SPE 99446

Real-Time Production Optimization of Offshore Oil and Gas Production Systems: A Technology Survey

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This paper was prepared for presentation at the 2006 SPE Intelligent Energy Conference and Exhibition held in Amsterdam, The Netherlands, 11–13 April 2006.

Abstract

The information flow used for optimization of an offshore oil production plant is described. The elements in this description include data acquisition, data storage, processing facility model updating, well model updating, reservoir model updating, production planning, reservoir planning, and strategic planning. Methods for well allocation, gas lift and gas/water injection optimization and updating of the models are reviewed in relationship with the information flow described. Challenges of real time optimization are discussed.

Introduction

In the daily operation of an oil and gas production system, or plant, a lot of decisions have to be taken that affects the volumes produced and the cost of production. These decisions are taken at different levels in the organization, but eventually they will reach the physical plant. For such plants this is related to the choke/valve openings, compressor, and pump settings at every instance of time. These are the control elements.

In the efforts towards better performance of the plant, the question to be answered is therefore how to decide how to operate the control elements. In the process of finding good control settings, information about the plant is used. This information may be the physical properties such as pipe diameters and lengths, or it may be measurements from the plants.

The environment in which the production is performed is under constant change, and this will affect the quality of the control settings being used. If the cooling capacity of the plant is an operational bottleneck at a given moment, this may not longer be the case if the sea water temperature drops. Incidents at the plant may also affect the quality of the control settings; partial shut down of the plant due to maintenance will most likely affect the bottlenecks.

Real Time Optimization (RTO) is a method for complete or partial automation of the process of finding good (optimal) control settings. By continuously collecting data from the plant, the data are analyzed and optimal control settings are found. These settings are then either implemented directly in the plant or they get presented to an operator. If settings get implemented directly, the RTO is said to be in a closed loop.

The main aim of RTO is to improve utilization of the capacity of a production plant to get higher throughput. The idea is to operate the plant, at every instant of time, as near optimum as possible [1]. To achieve this, a model of the plant is optimized giving optimal control settings. The model is continuously being updated by plant measurements to better fit the actual input-output behavior of the processing facilities, wells/network, and reservoir.

A general RTO system used in for example downstream petrochemical plants consists of the following four components [2] as shown in Figure:

- Data validation: The input and output data are validated using data reconciliation and signal processing techniques, e.g. using material and energy balances.
- Model updating: The processing facility models, well/network models, and reservoir models are updated to best fit the input and output data available.
- Model-based optimization: An optimization problem based on the updated models is set up and solved to obtain the optimal control settings.
- Optimizer command conditioning: A post optimality analysis is performed to check the validity of the computed control settings.

RTO was defined by Saputelli et al. [3] as “a process of measure-calculate-control cycles at a frequency, which maintains the system's optimal operating conditions within the time-constant constraints of the system”. Even if the definition was written with oil and gas production systems in the mind, it is general in the sense that it is not restrictive to some specific type of plant or method, and it can be related to Figure.

Recently, SPE started a technical interest group that focuses on RTO on oil and gas production systems. The driver behind this development is, as in any industry, the demand for more profitable plants. This survey will help to organize previous work related to RTO. The focus will be on offshore oil and gas production systems; however relevant references from other industries are also included.

A previous review paper [4] was recently published. It focused on the organizational issues of using RTO. Because a review on the organizational issues is already given, this review will focus on the existing software, tools, methods, and approaches that can be applied for RTO usage. However, the survey will not focus on the (surface) processing facilities.

This paper is organized as follows. A description of the information flow associated with the optimization of offshore oil and gas production systems is given to relate the general RTO technology to this specific application area. Technologies for optimization and model updating of such plants are reviewed, and reference cases will be presented. Finally, key challenges are addressed and conclusions stated.

Information Flow in Production Optimization

The operation of an oil and gas production system may be illustrated according to Figure 2.

Data Acquisition. Modern plants usually have good instrumentation. Level, pressure, and temperature transmitters are probably most common. There are often also a few flow transmitters to measure the flow rates in gas, water, and oil pipes. Flow transmitters for multiphase flow may also be available, but they are rare. This is probably because the technologies are not very accurate. Various offline analyzers of values including oil-in-water and product quality will often also be available.

Control. A typical oil and gas production system has many (automatic) feedback control loops to support an efficient production and meet the production targets. A feedback control loop generates control settings, such as valve openings, based on production system measurements. The simplest form of such control is used to control levels and pressures in the separators. Centrifugal compressors are always protected by an anti surge control loop. As the name implies, the control loop ensures that the compressors does not go into surge, and thus gets damaged. Control is also used to balance the load between parallel processing units. A phenomenon that may be observed in an oil and gas production system is severe slugging. The pressure (and flow rate) in a well or flow line starts oscillating, and the effective production capacity is reduced. This can sometimes be stabilized by feedback control [5].

Operator. The operator is responsible for ensuring safe operation. Then, they are responsible for implementing the recommendation from the production and injection plan; that is to meet the operational targets while obeying minimal and maximal limits on values including pressure, temperature, and rates.

Production Planning. A typical oil field is operated by periodically generating a production and injection plan. This plan lists the target production of oil, gas, and water for the given period for each individual well. Similarly, the injection of gas and water is listed for the injection wells. The cycle time of the plan depends on the policy of the operator company, but it will typically be between a week and a month. The models of the processing facilities and wells/networks are used together with constraints from the reservoir planning as inputs to the planning. Politics from the strategic planning may also be enforced here.

Reservoir Planning. The long term field drainage is planned here. This includes planning of gas and water injection. The updated reservoir model is used for finding proper draining strategies. Politics from the strategic planning may also be enforced here.

Strategic Planning. The production and injection plan is somehow connected to the market and the strategic considerations/policy of the company.

Well Model Updating. To help taking good decisions, models may be used to develop the production plans. Typically, well tests are performed to determine the gas-oil-ratio, water cut, and production rates of each individual well. The well model is then updated based on the measurements during the test.

Processing Facility Model Updating. Typically, the processing facilities are modeled as constraints on oil, gas, and water processing capacity. This means that the model is updated whenever the capacity changes.

Reservoir Model Updating. To be able to conduct the reservoir planning, a reservoir simulator may be used to evaluate different drainage strategies for the field. The simulator consists of a dynamic model of the reservoir.

The state and parameters of the reservoir model must be updated by measurement data. The volumes produced and injected are important measurements used in this updating process. To ensure good accuracy of the model, its parameters may be fitted to longer series of historical measurement data.

Technology and Reference Cases

In the view of Figure 2, many of the decisions are supported by technology. This section will give a brief of relevant technologies and reference cases from the industry. Technology belonging inside the large rectangle of the Figure 2 will be discussed here.

Production Planning. The goal of this plan is typically to maximize the daily production rates, and to inject gas and water according to some given rules provided by the reservoir planning.

Well Prioritization. If the goal is to maximize the oil production, some method is required to find the optimal way to prioritize between wells. It is often needed to prioritize because the processing capacity is less than the well capacity. This processing capacity constraint may be related to quality or safety.

A commonly used technique for doing this prioritization is to open the production chokes of the wells until some constraint is hit. If the constraint is related to the well itself (e.g. allowed maximal drawdown or sand production), then the operator continues by opening the other wells. Eventually all wells will be fully opened or some constraint in the processing facilities will be hit. On most plants the processing facilities are a limitation. Alarms warning the operator about too high temperatures or pressures will force the operator to choke back some wells. If the alarm is due to a too high temperature in the gas production, the well with the highest gas-oil-ratio is choked back until the temperature is below the limit. To better utilize the production, the well with the lowest gas-oil-ratio is opened and the production from well with high gas-oil-ratio are choked back. This is continued until a new constraint is met or all the closed wells have higher gas-oil-ratio than the opened wells. The method also works with water-cut for water or liquid constrained plants. It is however not straight forward to operate with multiple constraints.

Lo and Holden [6] used a linear program to find which wells that should be opened, partially opened or closed. They assumed that each well could produce any oil rate between the zero and the maximal oil rate, and that the water cut and gas-oil-ratio were the same for all rates (i.e. no gas or water coning). The method is able to handle multiple constraints on oil, water, liquid, and gas production for groups of wells (or all).

A way of handling a gas compression constrained field under gas coning conditions was proposed by Barnes et al. [7]. The method is able to handle wells where the incremental gas oil ratio (IGOR) is monotonically increasing with the oil rate. A similar method was proposed by Urbanczyk [8]. The idea is to increase production from the well with lowest IGOR with unused capacity, and reduce production wells with the highest IGOR. At the optimum, all the wells have the same IGOR or they are on a well constraint (minimum or maximum).

In [9] it was investigated how a combination of a reservoir simulator and real time data could be used to maximize the daily production of oil. The reservoir simulator was used to find derivative information, and the real time data were used to find the reservoir state. The cases consisted of a reservoir and a horizontal well with four continuous inflow control valves to control the segments of the well. The total water and gas processing capacity were constrained. A Successive Linear Programming (SLP) algorithm was used to solve the problem.

Gas Lift. Gas lift may be used to increase the productivity of wells. By injecting gas into the tubing, the density of the fluid is reduced and thus the pressure drop component due to gravity is reduced. However, the gas lift also gives a larger pressure drop component due to friction, giving a technical optimum lift gas rate for the well. Usually, the available lift gas is less than the sum of the technical optimum lift gas rates. The gas lift optimization problem is to find the lift gas rates for each well giving the maximum total oil production under such a constraint on gas rates or gas lift rates. A cost may also be associated with the treatment of gas, water, oil, and lift gas changing the problem into maximizing the profit.

Mayhill [10] generated a gas lift performance curve by plotting the oil production (or profit) versus injected lift gas for each well. The performance curves was later used in the equal slope method proposed by Kanu [11]. The equal slope method established a way of finding optimum lift gas rates. The name was given because of the characteristics of the optimum solutions where the effect of an infinitesimal increasing the lift gas would be the same for all wells.

Fang and Lo [12] developed a method for finding optimum lift gas rates using gas lift performance curves. Each curve was approximated by a finite number of break points, and the curve was assumed to be linear between any adjacent break points. The production of each well was formulated as the convex combination of the break points, resulting in a linear program. The method is able to handle oil, water, liquid, and gas production constrains for groups of wells (or all). The same is true for lift gas. Wells with variable water-cut or gas-oil-ratio is also handled. As pointed out by the authors, the method has problems if some wells can not flow naturally. This can however be solved by using mixed integer programming [13].

Buitrago et al. [14] combined of a stochastic and a heuristic method to find the optimal gas lift rates. The method uses gas lift performance curves, and is able to handle wells that require a (finite) non-zero lift gas rate to produce.

Gómez [15] proposed to fit the points defining the gas lift performance curve to a second order polynomial, and then solve the gas lift optimization problem by quadratic programming. The method was later extended by Alarcón et al. [16] to also include a logarithmic term for better fitting. For naturally flowing wells, a global optimum can be proven to be found due to the convexity of the problem. A heuristic was proposed to handle the shut in of wells which were not naturally flowing.

A method for finding the economical optimal gas lift rates on a plant constrained by liquid, gas, and lift gas constrains was considered in [17]. Instead of using a search method, an explicit method was proposed.

In [18] it was stressed the fact that many of the proposed optimization methods used for oil production optimization do not have global properties, and may easily be trapped in local optima. To elude this, they proposed to describe the production rate of each well as a function of the gas lift injection rate and the energy consumption. The total production was described as the sum of individual production rates. By using a hybrid optimization strategy consisting of a genetic algorithm and a tabu search heuristic, near global optimal values were found.

Network. Earlier in this section it was assumed that the production of each well was not dependent on the production from the other wells. The only things that mattered were the choke position and the lift gas injection rate. This may be true if the manifold pressure is constant and if the reservoir conditions do not change. However, the introduction of sub sea templates in offshore production plants has changed this. A few wells are connected to each template on the sea bed, and a common flow line connects the template to the platform or maybe a different sub sea template. The manifold pressure at the template will depend on the flow rates from each of the wells connected to it. Thus, if the production from one well is changed, then the others are changed too because of the changed pressure conditions. Increased flow from a well may actually increase or decrease the production from the other wells. For instance, a high gas-oil-ratio well may give a gas lift effect for the other wells in the riser. The opposite effect may be observed if the production from a high water cut well is increased.

In [19] the optimal lift gas rates for one, two, and three identical wells sharing a common flow line were compared. Also, larger field-wide networks were studied. Successive Quadratic Programming (SQP) was used. It was noted that optimal lift gas rates for each well reduced as the number of wells increased.

Wang [13] used SQP to optimize flow rates of gas lifted wells in a gathering network, and the results were compared to models ignoring the network. See also [20]. Later, Wang and Litvak [21] proposed to solve a piecewise linear approximation in each SQP iteration of the reservoir simulator.

The authors of [22, 23] studied the optimization of gas lift, well connections to manifolds and separators. A Mixed Integer Nonlinear Program was proposed, and it was solved to a local optimum using a modified version of SLP. Each iteration in SLP consists of solving a mixed integer program with connectivity constraints and piecewise linear gas lift performance curves. SLP was used to handle the nonlinear pressure equations.

In [24] it was proposed to solve this type of problem using a modified version of SLP. The wells were described using piecewise linear gas lift performance curves. According to the authors, this resulted in faster solving than standard SLP. See also [25].

Stoisits et al. [26] proposed to use a genetic algorithm to find the optimal gas lift rates and production rates for the wells. A large number of simulations were fitted to a neural network to speed up function evaluations. The method was able to handle constraints in gas and water treatment capacity.

Instead of considering the pressure drop between the wells and the separators, [27] modeled the pressure drop in the gas gathering and supply network of a oil field with gas lifted wells. They proposed the use of Benders decomposition to be able to solve the nonlinear non-convex problem to a local optimum. However, an upper bound was provided by a Lagrangian relaxation of the problem.

Various software packages are commercially available. GAP[1] allows the user to find optimal control settings using SQP. Processing facilities may be included in the model to provide better results. ReO[2] may also be used for finding optimal control settings. The software uses SLP for solving, and the method is described in [24, 25].

Sand Production. Sand production may further complicate the optimization process. It is an issue because the erosion that it will introduce may result in leaking bends or chokes. To handle this risk, [28] introduced an objective function that had a nonlinear term that penalizes sand production. It was assumed that there is a critical flow rate at which the sand production is started. A transient study was made, and control approaches with fixed and variable choke openings were considered.

Processing Facilities. The well prioritization and gas lift optimization problems do not typically include detailed models of (surface) processing facilities. In fact, it is often assumed that the processing facilities are able to handle a fixed amount of oil, water, gas, liquid, and lift gas. This is of course a simplified description, and the capacity of each component can not be investigated independently of what is being produced. For instance, the gas compression capacity may be limited by capacity of the cooling system. If two well streams have different temperatures, this may make a difference. This may justify the need for a way of optimizing the processing facility system.

The processing facilities often have units in both parallel and series. With parallel treatment facilities, routing becomes an issue. If two units in parallel are constrained by different variables, then it might be possible to produce the same volumes while moving off the constraint at the same time. Routing problems are typically binary by nature, thus requiring integer programming. Commercial processing facilities simulators such as HYSYS[3] often allow optimization of these parameters. Many of these real time production optimization problems have already been studied by the chemical engineering community. Konincky [29] gives an overview of various problems and solutions.

Reservoir Planning. An important part of the reservoir planning is the injection strategy of the field. The production from an oil field is to a large extent driven by the pressure difference between the reservoir and the surface. A typical strategy will ensure that the pressure is maintained by injecting roughly the same volume (under reservoir pressure conditions) of water and gas as the produced volumes of fluids. Some reservoirs are supported by large aquifers. As a result, the pressure in the reservoir is controlled naturally.

The volume balance of the reservoir is however not the only important property. Injecting close to the producer will typically increase the pressure faster than if the injection is far away. The permeability also makes a difference. This means that the pressure response between an injector and a producer is not instant; it is a dynamic system. Because of this dynamics, the water-cut and the gas-oil-ratio from the wells will change slowly until water or gas breakthrough happens. The location of the injectors and producers of the reservoir is therefore crucial to the performance.

In [30] strategies for water injection were studied for a 2D reservoir with miscible fluids with the same mobility. The effect of gravity and dispersion were neglected. The reservoir studied had one producer and multiple injectors. They proposed to use optimal control theory to maximize the time of arrival of the water breakthrough constrained by a constant total injection rate. In the cases studied, a bang-bang control was found optimal. The typical optimal result was to start injection farthest off the producer and then switch to a new injector at given times. The methods were compared with constant rate injection strategies.

Brouwer et al. [31] investigated how a simple heuristic algorithm could be used to delay the water breakthrough by using smart injection and production wells. Later, Brower [32] proposed to use optimal control theory on a dynamic model to allocate rates of each water injector. A reservoir with dimension 450×450×10 m was considered. Each block in the reservoir model was 10×10×10 m. The reservoir had two horizontal wells with 45 segments such that each grid block penetrated by a well represented a segment. The approach maximized the net present value with respect to volume balance, rate, and pressure constraints. The result was twofold: well operating on bottom hole pressure constraint benefited from reducing water production, while rate constrained wells gave accelerated production, increased recovery, and reduced water production.

In [33] the optimization of injection and production rates for smart wells was studied. They used a gradient based optimization algorithm to find local optimal settings for the injection and production chokes. The optimization algorithm was connected to a commercial reservoir simulator for objective function evaluation. The choke settings were

[1] Petroleum Experts Ltd.
[2] EPS Ltd.
[3] Aspentech Ltd.

assumed to be same within the optimization horizon. To forecast the development of the field, the optimization was divided into periods. The settings for each period were found by optimizing from the start of this period to the end of the last period. The initial state of the reservoir for each period was the state of the reservoir from the end of the previous period.

By the use of a history matched reservoir simulator, Thiele and Batycky [34] proposed to compare the efficiencies of the injector producer pairs. The average efficiency for each well was used to move injection of water to injectors with high efficiency.

Model Updating. To reduce model complexity, models only consider a subsystem of the plant, and only a subset of the inputs and the outputs are considered. Their static and dynamic accuracy may also be very different; some assumes steady state and some can only accurately predict changes. Because of this, a model may be good for one application and not so good for other applications.

Models use parameters to describe specific equipments, the reservoirs, and wells. Most parameters may be set by design data. However, because of wear or just simplifications done in the model some parameters change with time. It is therefore important to update them to make sure the model accurately describes the equipments, reservoirs, and wells.

Well. A well model provides the decision makers with data that can be used to decide which wells to produce from and which to not produce from. For instance, if a plant is constrained by its gas handling capacity, then it is crucial to know the gas-oil-ratio. A similar relationship exists for water production. Some wells may also be vulnerable to sand production. If so it is necessary to develop a relationship between some measured variables (e.g. pressures) and the sand production rate, such that the operator can ensure that the constraint is not violated. Other parameters such as the H_2S concentration of the produced gas may be interesting to avoid quality specification violations or for safety reasons.

Well tests are performed by routing a well to a dedicated separator. This separator will separate the three phases, and a flow transmitter is connected to the outlet of each phase. Depending on how the plant is constrained and what type of testing is done, this may or may not result in production losses during testing. In some cases, the test separator will be used for production when not testing. This means that some wells may have to be choked back to let the wells producing to test separator be routed to one of the main separators. Even if the separation capacity is not a limitation, testing may also result in losses because of transients; operators can not run the system on its limit while rerouting.

Well tests may be done on single rate or multi rates. If a single rate test is done, only one choke setting is used. Multi rate tests may be used to establish inflow performance relationships or gas lift performance curves. Nevertheless, they are more expensive because they take more time to run. For each change in the choke, it is necessary to wait for the important dynamics to settle.

As written in the section on *Data Acquisition*, a multi phase flow transmitter may reduce the requirement for well testing.

Instead of using multi phase flow transmitters, the current measurements can be used to estimate the flow from the well using a simulator. Systems such as Well Monitoring System[4] and FlowManager[5] estimate the pressure and flow profile of the well (or pipe network) by minimizing the deviation between currently measured values and the pressure and flow profile in the simulator.

Processing Facilities. During operation different parts of the processing facilities may be worn out. Thus, the capacity changes and the models should reflect this. The update of process capacity is important to ensure that the capacity is fully utilized.

In [35] it was investigated how RTO could be applied to topside processing facilities. Using a rigorous model of the natural gas liquid (NGL) subsystem, it was optimized to give maximal NGL production or “stabilizer bottoms”. Their calculations gave a 2 % potential gain using the optimization of this subsystem for the field considered.

Furthermore, [35] suggested that booster compressors, low temperature separators, stabilizers, MI compression, propane refrigeration, and crude blending could be applications for RTO.

Reservoir. In [36] it was proposed to use a genetic algorithm to do history matching of a reservoir. The solution found by the genetic algorithm was used as an initial solution for a local algorithm to do the fine tuning of the solution.

The approach by Brouwer [32] described above was later refined by Brouwer et al. [37] by including a continuous state estimation of the reservoir. An ensemble Kalman filter was used to estimate the states. The filter utilized the production and injection rates as well as downhole pressure gauges for each segment of the wells.

A data-driven reservoir management strategy was developed by Saputelli et al. [38]. The strategy uses two levels. The upper level optimizes the net present value and the lower level uses model predictive control to enforce the results from the optimization layer. By using system identification and state estimation this becomes a self learning reservoir management system. The concept was later elaborated [39] to a multi-level control and optimization framework. The levels where separated by their dominant time constants.

Kosmala et al. [40] investigated how the accuracy of a reservoir simulation could be extended by including a production network simulator. The two simulators were connected by a common bottom hole pressure. Various control settings were adjusted by a SQP algorithm to maximize the oil production.

Challenges

The term RTO has recently found its way into the oil and gas industry. However, Saputelli et al. [3] noticed that it is used more like a slogan than a system that truly, in a mathematical sense, optimizes anything at all. The technologies in the sections on *Production Planning* and *Reservoir Planning* offer optimization. Often the other references on model updating or estimation somehow claim to optimize too. This is hardly true, even though they support the optimization process. To qualify to a RTO, the system must maximize or minimize some

[4] ABB.

[5] FMC.

defined performance indicator. Furthermore, the method should be systematic.

RTO is, however, not just optimization. According to Figure there are four components in addition to the plant itself. If only the model-based optimization process was included, the same result would be produced over and over again. The model updating component ensures that measurements are fed back to the optimizer. Data validation and optimizer command conditioning do pre and post validation of data, ensuring reliability. A RTO system must at least consist of the model-based optimization and the model updating. Furthermore, few results on systems with all four components of the RTO have been published.

Usually, RTO uses a pure steady state model of the plant. Thus, such RTO only makes sense if the (near) steady state periods are long compared to the transient periods. An oil and gas production system is never in steady state because the drainage process changes the reservoir state. This effect is accounted for in the reservoir planning problems, but more or less ignored in the other problems. Thus, a high short time production rate may hurt long time production rates [3]. Nevertheless, such time decomposition of the optimization has been found to be useful in practice. This is probably because the time constants of the reservoir are very large compared to the fast dynamics of the processing facilities. In fact, a frame work for such a decomposition was proposed by Saputelli et al. [38]. It was emphasized that:

- Separate levels in the optimization problem are necessary to handle complexity.
- Field data should be integrated for continuous learning of key reservoir features.
- The reservoir performance should be continuously optimized without violating constraints.

Until now, few implementations of RTO exist on real offshore oil and gas production systems. Fitting a steady state model to transient data can be challenging and result in erroneous parameters. Some of the models include too many parameters to be fitted using only commonly available measurements. Using simpler models will allow more frequent updates and optimization due to less computational burden. Finding a model with the correct level of accuracy should be addressed. Starting with simple RTO system that solves small sub problems well and later extending them to include new features may be the way to go. Such systems tend to be easier accepted by the management (and the operators) of the plants.

As the RTO uses a steady state model, it requires a stable plant that is able to enforce control settings without violating constraints. For instance, gas lifted wells are often over injected to ensure stability. By implementing stabilizing controllers, production can often be increased without the help of RTO. By installing new feedback control loops or tuning existing, the capacity of the plant can be increased by enabling operation nearer alarm and shutdown levels without increasing the risk of shut down. Such improvements can be done independently of RTO.

Even if the RTO assumes that the plant is stable, there will be transients due to disturbances and changed recommended operation. None of the reviewed papers included a theoretical analysis of the closed loop dynamics of the RTO.

In production optimization, constraints are usually active at the optimal operation conditions. This means that any change in these constraints will affect the optimal operation. None of the reviewed methods consider how the constraints of the plants should be handled in a closed loop way. Thus, if the recommended operation results in violated constraints in the real plant due to plant model mismatch, ad hoc rules will be required to adjust the operation. Such ad hoc rules will reduce the production and perhaps lead to suboptimal production. If the recommended operation has some active constraints, and these constraints do not become active in the real plant operation due to the plant model mismatch, then production can be increased by updating the constraints in the model. A RTO scheme should have such a strategy. Other parameters should be updated as well. The handling of model uncertainty is a key challenge for the success of RTO.

Conclusions

A vast number of optimization strategies for offshore oil and gas production systems have been proposed in the literature. Most of the reviewed strategies were designed for planning the operation of the field. Only a very few of the strategies were designed for closed loop operation. Most were designed for running in open loop as recommendations.

RTO is not a replacement for the base control layer of a plant, but utilizes the base control layer in its operation. RTO is a scheme that uses a mathematical model of the plant to optimize the production. The model is updated by using available measurements. The scheme should update processing facility constraint parameters to cope with plant model mismatch.

For the reservoir planning, various strategies have been proposed that use a dynamic model in the optimization. This is due to the dynamic nature of the drainage process and the injection. For the more short term production planning, steady state models are dominating and few RTO approaches have been proposed. The varying and hard to measure feed from the wells make it hard to reuse existing steady state RTO solutions from the petrochemical industry. To succeed with RTO here, a key challenge is to be able to handle the uncertain and changing properties of the feed and the dynamics it introducing in the processing facilities. Using RTO with dynamic models will allow handling of the uncertain and varying feed.

Acknowledgement

We thank The Research Council of Norway for financially supporting this work.

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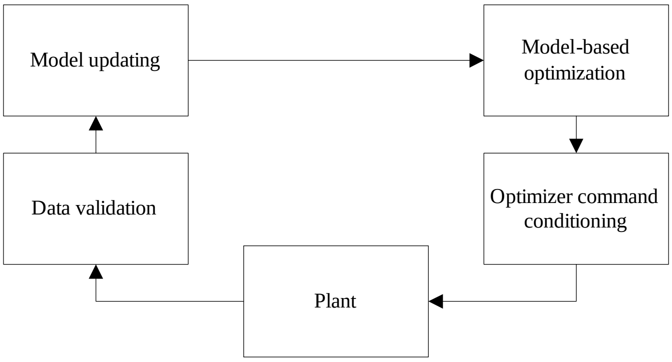

Figure 1 The process flow in a typical RTO.

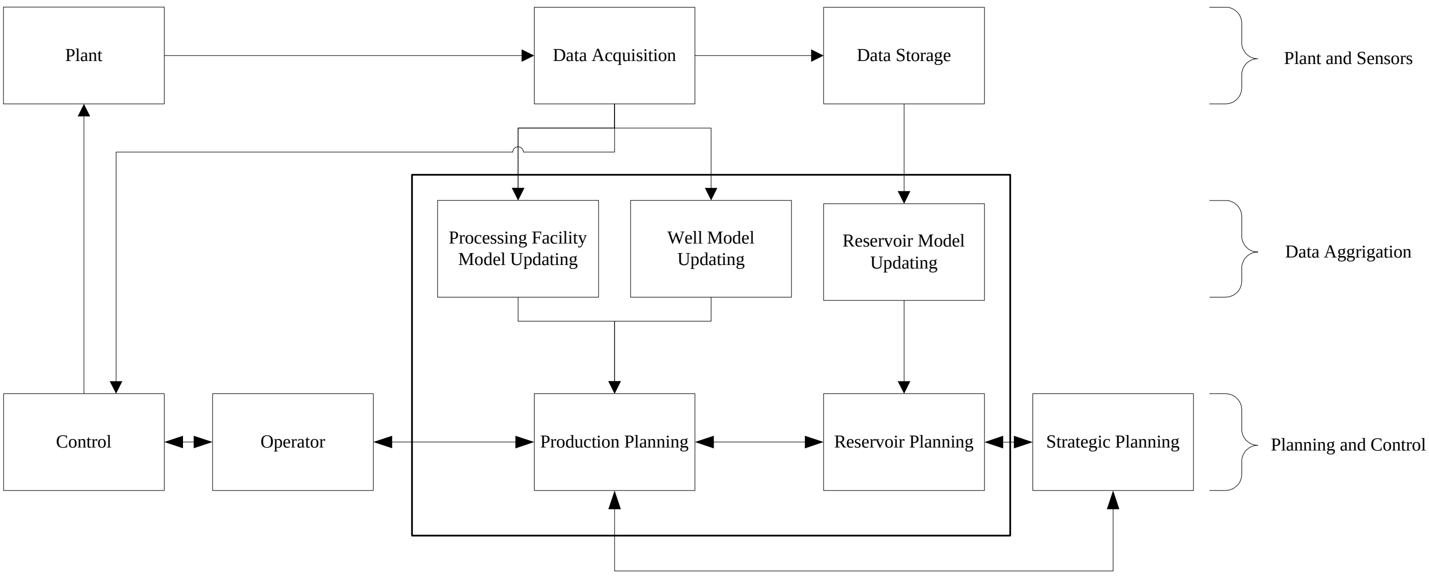

Figure 2 Information flow in production optimization.