Uncertainty, Risk and Decision Management on the Ormen Lange Gas Field Offshore Norway*

By
Eirik A. Berg[1], Per A. Kjarnes[1]

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[1]Norsk Hydro ASA, Oslo, Norway

Abstract

The Ormen Lange gas discovery contains approximately 500 GSm^3 gas initial in place. The gas is dry (GCR of approximately 11,000 Sm^3/Sm^3). The field is planned for governmental sanctioning by 1st quarter, 2004. Production start-up date planned is October, 2007. This paper reviews, historically, the partnerships effort in risk and decision management and actions taken in reducing the subsurface uncertainties. Furthermore, risk assessment and mitigating processes are discussed. The methodology used in evaluating the uncertainties and risks are presented, emphasizing the rapid modeling update approach used to ensure a sufficiently detailed and technically sensible approach within the limited time frame between the final parameter updates and project decisions.

Introduction

The Ormen Lange gas field is operated by Norsk Hydro (development) and Shell (production). The Ormen Lange Field is situated 100 km off the west coast of Norway (Figure 1) and has an areal extent of 350 km^2. Four gas wells and one dry well have been drilled to appraise the gas discovery. The reservoir (Figure 2) is severely faulted by polygonal faults. The reservoir is at 2913 m at the deepest in south and approximately 2650 m at the shallowest to the north.

Field development (Figure 2) involves 24 subsea production wells, two 8-slot templates from production start-up, and 2 more templates, if required, at a later date. The gas will be depleted with compression added as required. At DG3, an alternative concept, with clustered platform wells, was also evaluated.

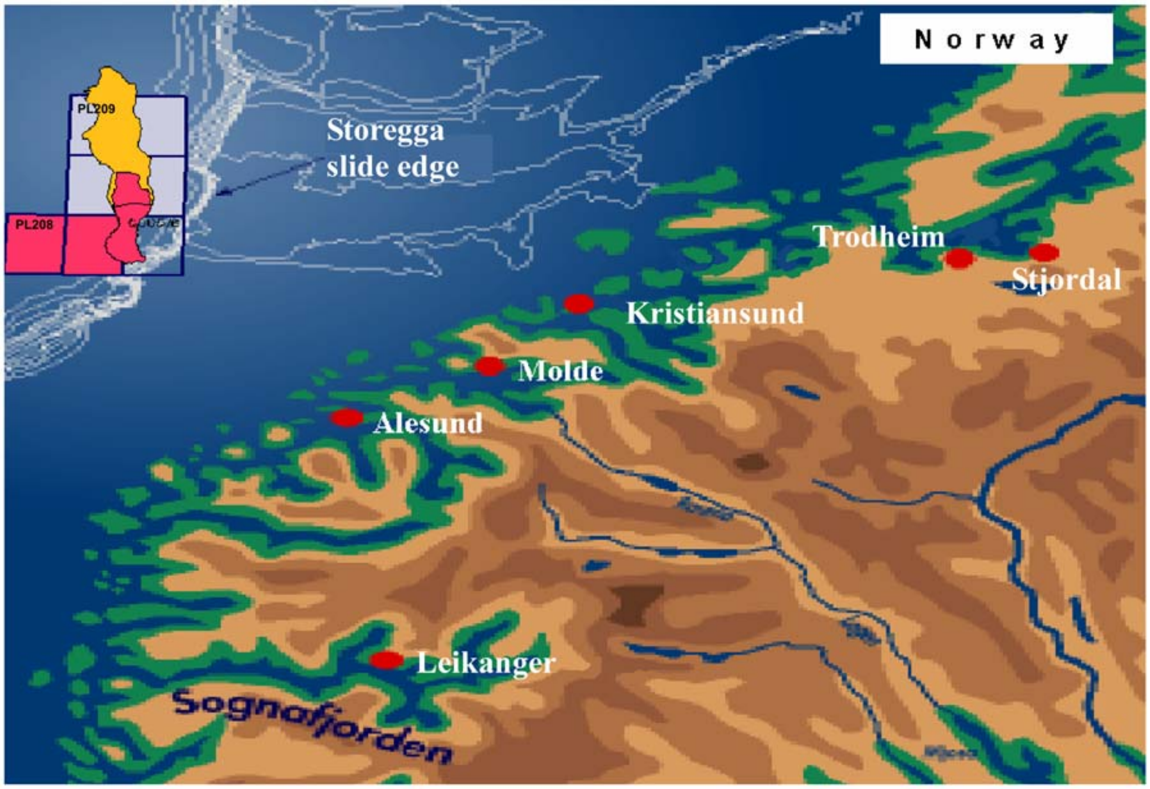

Figure 1. Location map of Ormen Lange gas field, offshore Norway.

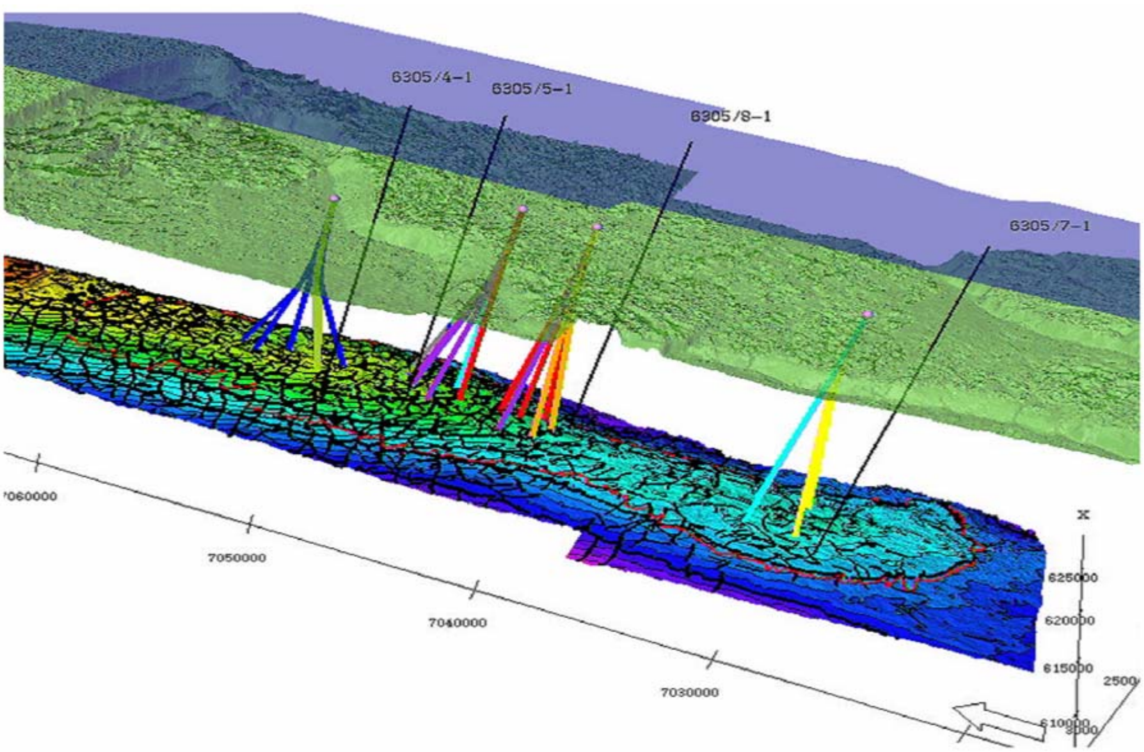

Figure 2. Water, seabed, and reservoir maps with planned wells

Uncertainties / Risks, Decision/Management Process, and History Lessons

Uncertainties and Risks

The main subsurface uncertainties and risks anticipated since the discovery (1997) have been:
1. GIIP uncertainty (lack of well control)
2. Reservoir quality: Related to the thinning and possibly increased shale content in the turbiditic sandstones in flank, saddle, and distal areas.
3. Fault properties: Approximately 700 polygonal-type faults have been interpreted within, or close to, the reservoir-containing section. Stepping of GWC is observed. The fault-sealing properties (modeling) are important for estimation of reserves and field development considerations.
4. Rough seabed and varying water depths lead to challenging depth conversion, and great efforts are required in planning the placement of seabed installations (templates and pipelines).
5. High water production from formation or surrounding aquifer may lead to hydrate problems.

Decision and Management Process

A decision and management process was agreed to by the joint partnership (1999):
1. A governance process divides the project into stages, milestones, and decision gates with agreed-upon support documentation.
2. A risk assessment process supports the governance process. Risks and opportunities are ranked in accordance with probability and consequence. The highest ranked risks have high-occurrence probability or large consequence. These are treated as management level issues. Lower ranked risks are then technical or watch-list-level issues. Risks throughout the governance process either will be resolved, through work, or mitigated through the field development strategy.
3. A risk-based internal and external verification process is carried out.
4. Technical and economical evaluations and approvals at each decision gate, involving base, low and high cases and scenarios and uncertainty evaluation at discipline and total project level.
5. Use of decision trees and value of information exercise to decide on further investments.

History: Objectives and lessons learned:

Lead Phase

The flatspot was interpreted as a GWC on a single seismic line in late 1980's. 2D data (1992) supported initial observations, and in 1996 3D seismic data were acquired and processed on board (Norsk Hydro). The seismic interpretation (Figure 3) confirmed early work. Mapping of interpreted flatspot and AVO (amplitude versus offset), DHI (direct hydrocarbon indicator), showed that the 350-km^2 field outline was likely gas-filled.

The geological model was a turbidite sourced from the southeast with potentially deteriorating reservoir quality north of the mapped DHI.

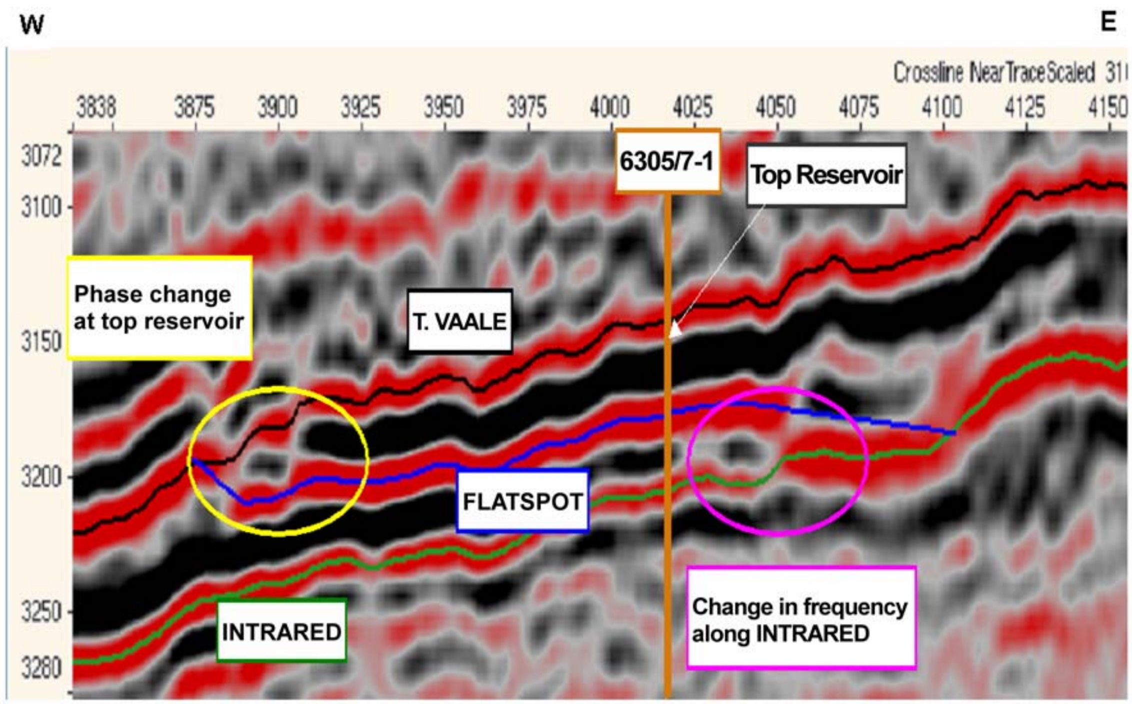

Figure 3. Seismic profile, showing flatspot and reflectors enveloping the main reservoir Egga Unit--T. Vaale and Intrared.

Exploratory Phase

PL209 (Norsk Hydro operated) and PL208 (BP operated) were awarded in early 1996.

6305/5-1 (NH 1997) was drilled high on the structure proving gas down to 2763 mMSL. The reservoir model (Figure 4) was confirmed as an Upper Cretaceous and Lower Tertiary sand-rich, high-density turbidite. The reservoir may be split into sand-rich channel and channelized lobe facies and frontal splay and a distal mudstone facies with thin interbedded sandstones. The main reservoir, Egga RU, contains sand with a thickness of approximately 50 m, a net to gross ratio of 90% and permeability approaching 500 md in average. The water saturations are ranging from less than 20% to more then 40%. At this stage the cause of the high water saturations was questioned. It was found that the reservoir sands might be divided into a clean sand (C-Sand) and a green shale-rich part (G sand). The C sand was split into an upper (low Swi) and a lower (high Swi) part. The non-reservoir part consists of shale and calcite (cemented) zones. This forms the building blocks of the reservoir modeling work.

· 6305/7-1 (BP 1998) to the south proved a GWC at 2913 mMSL. The well successfully tested and confirmed the good reservoir characteristics anticipated. No faults were observed. Similar gas pressure was found as in 5-1. A 14-m zone of residual gas was encountered below the FWL.

· 6305/1-1 (NH 1998) was drilled to the north of the mapped DHI gas effect. The well had only gas shows in a silty and shaly sequence (less than 1 m of sand). Reservoir pressure was 80 bar overpressured as opposed to the normally pressure gas-filled Ormen Lange.

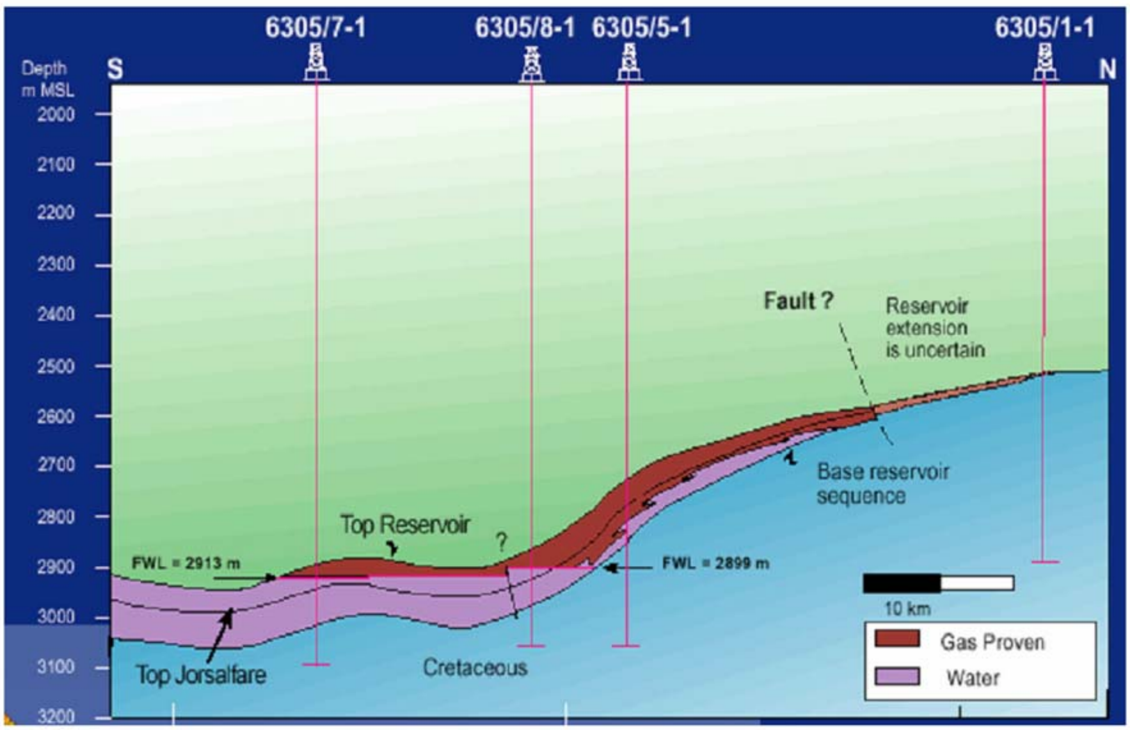

Figure 4. Simplified cross-section through the reservoir.

Appraisal Phase

PL250 (Shell operated) was awarded late in 1999. The Ormen Lange unit was established with Norsk Hydro as operator for the development and Shell for operation. It was decided to enter the concept selection phase. An appraisal strategy was agreed to, with one firm and one optional well.

· 6305/8-1 (NH 2000) was drilled in the saddle area (Figure 4), considered to have uncertainties in reservoir quality. The well proved good reservoir quality. A specially designed MDT water sample proved fresh formation water, confirming previous high Swi calculations. The high Swi was shown to be a function of pore throat size (sorting) and clay content and type (coating or particles and smectite content). The well proved a shallower contact (FWL of 2898 mMSL) than 7-1 and penetrated a 2-m thick oil column and 7 m of residual oil at the base.

· Seismic modeling work was performed in 2000 to evaluate the influence of residual gas on the interpreted flat spot. It was concluded that this zone may influence the well tie.

· In 2001, after a period of testing and evaluation, the partnership approved reprocessing of the seismic data focused on removal of seabed-generated multiple energy, in combination with improved seismic imaging by pre-stack depth migration (PSDM).

· It was decided to drill, and test, 6305/4-1 (NH 2002) prior to deciding on concept (DG3). The well was designed to penetrate the reservoir north of, and deeper than, the 5-1 well to disapprove a possible dynamic aquifer fed from the north. The main objective was, however, to perform a fault seal / depletion test in a closed and fault-bounded segment with good reservoir quality. It was desired to drill the well in an area with high seismic quality inside a clearly defined flatspot. Special efforts were placed on planning the test design. A numerical simulation model was required that could be used for evaluating test results. The grid was designed to minimize numerical dispersion (local grid refinement). The well successfully penetrated a gas-filled reservoir deeper than 5-1. The result supported a reduced GIIP uncertainty acceptable to all partners for approaching the DG4 stage. Furthermore, the test well (Figure 5) clearly showed faults seals in a limited 1x1x1-km u-shaped fault intersection just west and 500 m to the east of the well. However, the test disapproved depletion and also showed pressure support from outside the mapped faults east of the u-shaped fault.

The PSDM-reprocessed seismic data successfully improved the data quality in large areas, increasing the confidence considerably of the seismic interpretation, including fault definitions and well ties.

The uncertainty evaluation has been built on a principle of system development:
1. Get the owners and users involved.
2. Use a problem-solving approach.
3. Establish phases and activities.
4. Establish standards for consistent development and documentation.
5. Justify system as capital investment.
6. Don't be afraid to cancel.
7. Divide and conquer.
8. Design system for growth and change.

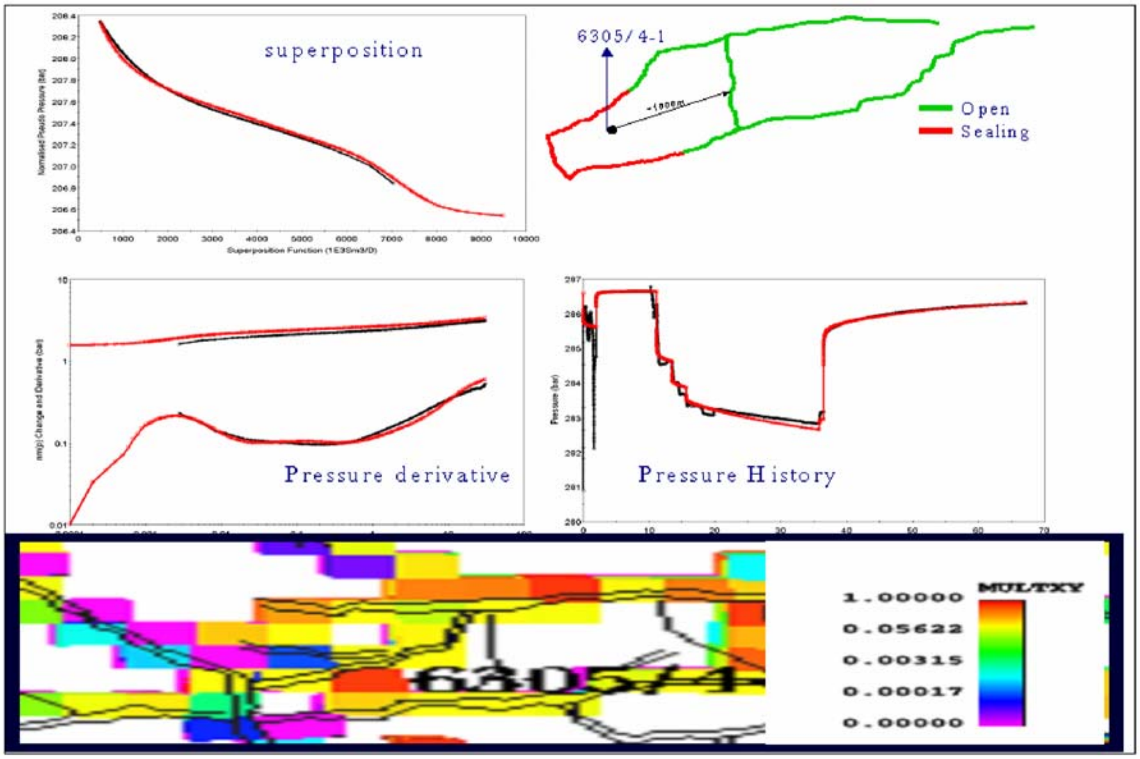

Figure 5. Test results, well 6305/4-1.

Uncertainty Work Flow

An Uncertainty Work Flow was set up early in the project, as follows:
a) Selection of input parameters--Task, milestones, and meetings on inter- and intra-disciplinary level. Qualitative and quantitative evaluations to limit parameters to be brought forward; i.e., uncertainty in porosity estimates is small compared to depth map and water saturation uncertainties.
b) Definition of input parameter levels--Parameter levels spanning the range of possible outcomes were identified early, while probabilities and weights to carry forward were not requisite until later in the uncertainty workflow. The results were files or values that may be combined in volume and dynamic models.
c) Experimental design was used to reduce the number of required dynamic simulations to about 100 without loosing significant information. The D-optimality procedure was used.
d) Calculations of response parameters were made by use of reservoir modeling and simulation to evaluate parameters having an influence on bulk, GIIP, reserves, production profiles and plateau.
e) Regression models were estimated for recovery factors and plateau length. Based on statistical and visual quality controls, simulations were added iteratively to achieve a satisfactory confidence level for the model.
f) Distributions/correlations of input parameters were evaluated late in the process when the technical work had sufficiently matured. The benefit of the workflow is the possibility

to change distributions and individual parameters at any time during the uncertainty workflow.
g) Monte Carlo simulation was used to combine the regression models including model uncertainty and the probability distributions of the input parameters. 5000 iterations were run.
h) Analysis and recommendations--The results were analyzed by extracting key statistics (P90/Exp./P10) from the data, plotting probability distributions, and using tornado graphs to rank the input parameters quantitatively.

Recommendations for Further Work and Focus

Recommendations for further work and focus were given. A rapid modeling update approach was used in order to be able to run the project in parallel within the time constraints at each decision gate; it was decided to: 1) Prototype the work flow, 2) Use programming scripts to initiate, close, and monitor the different modeling and simulation tools in an automated way, and 3) Encourage, in practice, a flexible approach in which both fully or semi-automated workflow is allowed. This preserves available deterministic models and scenarios and simulations that would be tedious and unnecessary to rerun in a loop. As example, in DG2 all models were simple, while the time was constrained. As such, a fully automated loop was first prototyped, then updated, and simulation finally rerun overnight. Later studies involved more complex and slower models, and a more semi-automated process was implemented. Automation was used to fill gaps in simulations run. The methodology proved flexible concerning iterations with a possibility to modify continuously probability distributions, change the number of input parameters, including additional simulation results and have late updates of input data.

System Growth and Change

A success factor for projects with constantly new data and access to more sophisticated procedures is to establish a framework where the individual elements easily can be replaced. New ideas, possible refinements, simplifications or tests of work around to save time were planned and, if possible, prototyped prior to full implementation. New methods or tools require backup solutions.

From Reservoir to Market

All parameters from geology to production technology that may influence reserves, well layout, and production profiles, including uncertainty in well performance and pressure calculations, were considered. The results were directly used as input to the economical and field development evaluation.

Results/Analysis

The results were analysed and used as input to the governance process. The relative ranking of the input parameters, as shown in the example tornado graph in Figure 6, indicates which parameters should be the focus in the next phase. GIIP, fault properties, and pressure available at well head are found to be of high importance for reserves estimates.

Divide, Conquer, and Solving Problems

Simple process and data-modeling techniques were used to divide the tasks and uncertainties into individual workflow, as exemplified in Figure 7 and Figure 8.

In the example, bulk volume uncertainties related to geophysical interpretation, velocity models, and depth maps were performed using a Monte Carlo based reservoir model loop, with results later integrated into the main study.

Fault Modeling

The technical level of the fault modeling has increased several times since 1999 when all faults were distributed stochastically in the geological model. In 2000 the largest faults were interpreted as deterministic and the smaller faults were included stochastically. In 2001 the location and throw of the smaller faults were estimated from dip maps. The fault sealing properties were estimated based on throw classes. In the latest models, all faults are deterministic, and the sealing properties are estimated from throw and amount of shale (Vsh).

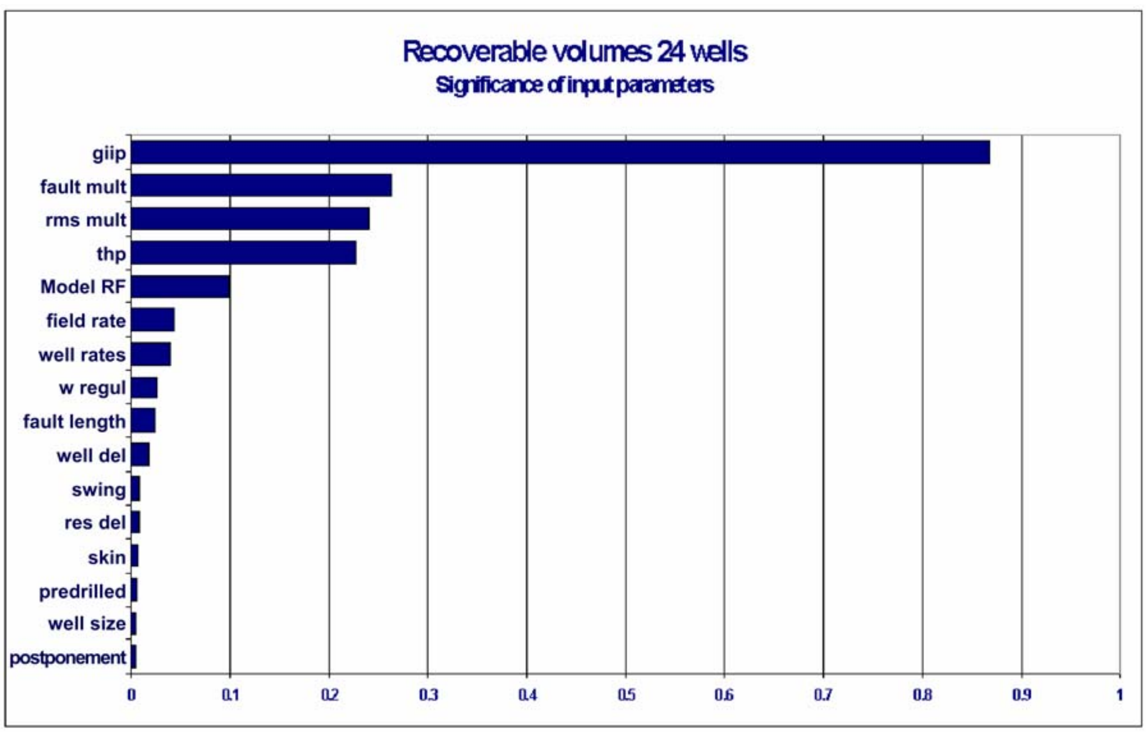

Figure 6. Tornado graph: Recoverable volumes.

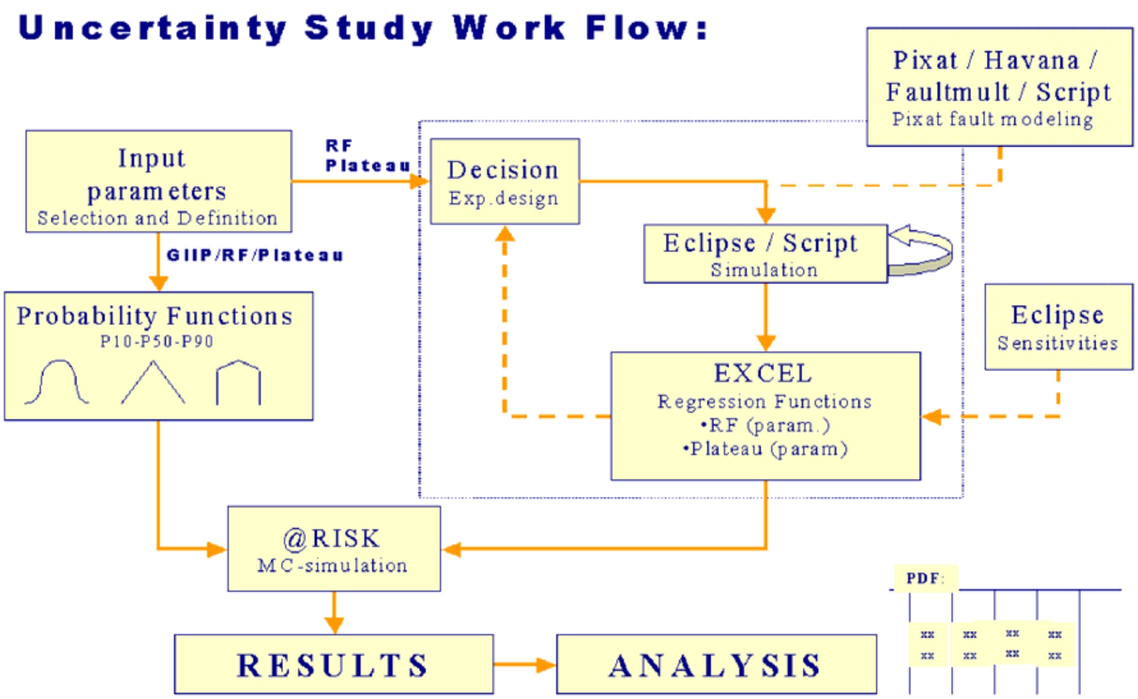

Figure 7. Uncertainty study workflow.

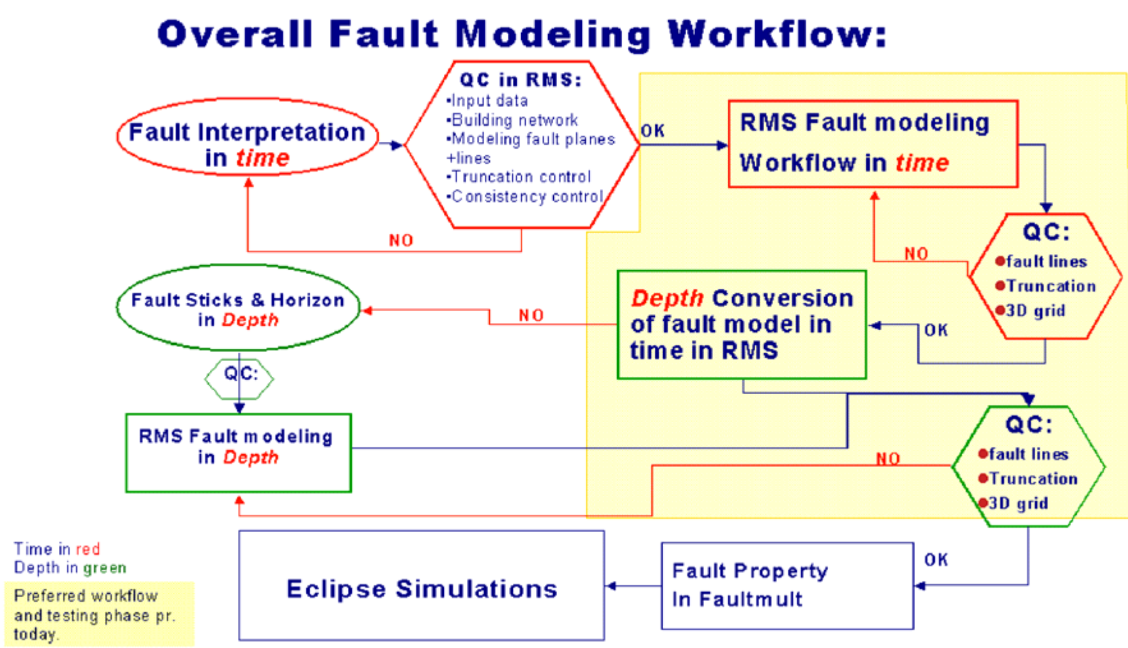

Figure 8. Fault modeling workflow.

Water Production

Aquifer mapping, sensitivities, analogy studies, and analytical evaluation were used to study water production. Only small volumes of water are expected. A water handling strategy was established with a plan to reduce gas rates or shut-in off-water-producing wells. Need for non-saline water-measuring equipment was noted as a risk mitigating requirement.

Quality Control and Calibration

Special care was taken, using company guidelines, to honor all input data whether soft (interpretation) or hard (wells); i.e., input and out put data must be matched by inspecting statistical data and log data (blocking of wells) and comparing the conceptual models against reservoir modeling results. The upscaling from geological model to the reservoir simulation model was tested with alternative algorithms, and numerical and grid size issues were sufficiently tested. As an example, visual inspection showed that use of a grid that was too coarse led to severe fault sampling (alias) errors with individual faults linked-up in the grid.

Conclusion: Impact Concept Selection

An integrated methodology for uncertainty evaluation has been developed. Results have been used in risk assessment and management, appraisal strategy, governance process, and selection of field development concept.

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