that regardless water-displacement process in the tubing, crossflow from the lower into the upper zone will start immediately and will continuously decrease the pressure imbalance between the layers. After the tubing has been filled with oil to a point below the upper perforated interval, the lower zone starts producing only into the upper one.

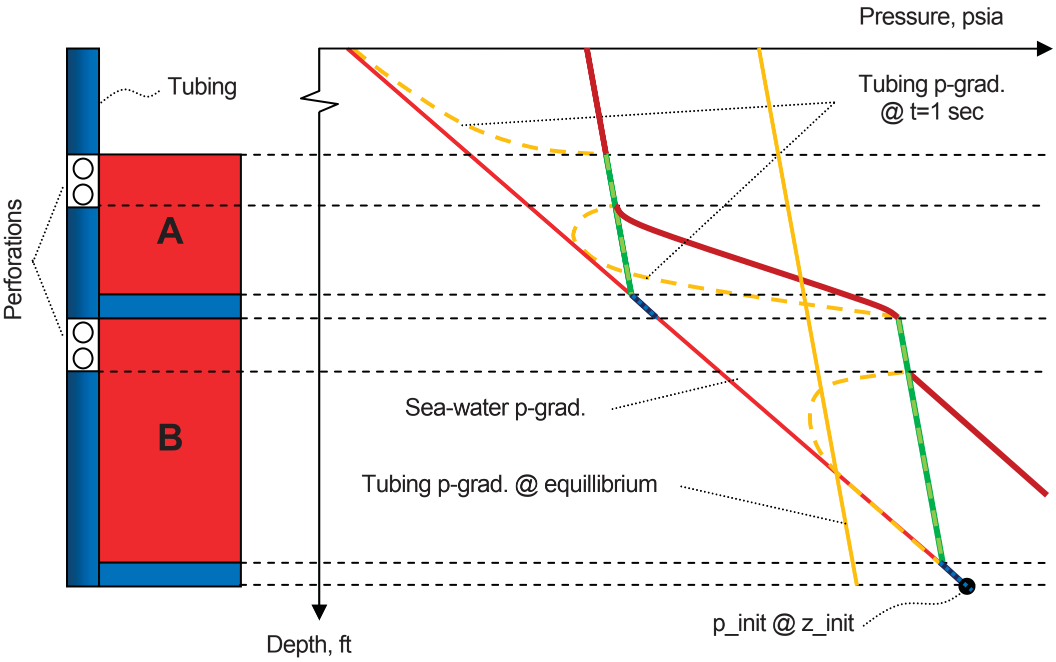
As already indicated in the oil-filled-tubing-case, it takes a long time until pressure equilibrium is reached. Water inside the tubing will slow down this process substantially, because the p-difference across the lower perforation is reduced. Running long time simulations surprisingly reveal, that the WOC will not decrease further down than slightly below the upper perforated interval, even if the well was shut in for years. However, as soon as the well is put on production the water can be produced and the WOC retreats down to slightly below the lower perforation.

c) Shut-in after producing for ten years (undersaturated reservoir)
In this third case the same initial conditions have been applied as in case **a)**, i.e. the well was filled with water up to 1000 *ft* TVD. The objective of this was on the one hand to see whether it is possible to produce out the water column at rates not larger than 10.000 *STB* liquid per day and more importantly to see if the crossflow behaviour is influenced or even reversed by long-term production.

Shut-in behaviour of the well strongly depends on the production rate history. Firstly, it determines whether there is a WOC maintained inside the pipe or not – e.g. if the well is produced at very low rates or high WC, water will accumulate in the tubing and seep back into the reservoir after shut-in. Secondly, the crossflow occurrence and/or direction is strongly affected by previous production rates: layers might be unevenly depleted or initial pressure unbalances might not have been completely equalized during production and will continuously cause interlayer fluid flow. An example for uneven depletion would be a two-layer case, where the lower zone is overpressured and high permeable: production will deplete the lower reservoir quicker and therefore will not only offset the pressure difference, but also result in the upper layer having a slightly higher reservoir pressure. Shutting in the well will again lead to crossflow – but this time from top down.

Crossflow during shut-in periods is not necessarily a transient phenomenon. Once bottomhole tubing pressure has stabilized, steady-state flow from one formation into the other formation will establish and continue until formation pressure at the lower perforation depth is equal to the one of the upper plus the difference in hydrostatic head. How long this process lasts is – the reservoir properties aside – determined by pressure conditions.

d) Tubing initially filled with water up to 1000 ft TVD (saturated reservoir)
With an initial WOC inside the tubing at 1000 *ft* TVD, the initial situation is similar to the one in case **a)**. However, this time a gas reservoir model with reduced permeability and 500 *psig* saturation pressure has been employed, to demonstrate the impact of a water column in liquid loaded gas wells during shut-in.



p-Gradients	oil-zone	water-zone	p-tubing	Phase
Initial				Gas
@ t = 25 days				Water

Figure 38: P-gradients for GWC inside tubing at 1000 ft TVD (saturated reservoir)

Upon simulation start, the tubing pressure is instantly adjusting to the reservoir pressure at the two perforation intervals. (The tubing pressure gradient after 1 *sec* is shown as a dotted orange line in *Figure 38*.) There is no residual pressure difference across the perforations anywhere nearly as large as in the oil-water case. The reason for that is the higher compressibility of gas, which results in inertia towards pressure changes and hence allows larger pressure gradients.

After 25 days, the water column is entirely displaced into the reservoir and the tubing section above the top perforation is filled with gas. From that time on, only interlayer crossflow will be present, as long as there is a difference in reservoir pressure of the two zones. In gas reservoirs, crossflow is not likely going to stop within years – not even in high permeable rocks. This is in large contrast to the all-liquid cases previously simulated and can be also contributed to the higher compressibility of gas, which drastically increases the required fluid volume exchange to achieve a pressure equalization. If the well was shut in for more than 50 years, the two gradients would finally align in a place indicated in *Figure 38* by the dotted solid orange line.