Successful Application of a Robust Link to Automatically Optimise Reservoir Management of a Real Field

2. Introduction

The integration of the reservoir simulator with the wellbore and surface facility models forms an essential part of the “intelligent” field concept. It allows accurate management of the reservoir(s) potential under specified well, facility or other constraints. The full value of such an integrated modelling workflow is only realised when a flow network optimisation capability that maximizes oil production (or other measures of value) is included in the software package. The optimiser works by making adjustments to the production strategy throughout the field life through its close coupling with the reservoir, wellbore and surface facility models.

Many commercial software packages offer the capability to integrate subsurface and surface models. However, not only are there differences in the degree of coupling between the individual software programs, but these links usually place high demands in terms of computing power, network architecture and, frequently, manual intervention of the engineer. In this paper we will illustrate a successful application of a robust and efficient linking tool developed to couple a commercial reservoir simulator with a surface network simulator and Sequential Quadratic Programming (SQP) optimiser. The S-Field (a case study based on redevelopment of a real field with an Advanced or Intelligent Well development strategy) has been previously studied in depth. It has been found to be a very useful case history to illustrate the potential advantages of implementing an Advanced Well development scheme. We have been able to show how the SQP optimiser can be used to increase the recovery compared to manual optimisation. This was achieved with a limited engineering manpower compared to the previous manual optimisation approach while the computer power requirements were less than that anticipated with other commercial optimisation software packages.

2.1 Advantages of integrated production modelling

Integrated production modelling is a concept that has been in development within the industry since the 1970s. However, the application of this concept gained a lot of momentum in recent years due to successful, early applications to Field
Development Planning. The speed of development has increased further with the advent of ever increasing computer power along with the advent of the “Intelligent Field” concept and Real-Time Optimisation. Integrated production modelling has now become essential to take advantage of the investment in downhole sensors, downhole flow control valves and the associated data networks. Real-Time production optimisation had now become a realistic possibility in creating value where suitable algorithms are used.

Such an integrated modelling system allows dynamic well network and surface facility deliverability and capacity constraints to be closely coupled with the reservoir simulation model. Integrated systems bring many other advantages, including the:

- Integration of engineering disciplines (i.e. reservoir, production and facility engineers), allowing better decisions to be made.
- Flexibility to rapidly modify the surface and subsurface networks configuration and the individual component settings to respond rapidly to, possibly unforeseen, changes in the asset’s operational conditions.
- Ability to recognise, at an early stage, slowly developing differences between the modelled and the actual reservoir performance. This also requires adjustment of the reservoir model.
- Ability to easily recognise changes in the:
  - Well’s inflow performance (e.g. development of a “skin” requiring well stimulation for its removal) or
  - Well’s outflow performance requiring adjustment of the flow correlations used to model fluid flow in the network elements
- The observed field behaviour should be closely matched once these changes are implemented.
- Ability to quantify the costs of surface facility capacity constraints, allowing convincing justifications to be easily prepared for management’s approval of facility extensions or modifications.

Several commercially available simulators have had the facility to reflect the fluid flow behaviour and pressure drop across some of the surface network components by hydraulic (or Vertical Lift Performance) tables for some years. This was frequently limited in the number of components that could be included in the hydraulic network and the gathering topology of the network architecture in which flow from any node in the network can only be directed to another node (Figure 1). Further, flexibility to modify the network components settings once the simulation had started is not available. This could only be included by stopping the simulation, manually making the necessary changes and then restarting the simulation. This illustrates why any flow matching to observed field performance of the network components (i.e. pressure drop in pipes and compressors) has to be performed ahead of the simulation. This is not the case when an integrated production system model is available since modifications can be scheduled or entered during the simulation pauses. Also, flow from any node in the network can be directed to multiple subsequent nodes rather than one node only.

3. Literature review
Most of the published reservoir/surface network integration systems are:

- Commercially available products employing parallel, open server computing architecture with full or partial coupling of the two simulators (Figure 2). Incorporated in the reservoir simulators through implicit, full or partial, coupling of the subsurface/surface network with the reservoir, or
- Specially developed programs for specific application within an organisation that have not been made generally (commercially) available.

One of the early coupling examples is the development by Hepguler et. al. of a tightly coupling interface between the reservoir simulator provided by Supplier 2 and the network simulator and optimiser provided by Supplier 4. The coupling was based on a Parallel Virtual Machine (PVM) interface and required convergence of the surface and reservoir simulators results at every time step. This requirement results in the necessity of multiple iterations of both models to reach a convergence point.

On the other hand, Coats et. al. have developed a fully coupled reservoir/network model that is solved simultaneously at the end of each simulator’s Newton iteration. The capability of modelling advanced well configurations was included. The model decomposes the wells and the facility networks into small domain models. These are then run simultaneously and iterated to solve the equations for each domain. The utilization of such coupling architecture is often time consuming when compared to explicitly coupled models with data exchange at every time step. Further, the explicit, partially coupled, model delivers accurate results when the reservoir simulator-wellbore calculation boundary is limited to the reservoir/wellbore connection points (the perforations).

An example of the latter has been published recently by Hyder et al. He presented their work to optimise the quality of the crude oil production from three reservoirs with different crude properties producing from a giant Saudi Arabian field. This optimisation involved minimising the volume of light crude oil required for blending with heavier production so as to meet the quality requirements in order to maximise the value of the exported crude. They developed a driver to loosely couple Saudi ARAMCO’s in-house developed reservoir simulator to a commercially available surface network optimiser through the vendor’s communication software.

4. History of the field case study
The S-field is located in the Norwegian sector of the North Sea. The field was originally developed with seven conventional wells completed on only one of the two, separate
pressure regimes present in the four reservoir sands. A study by Elmsallati identified significant extra value would have been gained from the application of intelligent well technology if it had been used to develop the field. At the time of the first study, a (commercial) link between a surface network modelling software with optimisation capability and the reservoir simulator provided by Supplier 2 was not available. The optimum choking polices of the modelled intelligent wells were implemented manually using the “Action” triggering techniques available for many years within the reservoir simulator. This methodology allowed him to identify a significant increase in the field recovery compared to the actual, conventional Field Development Plan that had been implemented. However, it proved to be an exhaustive task, both in terms of the time and engineering effort required as well as the computing power employed.

Sometime later, a (commercial) coupling software became available which was able to link the network optimiser and the reservoir simulator provided by the same vendor (Supplier 3). The S-Field reservoir model was thus transferred from the old reservoir simulator (Supplier 2) to the new reservoir simulation software (Supplier 3) to take advantage of this new opportunity. As expected, this shift produced different values in term of the Oil-Originally-In-Place and the cumulative oil production due to the differences in the calculation methods employed by the two reservoir simulators. Extra value was identified since the optimiser identified extra opportunities during the field’s decline phase compared to manual techniques. This work thus proved the potential application of such technique to optimise the full field production in an efficient and automated manner.

In this study, on the other hand, we were able to successfully couple the original reservoir simulator to the same surface network model and produce even better results than the previously reported manual optimisation of the ICV settings with the "Actions" Keyword. Our results are not quantifiably comparable to the results of the second study (discussed in the previous paragraph) because of the differences in the calculation methodology employed by the reservoir simulators.

4.1 The S-Field reservoir simulation model

A detailed description of the reservoir simulation model has been published previously. This included the reservoir layering, the rock and fluid properties, the production and injection well completions and the Interval Control Valves (ICV) locations. Figure 3 indicates the reservoir layering. Key parameters are the:

- Low oil viscosity,
- High gas-oil-ratio,
- Very high formation permeability,
- Strong aquifer support and
- Presence of two regions of differing pressure due to low permeability layer splitting the reservoir into two zones.

These parameters result in very high deliverability wells.

4.2 Wellbore and surface network model

The (hypothetical) advanced well development plan called for the installation of five intelligent wells with a total of 18 completion intervals each controlled by its own interval control valve (Figure 4). A group of three and two wells were respectively connected to two Subsea templates (SM and SL). The proposed wells replaced the existing seven conventional producers that were originally used to develop the field. A full description of the well completion models and network piping was published previously.

5. The coupling of subsurface/surface models

The methodology followed by Supplier 1 to link the reservoir simulation model to the subsurface/surface network model is a “loose coupling” in which the exchange of data between the two models takes place at every user specified time-step. The linkage utilizes the restart functionality of the reservoir simulator extensively. The coupling is initiated from the restart file of a reservoir simulation run so that the reservoir simulation model is run for a short time step. Only then, each well required data is transferred to the subsurface/surface network model. There are two data transfer methodologies, depending on the chosen well data input functionality in the network optimiser. The first method requires the reservoir pressure in the vicinity of the well along with the well Productivity Index (PI), Gas-Oil Ratio (GOR) and water cut (WC). The second method requires multiple well bottom hole pressures and their associated flow rates, WCs and GORs to be available in a look-up table format.

The input for the second methodology is generated by the linkage tool through the following steps:

1. The reservoir pressure in the wellbore and the vicinity of the well is recorded by the linkage tool.
2. Multiple well bottom hole pressures are generated from the recorded pressures with an incremental range higher and lower than the original bottomhole and near wellbore pressure.
3. Multiple reservoir simulation time steps are then conducted for short or long time steps (user defined) to obtain the fluid flow rates, GORs and WCs associated with the newly calculated well bottom hole pressures.
4. The above data are then used to populate the completion look up table in the network optimiser.
5. Next, the network model is solved and the optimum production rate is allocated to each completion using the network chokes (representing the ICV of the intelligent well completion). These liquid flow rates are imposed as target rates in the reservoir simulator for the next time step.

The advantages of this coupling method include the:

- Elimination of the requirement for a Parallel Virtual Machine interface with reservoir simulator.
- Ability to modify the well configuration at any time-step specified by the user for the coupled optimisation run.
• Coupling taking place at the user specified time stepping.

6. Results and Discussion
The S-Field hypothetical development plan utilized five oil producers with 18 intelligent completion zones and three conventional water injectors. Elmsallati et al. previously published results employing manual optimisation of the ICV settings to control the contribution of each zone will be used as the base case for this study. The automatic optimisation technique reported here employed a time step interval of 30 days i.e. at the end of every 30 day time step the production from each zone was evaluated and adjustment of ICVs settings was triggered by pre-set WC and GOR limits. These limits were modified through multiple iterations of the simulation model to achieve the optimum cumulative oil production from the field.

Utilization of the automatic optimiser with the new coupling technique improved the cumulative oil production by 7.0% compared to manual optimisation. The additional cumulative oil production was mainly produced during the decline period which proved to be particularly difficult to optimise using the manually selected value for the “Actions” keyword (Figure 5). Also, the cumulative water production was reduced by 10.0% (Figure 6). The time required to complete a fully coupled and optimised simulation run is about 8 hours for 18 years of the field life.

However, one difficulty was identified during the work. The automated optimiser did not maintain a stable plateau for the 30 day-time step. Therefore, a time step length optimisation study was carried out in which the 30 day-time step was sequentially reduced to a 5 day time step; yielding an optimum time step value of 15 days. This choice was based on the:

○ Stability of the plateau period (Figure 7),
○ Time required for the 18 year simulation period to run.

Figure 8 illustrates the change in the coupled simulation run time based on the length of the time step and
○ Adverse effect of employing such frequent choking strategy on the reliability of such completions19.

Similar results were achieved when the coupling was introduced after the plateau production period had finished. This was done in order to verify if any added value can be gained if this type of optimisation techniques was introduced at different points of the field production life.

The oscillation of the automatically optimised results is a persistent challenge that has been identified by several authors2,16,20. In our, case, the oscillation was partially attributed to the well bottomhole reference depth mismatch between the models which was rectified later, and partially due to the none convergence of the network solver causing optimiser fluctuation between choking alternatives in an attempt to identify the best possible solution.

This paper has illustrated the advantages of using the link software to couple the reservoir simulator provided by Supplier 2 and the network optimiser provided by Supplier 3. Similar advantages could have no doubt been derived from the coupling of other commercial reservoir and surface network simulators to a different surface network optimiser. This has not been tested, but the vendor claims that the software is capable of such links.

7. Conclusions
1. The new coupling technique between the commercial software provided by Supplier 2 and Supplier 3 was successfully applied to the S-Field.
2. The time required to configure and conduct the coupled simulation run was short compared to the manual identification of ICV adjustment triggering values and appropriate settings to optimise the full field cumulative production.
3. The need to link the programs using a Parallel Virtual Machine interface was eliminated.
4. The linking software is commercially available. It can be expected to be capable to link other commercial reservoir simulators to surface network optimisers after suitable testing.

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References


Figure 3: The reservoir simulation model (oil zones in green colour)

Figure 4: The Wellbore/Surface network model

Figure 5: Comparison of cumulative oil production of manual & automated S-Field production optimisation

Figure 6: Comparison of cumulative water production of manual & automated S-Field production optimisation

Figure 7: Comparison of the stability of the oil production rate as a function of the time step length with manual optimisation.

Figure 8: Simulation run time and number of steps as a function of time step length