Uncertainty Study on In-Place Volumes in Statoil

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Abstract This presentation focuses on a field case where the Statoil standard workflow for estimating the uncertainty in in-place volumes is used. It is exemplified by a complex field outside Norway. Uncertainties analysed, modelled and combined are seismic time interpretation, depth conversion, isochore thickness, fluid contacts, petrophysical uncertainties, uncertainties in geological mapping and uncertainties in fluid formation factors.

Introduction

In Statoil there is a requirement to undertake a thorough uncertainty analysis before making an investment decision. The decision to go for the project or not, or the choice between different field development concepts, are made on mean values and not on deterministic reference values. Hence it is important to estimate mean production, mean net present value, mean cash flow etc. for the different alternatives and decisions. Understanding the volume uncertainty and estimating the volume uncertainty range are important input for risk mitigation actions such as defining flexibility in the field development plan and finding robust solutions that are optimal over a range of outcomes rather than optimal on the reference case understanding of the field.

Hence, a good decision basis should include good estimates of the uncertainty in both the in-place volumes and in the dynamic properties affecting flow. This presentation focuses on the in-place uncertainties.

Introduction to the exploration history

An overview of the field and a map with the drilled wells is given in Figure 1. The field was discovered in the 70s and classified as a gas discovery. Several new exploration wells have been drilled. Many of the new wells gave surprising results

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conflicting with the former conception of the field. The new data showed a higher degree of complexity of the field than realized before. The first two wells gave a good indication that this was a pure gas field, see Figure 2. The project was heading for a gas field development, but decided to postpone the decision while waiting for the result of a nearby exploration well. This well, Well 3, was a surprise, proving an oil leg on the east side of the structure, see Figure 3. This raised the possibility of an oil leg on the western side as well and Well 4 was drilled confirming the oil leg, see Figure 4. This changed the understanding of the reservoir to a case where the oil leg is communicating through the entire structure. Well 5 and its sidetrack were drilled failing to prove the oil leg in the center of the field, see Figure 5. Hence the understanding of the field changed again showing increased complexity.

So, looking back on the exploration history of the field, the conceptual understanding of the contacts has changed several times through its history. Hence there is no reason to believe that the present understanding of the field is absolute and will remain unchanged as new wells are drilled. It is therefore important, when making a field development plan, that this uncertainty is acknowledged and estimated. If one does not acknowledge that the present day understanding of the field is incomplete, one is likely to develop the field in a suboptimal way without having the opportunity for capturing upsides or mitigating downsides that might appear.

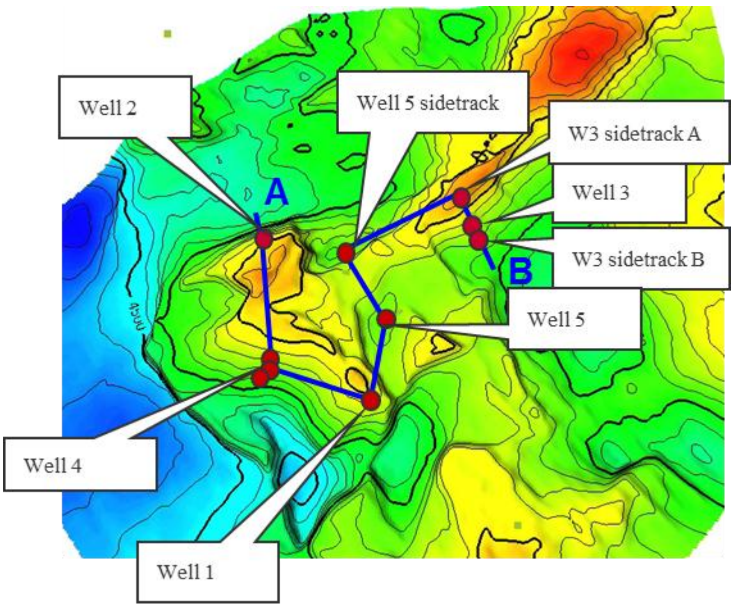

Figure 1. Overview of the field with the position of the different wells. The blue line indicates the position of the random lines in Figure 2 through Figure 5.

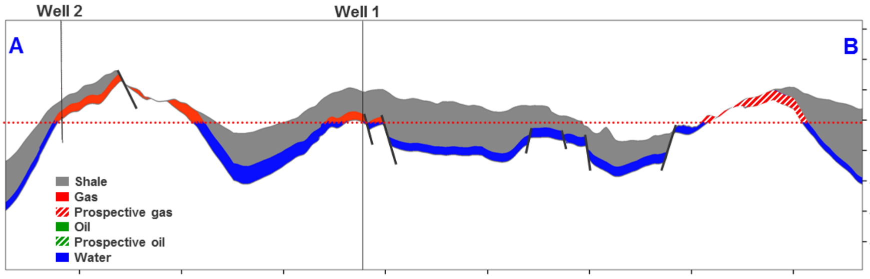

Figure 2. After 2 wells. The concept was a gas field with prospective gas area to the east (right hand side). The position of the random line is indicated on the map in Figure 1.

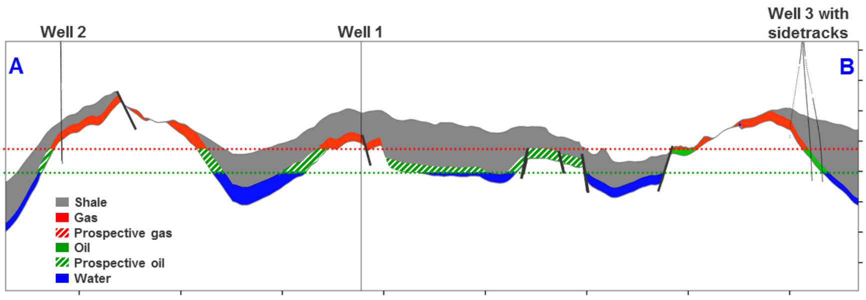

Figure 3. After 3 wells. An oil leg is discovered to the east, suggesting a model with a continuous oil leg.

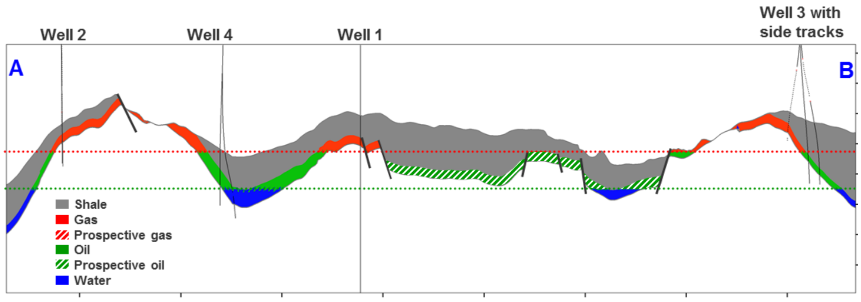

Figure 4. After 4 wells. The oil leg model is apparently confirmed giving prospective oil in the central area of the field.

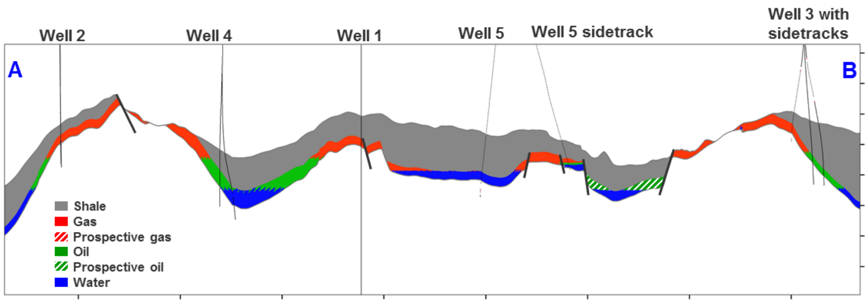

Figure 5. After 5 wells. No oil leg in the centre of the field. The model is growing in complexity.

Uncertainties

When building a geological model one has to go through a thorough subsurface evaluation including interpreting seismic data, performing time-to-depth conversion, interpreting log data, establishing geological conceptual models, building a 3D reservoir model, and estimating fluid contacts and fluid types in the different areas. Then it is important to acknowledge that at each step there are uncertainties, both in the data that are used, the selection of which data to include, and in the interpretation of the data. In an integrated uncertainty analysis it is important to include all these uncertainties in the value chain from seismic interpretation to volume and value calculation.

The uncertainties included in the uncertainty analysis of in-place volumes are

1. Seismic interpretation.
2. Time-to-depth conversion
3. Hydrocarbon contacts
4. Isochore thickness
5. The estimate of the petrophysical properties from the well logs.
6. Mapping of petrophysical properties between the wells.
7. Facies distribution and conceptual geological model
8. PVT as Bo, Bg, GOR, LGR.
9. Probability of discovery of undrilled segments.

Estimating input uncertainties

Seismic interpretation

Uncertainty in seismic interpretation is estimated based on the resolution of the seismic signal and quality of seismic well ties. This uncertainty is modeled as a Gaussian random field with expectation zero. The sill is varying laterally from segment to segment and estimated by the seismic interpreter. An alternative interpretation with deeper erosion in some areas is also included as a scenario.

Time-to-depth conversion

A velocity model is estimated between each of the seismic reflectors, see Figure 6. The uncertainty model includes uncertainty in the average velocity (velocity trend) as well as local lateral variations on top of the trend. Alternative velocity models are also evaluated but only the reference model is included in the uncertainty evaluation.

The depth conversion model is illustrated in Figure 6. Consider the thickest interval being from Seabed to the seismic reflector in the overburden. The velocity model is simply a constant velocity. The value is estimated as the average of four of the exploration wells. The average model is clearly a simplification of the reality as it does not fit any of the wells, see Figure 7. Hence there is an uncertainty in the average velocity and, in addition, there must be a component of laterally varying velocity. This is a general statement valid for all velocity models. It is important not only to include the residual uncertainty being local variations around the trend, but also the trend uncertainty. For large fields the effect of including only the residual uncertainty tends to average out, while the uncertainty in the trend can lift or lower large areas of the reservoir at the same time. The stochastic velocity model is defined as

$$V_{int} = A * const + R_v$$

where *const* is a map with value 1 in each grid node, *A* is a normal distributed variable with mean 2239 m/s representing the velocity trend and a standard deviation equaling 7 m/s representing the uncertainty in the velocity trend. R_v is a Gaussian field with a spherical variogram with range 1500 meters and sill 15^2 m/s. Since there are only a few wells the variogram shape is hard to estimate.

Hence a standard shape is used based on experience from fields in the same area with more wells.

Similar models are made for the other intervals, but will not be discussed here.

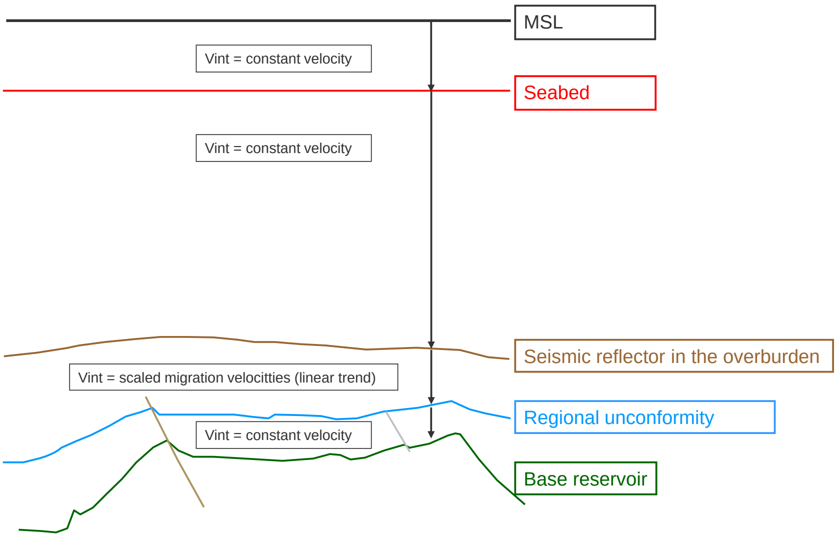

Figure 6. A sketch of the depth conversion model with the seismic interpreted surfaces.

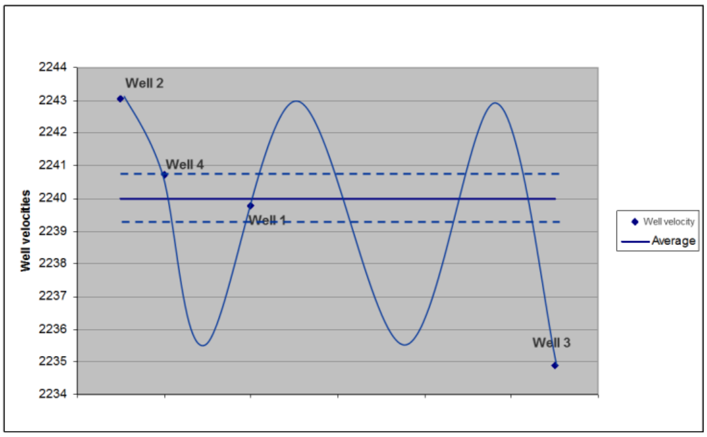

Figure 7. A constant velocity model (average velocity) is used for the interval between Seabed and the seismic reflector in the overburden. This model is clearly a simplification as it does not fit in any of the wells. Hence there is an uncertainty in the average velocity illustrated by the dashed lines. In addition there must be a component of lateral varying velocity illustrated by the undulating line.

Gas-oil contacts and oil-water contacts

There is a large variety of contact observations. In some segments actual contacts are observed. For some of these, the gas-oil-contact is observed but not the oil-water contact and for other segments only the oil-water contact is observed. One of the segments has a possible oil column, and hence possibly observations of both the oil-gas-contact and the oil-water-contact. . Uncertainty in the fluid contacts is established through a cross-disciplinary team effort. The input comprises log-observations, pressure data, fault-seal analysis, analysis of spill-points and break-over points, a general understanding of the kitchen areas and migration, and general understanding of the field and information from wells in the area near the field under study. The most likely values of the distributions are generally estimated using pressure data and gradient intersections.

It is important not only to include the uncertainty in the contact given the underlying assumptions, but also the uncertainty in the underlying assumptions.

1. If an oil-down-to is observed the maximum contact depth is the spill point. However, the depth (and position) of the spill point is uncertain due to uncertainty in the depth conversion model. Presence or absence of sealing faults may change the definition of spill point drastically.

2. In some cases the gas-oil contact is observed and pressure measurements and fluid samples are taken from the oil zone but no samples or measurements are made in the water-zone. If the neighboring segment has pressure measurements in the water zone it is assumed, as a reference case, that the water zones in these two segments are in pressure communication. Then the oil-water contact can be estimated with the uncertainty defined by the uncertainties in fluid density and pressure measurements. However, the assumption that the water is in pressure communication should also be challenged and included in the uncertainty evaluation giving a complex uncertainty picture and large spans.

Hence segments with observations of both gas-oil and oil-water contact has smaller uncertainties, while other segments are assigned an uncertainty of several hundred meters in both gas-oil contacts and in oil-water contacts. The contact uncertainties within a segment are of course correlated.

Isochore thickness

The individual reservoir zones cannot be interpreted from the seismic data. The zonation is based on biostratigraphy from well cores and cuttings. There is a large variation in the isochore thicknesses observed in different wells, with rapid changes between neighboring wells. The isochores are estimated by combining well observations and a conceptual understanding of the depositional model, erosion and tectonic activity. The uncertainty in average thickness and the lateral variations are estimated based on expert judgment and the variability between wells. Hence the stochastic model for the isochore thickness is similar to the velocity model

$$D_{isochore} = F*BC_{isochore} + R_{isochore}.$$

A similar model is used for all isochores but with different input statistics and trends. $D_{isochore}$ denotes the thickness of the isochore, F is a normal distributed variable with mean 1 and standard deviation around 0.05-0.1 varying from isochore to isochore, $BC_{isochore}$ is the deterministic isochore in the reference model and $R_{isochore}$ is a Gaussian random field with zero mean, sill varying from 15^2 to 30^2 meters for the different intervals and range 2500 m.

Estimates of petrophysical properties in the wells

It is not uncommon that the estimates of net-to-gross, porosity and saturation from the well logs are considered as hard data. There can, however, be a significant uncertainty in these estimates, see [1]. Since all wells are using the same petrophysical models, the uncertainties might be strongly correlated since they share common assumptions and common model parameters. These model parameters also have a significant uncertainty. Since the well properties are used to condition the property distribution in the reservoir model, the well uncertainty influences the volumes in the reservoir. The well uncertainties are estimated by the petrophysicist and reported as a univariate probability distribution for zone average for each well. The various distributions are correlated since common model parameters are used in the estimates of the petrophysical properties.

Mapping of the petrophysical properties between the wells

This is estimated by running several stochastic realizations of the (transformed) Gaussian field on the reference case model and by evaluation of the uncertainty in the geological conceptual model. The uncertainty related to geological concepts is quantified by creating different models and comparing model volumes.

Mapping of facies

This uncertainty is estimated in two ways.

1. Assume that the reference geological conceptual model is correct. Estimate the uncertainty in fractions and spatial distribution of facies. The corresponding volume uncertainty is estimated by running several stochastic realizations varying seed and facies fractions.

2. Acknowledge that the geological conceptual model is not fully understood. Make alternative deterministic cases representing an optimistic concept and a pessimistic concept.

PVT

Fluid samples are retrieved from most of the segments with wells. Here the uncertainties in the expansion factors Bo and Bg and ratios LGR and GOR are relatively small and mainly due to uncertainty in the lab-results. The fluids change significantly across the field, and there is a large uncertainty in segments with no fluid samples. This uncertainty is estimated using information from the drilled wells and the variation in fluid properties across the field.

Probability of discovery

Since several of the segments are undrilled, volumes are not proven. The probability of discovery ranges from 0.02 to 0.9. The field development concept is chosen based on proven segments only, but some additional capacity such as number of slots and processing capacity, are added to be able to produce from these segments if they prove to be a success. Some of these segments cannot be reached from the planned platform, and must be drilled using an exploration drilling rig.

Modeling and combining uncertainties

The uncertainty workflow

The best way to combine all these uncertainties is to build hundreds of different geomodels with different sets of depth surfaces, fluid contacts, facies distributions, petrophysical properties and PVT. This would, however, be a complex task and potentially too time consuming. One of the problems is that including the uncertainty in well log estimates are difficult in the software used (IRAP RMS).

Hence the overall workflow for the field under study is like this:

1. Use Cohiba, see [2] and [3], to model and combine all uncertainties in seismic time interpretation, the velocity model and the isochores to generate hundreds of sets (realizations) of depth surfaces. Cohiba is a tool based on Bayesian kriging and simulation

2. For each of these realizations build a 3D geological grid.

3. Combine contacts sampled from the contact uncertainty model with the grids and calculate GRV for gas and oil zones in the different segments and the different geological zones.

4. The effect of the uncertainty of petrophysical well estimates and in the mapping of the petrophysical properties are estimated based on the reference model. Similar for uncertainty in facies distribution, Bo, Bg, GOR and LGR. These are represented as scalar uncertainties for each variable for each zone and segment. Correlations across zones and segments are applied where appropriate.

The STOIIP-uncertainty for a given segment in a given zone is modeled as

$$STOIIP = GRV * hcpf_{model} * E_{well} * E_{map} * 1/B_O * P_g$$

where GRV, E_{well}, E_{map}, B_O and P_g represent scalar stochastic variables. GRV is the volume calculated from combining the uncertainties in time interpretation, alternative erosion scenario, depth conversion isochore thickness and the fluid contacts. A histogram is displayed in Figure 8. The term $hcpf_{model}$ is simply the $hcpf = hcpv/grv$ from the reference model. E_{well} is the volume uncertainty resulting from the uncertainty in the petrophycial properties from the well logs. E_{map} is the volume uncertainty estimated from sensitivities in the mapping of petrophysical properties, B_O represents the uncertainty in the B_O factor. The uncertainties in E_{well},

E_{map} and B_O are modeled by beta-distributions. The choice is just a pragmatic choice because the beta-distribution is flexible and can be skewed both ways and has compact support. P_g is a discrete stochastic variable representing the probability of discovery of the non-proven segments.

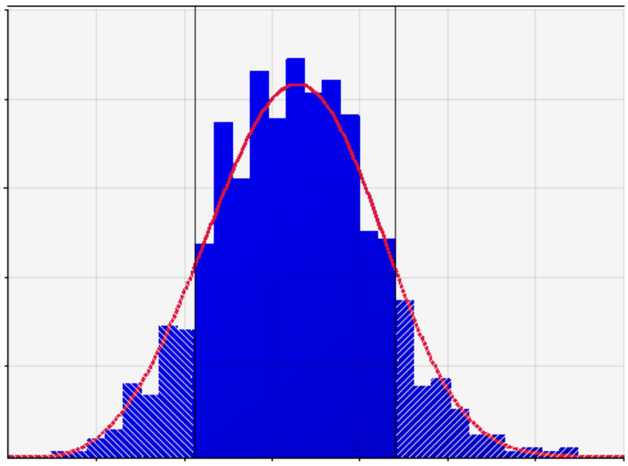

Figure 8. GRV-distribution for a given zone, segment and fluid type generated by combining depth surfaces from Cohiba and sampled fluid contacts.

Results

The alternative seismic interpretation with the deeper erosion gave a significant downside on the gas volumes.

Uncertainty in fluid contacts and depth called for pilot wells to place the production wells in an optimal position.

The spread in estimated volumes is large considering the number of wells. It could span from a lot of gas and less oil and opposite, each outcome having a different optimal field development plan. There are large upside and downside potentials in volume and location of oil and gas. The results from the in-place uncertainty study are used as input to a dynamic uncertainty study where one seeks to find a development plan being optimal over the large range of outcomes and not optimal only on the reference case.

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