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Challenges and opportunities in subsurface uncertainty modeling – A geophysical perspective

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FORCE

Uncertainty handling in static-dynamic modelling workflows May 11 2017

New techniques and insights and not at least the continuous increase in computing power has provided us with a framework for quantifying the effects of uncertainties in input data and 3D earth modeling in a consistent manner. The results are hopefully more realistic estimates of available resources, like the most likely in place volumes as well as a better understanding of possible ranges. New tools are available, which we need to to understand the potential and limitations of and to use efficiently. In addition we will have to provide realistic uncertainties in our input data objectively.

Outline

- Introduction
- What type & ranges of uncertainties are expected
- Uncertainty modeling process
- Emerging Technologies and impact on Depth conversion and layer thickness uncertainties (BroadBand)
- Reducing uncertainties in history matching using 4D seismic (4D)
- Way forward

Consequences of the subsurface uncertainties paradigm

Need to :
- Understand
- Quantify
- Reduce
- Manage

In order to :
→ Optimize portfolio
→ Better field development decisions
→ Supporting well delivery & production optimization

Realistic models of uncertainty requires that we understand the concepts, and we need to be able to quantity uncertainty in input data and interpretation. The uncertainty ranges should be based on objectivity, however a general observations is that it may be easier for a group of expert to agree on the reference interpretation than on the uncertainty ranges , as the individuals background and experience may results personal biases and preferences.

The goals is not the uncertainty in itself how the insight on the end effects may help us to set the focus for reducing the main contributors and help prepare for mitigating against downside and to define strategies capturing the upside .

Example in use of uncertainty modeling are : portfolio management, to balance the risk ; to help make better field development decisions, to support planning and delivery of new wells, to optimize production.

Challenges

Opportunity:
" Uncertainty evaluation is an integral part of any static and dynamic reservoir modelling – has always been – main difference is in the rigors on how it is and can be addressed "

Driven by Expectations:
"We require that reservoir models used for business decisions provide volumes that are "forventningrett" and robust"

Implications:
Need to understand the potential and limitations of the methodology, software and how to define the input data

Introduction

Uncertainty is not new to use, it has always been a known that any model of a reservoir, whether static og dynamic includes uncertainties. The interpretations and parameter estimations process even in deterministic modeling is based on numerous decisions which includes an assessment of what the most likely solution.   The main difference today is in the rigor how this know can be addressed by software tools and workflow,

The expectations is that the reservoir models used for commercial decisions are unbiased and robust, which kind of imply that the input parameter are unbiased. And as low, high and expected cases are expected, the uncertainty ranges also needs to unbiased. This implies certain level on objectivity for our work, which may only be achieved by a comprehensive knowledge and analysis.

A reliable analysis require a good understanding of the the methodology chosen for the uncertainty modeling, and especially how this is implemented in the software we use.

For most of us this means that we have to maintain and develop our skills to provide the right basis for the work. We get more and better data and we need

Subsurface experts may have quite different views on subsurface uncertainty:
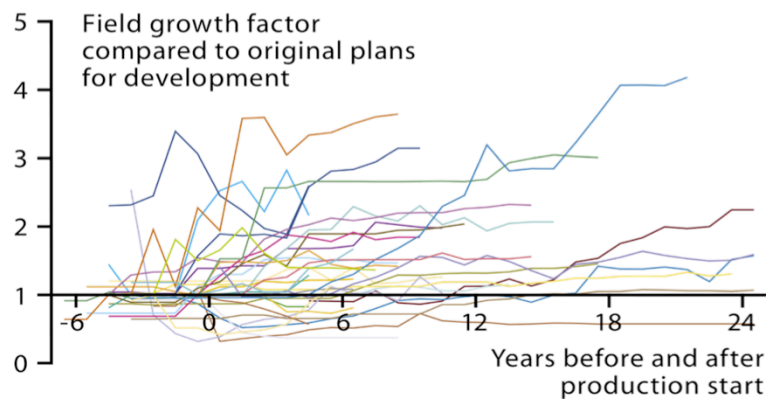
- **Geologist**: uncertainty due to the part of the reservoir without direct observation (hard data –vs soft data)
- **Reservoir engineer**: uncertainty due to the simplifications in the modelling
- **Geophysicist**: Uncertainty due to that any data fails short of defining the reservoir accurately (all data is data is "soft" data)
- **Petrophysicist**: Uncertainty due to measurements uncertainty
- **Asset manger**: Uncertainty due to the value assessment supporting a decision

Introduction

Reservoir modeling involves several specialized disciplines and each may have different views on on uncertainties which may complicate the process. While the end results probably are well understood there are aspects that influence the end results. The most important are what the resulting model is to be used for, while the modeling process has a a value in itself forcing the disciplines to work together and balancing the efforts end up with efficient workflows.

Uncertainty In Reserves Estimates

Field growth factor compared to original plans for development

Years before and after production start

Based on reserves per field compared with their original plans for development and operation

Source : Gov. White Paper

Expected Ranges of uncertainties

Uncertainties in reservoir estimates may be huge – On average the reserves in the Fields on the Norwegian Continental shelf has increased by 70 % since the initial plan of development was filed. The larger field has increased the most – smaller fields less. Maybe there were a need for some optimism to get them of the shelves ? This figure are from The Governmental White paper from the Åm committee, and we should keep in mind that there are other factors than subsurface that impacts. Oil price, commercial decisions and infrastructure will have an effect. However the relative variations are in some cases huge, and some of the undulations is certainly linked to "geological" surprises"

What type of uncertainty ranges are typical

Measure for benchmarking uncertainty:
- P10/P90 Range
- K – Coefficient of Variation

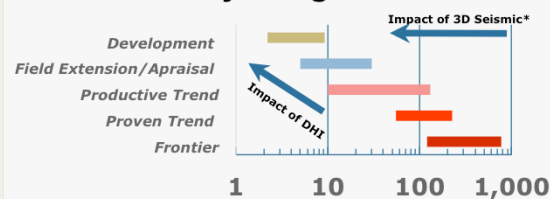Typical ranges observed on recent NCS fields:

Development	P10/P90	K
STOIIP	1.46	0.15
RF	1.45	0.14
EUR	1.29	0.11

STOIIP – Initial In Place volume
RF – Recovery Factors
EUR – Estimated Ultimate Recovery

From the literature:
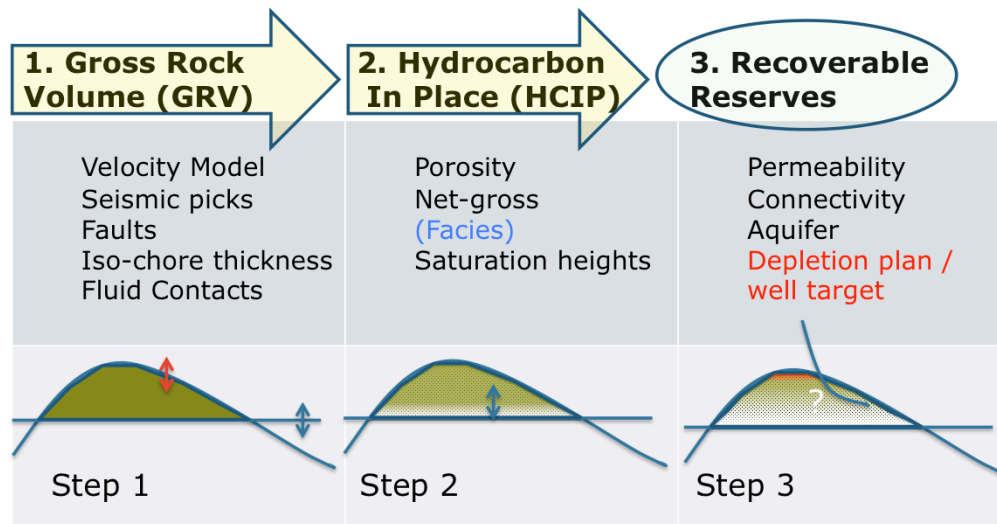Categories of P10/P90 (modified from Rose & Edwards, 2001)

Uncertainty Ranges - P10/90

Impact of 3D Seismic*
Development
Field Extension/Appraisal
Productive Trend
Proven Trend
Frontier
Impact of DHI

1   10   100   1,000

* 3D seismic samples the entire reservoir – vertical resolution is limited, data is measured in time

Expected Ranges of uncertainties

Are our uncertainty models REALISTIC?

The ratio between the high case or P10 and the low case or P90 is standard way to describe uncertainty another measure is the coefficient of variation which is the ratio between standard deviation and the mean value of the estimated resources in a reservoir. These are useful benchmark figure and the ranges we typical see for reservoirs on the NCS are shown in this table. We don't find discussions on expected ranges in the literature, however in a paper in Edward and rose from 2001 we find benchmark figures reported according to the stage of development. The ranges are generally higher than we have observed in our portfolio. One reason for this could be that our focus may be in more mature areas and field, furthermore 3D seismic – who addresses some of the most significant uncertainty issues in today are used extensively, also in exploration. As Edward and Rose points out 3D seismic reduces uncertainty ranges. The number of wells drilled in a reservoir or prospect will also impact the number, however if these ratios becomes to small there might be reasons for having a closer work on what he uncertainty assessments are based on.

Volumes – Basis for Decision

1. Gross Rock Volume (GRV)	2. Hydrocarbon In Place (HCIP)	3. Recoverable Reserves
Velocity Model Seismic picks Faults Iso-chore thickness Fluid Contacts	Porosity Net-gross (Facies) Saturation heights	Permeability Connectivity Aquifer Depletion plan / well target
Step 1	Step 2	Step 3

Uncertainty in Modeling

Most all reservoir modeling follow these three steps and the listed parameter an elements are the most critical in each step. The recoverable reserves is of primary interest for the decision to invest in this field or not. A first approach will may be to use a recovery rate which are typical for the type of field, but normally calculate the recoverable by simulating the effects of actual development scenarios. As computing resources may be limited, a common approach is to define a low (P90) , mean P(50) and high (P10) geological reservoir model based on HCIP and in order to get some appreciators on the ranges to expect. Unfortunately the relationship between the geological reservoir generally non-linear, which implies that a different set of HCIP cases may be the one corresponding to P90/P50/P10 cases based on recoverable reserves,

Uncertainty – A 3D modeling workflow

Interpretations

Reference Geo/Res Model

Sensitivities Alternatives (Distributions)

Uncertainty Measure

Selections

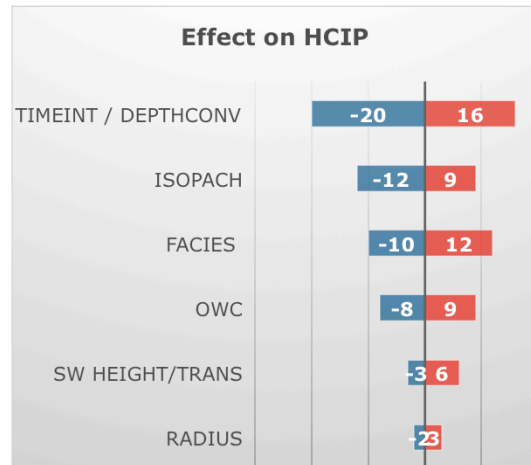Uncertainty Analysis (Multiple 3D model realizations)

Simulations

Delivery:

P90-mean-P10
- HCIP Volumes
- Recoverable
- Production profiles
- MODELS

Uncertainty in Modeling

Today there are several software packages available for use in 3D uncertainty modeling – most all of them follow this general line. A reference model I build based on the initial input, interpretations and properties. Additional uncertainties measures on all relevant parameters are feed in to the process and used to pertubate the model – a new static model is made – upscale to a dynamic model for simulations and out comes the various volumes and profiles we need to design the facilities and to calculate economics. If we can´t afford running several hundred reservoir simulation there are alternative approaches can can guide us to establish uncertainty ranges. However the critical factor remains, reservoir uncertainty studies or modeling all the relevant factors needs to be addressed jointly.

Parameters most effecting HCIP the most "typical cases"

- Velocity Model*
- Seismic picks
- Thickness
- Facies
- Fluid Contacts*
- Porosity
- Saturation

Effect on HCIP

TIMEINT / DEPTHCONV	-20	16
ISOPACH	-12	9
FACIES	-10	12
OWC	-8	9
SW HEIGHT/TRANS	-3	6
RADIUS	-2	3

Uncertainty in Modeling

If we look on the parameters influencing hydrocarbon volumes in place the most, Velocity modeling or depth conversion, seismic pick uncertainty and thickness variations away from the wells is commonly the top 3.
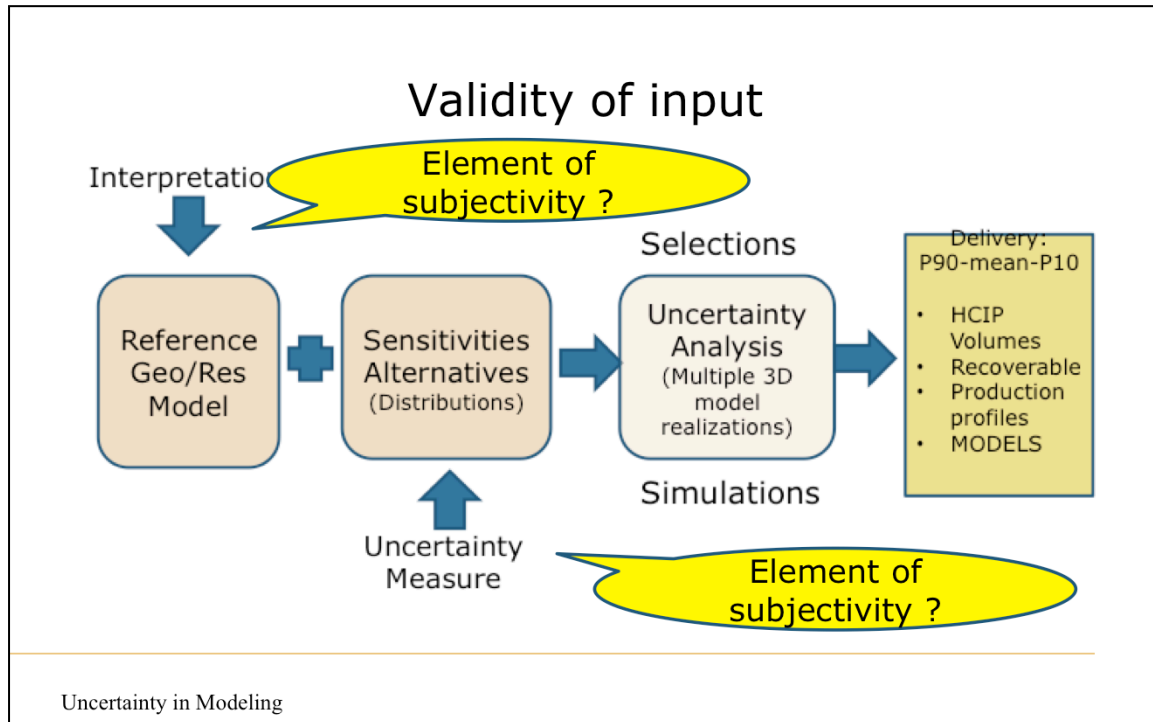
Garbage in – garbage out. The validity of the outcome of the process is entirely up to what we put in. The interpretation forming our reference case includes interpretations, with some risk of subjectivity involved. The same is true about the uncertainty measure, although we should have respect for the relative rigorous analysis done to support this, it quite common the the expert views on the reference interpretations are much more aligned than it´s come to the uncertainty ranges. These are often influenced or biased on the individuals experiences.

We need techniques, workflows and approaches that are based on the information in the data to help us to come up with objective reference models and objective uncertainty ranges.

impact on Depth conversion and layer thickness uncertainties

Depth conversion

- PSDM- the favorable imaging option
- Anisotropic velocity models becoming standard
  - Major Source of errors : geological markers picks
- Small scale overburden velocity anomalies defined
  - At best addressed in a 1D sense (linear local vertical stretching)
- Challenging to quantify uncertainty in velocity & propagation effects – tools and competencies not at hand

Depth conversion and layer thickness

PSDM is established as the favorable imaging option today, also at the Norwegian Continental Shelf. Anisotropic model becomes standard, and in deriving this we are somewhat in the mercy of the geologist marker definition. The quality of this may be so and so, but its not consider acceptable to change these picks and it´s often to time-consuming and not planned for a check in with the geologist during the velocity model building. The depth images are converted to time, and the interpretations are then converting to depth using well data and seismic velocity to a varying degree.

We have learned to appreciate the impact of shallow overburden anomalies, due to ice-tunnels, injectites, gas charging, etc – and this may be taken into considerations during our uncertainty assessment, but only in a 1D sense. We know that these anomalies has lateral impact – and especially in developing marginal areas of the field an depth error of a few meter may be the difference between failure and success.

We do have sophisticated tools to quantify the depthing uncertainty due to the uncertainty in velocity and propagation effects, by modeling. Unfortunately the processing and interpretation of the seismic data still mostly done in a

Surface rugosity – Real or artefacts?

Data in Travel Time !

Contour Interval 1m
Compressed lateral scale
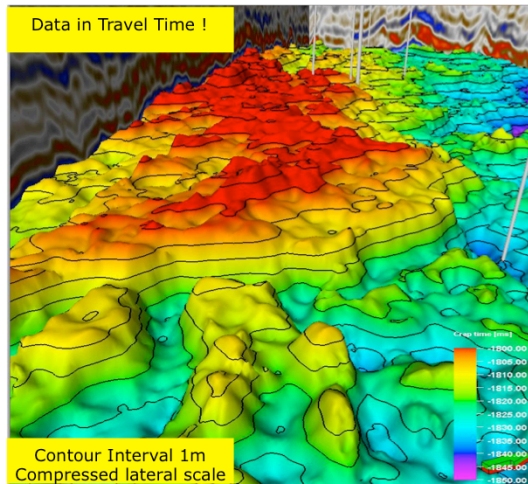
Velocity-depth ambiguities:
Certain geometries makes it difficult to
separated and reflector depths from (lateral) velocity
Variations. Needs PSDM approach to be addressed.

Velocity
Fast

Slow
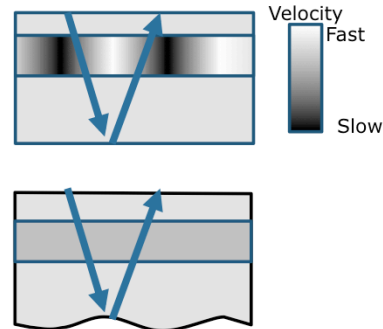
Depth conversion and layer thickness

The local undulations as demonstrated in this surface interpreted in time is a quite common observation. This might be real or an effect of imperfections in our velocity models used in constructing the seismic interpretation which may be due to small scale lateral velocity variation above the surface not being defined or simply due to limitations in our seismic velocity modeling techniques due to ambiguities in separating between real depth and velocities in certain geometrical cases . Such undulation could results in quite different recovery, as the placement of the wells is critical. If we located wells in the top of the structure, gas forming during depletion could result in suboptimal depletion, while if the wells are placed in the lows, in an under saturated reservoir, the possible oil in the high may not be recovered.

If this rogousity is real the top reservoir are more rugouse in reality, we use it to our advantage when placing wells, or we might implement gas injection to push the oil down from these highs. Nevertheless, this is a time surface – and we are not getting any smarter using a simplistic well based velocity model to stretch back to depth.

Emerging " tools "
Comparing tomography and FWI results

Depth conversion and layer thickness

Barkved et al. SEG2010
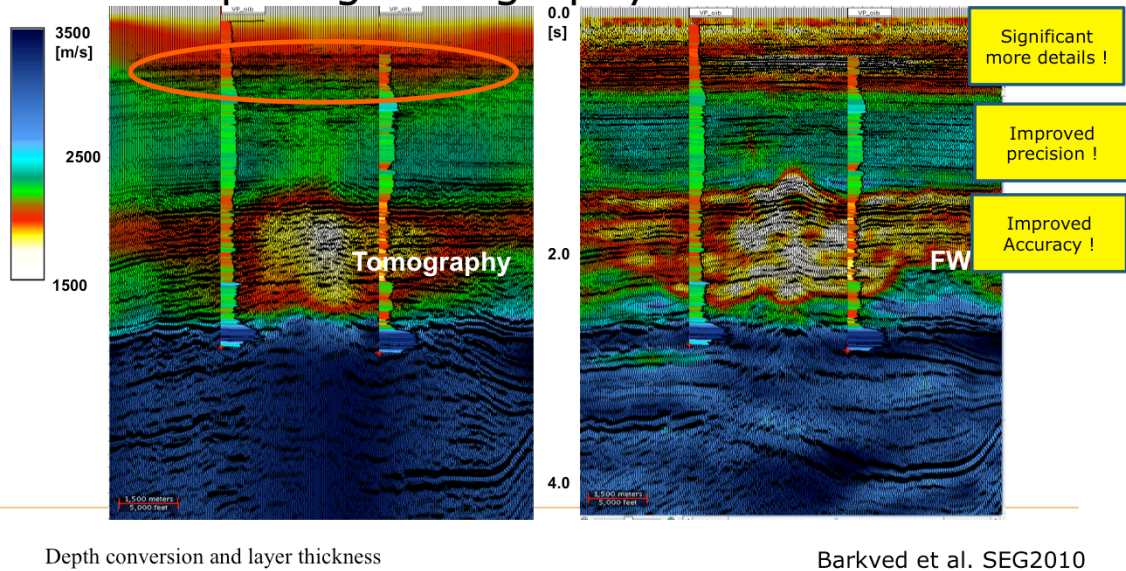
During the last 10 years we have seen a continuous increase in making use of a technique named full waveform inversion (FWI). This allows us make use of other elements of our seismic data, referred to as diving or refracted waves. By adding these seismic waves in our seismic velocity modeling we may be able to define the velocity in more detailed an accurate by reducing the ambiguities. As shown in this example from the Valhall field the velocities defined by FWI shows more details and a significant better correspondence to the the velocities logs in wells than other high end technologies like tomography.

Improved depth conversion with FWI

- O´Neil, A.J. and Thompson T. A : first break volume 34, October 2016:
  - full-waveform inversion combined with geostatistical calibration to wells provided an accurate velocity model for accurate depth conversion of development fields with a notorious heterogeneous carbonate in the overburden. 1% accuracy @ 3200 m TVDSS.
  - Improved resolution and accuracy of FWI model deemed it more suitable than the reflection tomography 3D TTI FWI

Depth conversion and layer thickness

Sharing of best practice is an important way of reducing the uncertainty of our velocity models, Neil and Thomson in a recent article demonstrate how the use of Full wave from inversion has reduced the depth conversions errors and uncertainties in a rather complex geological setting.

Layer thickness uncertainties
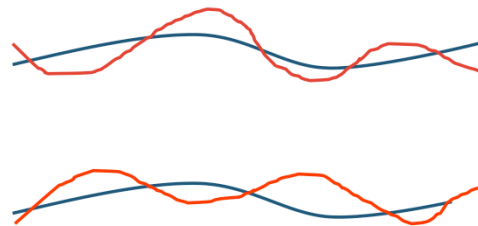
Thick layers:
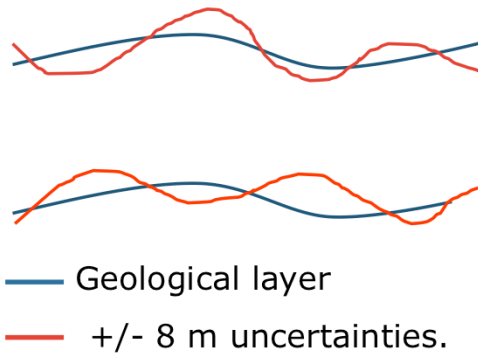
Main Uncertainty:

- How well does the seismic (time) picks match the geological markers

- Qualifiers:
  - VSP, logs, synthetics

——— Geological layer

——— +/- 8 m uncertainties.

Thicknesses away from wells is another of the key uncertainties. For thick layers or packages of layers bounded by well defined reflectors, the main uncertainty – how well the the seismic picks match the geological markers is commonly established by well-known methodology.
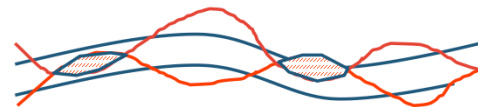
Layer thickness Top & Base uncertainty

Thick layers: Thin layers:

─── Geological layer   ◇ Negative volumes for ?

─── +/- 8 m unc.   Solution:
   Inversions, "pushing" resolution

Depth conversion and layer thickness

But what happen if the layers get to thin. The pick and depth conversion uncertainty can easily get larger that the layer thickness. And we end up with negative volumes,

An obvious mistake, Should it be avoided by how we assign the uncertainty or by the software tools we use ?

We may split the problem by dealing with thin layers differently than with thick layers, but if the layers varies from thick to thin in same the reservoir, we introduce a possible inconsistencies. I don't have the right solution, but obviously the layer thickness becomes more of a problem, and the problem are linked to the methodology of the uncertainty study rather than the physics of how seismic respond t to variation in layer thickness. The solution is probably better found by framing the problem in the physical context ?

Thickness and Seismic Tuning
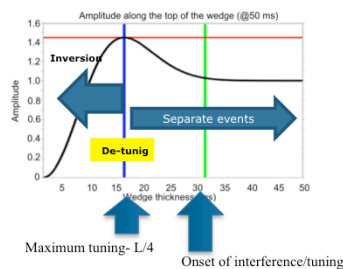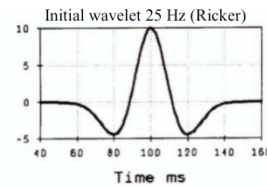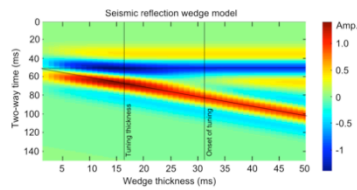
Depth conversion and layer thickness

The common approach to solve this issue is to of a tuning model or a wedge model, which tells us that the minimum thickness be might be able to detect is ¼ om de dominant frequency, provide that the acoustic properties above, below and within the layers are constant – typically in the order of 12-24 m . Below the onset of the tuning we need to relay on the amplitude behavior and below tuning thickness we are in a non unique situation, and which reference thickness should we use in this interval. Furthermore how do we deal with assigning reference thickness and uncertainty ranges in the area below the tuning thickness? The time separation below this thickness is constant and equal the tuning thickness.
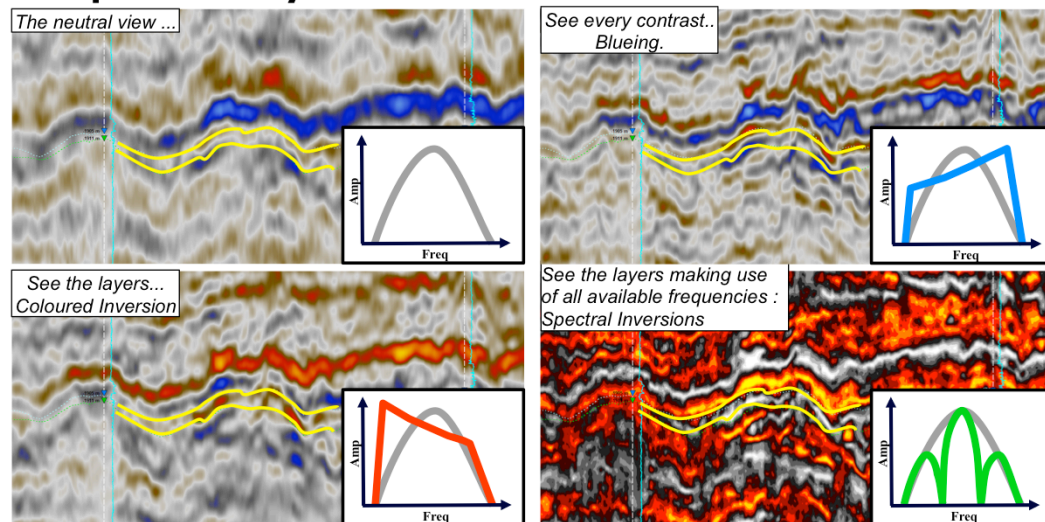
BroadBand data: Impact of Frequencies on Layer Properties & Thicknesses

10-50 Hz
Conventional

10-80 Hz
Adding High

2-80 Hz
Adding Low

2-50 Hz
OnlyLow
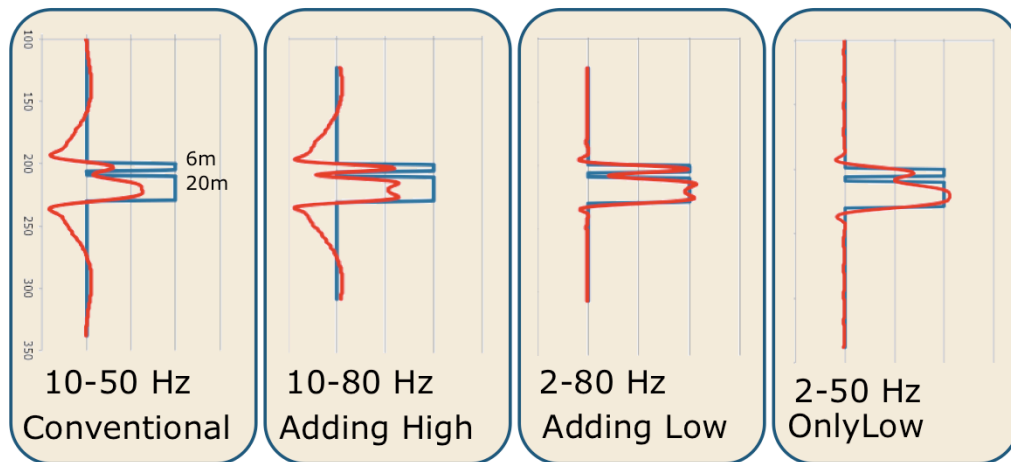
Depth conversion and layer thickness

Modern broadband data could help us improve mapping thin layers . In reality our subsurface setting are somewhat more complex than we can capture in a simple homogeneous wedge model. We might have interference defects due to layers surrounding the layer of interest, which may complicate our interpreations or even sometime help contrain the problem, i.e. providing a better basis for our analysis.

Assessing thickness uncertainties using complementary views :

The neutral view ...

See every contrast.. Blueing.

See the layers... Coloured Inversion

See the layers making use of all available frequencies : Spectral Inversions

Depth conversion and layer thickness

Ref: J. Steindl et al NPF 2016

20

The frequency content in a seismic image is a results of the frequency content of our seismic source, attenuation effects in the earth and decisions made during processing. The raw output from processing has often the shape seen in the upper left image. This does not match the natural frequency of the earth. Observations from wells tells us that reflection data depicting the layer interfaces should have a spectrum closer to the blue line we see in the upper right captions. There should be more high frequencies than low frequency in a true earth response. This is referred to a blue spectrum. We may mimic this effects by applying a shaping filter to our data,. By allowing the data to be richer in high frequencies, we may improve the resolution. At the same time well observation shows that looking at acoustic impedance, or the layer properties the earths response should looks like the one shown in red in the lower left caption. This leaves us with a simple way of approximating layer properties. Furthermore, the problem of defining thicknesses when in tuning should be addressed by an inversion methodology. On theory we could be able to resolve as thin as $1/64^{th}$ of the tuning thickness by a technique referred to as spectral inversion, provided appropriate signal noise ratios.

Alternative views of the same data might provide insight that help defining the needed strategy for delivering the relevant interpretations and the associated uncertainty ranges, an provide addition tools adding objectivity in the analysis.
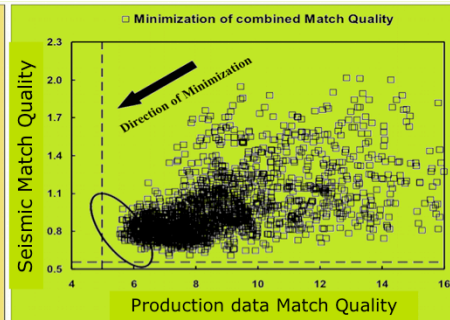
Reducing uncertainties :
Use of 4D in History matching
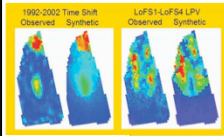
Input: production data from ~6 wells, 4 seismic maps
Process: 10 variable, 2000 iterations
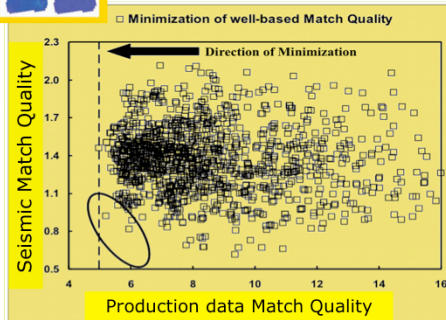
Matching to **well data only**

Matching to **well data and seismic**

Walker et al. (2006), EET VI

Reducing uncertainties

4D seismic provide us opportunity for qualifying uncertainty ranges.

4D seismic and history matching goes hand in hand. Some kind of Automatic or Semi Automatic history matching algorithms now commonly used, at less matching to production data. This a a version of history matching of a local area 3D model. To the left we see the results matching to well data only while also computing the match quality to the 4 seismic attribute set we have.
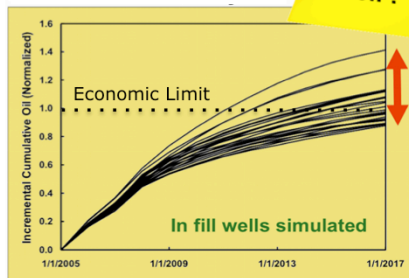
Notice the wide spread in seismic match quality using well data only, and versus the solutions we end up with including the seismic 4D response in the matching process. Production history from 8 wells were used in the process. The 4D seismic first off all contribute by constraining the model uncertainty away from the well.

This is case study from the valhall field in the North Sea
TDRM™ workflow – 3D modeling based, 10 variable

We use 24 best realization for both cases to test a one-well infill scenarios in prediction mode: l

Outcome

Production data only – DO NOT DRILL

4D Seismic + Production data : DRILL WELL

Conclusion

- Increased computing power, software tools and methodology are available to help us modeling the uncertainty in our reservoir with more rigor.
  - Business decisions requires unbiased and robust model
  - In depth understanding of these tools and method is required to be able to provide the right input
  - We do have some insights to what ranges of uncertainties to expect
- Emerging Technologies has the potential for reduced and improved quantification of uncertainties
  - Uncertainty ranges needs be based on the data to ensure objectivity
- Integration – i.e. 4D & history matching has the impact on reducing uncertainties and to enable sound decisions to be made
  - Realistic input parameters and associated uncertainty ranges are critical, as these are the only ones to be addressed in a qualification process, i.e. history matching
- While my focus has been on seismic, the key conclusion remains
  - Studies needs to be worked jointly across the discipline
  - More rigorous analysis is needed to conclude on objective assessments of properties and uncertainties

Conclusion