The role of Geophysical Uncertainty in Field Development concept selection*

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We present a great way to improve the net present value of a field development project through cooperation between the subsurface and engineering teams. This study shows how field development concept selection can start at least one phase earlier, in parallel with appraisal drilling, leading up to earlier start of production.

Abstract

The paper presents a parallel, probabilistic approach to field appraisal and development concept selection, rather than the conventional sequential approach. Instead of waiting for appraisal drilling to confirm and finalize the reservoir model, front end concept selection work is started at an earlier stage, based on a model with a high degree of uncertainty. Stochastic depth conversion uncertainty analysis is used to calculate P10 - P50 - P90 structure maps and gross rock volumes, thus quantifying the uncertainty. A series of field development concepts are being estimated to handle the entire uncertainty span. An optimized appraisal drilling program is then proposed, for the purpose of eliminating those uncertainties which would swing the field development concept selection. This combination of geophysical and engineering disciplines leads to a field development scenario with a minimal drilling cost spent on appraisal, and with an assurance that the optimal field development concept has been chosen.

Introduction

A number of cost intensive and technically crucial decisions need to be made in oil and gas field development. A broad range of issues are involved, within geology and geophysics (G&G), reservoir management, drilling/completion technology, production strategy, facilities size/solutions, infrastructure and transportation to the market. Deciding on the right field development option requires an organization that works closely together across the disciplines. Oil and gas companies have come a long way in using modern simulation and modeling tools which are suited for such cooperation.

We have, for the purpose of this study, constructed a synthetic data set, the Aker Field, which is in the early stages of field development planning. The latest exploration well has made a significant oil discovery. The field is located in the Norwegian North Sea. The reservoir is situated relatively shallow, at a depth of about 4675 ft. under 660 ft. of water. Current data indicate that the reservoir has excellent flow properties in clean sands with no indications of complex faults and barriers, but there is still significant uncertainty with regards to top reservoir depth, and as a consequence, the lateral extent of the field. Based on seismic mapping, and reservoir properties from wells in the area, the Aker Field looks very promising, and plans for field appraisal drilling and field development are being made.

The conventional (sequential) approach would be to start with appraisal drilling, confirming the reservoir model of the field, and then hand that model over to engineering as the basis for development concept selection. The alternative, which we are exploring in this paper, is instead to use a parallel, probabilistic approach, where early phase development concept selection is started before appraisal drilling, when the reservoir model still is very uncertain. This is challenging, because people from disciplines who normally do not interact closely have to cooperate, but it can be very rewarding, because the problems are being looked at from additional angles, pulling in expertise that normally is not used at this stage. It is very likely that this approach will lead to improvements in the appraisal program, and in the field development, and thus to significant economic gain.

With the parallel approach it is not necessary to have a final, fixed model of the reservoir, instead it is necessary to understand, and be able to quantify, the most significant G&G and reservoir engineering uncertainties. From this, a small number of reservoir models are made, each with associated probability. For the purpose of this paper we have chosen to concentrate on depth conversion uncertainty, and to construct three reservoir models, at P10, P50 and P90 probability.

Based on these, we have evaluated different appraisal and field development scenarios, and derived an optimized appraisal strategy together with a field development program that includes the entire uncertainty span, reaching the best development solution at the end of the day.

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Formulation of Problem

1. Evaluate different field development options including the full span of uncertainties
2. Adjust for proposal of an appraisal strategy to reduce the geophysical uncertainties
3. Decide on the best field development scenario in terms of technical robustness and the best economic value.

Methodology

The different geophysical maps resulted in different outcomes. An initial appraisal program was proposed by the G&G team for the purpose of reducing the subsurface uncertainties. In generating the different development schemes including the economics a computer program (IPRiskField) was used. In this program every parameter is input in a probabilistic manner. Every simulation results in a full uncertainty span. Interpretation of these results formed the basis for deciding on a preferred development solution as well as a preferred appraisal program with respect to field development decisions.

Geology & Geophysics

The Aker Field, Figure 1, is a synthetic data set with properties which are typical for the North Sea.

The reservoir is a Lower Tertiary basin floor fan, residing unconformably on Cretaceous limestones. The top and base horizons are well defined from seismic. It is a massive sand body of regional extent, which pinches out towards the west. Excellent aquifer support can be expected. Within the Aker Field there are no continuous shales or faults which could act as barriers during production.

Four exploration wells have been drilled, targeting structures at a deeper level. No oil or gas was found there, and the first three wells were completely dry. Exploration_4, the discovery well, unexpectedly found oil in the Lower Tertiary. It penetrated 44 ft. of oil in massive, clean reservoir sand. The OWC is at 5007 ft. This well controls the northern part of the structure, but the lack of crestal wells in the south and center leaves a significant depth and volume uncertainty. This uncertainty was studied using a self-optimizing depth conversion method which uses seismic processing velocities and well data.

Seismic processing velocities are commonly used for depth conversion down to top reservoir in the North Sea. A seismic processing velocity field is a direct measurement of the average velocity, but it also includes noise.

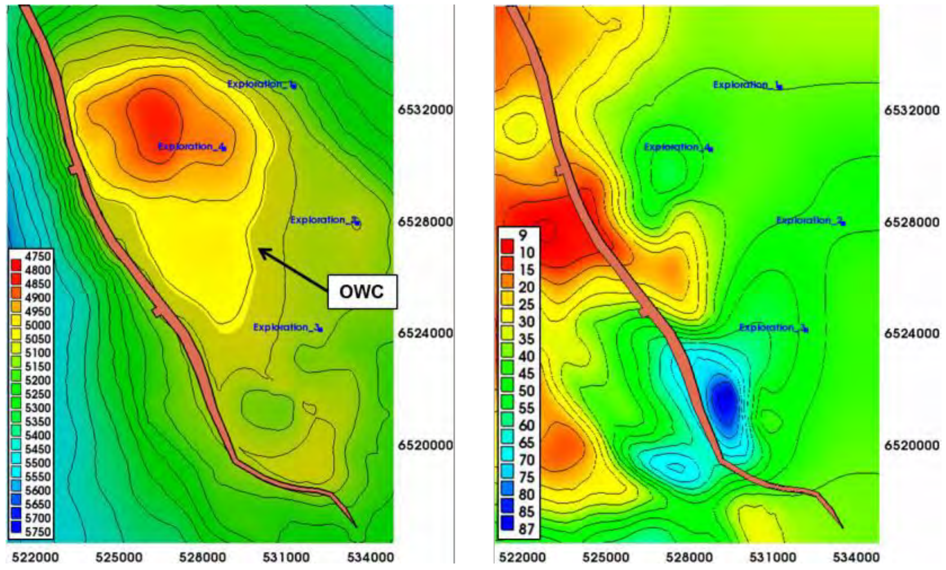

Figure 1. Base Case depth (left) and reservoir isochore (right)

The self-optimizing method searches a large number of noise filter realizations, and finds the best deterministic depth case, measured in terms of depth prediction error in the wells. The method can also be used for stochastic velocity uncertainty modeling. With proper parameter search boundaries, the set of realizations scanned for optima will span the full range of realistic modeling solutions, and it is then possible to calculate meaningful statistical parameters, including standard deviation, mean, minimum and maximum depth maps.

Figure 2 shows standard deviation of depth to top reservoir in the Aker Field. It is zero in the wells, because all realizations have been well tied. The largest uncertainties are located along the fault. This is partly a consequence of soft sediment deformations, and partly an effect of shallow gas, both related to the zone of weakness created by the fault. (A real velocity data set was used to make this map.)

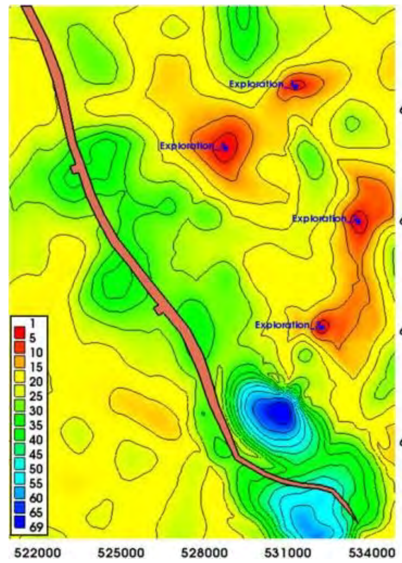

Figure 2. Standard deviation of top reservoir depth

Depth uncertainty is the sum of velocity and seismic interpretation uncertainties. In this study no seismic interpretation uncertainty estimate was available; instead the total depth uncertainty was set to twice the velocity model uncertainty. Based on this, and assuming normal distribution, P10 and P90 depth maps were calculated from the mean depth map, adding / subtracting 2 * standard deviation * 1.28.

The depth conversion Base Case will give the most likely gross rock volumes, and should form the basis for a field development decision. There are two outputs from the optimization routine which can be used as Base Case, either the best deterministic case, which has the smallest depth prediction errors in the wells, or the mean case, which is centered (P50) in terms of velocity uncertainty. In the Aker Field, the analyst used the mean. The P90 (Low Case), P50 (Base Case) and P10 (High Case) depth maps from the Aker Field are shown in Figure 3.

The structural uncertainty in the Aker Field is evident from Figure 3. The northern part of the field has a robust closure. The middle and southern parts are flat, and can either be above or below the OWC.

An appraisal program consisting of two wells has been proposed by the G&G team in order to eliminate this uncertainty. Without appraisal, only the northern part of the field, which is above the contact in the Low Case, can be developed.

The first apprisal well, Appraisal_1, is located

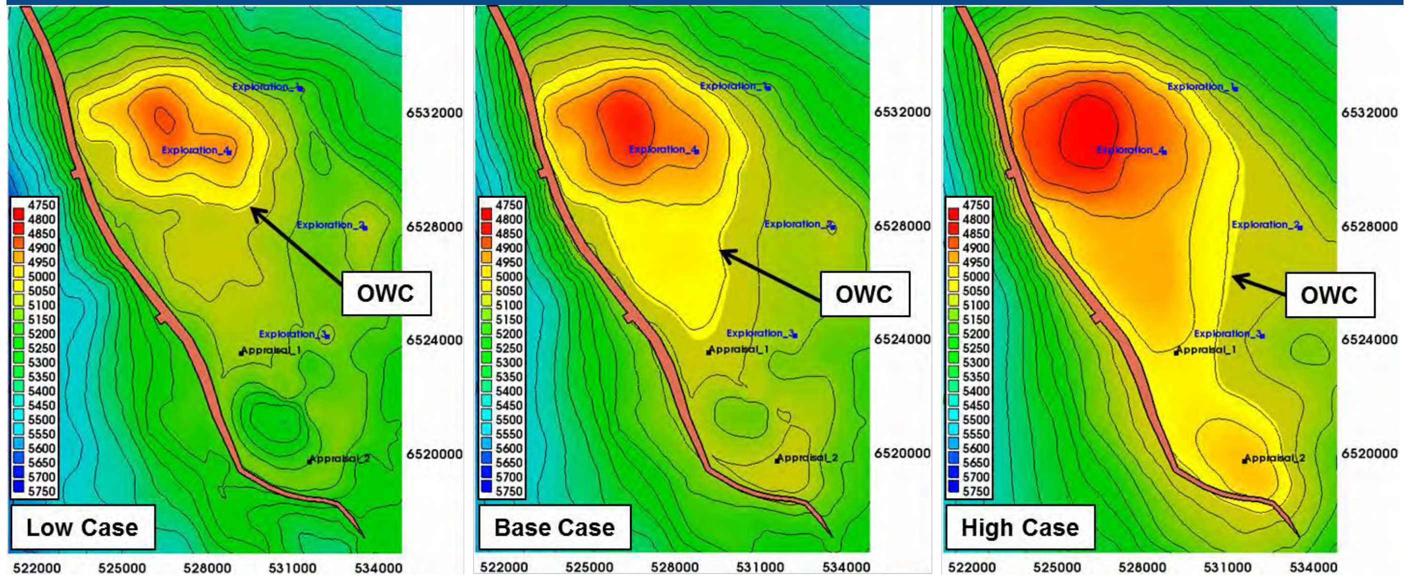

Figure 3. Low (P90), Base (P50) and High (P10) Case depth maps

in the centre of the structure, directly south of the OWC in the Base Case. If this well is successful, it will prove the Base (or High) Case here, and allow the middle of the field to be developed. The second appraisal well, Appraisal_2, is located on the structural crest at the southern end of the field. The purpose of this well is to test the High Case here. If successful, it will allow the southern part of the field to be developed. Seeing a need to confirm the most likely volumes before field development, and believing that the additional high-case potential in the south could wait until later, G&G proposed to drill Appraisal_1 before concept selection, and wait with Appraisal_2 until after start of production.

The geophysical uncertainty estimation method used in this study is a stochastic method which determines uncertainty directly from the data. Together with other objective uncertainty estimation methods, it is well suited for field developent studies, where accurate quantified uncertainties are extremely important as basis for field development decisions.

Reservoir

The Exploration_4 well drilled in 2011 proved oil in Lower Tertiary. Sand of excellent reservoir properties were found. The reservoir is undersaturated with a low GOR and a slightly viscous oil type (fluid analyses from Exploration_4 well). The rock properties are tested (core analyses from Exploration_4 well) to be excellent. The reservoir parameters used in the volume estimate are shown in Table 1.

Even if the reservoir properties from the discovery well showed high quality it is believed to have some variations between the different parts of the field. The field is therefore divided into three parts, North, North-S and South. The permeability and porosity of the sands is believed to stay more or less the same. What could differ are potential shale intrusions toward South, from the North segment into the Middle segment and further down into the South segment. An involvement of some shales in between the sands could easily reduce the recovery factor. Another factor that could easily reduce the recovery here is the fact that both the North-S and the South parts are structurally deeper, opening up the potential for more water encroachment. Based on these thoughts the recovery factors have been adjusted accordingly relative to the expected recovery factors in the North (Low case lowered due to some thinner sands). Despite the relatively small adjustments the well count and the architecture are kept the same. These would all be adjusted as more data becomes available. Estimated recovery factors and wells for the individual parts are shown in Table 2.

Parameter	Units	Mean
Water depth	ft.	660
Reservoir Area	Acre	11400
Top Reservoir Depth	ft.	4675
NTG	Frac.	0,7
Porosity	%	30
HC. Saturation	%	70
Permeability	D.	5
Reservoir Pressure	Psi	2660
Reservoir Temperature	F	176
Saturation Pressure	Psi	1320
Reservoir Oil Viscosity	cP.	2
Reservoir Oil Density	lb./Sft3	50
Oil Formation Volume Factor,Bo	ft3/Sft3	1,13
GOR	Sft3/STB	1590
OWC	ft. TVD MSL	5000

Table 1. Basic reservoir parameters

Parameter	Small development			Middle development			Large development		
	North	North-S	South	North	North-S	South	North	North-S	South
RF, %	35			40	35		40	35	30
Oil producers	8			12	4		15	9	5
Water injectors	4			6	2		7	5	3

Table 2. Estimated recovery factors and wells (well figures used in estimating CAPEX for the

The tested oil shows somewhat higher viscosity than most oil in the North Sea. A slightly unfavorable mobility ratio would then be expected. The plan is then to increase the number of oil producers and then keep low drawdowns through moderate production rates. Water injection is planned as a recovery mechanism to sustain close to original pressure and stay above saturation pressure. In order to avoid too early water encroachment the planned water injection would have to be under strong surveillance.

Drilling

A decision was made to not predrill any wells for the different scenarios. The reasons are the high risk exposure of drilling development wells without any production history. This was evaluated against the upside potential of earlier production but also the potential downside of expensive drilling rigs in a demanding market. Separate drilling rigs were accounted for in the scenarios including wellhead platforms (one for the small development scenario and one for the large development scenario in the southern part of the field). The wells which are all vertical / deviated will be completed one by one. Average drilling time is estimated to 35 days within the central area and up to 75 days for some of the long reaching wells being drilled southward.

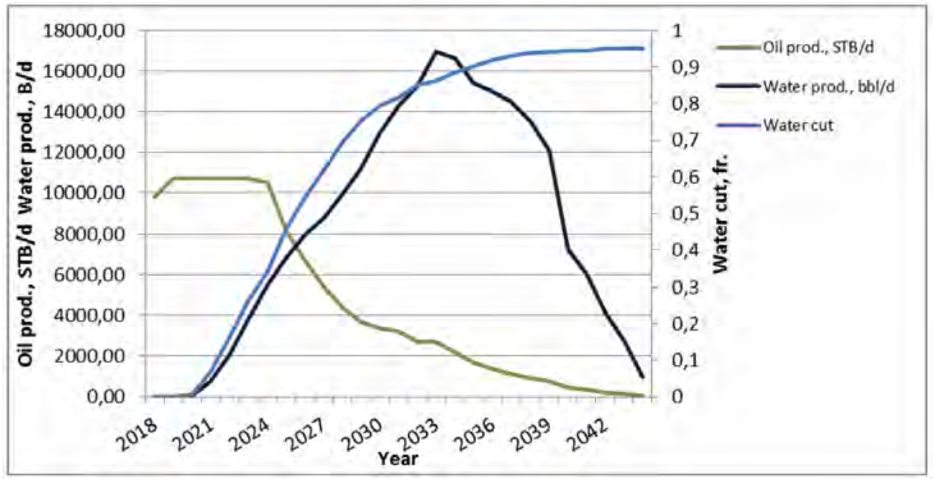

Figure 4. Average well oil, water production profile and water cut

Production

A chosen production scheme from the Aker Field involves the use of vertical/deviated oil producers for reservoir development under water injection.

The best production scenario from current subsurface knowledge of the field involves oil withdrawal with minimum reservoir drawdown. Even with pressure maintenance from both aquifer and water injection some parts of the reservoir will most probably experience some energy loss.

Furthermore, the strategy includes keeping the reservoir above saturation pressure. When the completion waters out owing to either influx and/or water injection, accountable amounts of oil might be left behind the front. In order to reduce this risk a somewhat smaller well spacing combined with moderate withdrawal were decided. Moderate production from this high productivity reservoir with Darcy sand will then demonstrate a long life production profile. However, produced gas which is of a smaller order would be handled and reinjected into a shallower formation. A set of average production profiles (oil, water) is shown in Figure 4.

Devel-opm.	#	Description	Producers	Injectors	Production Capacity (x10³)		
					Oil	Water	Liquid
Large	1	Field senter+ wellhead platform in South	29	15	315	490	570
Large	2	Platform+ subsea tie back in South	29	15	315	490	570
Large	3	Platform (dry wells only)	29	15	315	490	570
Middle	1	Platform w/ subsea tie back	16	8	190	270	315
Middle	2	Platform (dry wells only)	16	8	190	270	315
Middle	3	Wellhead platform, w/o drilling, tie-back 20-30 km.	16	8	190	270	315
Small	1	Platform w/o drilling	8	4	95	135	160
Small	2	FPSO w/ subsea tie back	8	4	95	135	160
Small	3	Minimum platform w/o drilling tie-back 20-30 km.	8	4	95	135	160

Table 3. Different development scenarios (figures used in estimating CAPEX for the different scenarios)

Key factors	Justifying Comments
Wells Intervention Areal spread Pipeline distance Production	High number of producers and injectors Possibility for sealing off perfs., reperforate Relatively concentrated area Long flowlines - high natural pressure drop Long production life

Table 4. Key factors – basis for choosing development solutions

Development and Facilities

A large number of different scenarios were considered. Table 3 shows those that remained after initial screening.

Table 4 lists some of the key screening factors. Another factor was the water depth, Figure 5, which is about 660ft in the center of the field, increasing steeply towards the east. We have assumed this to be beyond the capacity of jack-up rigs.

The Aker Field is not located in the vicinity of any hub or large infrastructure, but for the purpose of this study, we have assumed that a "Tora Field" exists about 25 km from Aker Field, that the Tora Field currently is in the maturation stage, and that a PDO (Plan for Development and Operation) submittal is planned in 2015.

The Aker Field has sizeable reserves and could be developed based on either a tie-back solution or a standalone solution. A tie-back solution requires that a host and a transportation system are available. Furthermore, additional main issues to be raised include capacity, fluid quality, flow assurance, physical distance, timing and certainly cost. Cost would both include the investments bringing the fluid to the host and further the cost of processing, operations and possible modifications at the host platform. For a standalone solution there are several options. One category is permanent structures connected to the seafloor and another one is floating devices. A third one might be complete subsea systems directly connected to export pipelines.

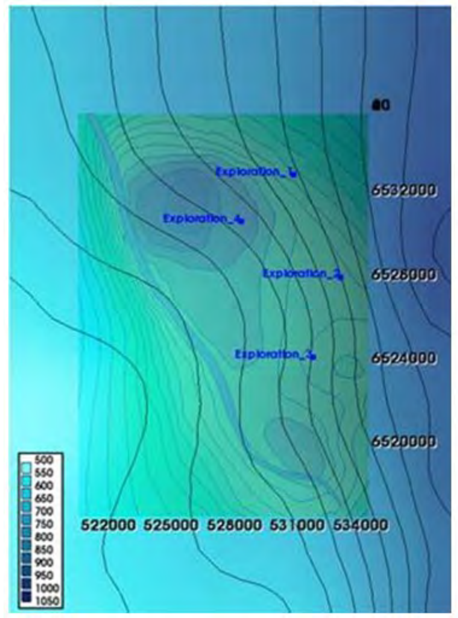

Figure 5. Water depth (ft)

We ended up with three scenarios, 'Small', 'Middle' and 'Large', which were optimized for the reserves in the P90, P50 and P10 reservoir models respectively. 'Small' development is a smaller wellhead platform (15 slots) where the well stream is routed through pipeline with tie-back to the Tora Field. All processing is conducted at the host platform and further export through their pipeline system. 'Middle' development is a 20 slots platform with processing and accommodation capabilities. Here, the well stream goes to an FSU which is a storage unit for further shipment to the market. 'Large' development includes a 30 slot full processing platform. A wellhead platform (10 slots) placed in the south is tied back to the main platform. The total processed well stream then goes from the main platform to the FSU for further shipment and export .

Parameter	Small development	Middle development	Large development
CAPEX OPEX	1,700 5% CAPEX	3,700 5% CAPEX	4,600 5% CAPEX

Table 5. CAPEX and OPEX figures for the development scenarios

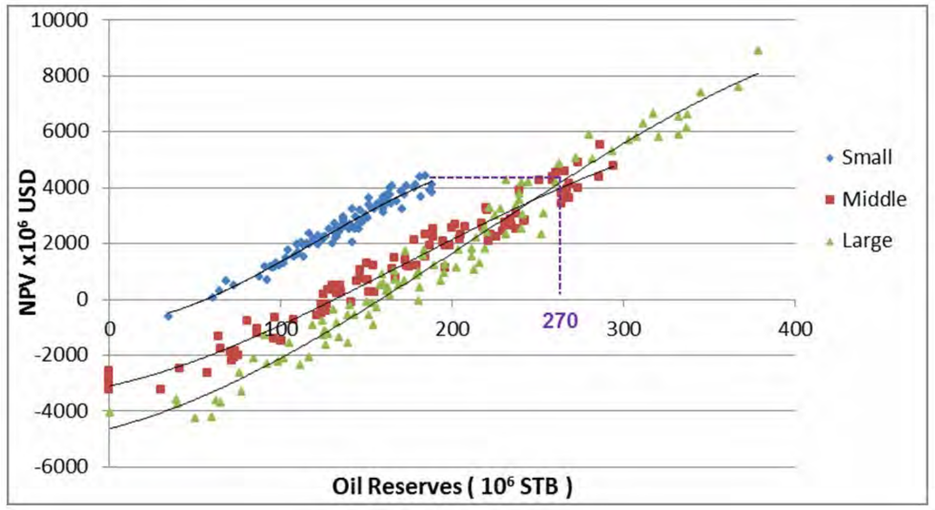

Figure 6. Cross plot of oil reserves vs. NPV, for three different development scenarios

Table 5 shows the CAPEX (excl. drilling cost) and OPEX figures used in the economic analyses. These numbers are input to the program as mode values and include full distribution within the uncertainty span.

An NPV analysis of the three scenarios, Figure 6, shows the 'Small' and 'Large' to be the most favorable.

Discussion of Results

Economics were run probabilistically in order to define the results in evaluating the different development scenarios. The program being used acquires data from different sources and models the various uncertainties. The probabilistic results being calculated gives a good overview of how the different parameters contribute to the overall uncertainty.

The cross plot in Figure 6 shows the reserves vs. NPV for the different development scenarios. The figure shows that the 'Small' development, which reaches a maximum NPV at 200 MM STB of reserves, has a higher NPV than the other scenarios up to 270 MM STB. The investments are relatively small for the 'Small' wellhead platform with minimum topside assumed. Additionally, the oil production is being transported to the host which includes some hook up cost.

The other two development scenarios have to exceed 270 MM STB before they show higher NPV values than the 'Small' development. In this volume range the 'Middle' development has been passed by the 'Large' development. The 'Middle' development is not the best choice in terms of NPV in any volume range. Therefore, only two realistic development scenarios remain, the 'Small' and the 'Large'.

This means, when compared to the P10, P50 and P90 reservoir models, which were derived from depth conversion uncertainty, that the 'Small' development is the best for the P90 and P50 cases, and that the 'Large' development is best for the P10 case, with the dividing line, at 270 MM STB, ca at the midpoint between P50 and P10.

The consequence of this is that it becomes unnecessary to drill Appraisal_1 (Figure 3) before the Aker Field is put on production, because the results of this well will not have any influence on the field development concept selection. Without this well, all we have proven is the P90 case, with well Exploration_4. If Appraisal_1 comes in as prognosed, then we would have proven the P50 case, but we would still go for the 'Small' development. And if Appraisal_1 comes in high, then we would not yet have proven the P10 case, because most of the additional volumes in that case would be in the South part of the field, where the depth uncertainty is larger than elsewhere (Figures 2 and 3). Instead, it becomes necessary to drill Appraisal_2, which is located in the middle of the South part. The purpose of this well is to test the P10 case. If it comes in high, proving the P10 case in that area, then it will prove up sufficient additional volumes to swing the optimal field development from 'Small' to 'Large'. This well must therefore be drilled before concept selection.
This is a complete reversal of the appraisal drilling program originally proposed by G&G. They had proposed to drill Appraisal_1 before concept selection and Appraisal_2 after production start.

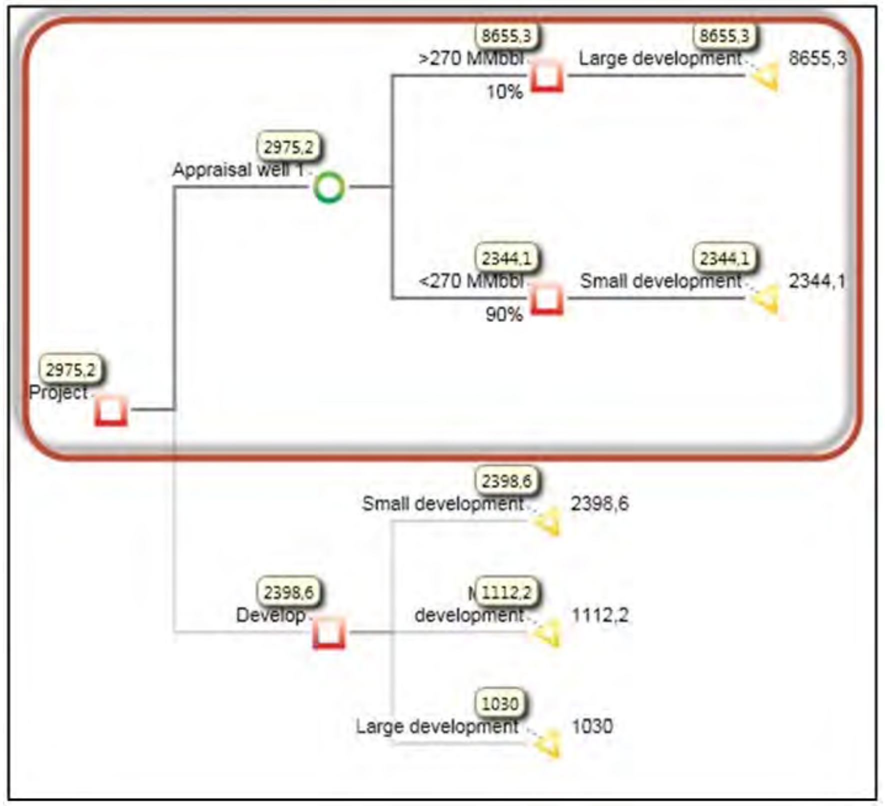

Figure 7: The optimal decision path

Development Scenarios	NPV (106 USD)
Small development Middle development Large development	2,398 1,112 1,030
Appraisal simulation (Small vs. Large dev.)	2,975

Table 6: NPV values for the different scenarios (NPVx106)

The decision of whether or not to drill Appraisal_2 was based on a risked NPV analysis. The results show that by drilling Appraisal_2 the NPV becomes 2875 MM USD compared to NPV of 2398 MM USD with no appraisal. This is further shown in Table 6. Based on these results the optimal decision path is shown in Figure 7.

Conclusions

On a NPV basis there were eventually two real development options left to compete out of three in total. The small development scenario showed best values up to approximately 270 MM STB in reserves. When the other two development scenarios came to that NPV level there was only the large development that could further improve the value.

Scenario analyses showed that drilling Appraisal_2 well would be beneficial and increase the overall value in choosing the large development option.

By going straight to Appraisal_2 and the chances for larger volumes we 'saved' the work and cost of drilling Appraisal_1. Drilling Appraisal_1 would only prove up volumes which could be handled by the small development scenario. This could also be drilled later directly from the platform to prove the volumes.

This study clearly shows the important role the geophysical uncertainty has in evaluating field development concepts in early stages. Working with the entire uncertainty range could early on rule out some options and easier converge to a certain solution relative to a deterministic approach.

One of the primary reasons for a successful field development study has been to have an innovative formulation of the problem. By this we mean having a manageable number of decision constraints and variables as well as effective workflows being implemented for the problem solution. The workflows would provide frameworks for the solution of the field development problem.

This study has again proved the value of working in integrated teams. By working in parallel and not sequentially as the classical way the team managed to pick up valuable information in an early stage. By having subsurface and facilities (engineering) teams working closely together, data and information exchange in the early phases become a valuable asset.

Having a parallel, probabilistic approach to the project covering the entire span of uncertainties improves the quality of the results and the field development decisions.

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