Stochastic inversion for reservoir parameters using time-lapse seismic and production data

Mrinal K. Sen, Paul L. Stoffa, Long Jin ,
Roustam. K. Seif, Armando Sena

Institute for Geophysics, Jackson School of Geosciences,
The University of Texas at Austin

Outline (Joint Inversion)

1 Introduction

Problem background

Joint inversion method

2 Parameterization methods

Experimental Model Description

Methods for Parameter Space Reduction

Wavelet Transform

Pilot Point

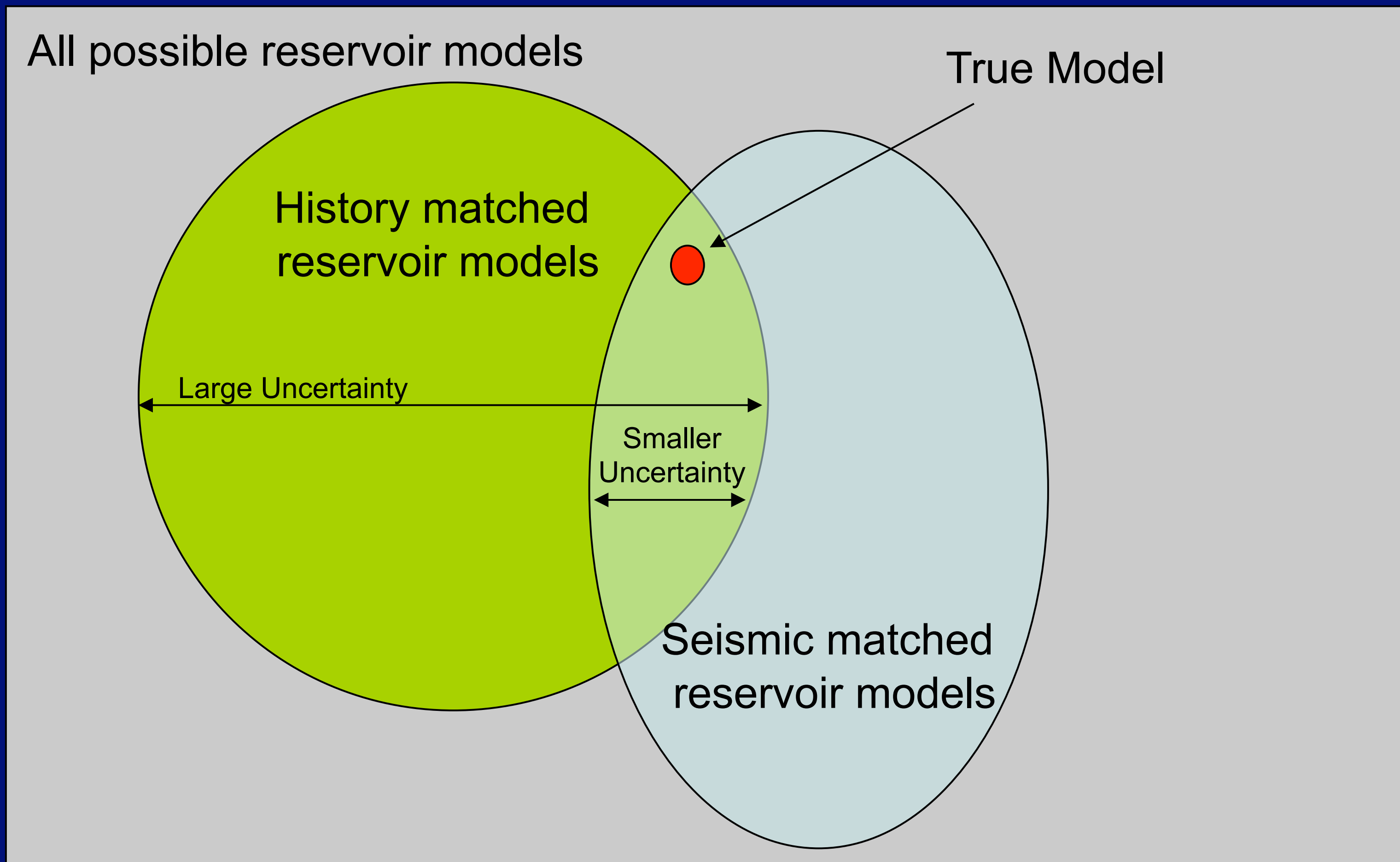
Pilot Point + SGS

Probability based pilot point

4 Joint inversion for porosity and permeability

5 Future Work

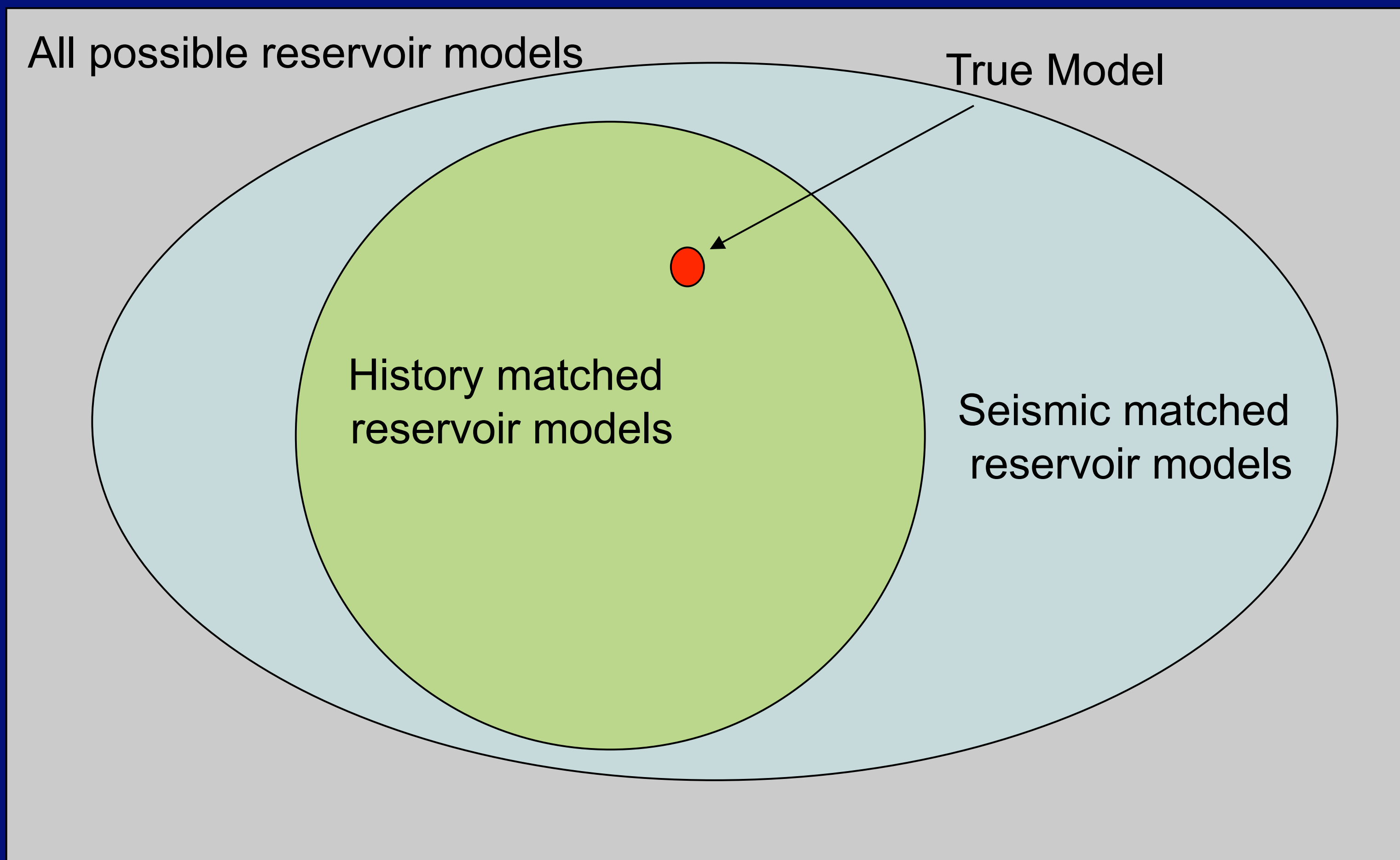
Joint Inversion and analysis of seismic and flow data



Aaron Jensen, Conoco-Phillips.

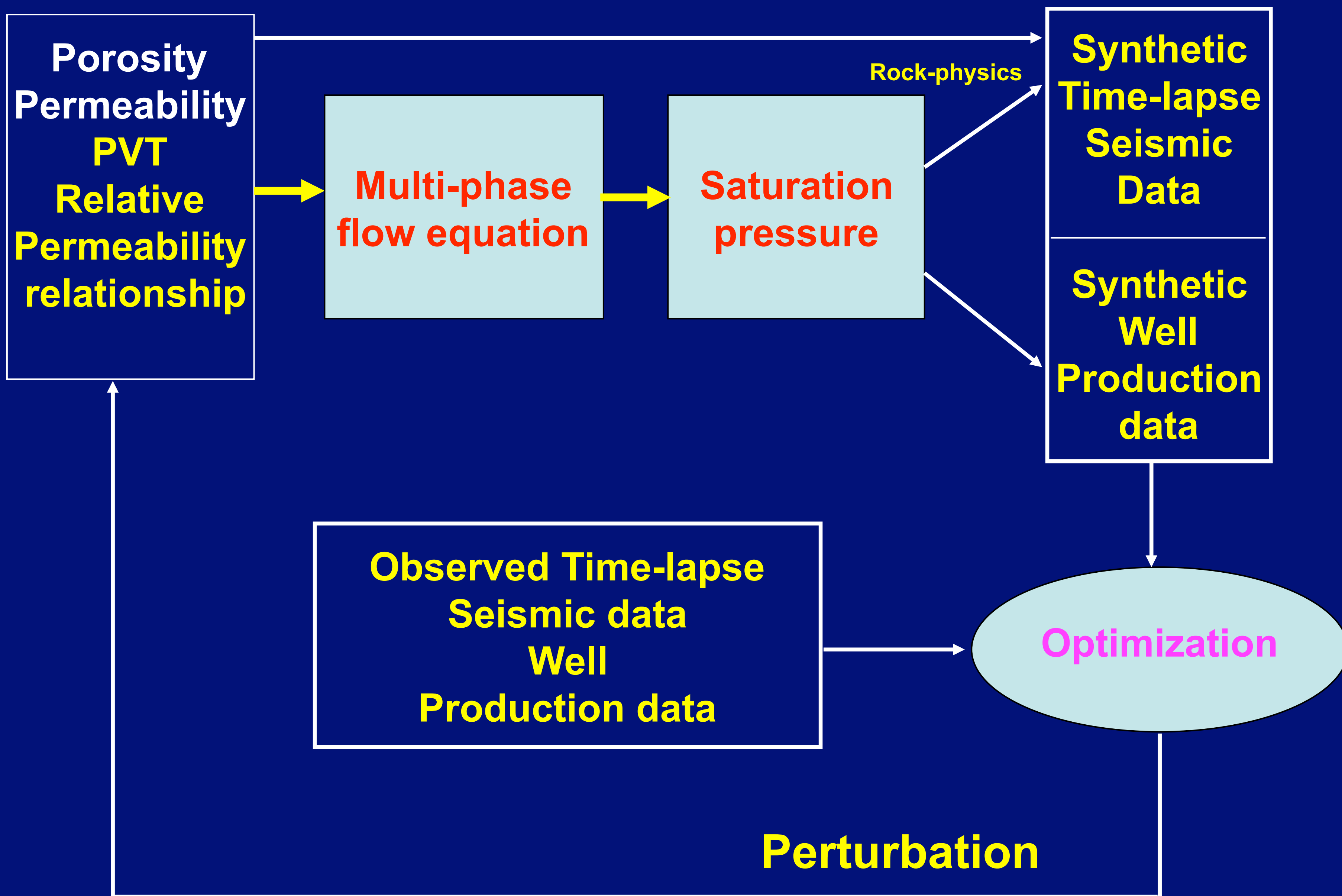
Joint Inversion and analysis of seismic and flow data

Alternative case…. Seismic data adds no value.



Aaron Jensen, CP.

Joint inversion method



Two important issues about inversion method

Optimization methods

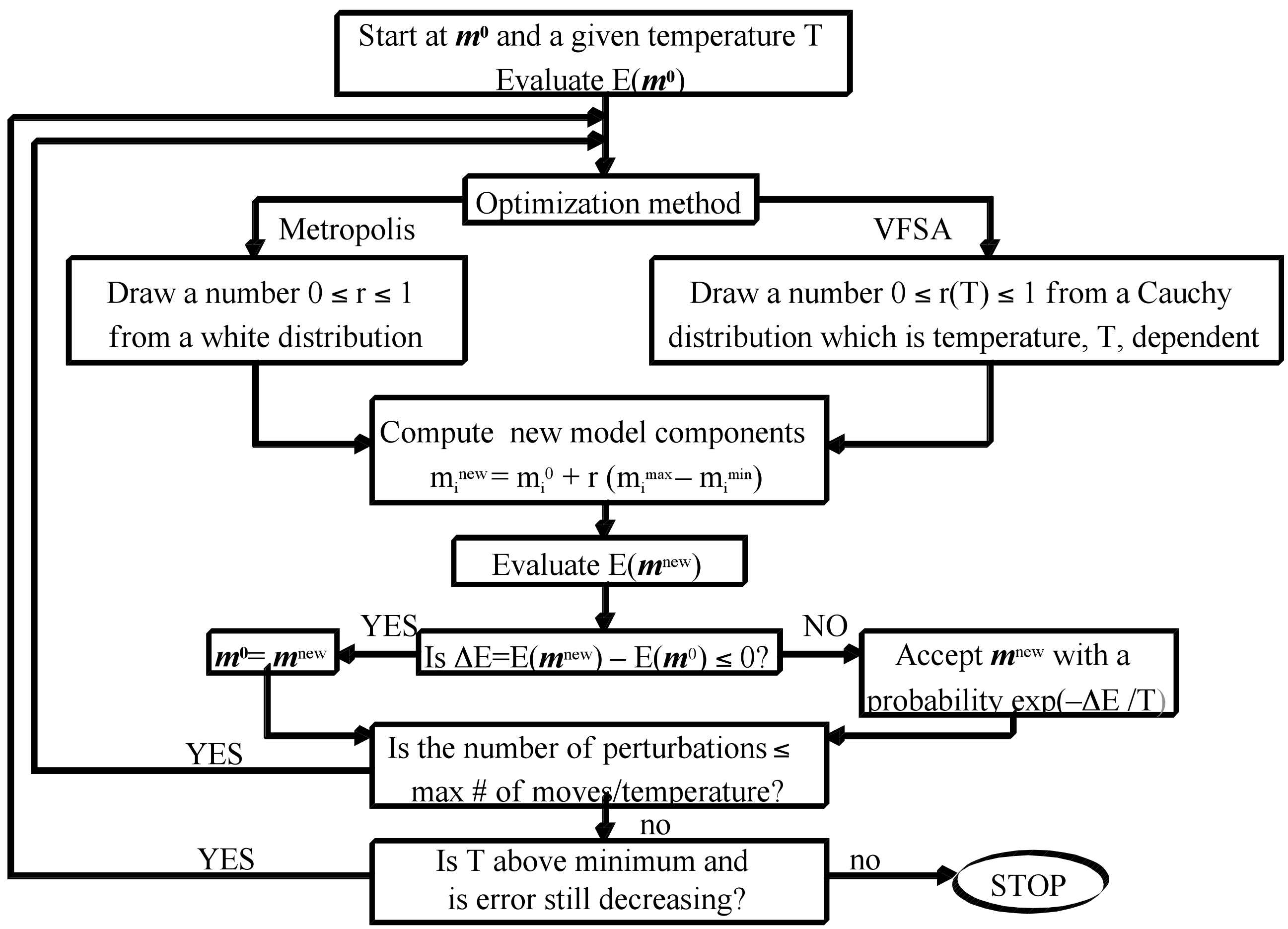
- Local optimization
  - Gradient-based methods
- Global optimization
  - Genetic algorithm
  - Simulated annealing
  - Very fast simulated annealing (VFSA)

Parameterization methods

- Zonation
- KL transform
- Spline interpolation
- Wavelet transform
- Pilot point

Need for parameter space reduction

Very Fast Simulated Annealing (VFSA)



VFSA

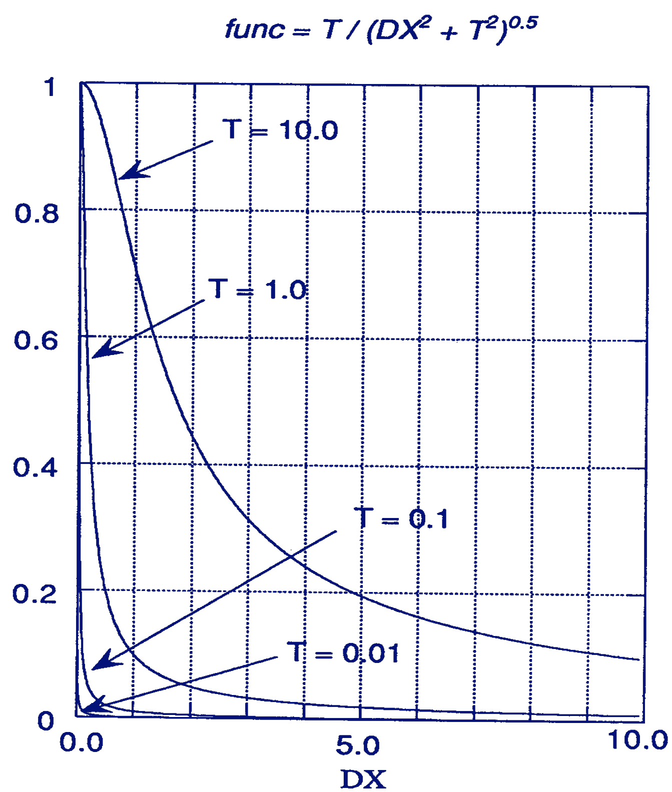
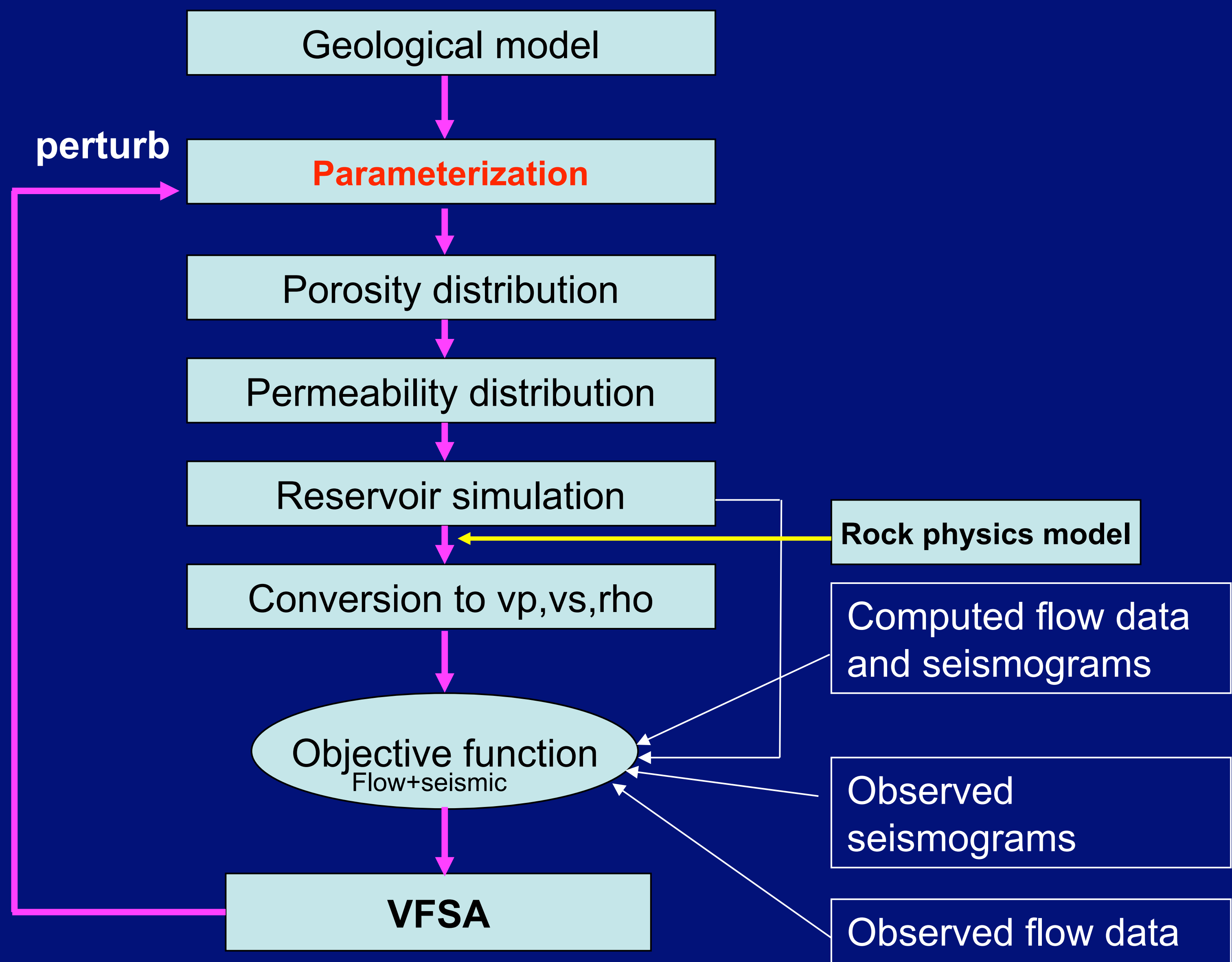


Figure 4.9.

Proposal distribution changes with iteration

Workflow of the joint inversion method



Objective function

$$objective = datamisfit + modelmisfit$$

$$objective = w_1 * seismic + w_2 * well + w_3 * prior + w_4 * spatial$$

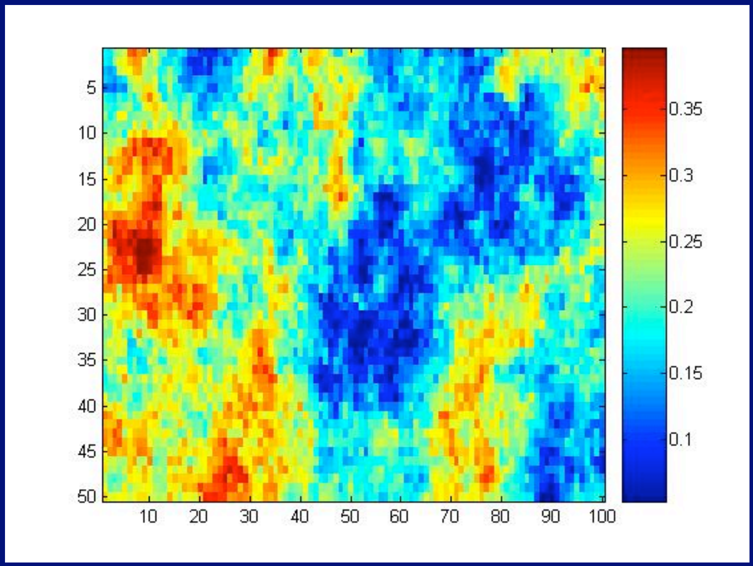
- $$seismic = \sum_{i=1}^{N_t} \| seis_{obs} - seis_{comp} \| / \left(\sum_{i=1}^{N_t} \| seis_{obs} \| + \sum_{i=1}^{N_t} \| seis_{comp} \| \right)$$
- $$well = \sum_{i=1}^{N_t} \| well_{obs} - well_{comp} \| / \left(\sum_{i=1}^{N_t} \| well_{obs} \| + \sum_{i=1}^{N_t} \| well_{comp} \| \right)$$

$$prior = \sum_{i=1}^{N_t} \| prior_{obs} - prior_{comp} \| / \left(\sum_{i=1}^{N_t} \| prior_{obs} \| + \sum_{i=1}^{N_t} \| prior_{comp} \| \right)$$

$$spatial = \sum_{i=1}^{N_t} \| vari_{obs} - vari_{comp} \| / \left(\sum_{i=1}^{N_t} \| vari_{obs} \| + \sum_{i=1}^{N_t} \| vari_{comp} \| \right)$$

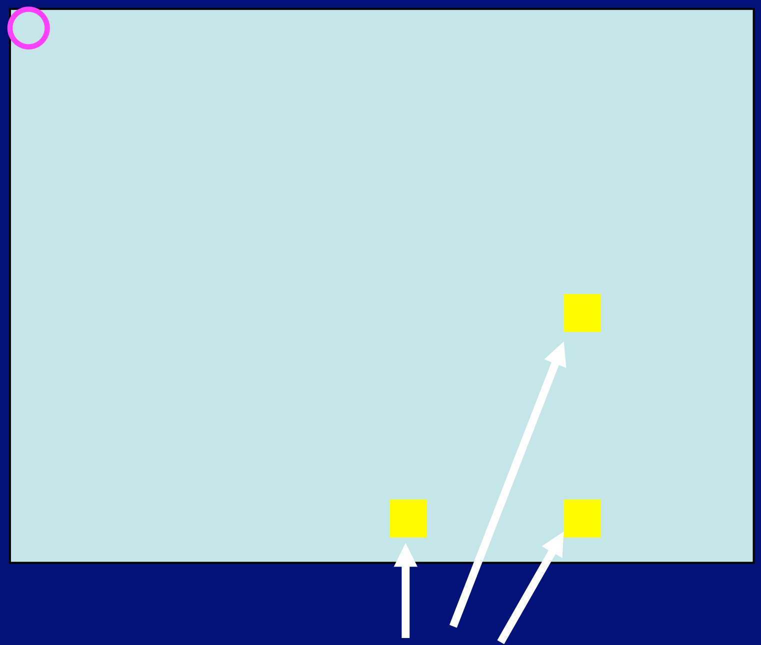
Objective function can include four parts, seismic, well, prior, and spatial constraints. At different stages, the norm of the objective function can be different as can the weights.

Experimental Model Description



Porosity

Injector



Producer

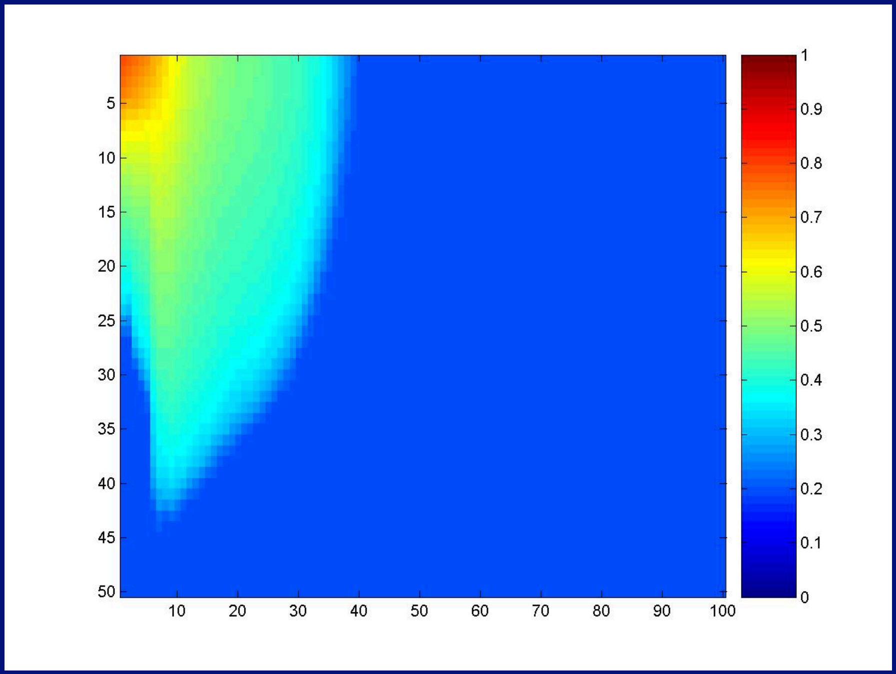
The model is part of SPE10 model.

Porosity and permeability are parameterized with a linear relationship.

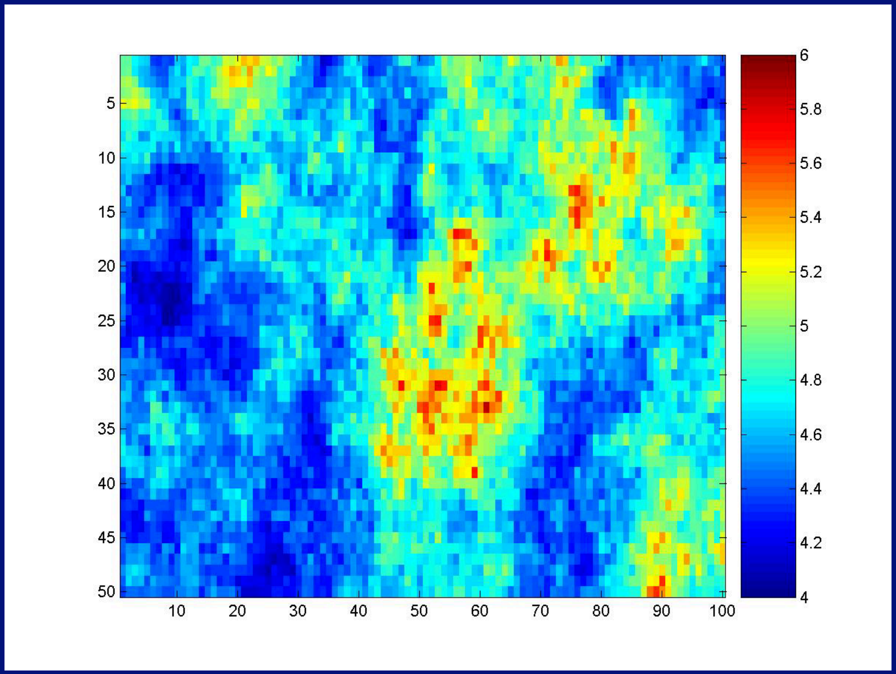
10 production steps are used. Each production step is 200 days.

The dimension is 50x100. So the number of parameters is 5000 if only porosity or permeability is considered as model parameter.

Evolution of saturation and time-lapse seismic data for 10 production steps

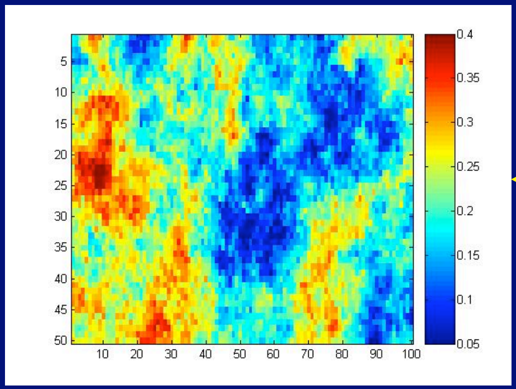


Saturation evolution

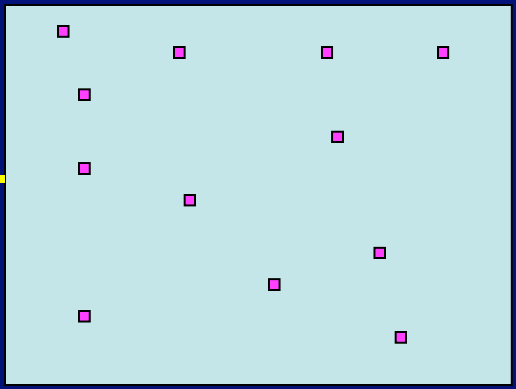


Time-lapse seismic data

pilot point method



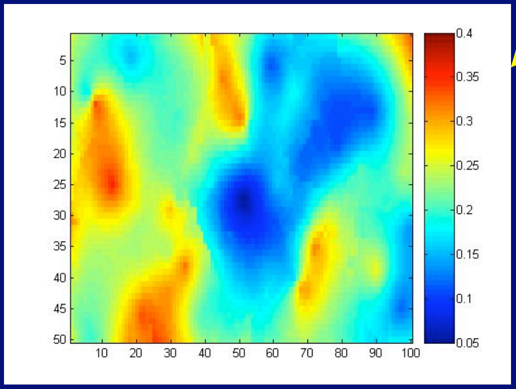
True porosity model



Pilot points

Representation model

Kriging interpolation



Interpolation result

VFSA

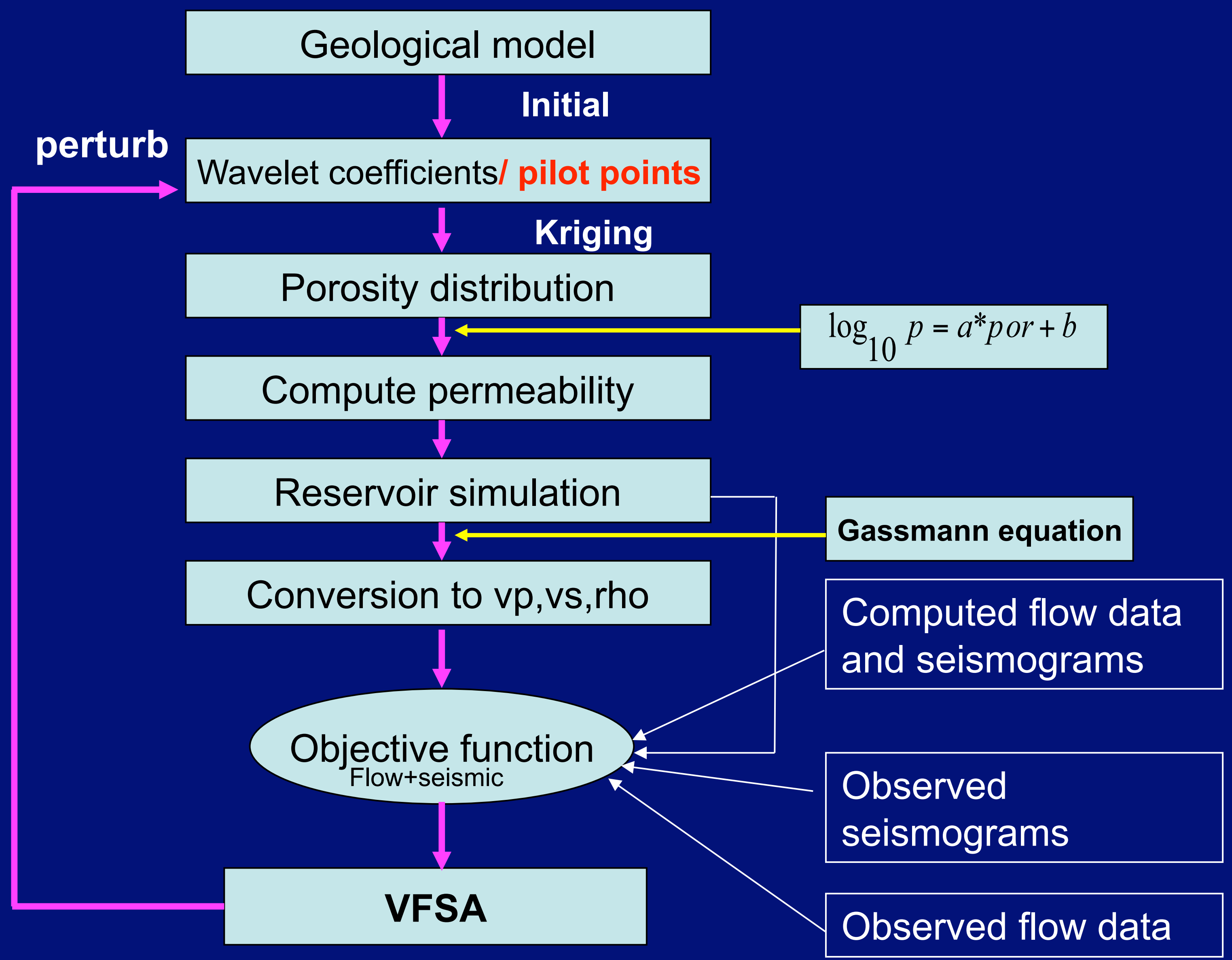
Grid Constraint

The parameters include values and positions of the pilot points

Pilot point based inversion using both time-lapse seismic and production data

- Pilot point parameterization is used to reduce the number of model parameters
- VFSA is used to optimize the positions of pilot points positions and the values
- Flow simulation is run to generate production data
- Rock-physics model is used to convert reservoir parameters to seismic parameters
- Seismic modeling is used to compute synthetic seismic response

Porosity inversion procedure using pilot point method



Three experiments

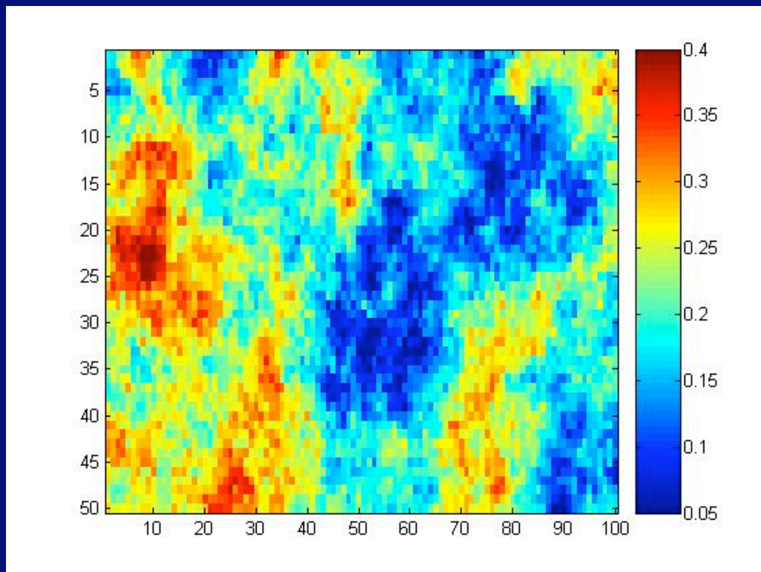
- **Inversion using only well data**
- **Inversion using only seismic data**
- **Inversion using both seismic and well data**

The number of pilot points is 50. Each one is constrained to be within one cell of a 5x10 coarse grid

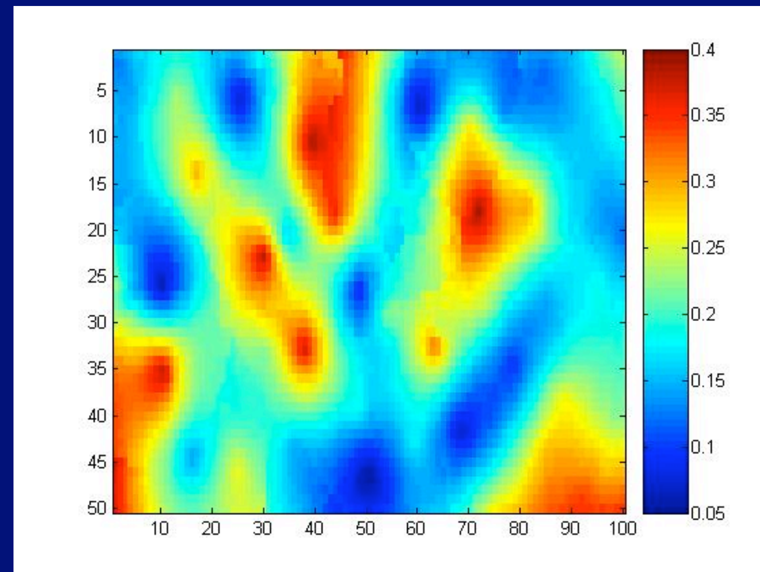
Variogram: Spherical model fitted to the true variogram

Production steps are 10

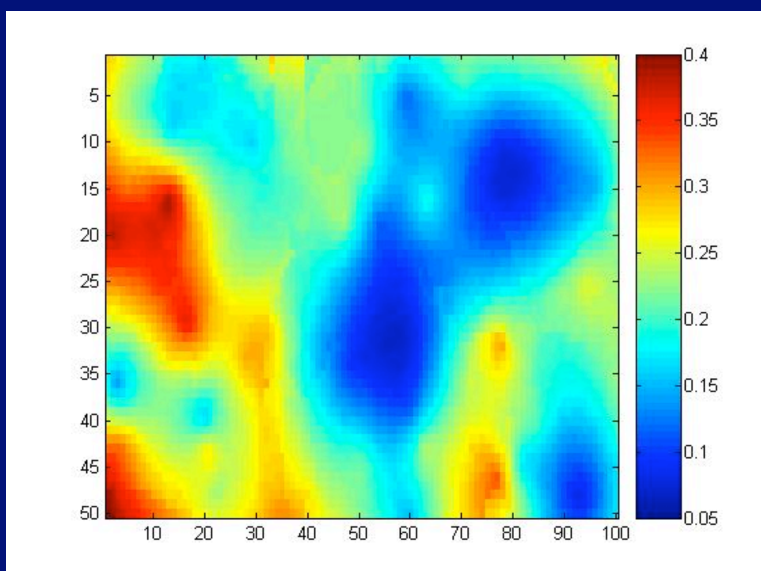
Inversion results



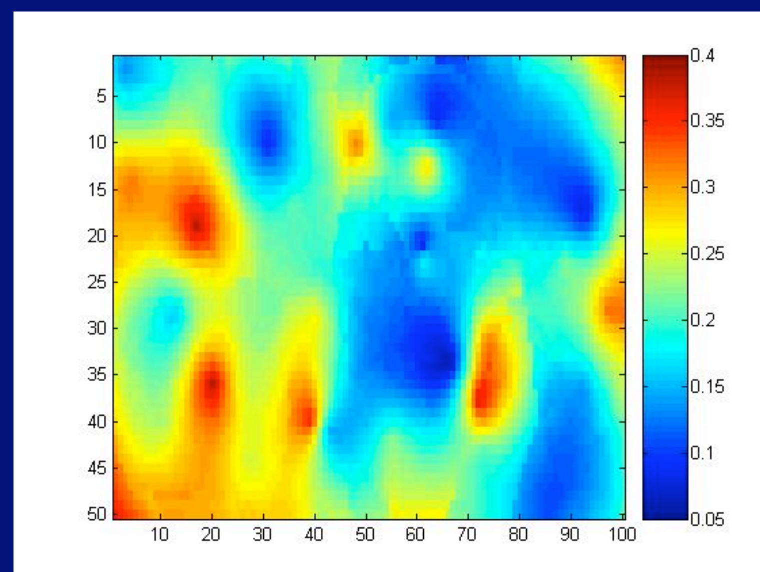
True porosity



Inverted porosity with only well data

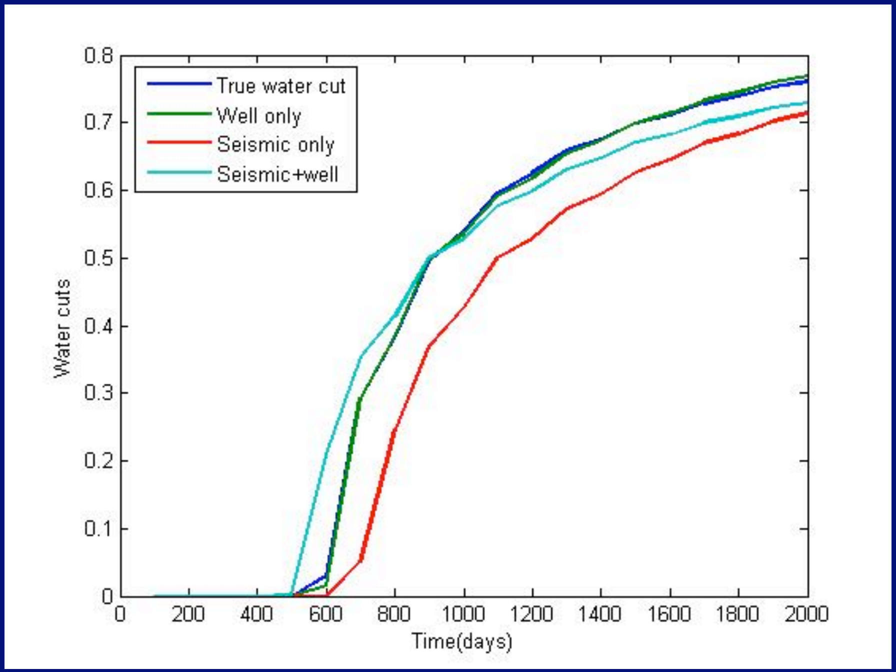


Inverted porosity with only seismic data

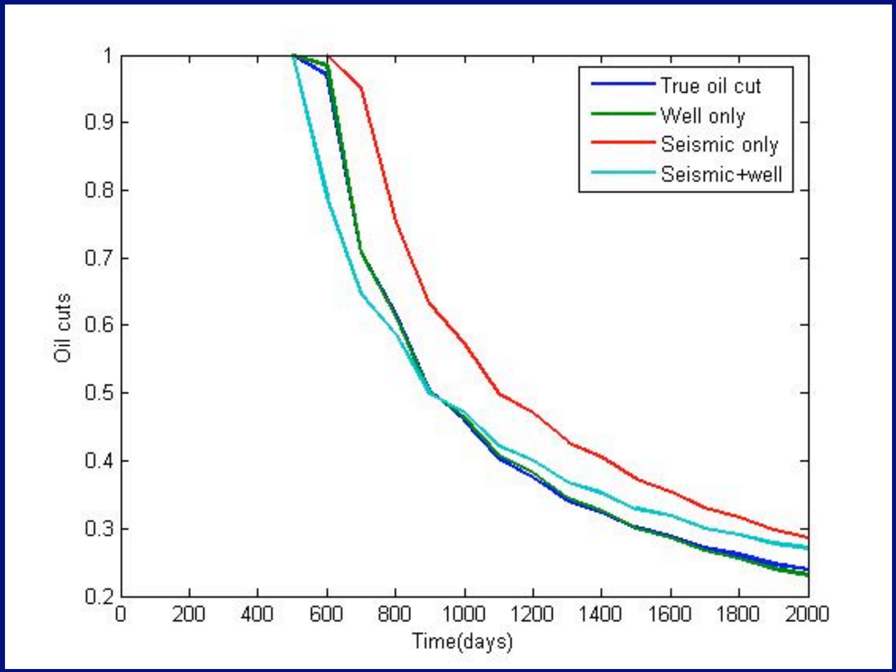


Inverted porosity using both seismic and well data

comparisons of well performance

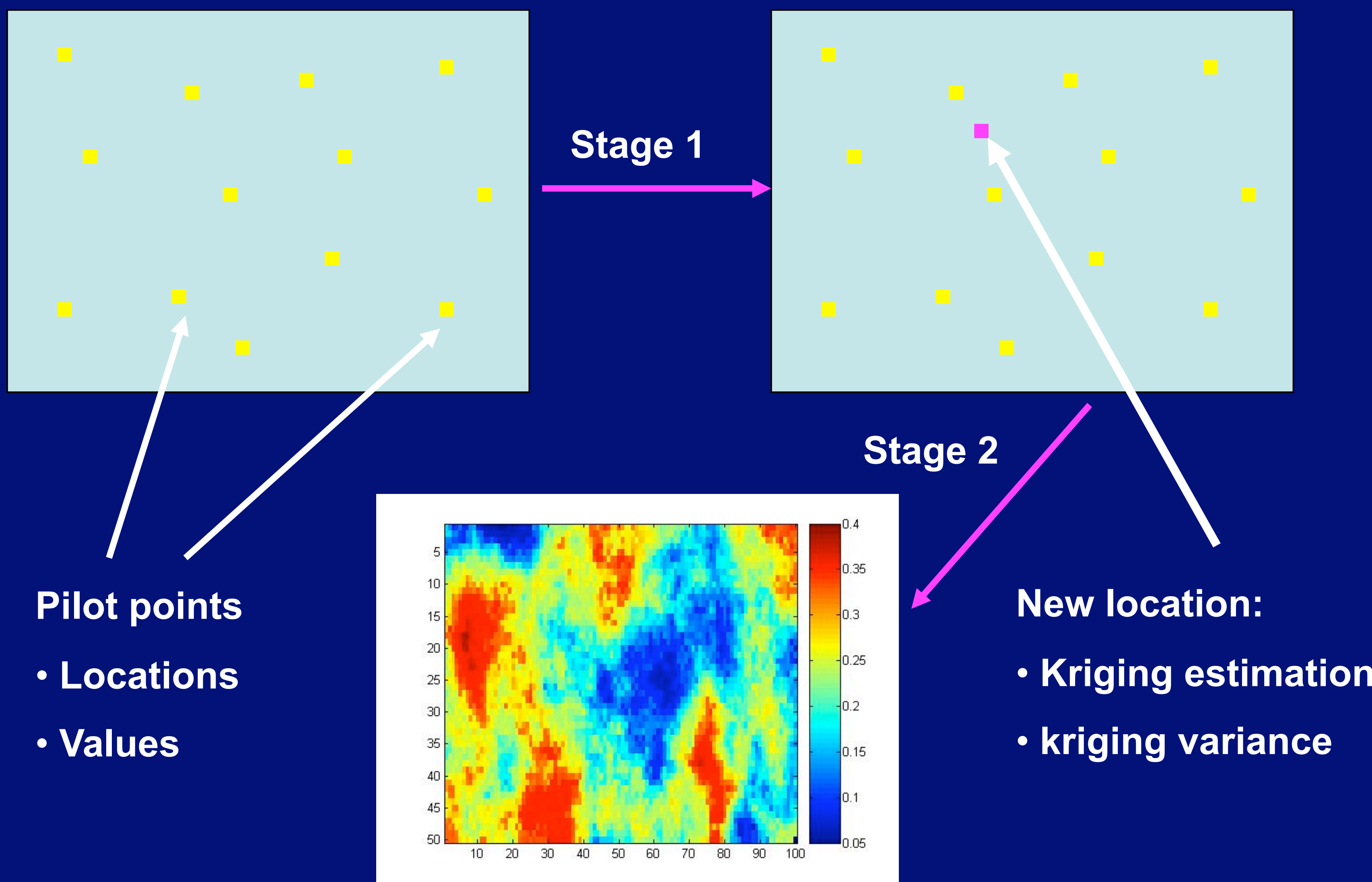


Water cut (well 1)



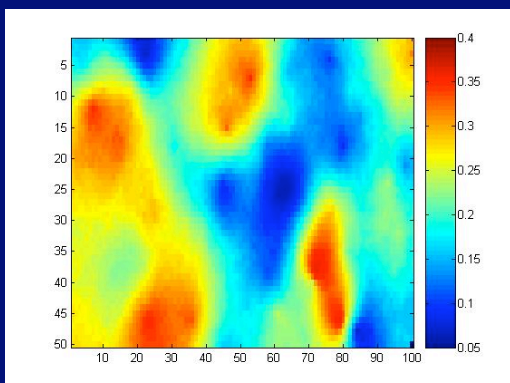
Oil production rate (well 1)

Two stage inversion method

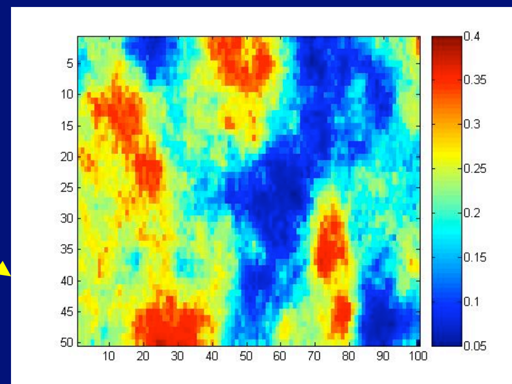


Comparison between deterministic and stochastic models

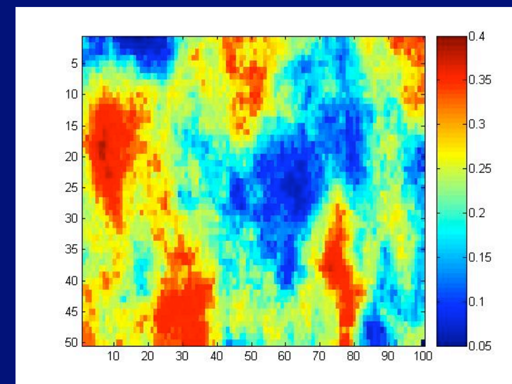
The same pilot points



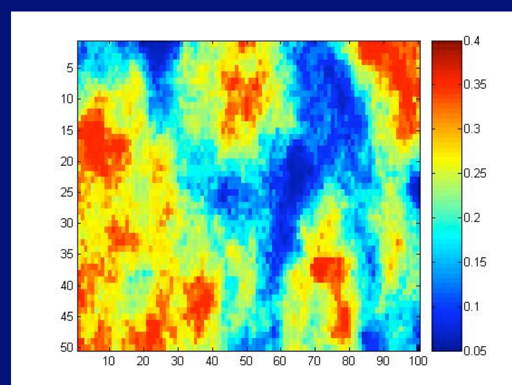
Inversion result of pilot point and VFSA



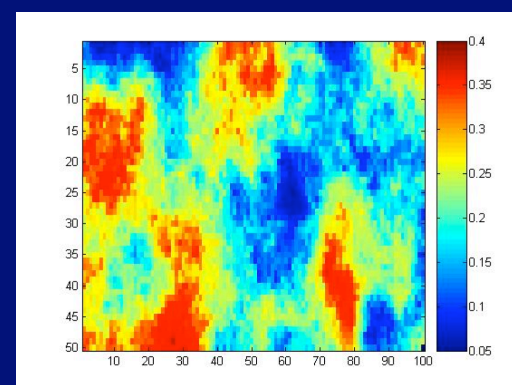
Realization 1



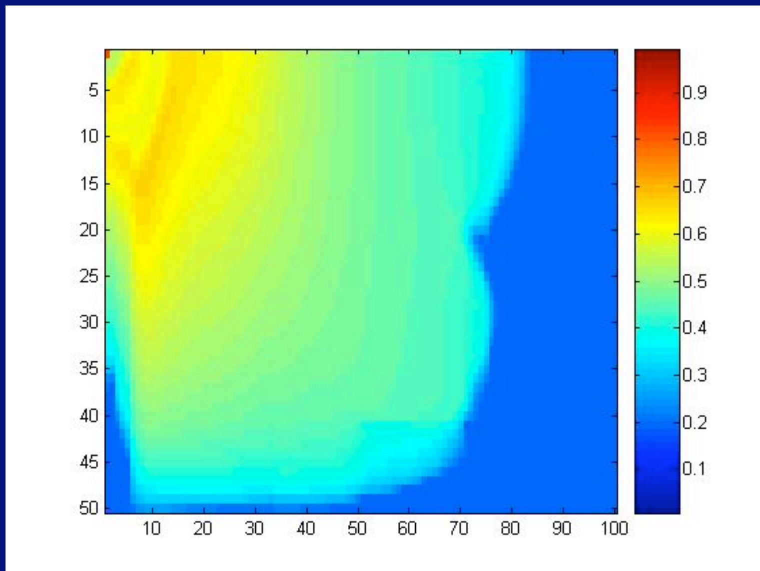
Realization 2



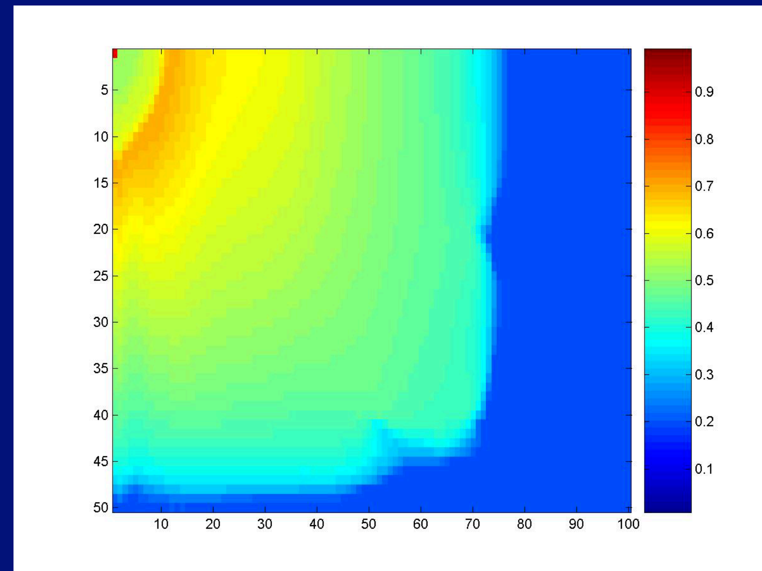
Realization 3



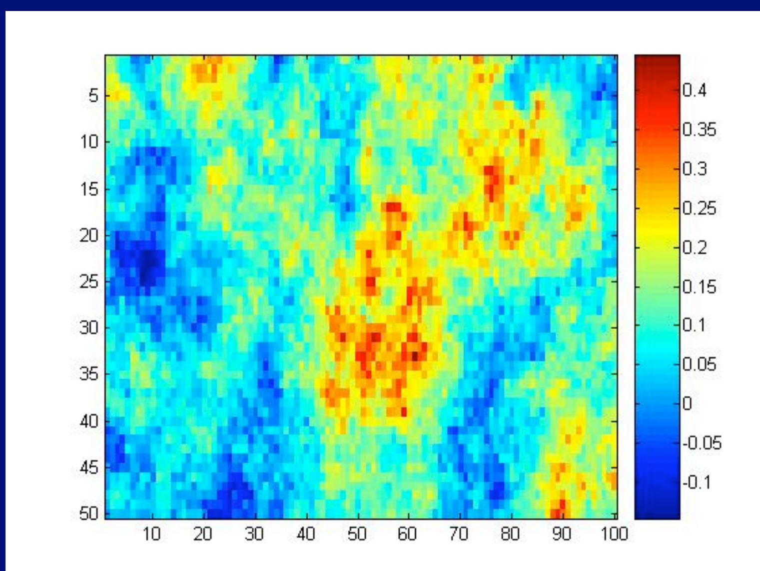
Realization 4



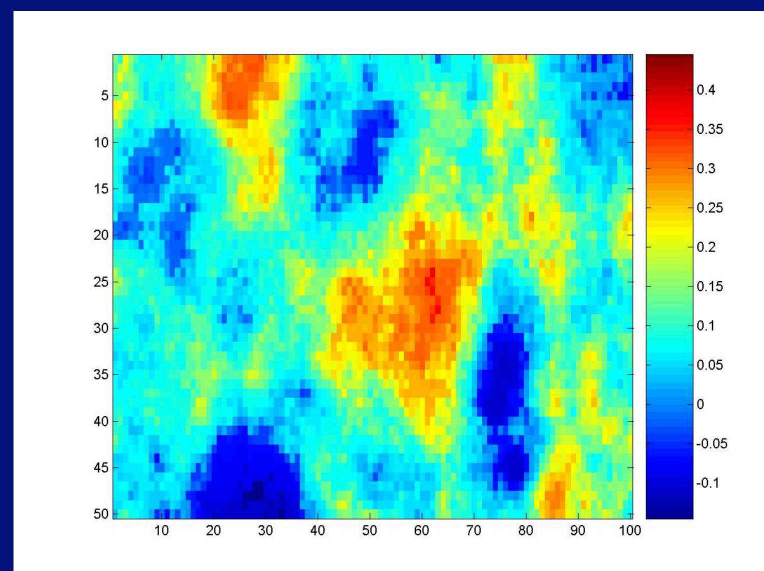
Saturation distribution in production step 5 (True)



Saturation distribution in production step 5 (50 models)

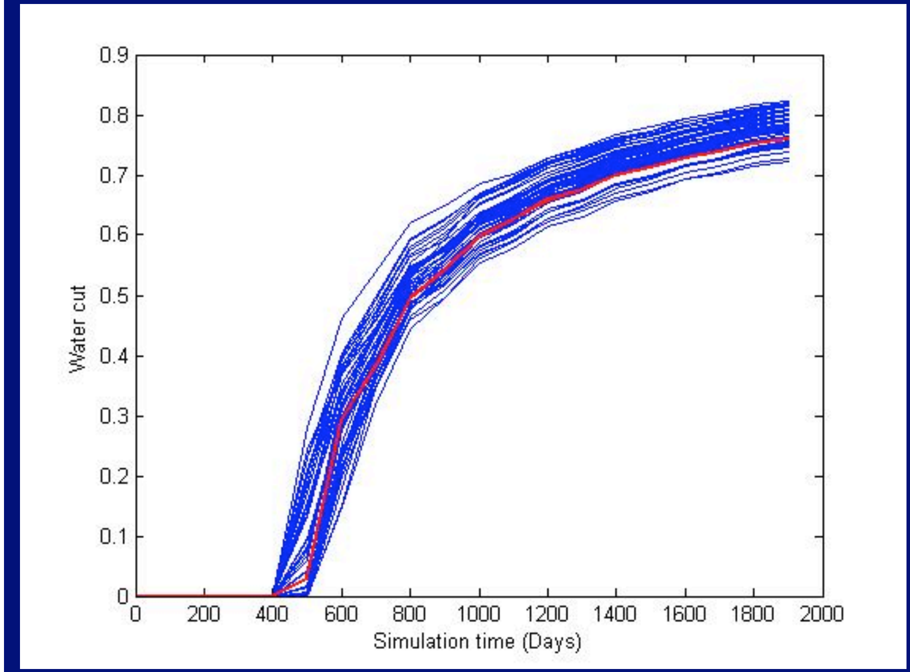


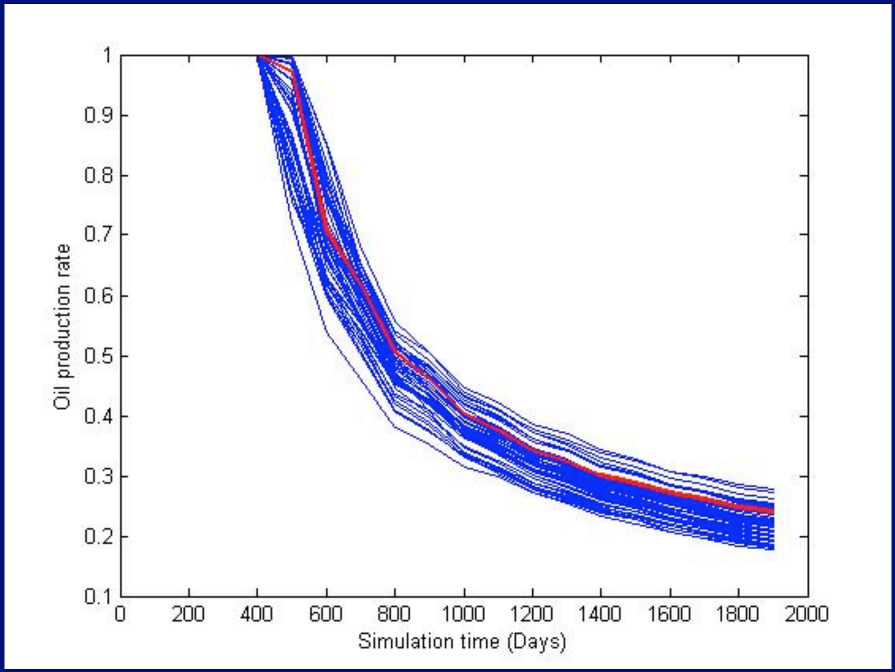
Seismic amplitude slice in production step 5 (True)



Seismic amplitude movie in production 5 (50 models)

The combination of pilot point and SGS

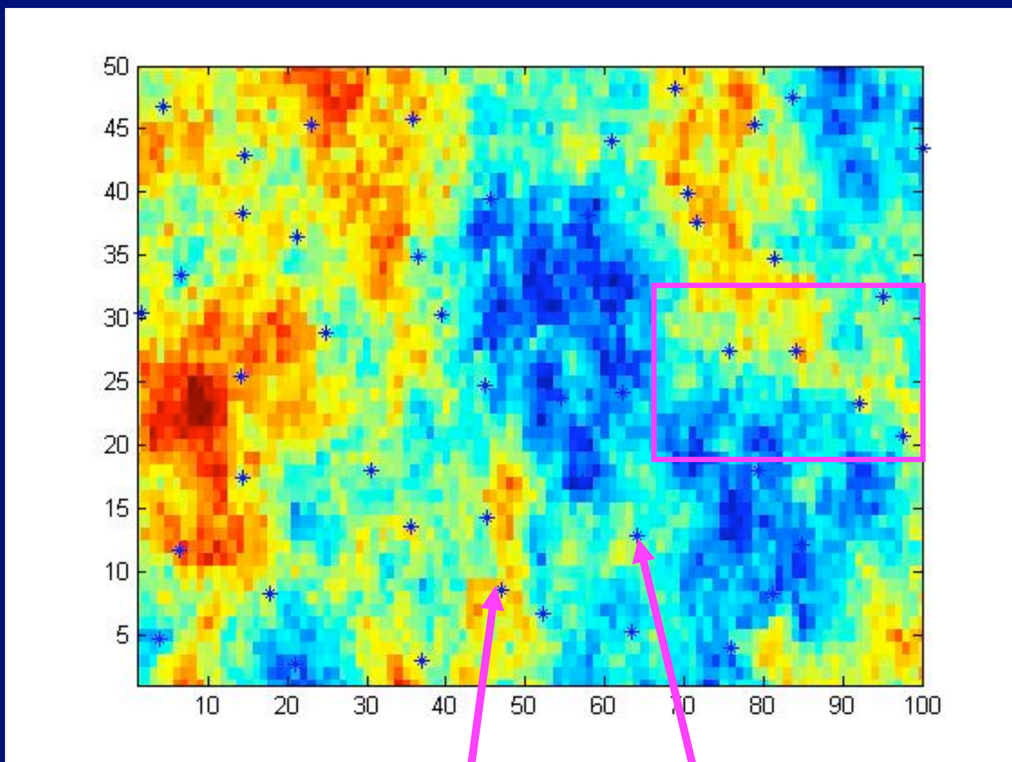




Water cut **Oil production rate**

The red line is the true solution. The blue lines are results of fifty stochastic models from SGS.

Probability based pilot point parameterization



Optimal pilot points with VFSA

Question 1: Where are the pilot points usually located?

Answer : Where the change is large !

Question 2: Do we have some information in advance to infer the position of the pilot points?

Answer: Yes, the 3D seismic data !

Probability based pilot point parameterization

Compute the probability based on prior information

↓

Draw pilot points based on the computed probability

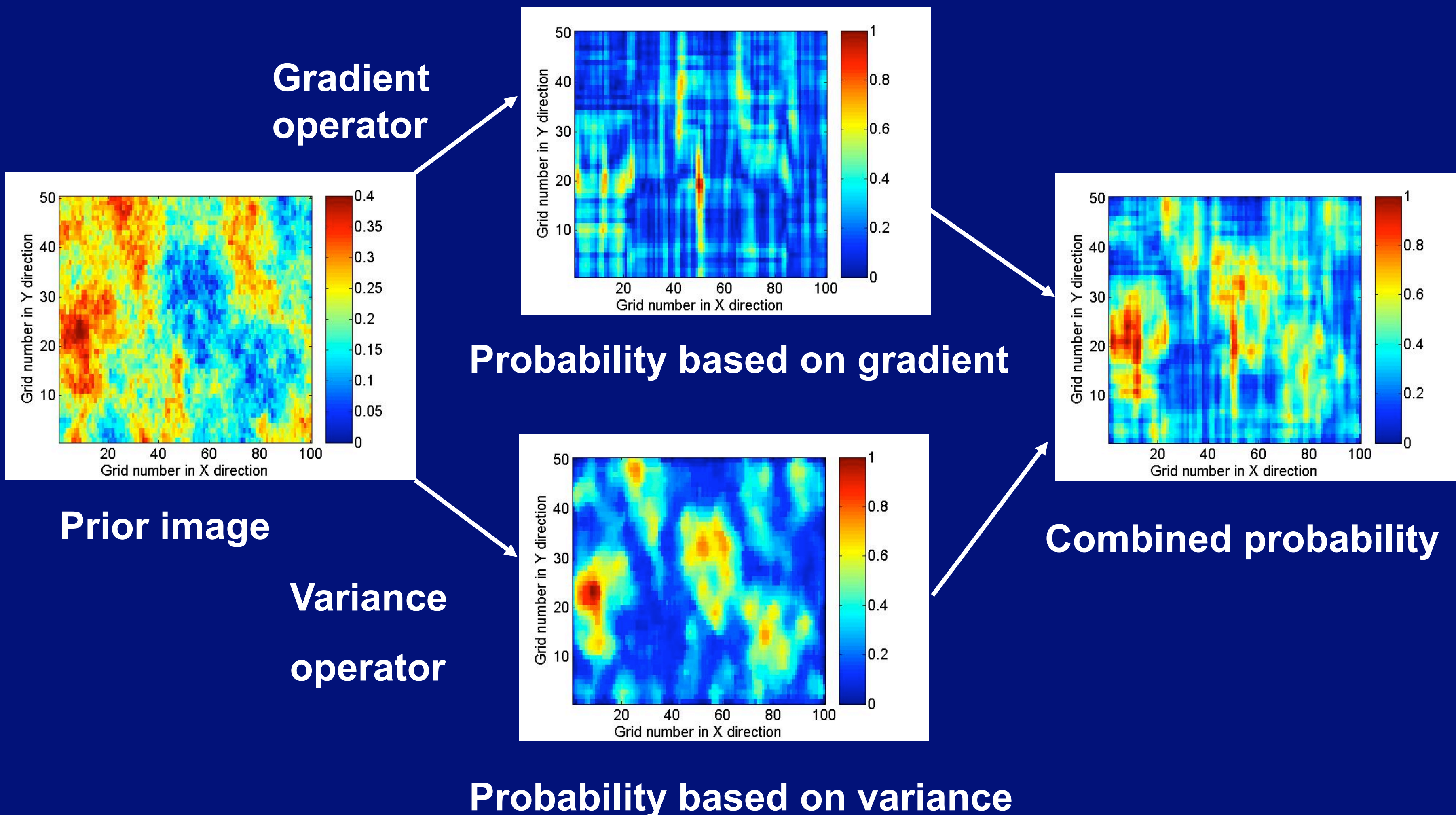
↓

Input the locations of pilot points to inversion loops

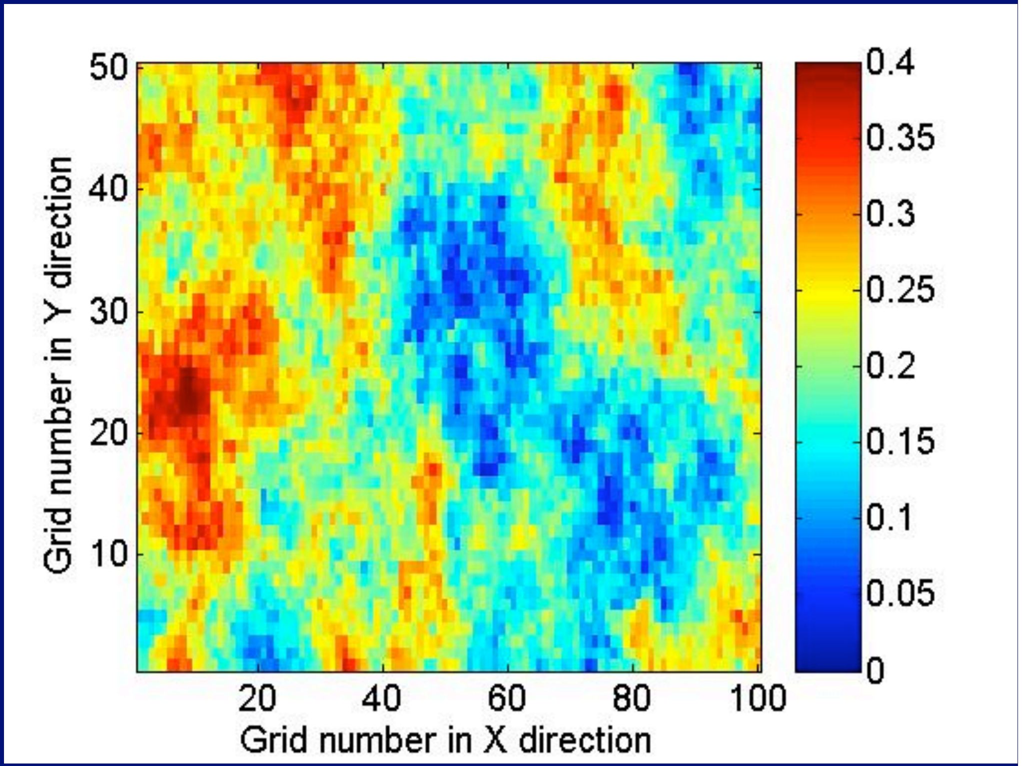
↓

Optimal positions and values

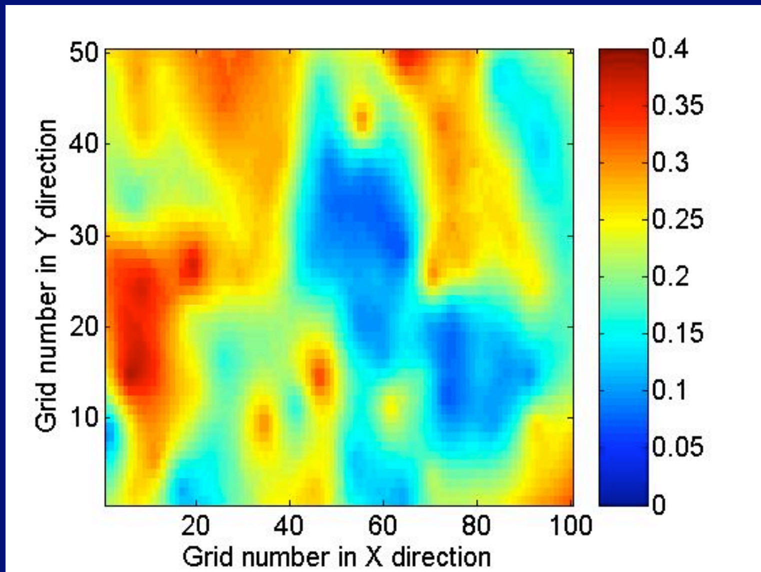
Probability based pilot point parameterization



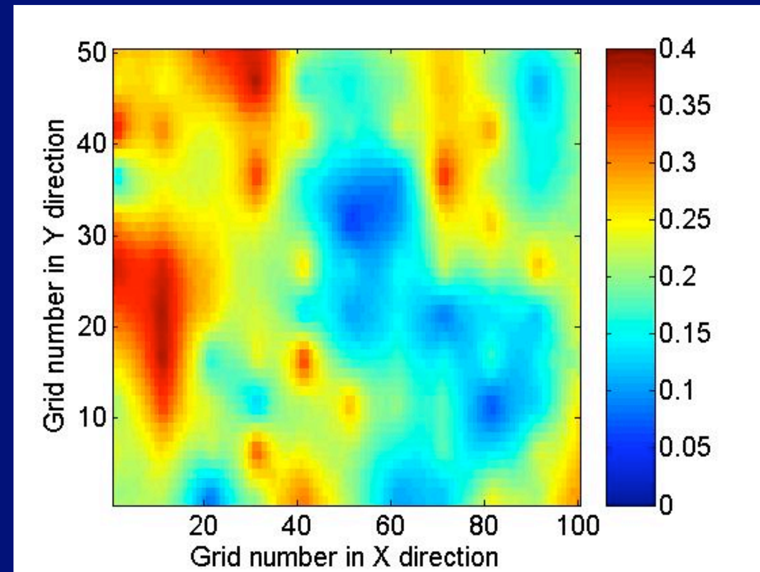
Probability based pilot point parameterization



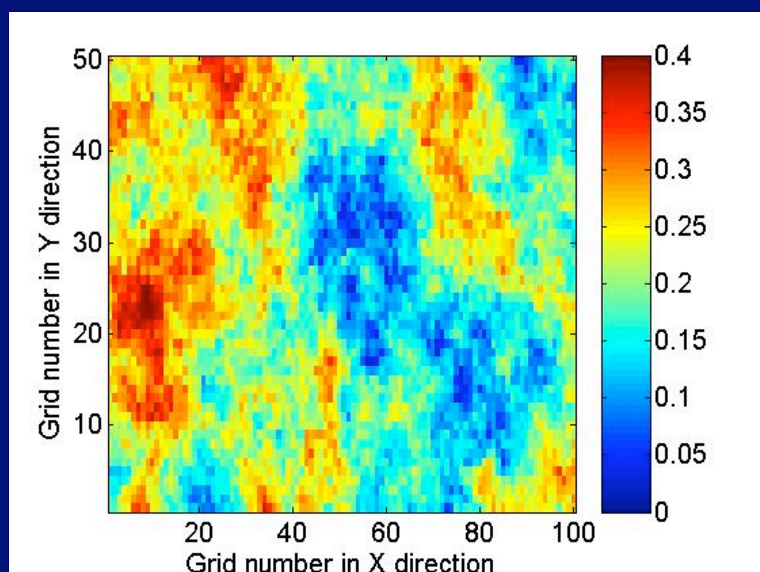
True porosity



Probability based positions



Evenly distributed positions



True model

Outline

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Problem background

Joint inversion method

2 Parameterization methods

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Methods for Parameter Space Reduction

- Wavelet Transform
- Pilot Point
- Pilot Point + SGS
- Probability based pilot point

Initial result of 3D pilot point

3 Joint inversion for porosity and permeability

Porosity and permeability model are correlated

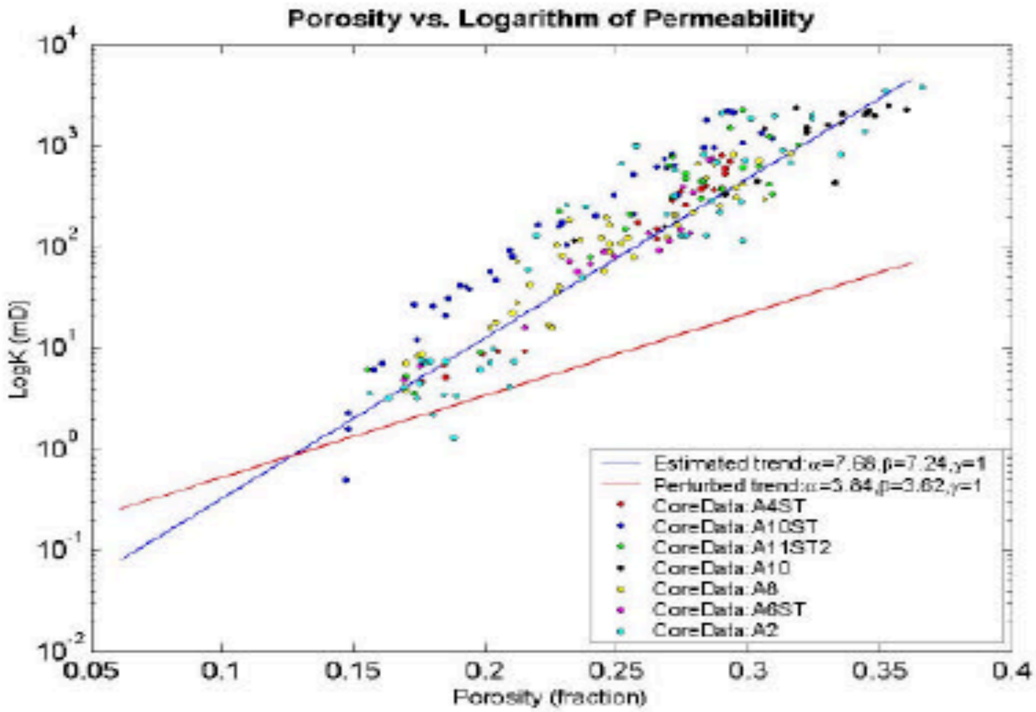
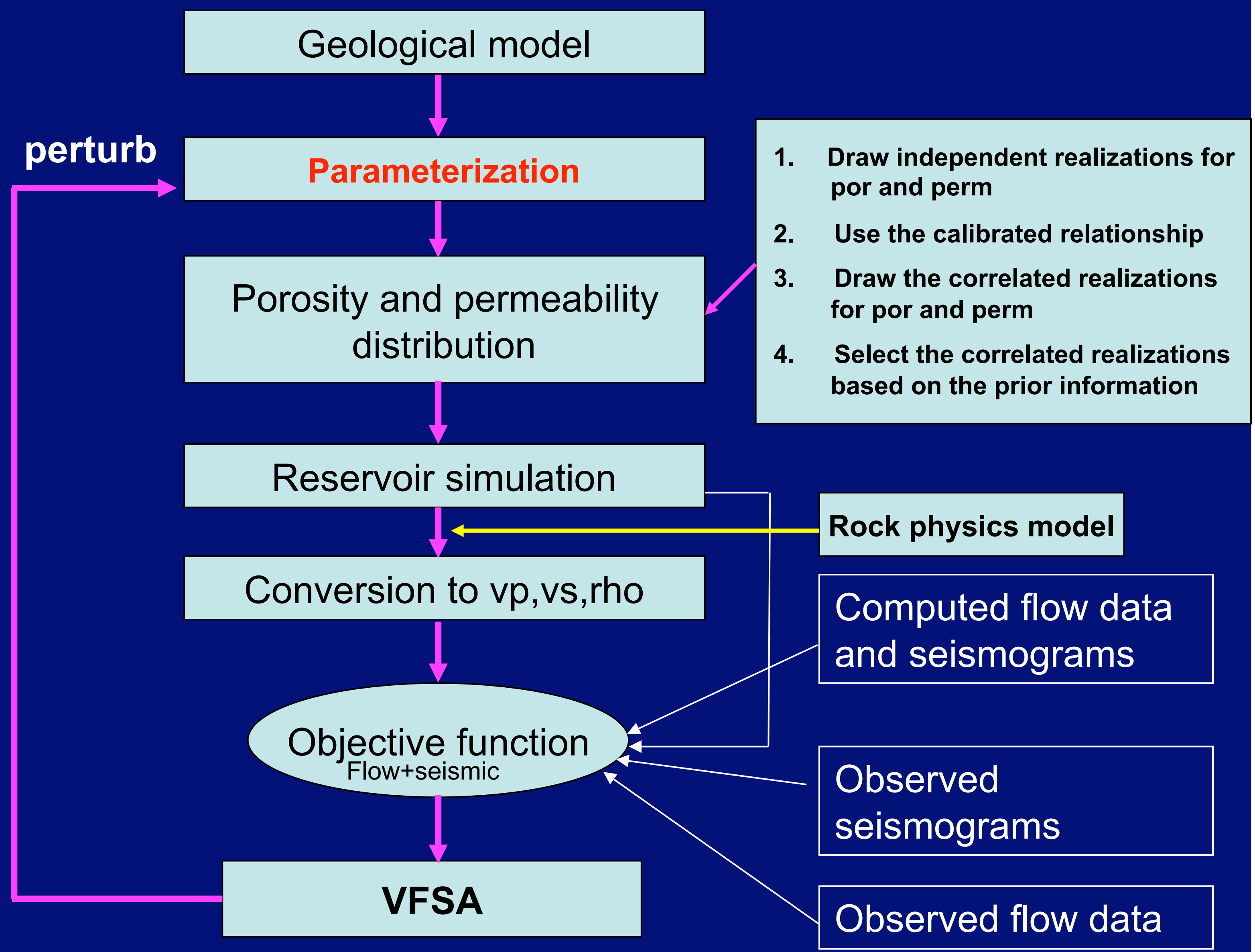


Figure 2.5: Cross-plot of porosity and logarithm of permeability constructed with rock-core laboratory measurements. The solid blue line describes the linear trend inferred from regression analysis, while the solid red line describes a 50%-perturbation trend used to assess the sensitivity of the linear correlation to the length of support of the rock-core measurements (Sensitivity Analysis No. 3; refer to case GI-5 in Table 7.1).

(from Ordaz 2005)

Workflow of the joint inversion method to invert both porosity and permeability



Two experiments:

1 Large bound for both porosity and permeability

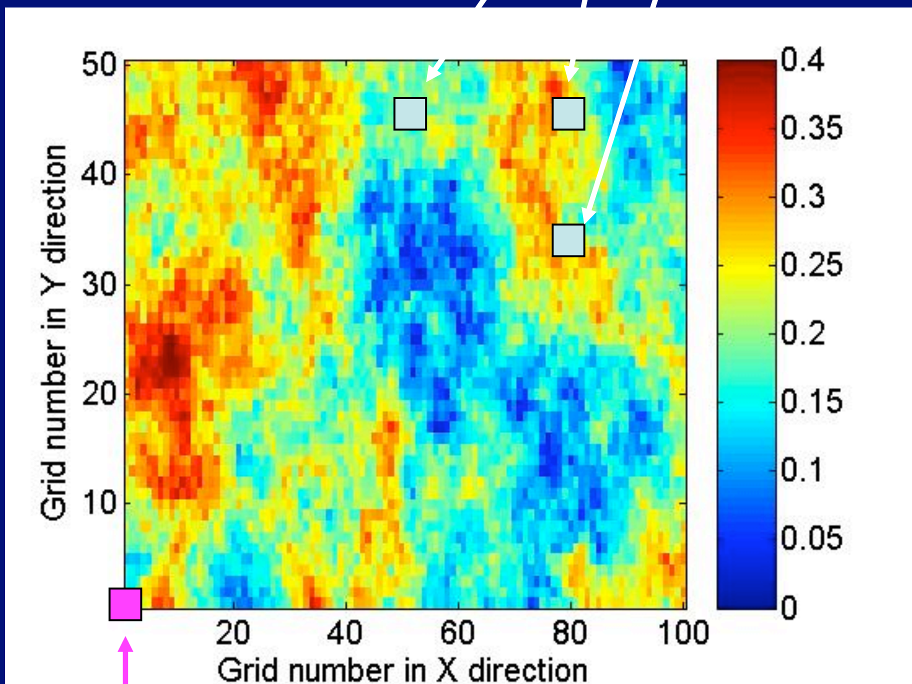
(We want to show that it will not work well to treat porosity and permeability equally because their different sensitivities to different data)

2 Small bound for porosity and invert only a and b for permeability

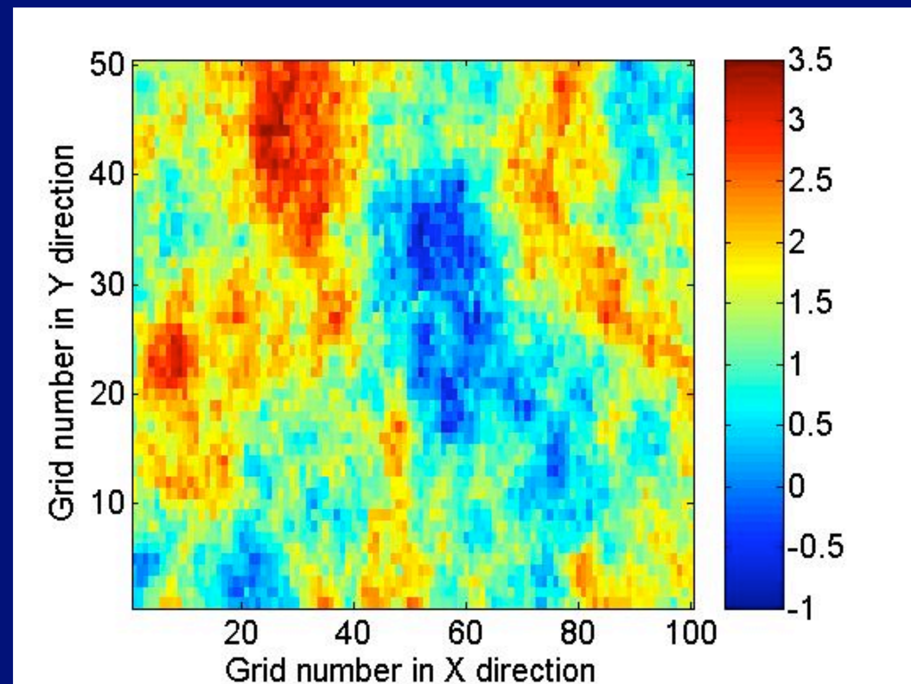
(We propose inverting porosity from only seismic data and then setting small search bounds for porosity and invert for a and b simultaneously for permeability)

True porosity and permeability

Producers



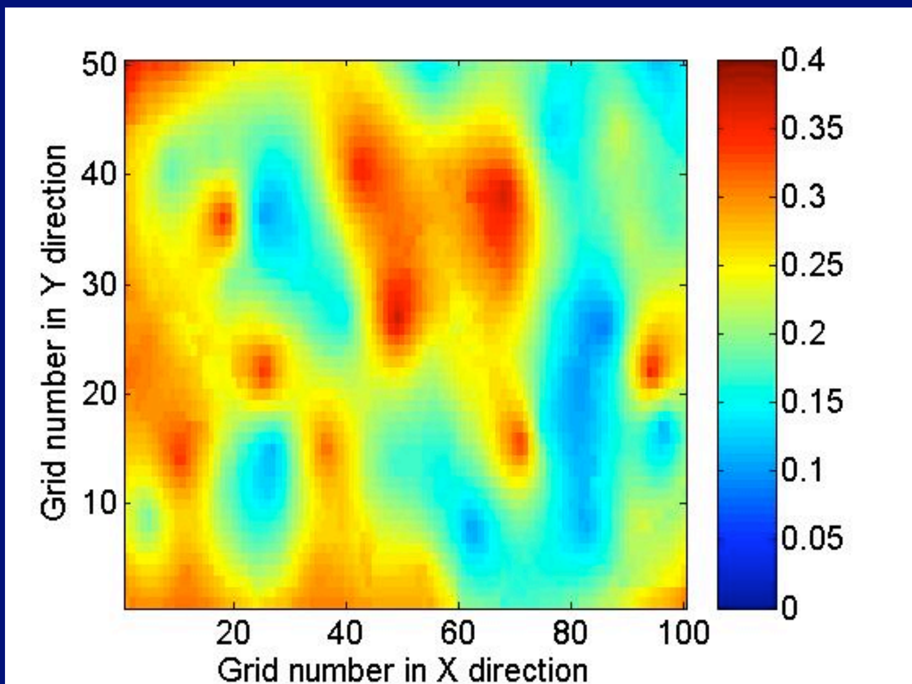
True porosity

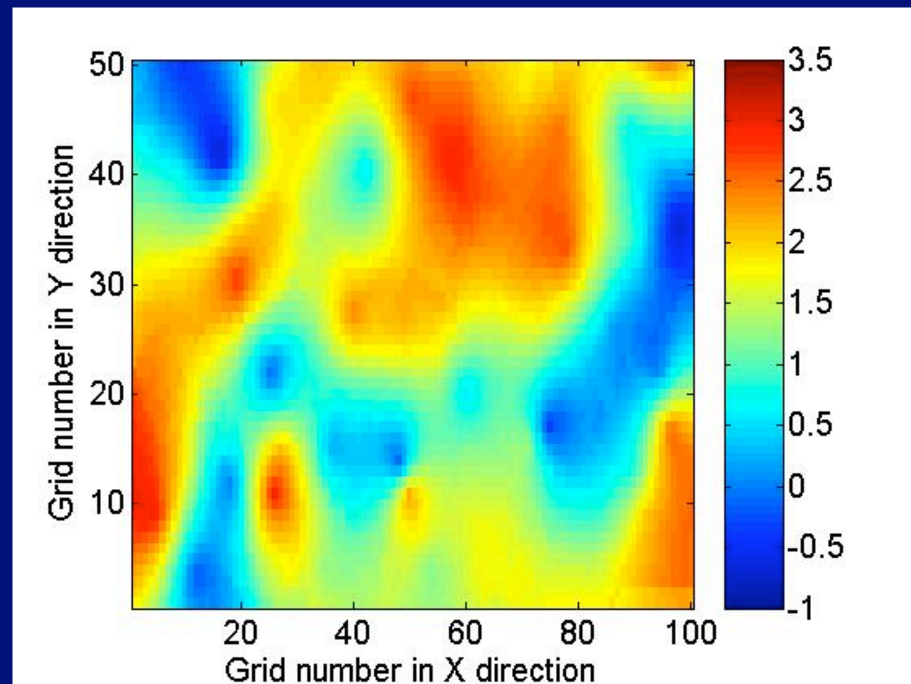


True permeability

Injector

Large bounds for both porosity and permeability



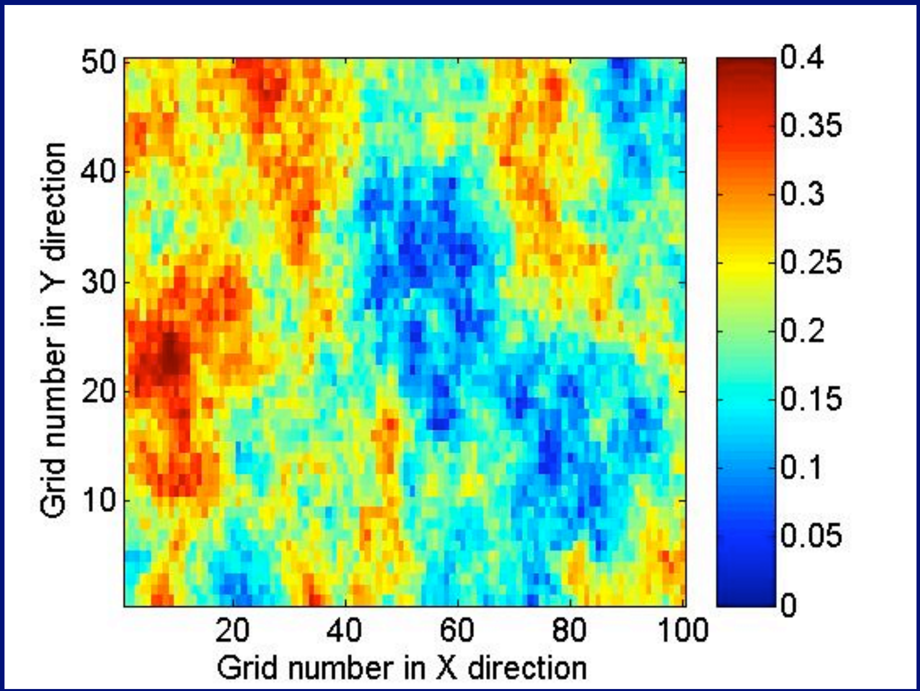


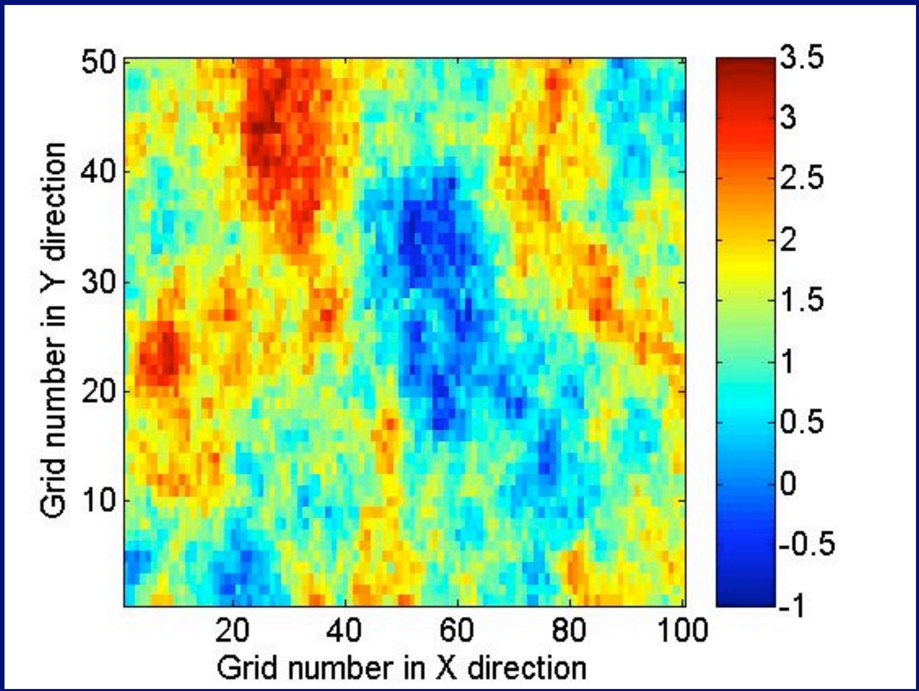
Inverted porosity

Inverted permeability

Using 1 production time steps data

True porosity and permeability

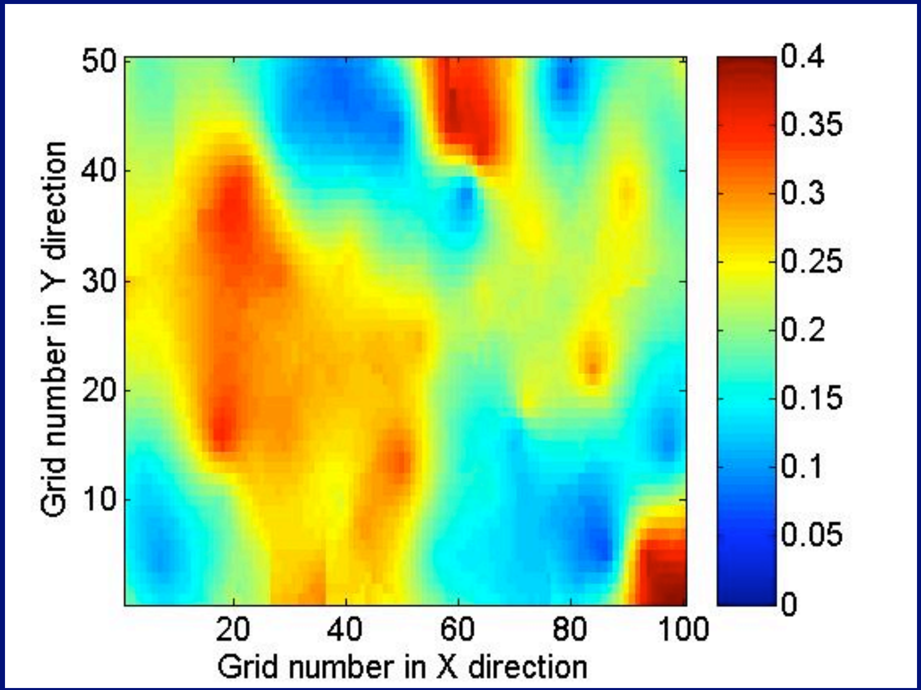




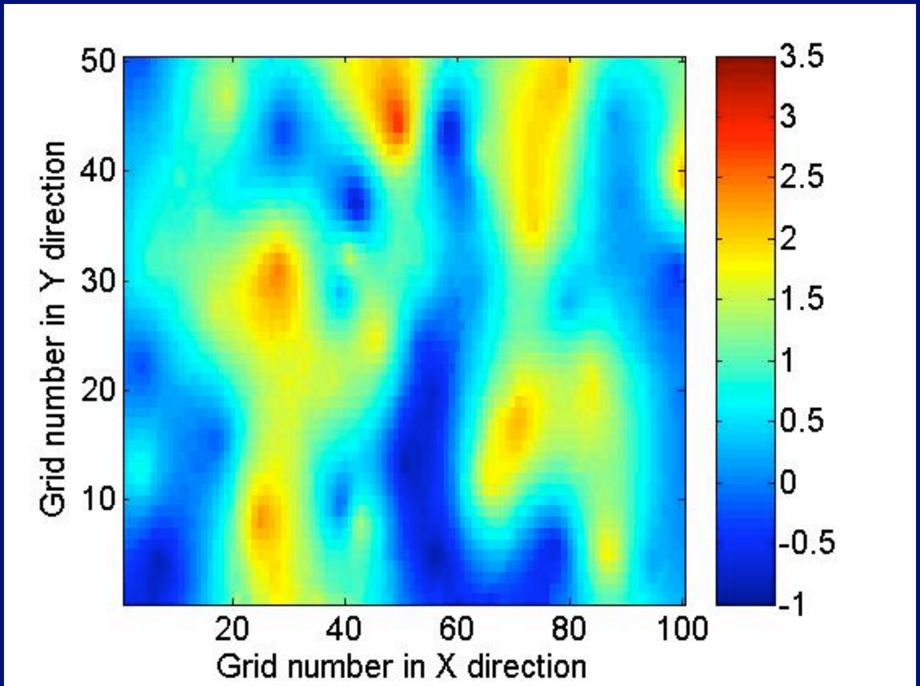
True porosity

True permeability

Large bounds for both porosity and permeability



Inverted porosity



Inverted permeability

Using 10 production time steps data

Two experiments:

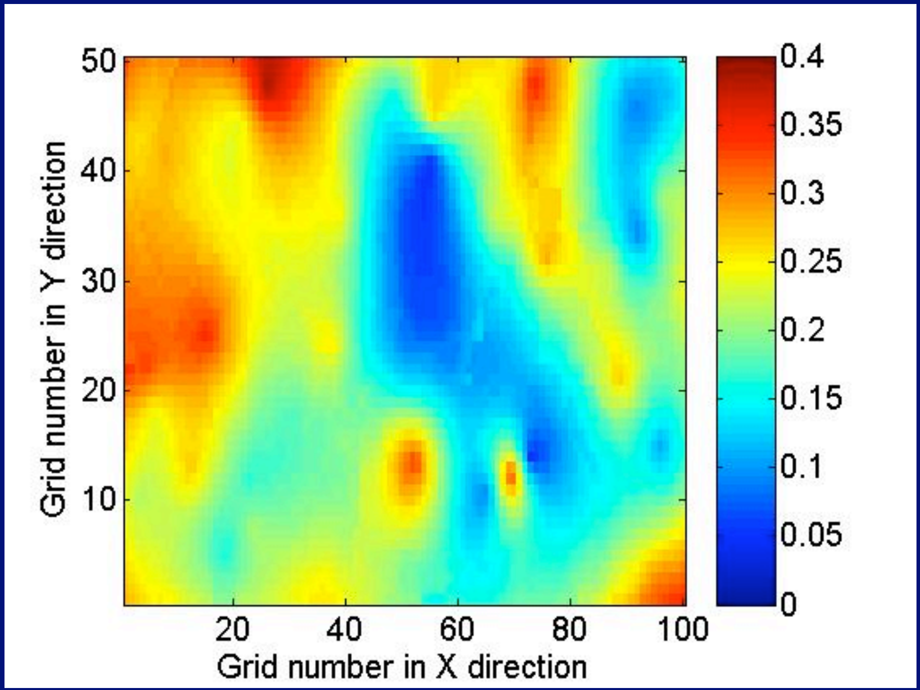
1 large bound for both porosity and permeability

2 small bounds for porosity and invert only a and b for permeability

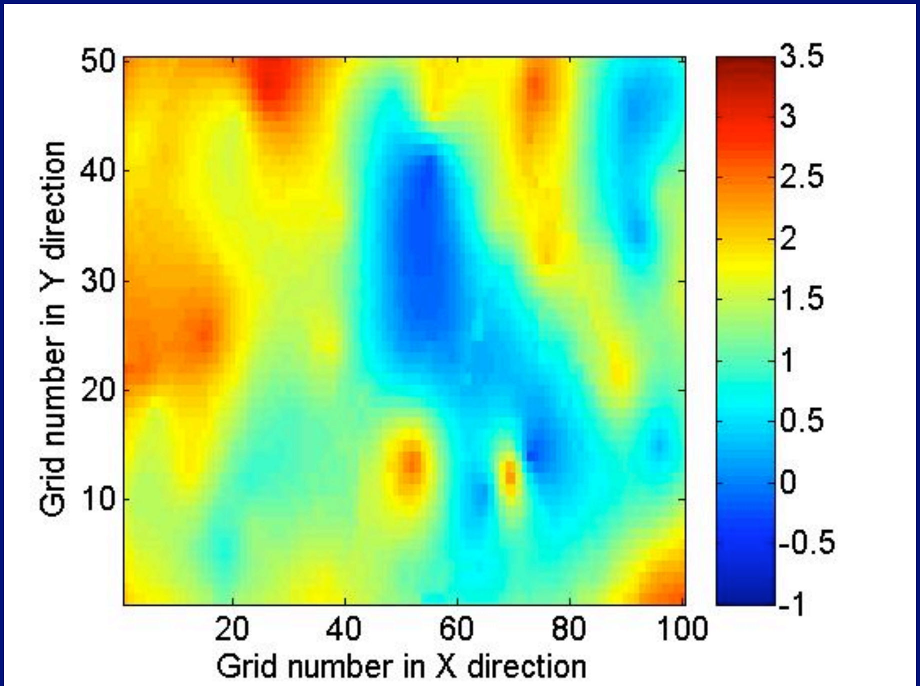
Log(perm)=a* por+b

a : [8 10]

b : [-1 0]



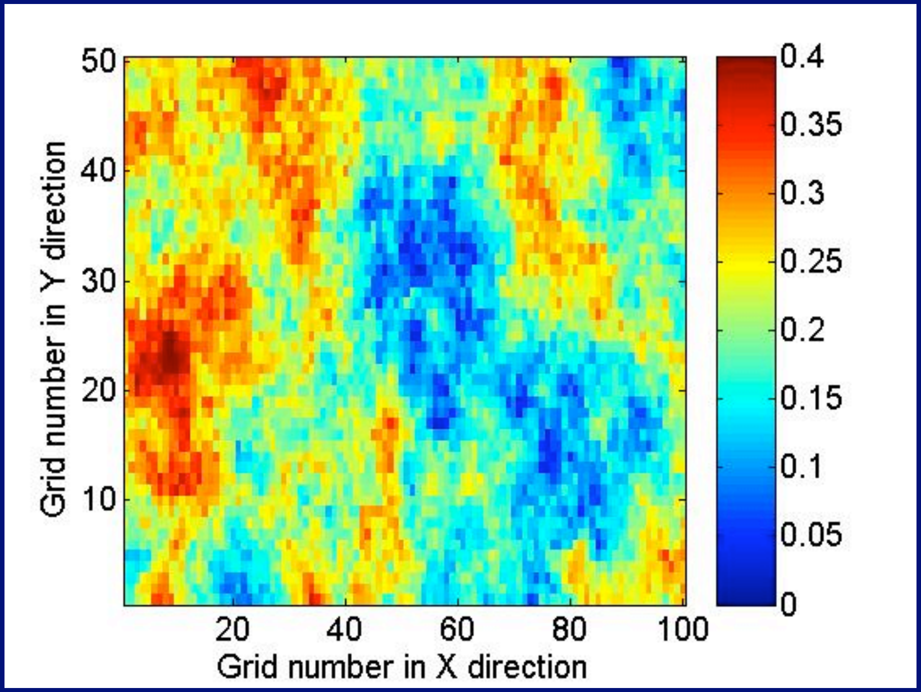
Inverted porosity

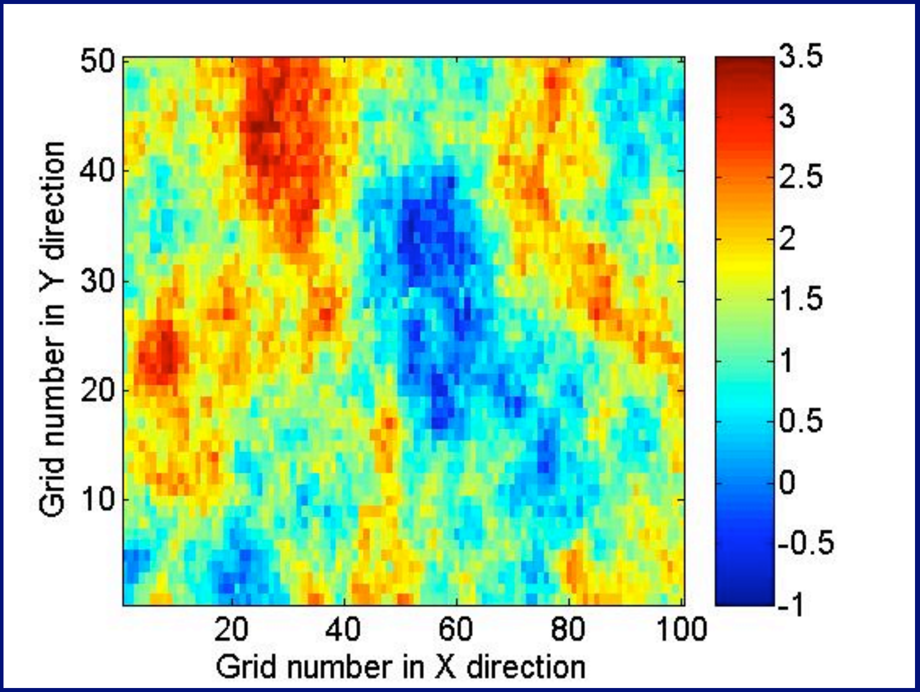


Inverted permeability

Using 10 production time steps data

True porosity and permeability





True porosity

True permeability

Summary of this talk

- Establish the framework for the inversion of reservoir parameters using both time-lapse seismic and production data

- Investigate possible ways to invert porosity and permeability simultaneously

- Propose a two stage inversion method to create stochastic model which honor both time-lapse seismic and well production data

Future work

• Build a software framework to incorporate different methods

• Compare and incorporate other optimization methods

• Compare and incorporate other parameterization methods

• Use fast MCMC methods (Sen and Stoffa 1996; Hong and Sen 2008) to characterize uncertainty

Acknowledgement

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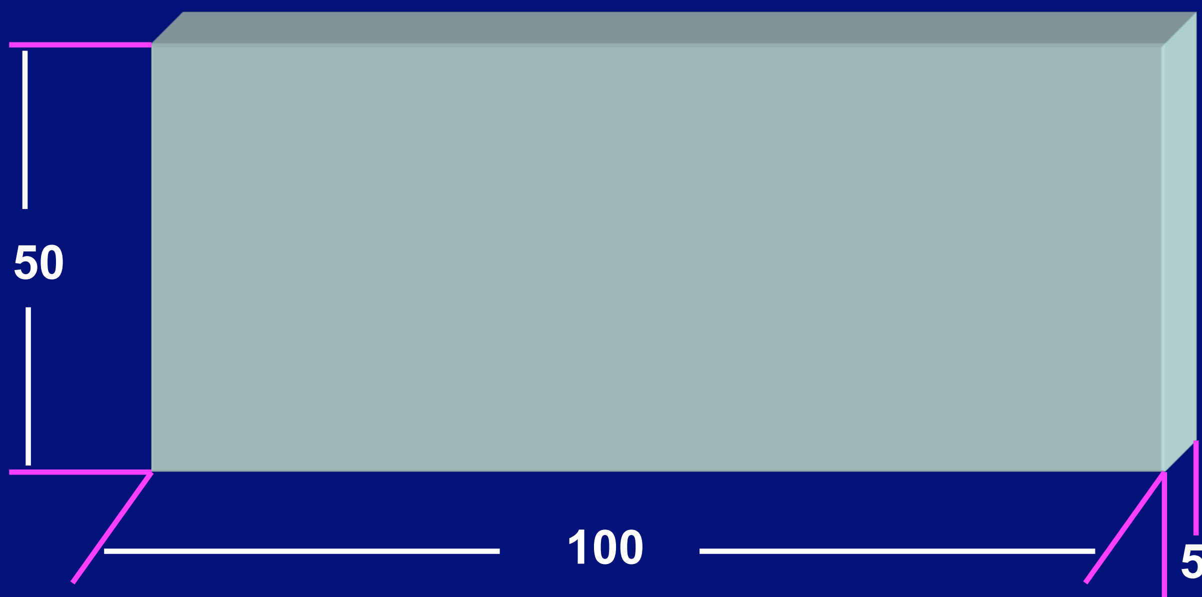
We thank ConocoPhillips and the Jackson School of Geosciences for giving us permission to present these results.

We thank Aaron L. Janssen and Bracken Smith for their suggestions and feedback.

Thanks

Experimental model description

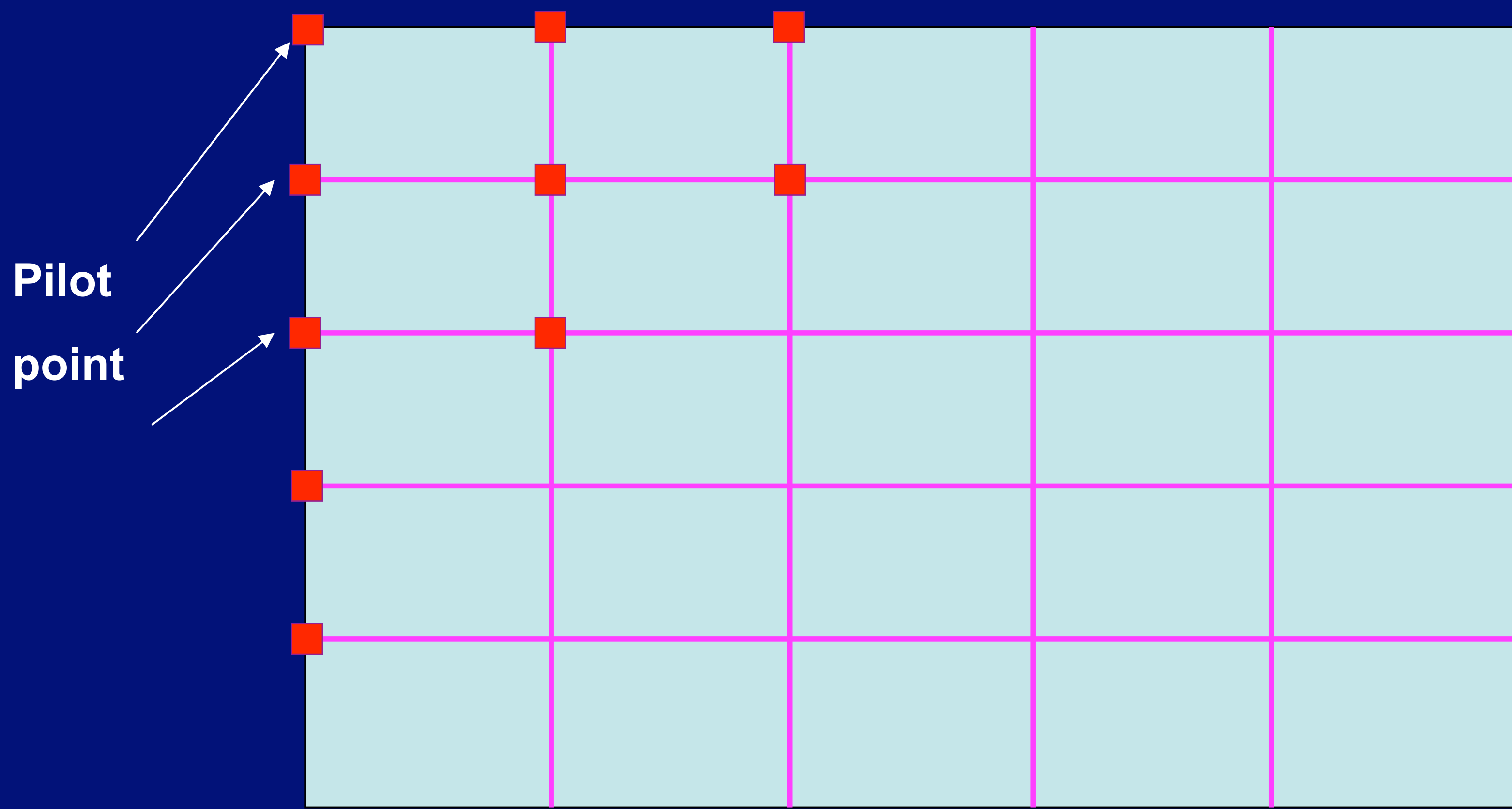


It is extracted from SPE10 model

Model Size: 50x100x5

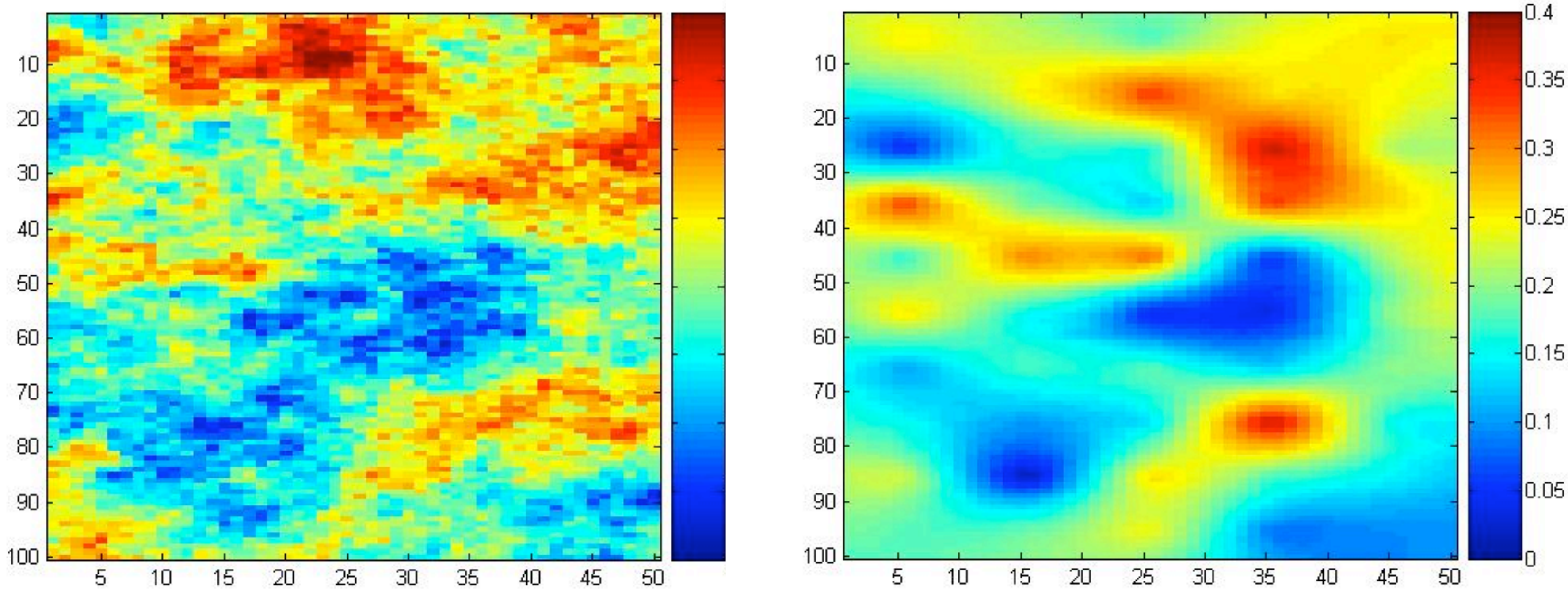
Total parameters: 25000

3D pilot point parameterization



The locations are known. The model parameter is the value at the grid point. The total pilot points are 250. The parameters are reduced to 1%.

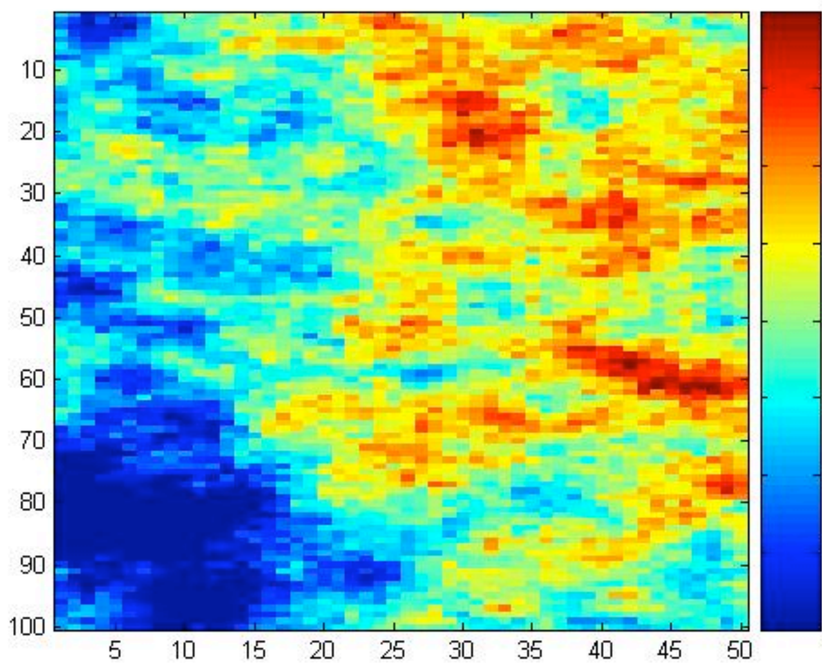
Layer 1

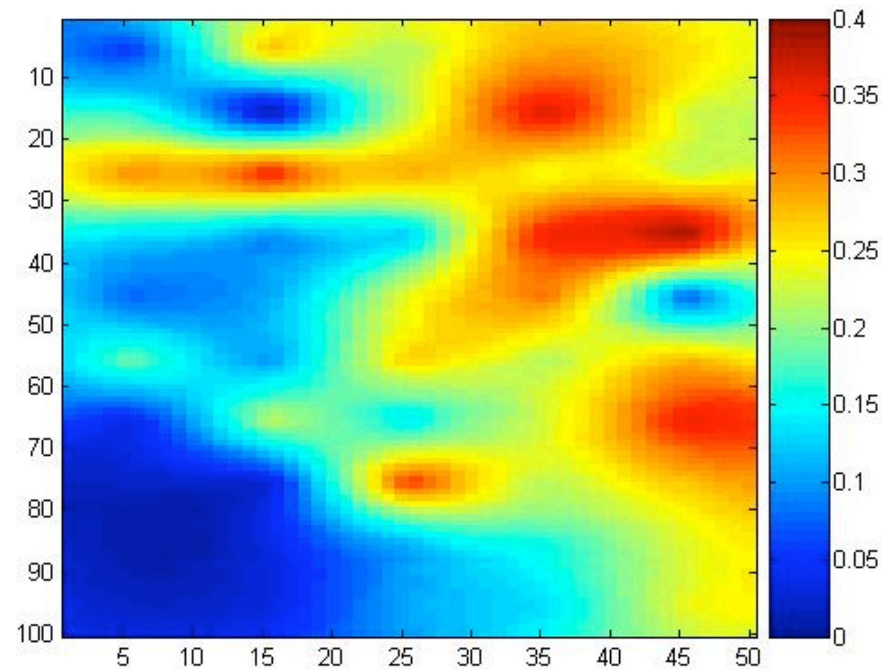


True Porosity **Inverted Result**

3000 iterations

Layer 2

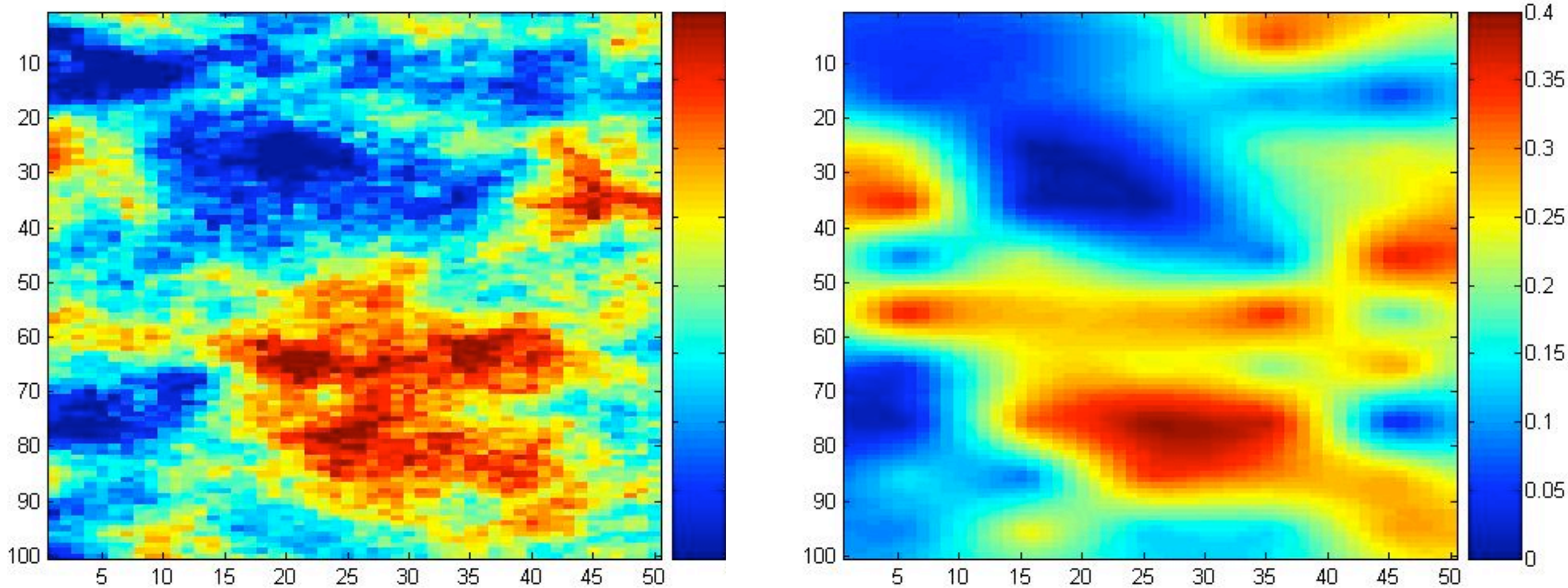




True Porosity **Inverted Result**

3000 iterations

Layer 3

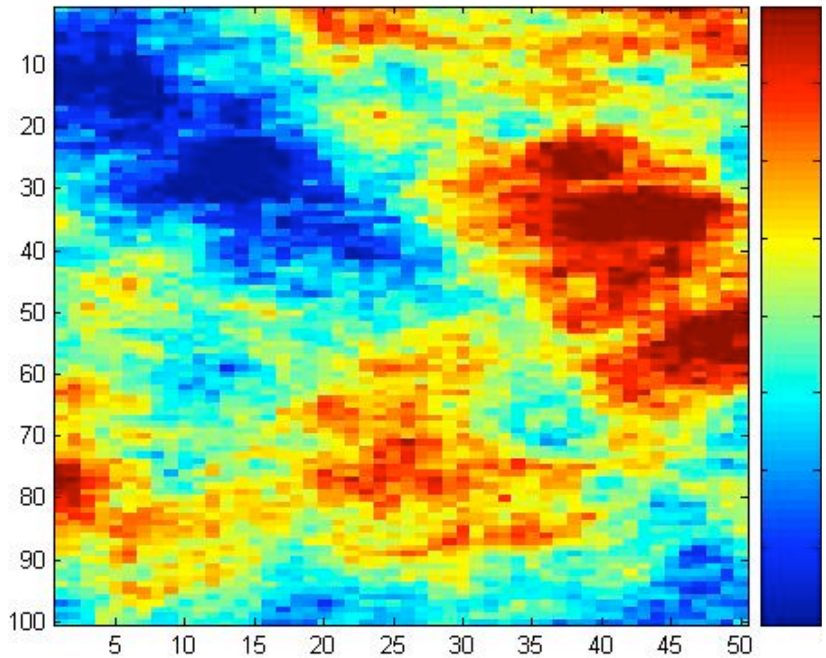


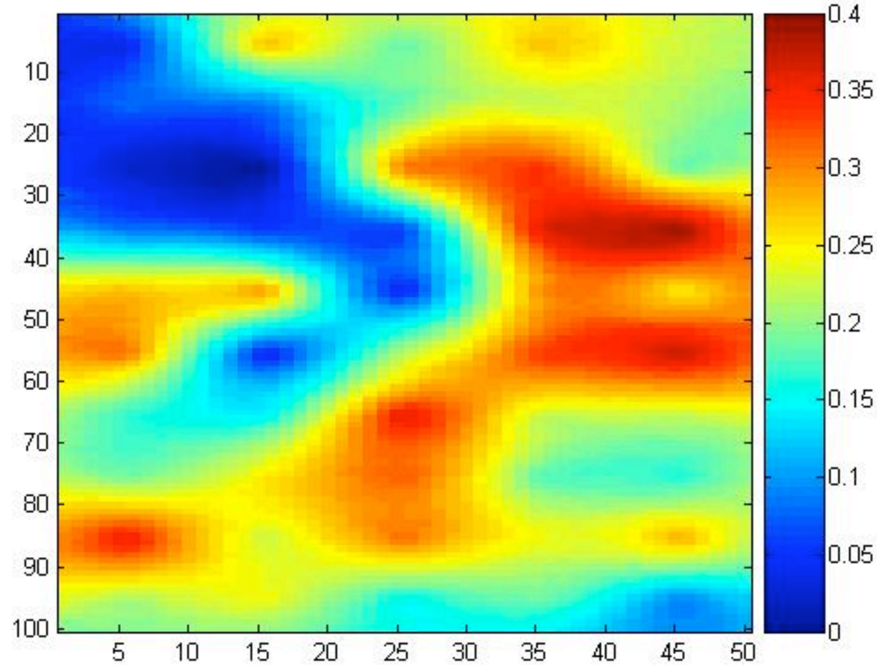
True Porosity

Inverted Result

3000 iterations

Layer 4

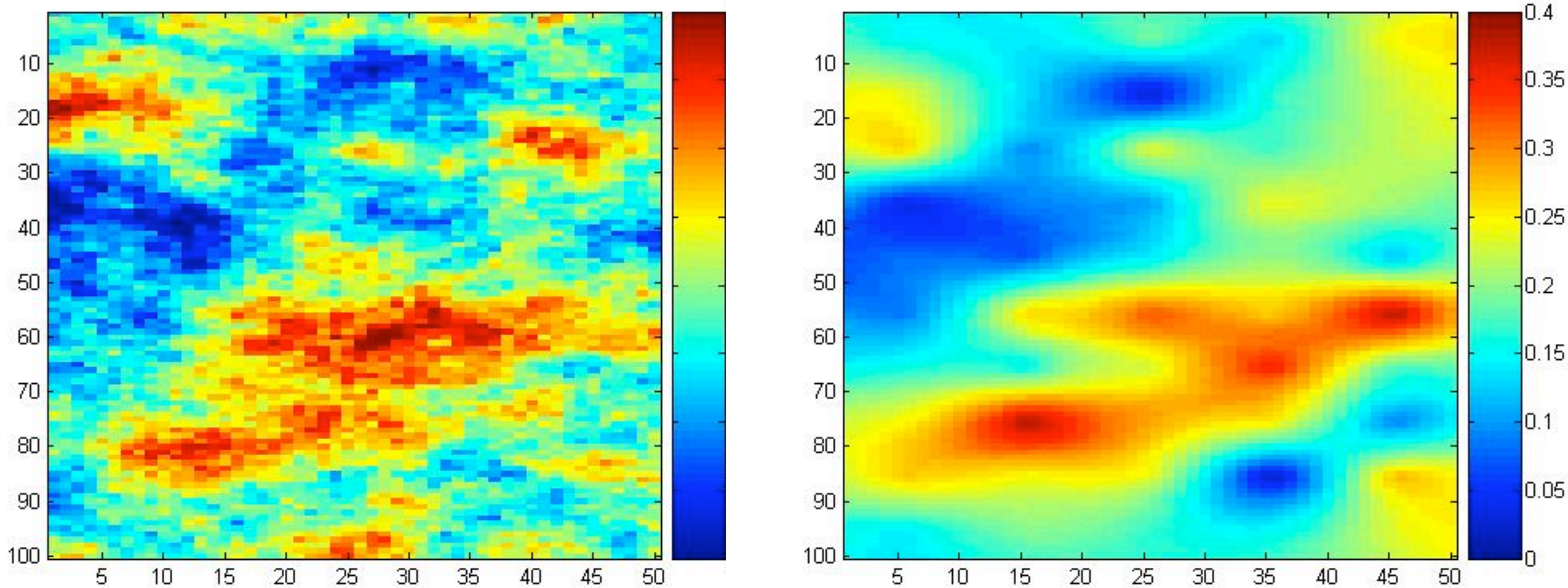




True Porosity **Inverted Result**

3000 iterations

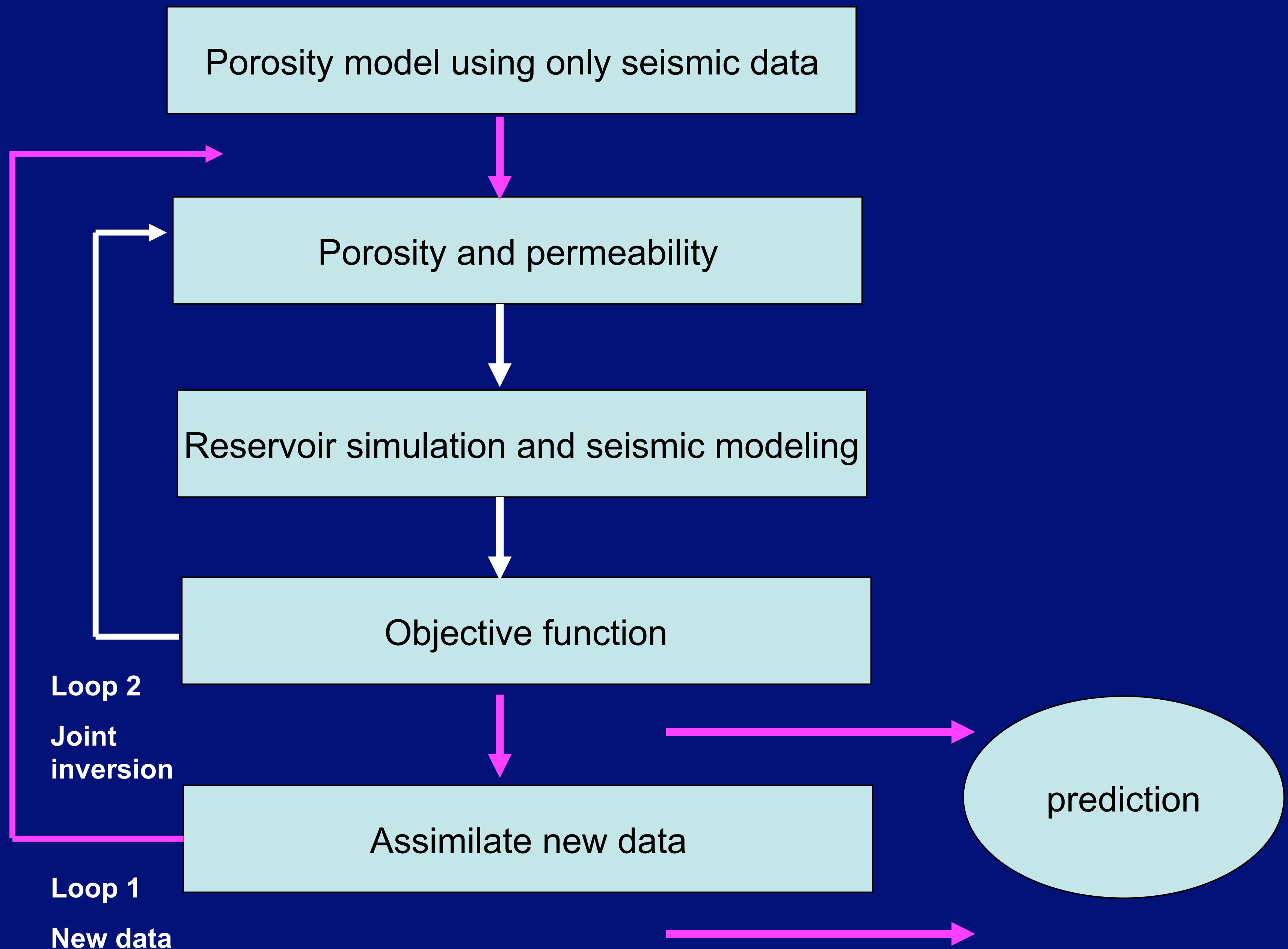
Layer 5



True Porosity **Inverted Result**

3000 iterations

Sequential time –lapse seismic inversion: Workflow

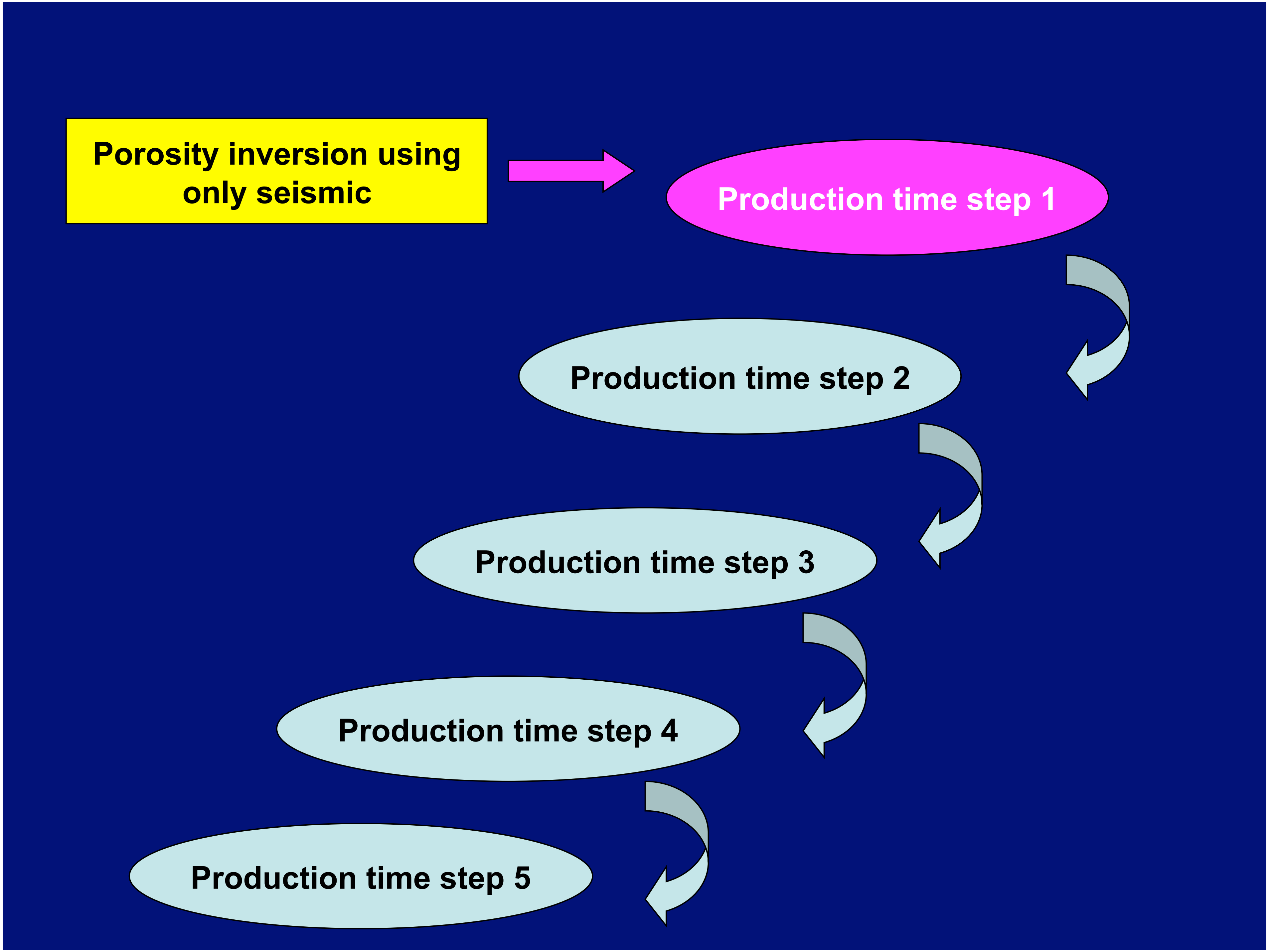


Sequential inversion (bring new data step by step)

1 Porosity model is inverted using only seismic data. No reservoir simulation is needed (initial model) ;

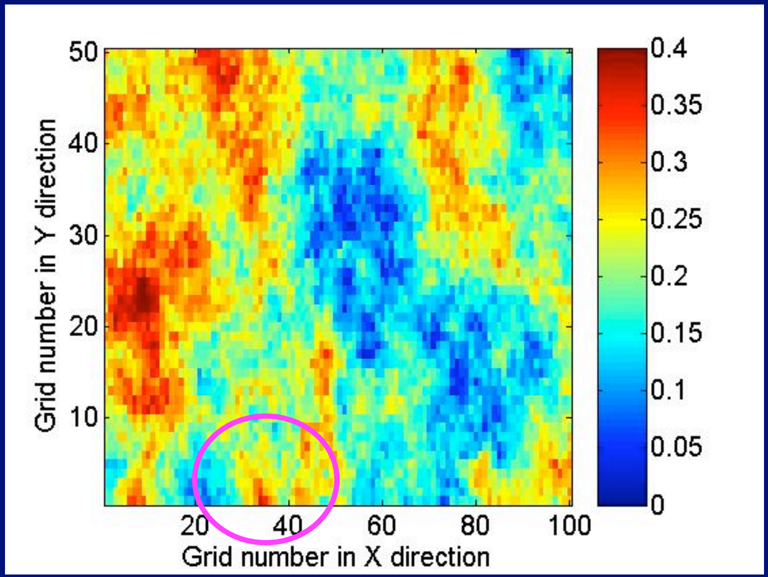
2 The inverted porosity model is used as the initial model for the next step inversion;

3 Time-lapse seismic data is assimilated step by step (saturation) . One time step data is assimilated one time.


Porosity inversion using only seismic
Production time step 1
Production time step 2
Production time step 3
Production time step 4
Production time step 5

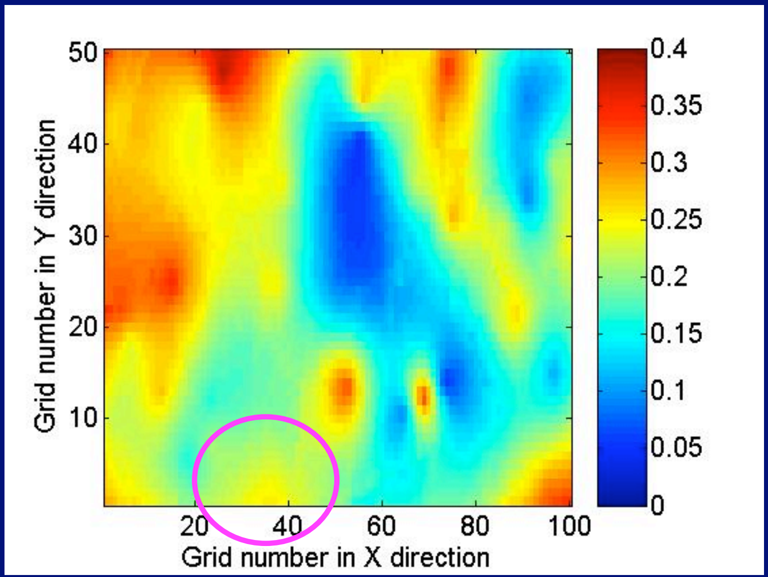
Assimilating time lapse data for time step 1

True porosity

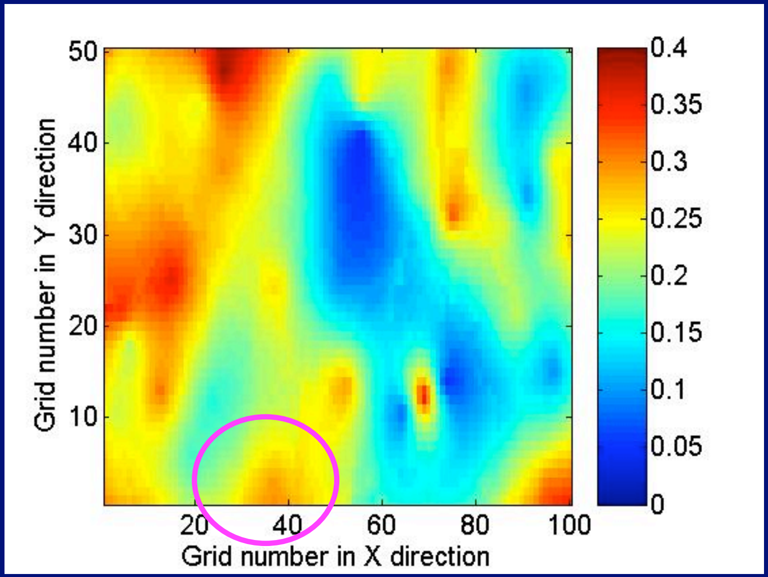


Seismic only

Seismic & Reservoir simulation



Inverted porosity (constant Sw=.2)

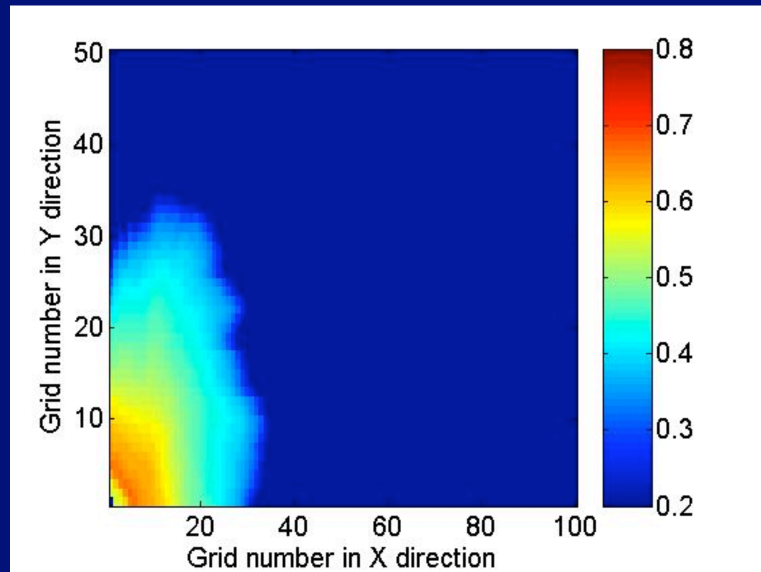


Inverted porosity for time step 1

Comparison of reservoir simulation results

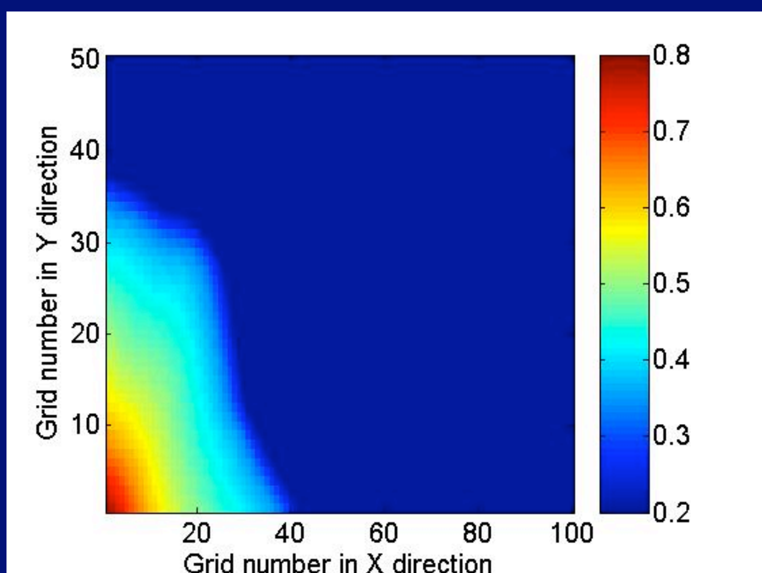
Saturation distribution at production time step 1

True Saturation

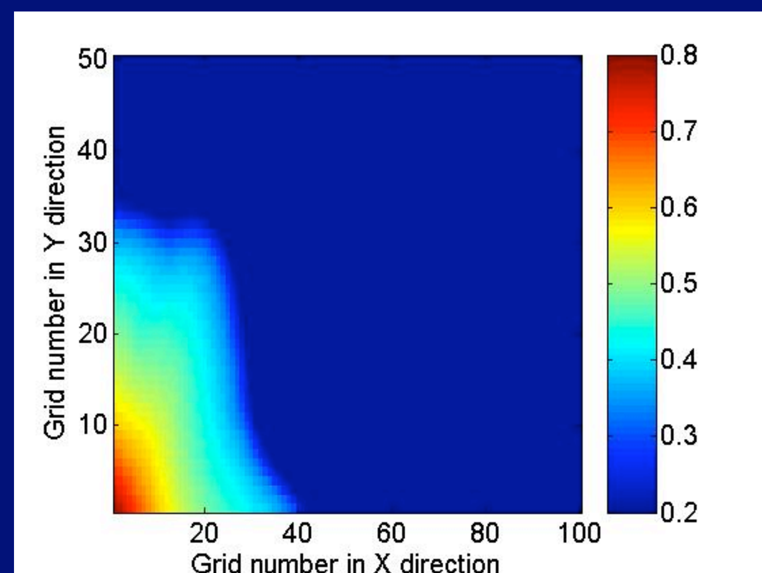


Input porosity based only on Seismic

Input porosity based on seismic & production



Sw using inverted porosity assuming permeability – porosity relationship

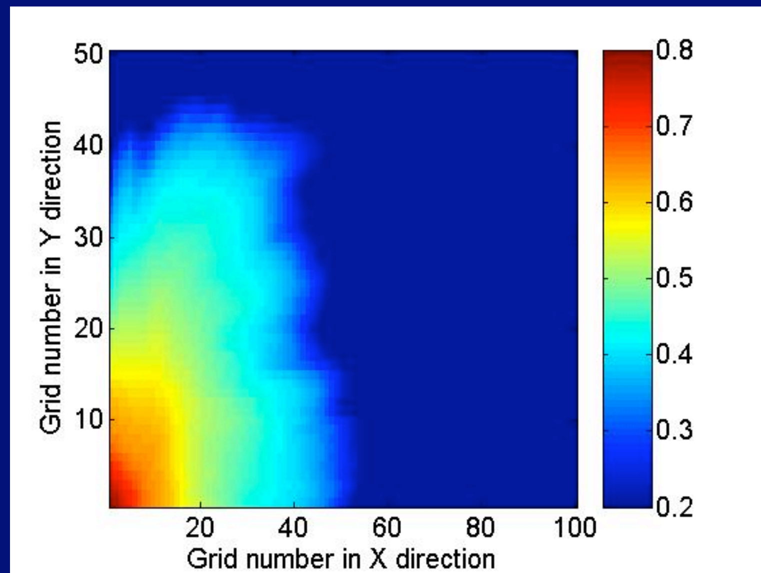


Sw using inverted porosity assuming permeability – porosity relationship

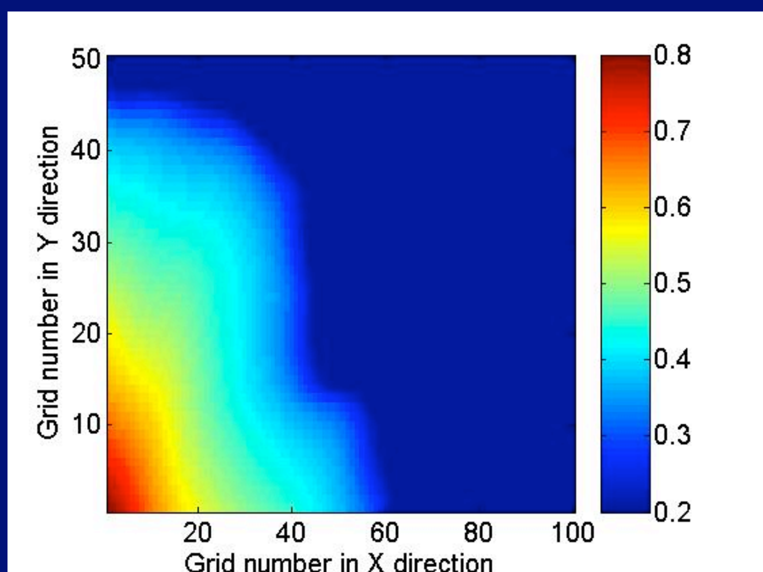
Comparison of reservoir simulation results

Prediction of saturation distribution for production time step 2

True Saturation

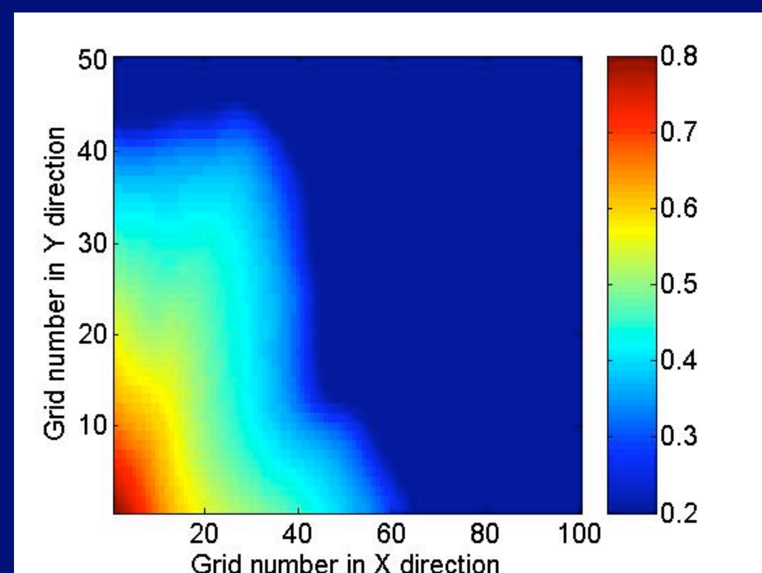


Input porosity based only on Seismic



Predicted Sw using inverted porosity assuming permeability – porosity relationship

Input porosity based on seismic & production

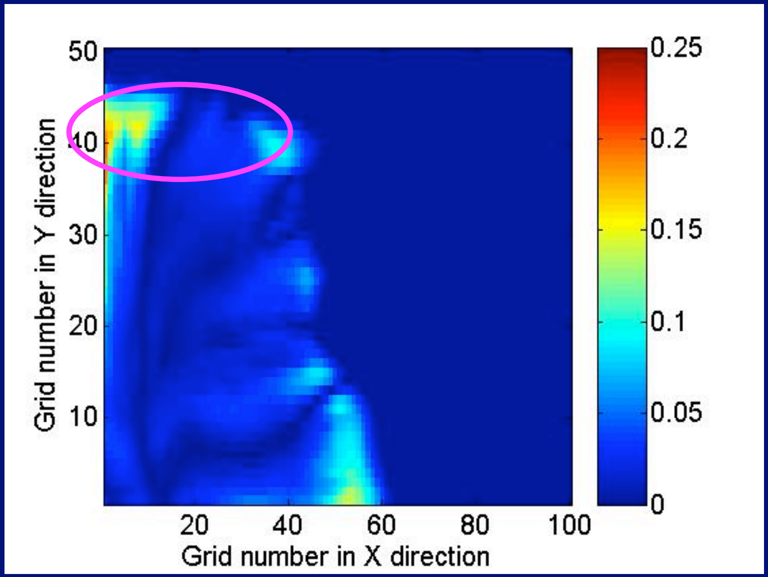


Predicted Sw using inverted porosity assuming permeability – porosity relationship

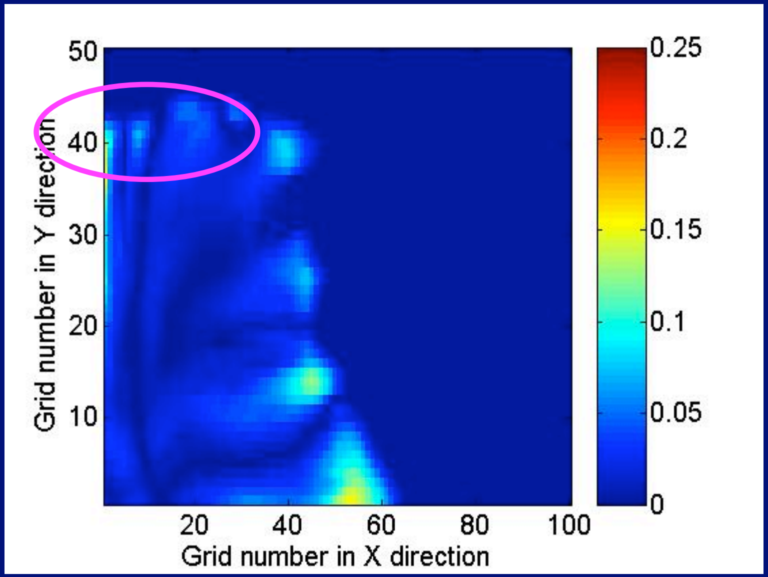
The error of predicted saturation distribution at production time step 2

Input porosity based only on Seismic

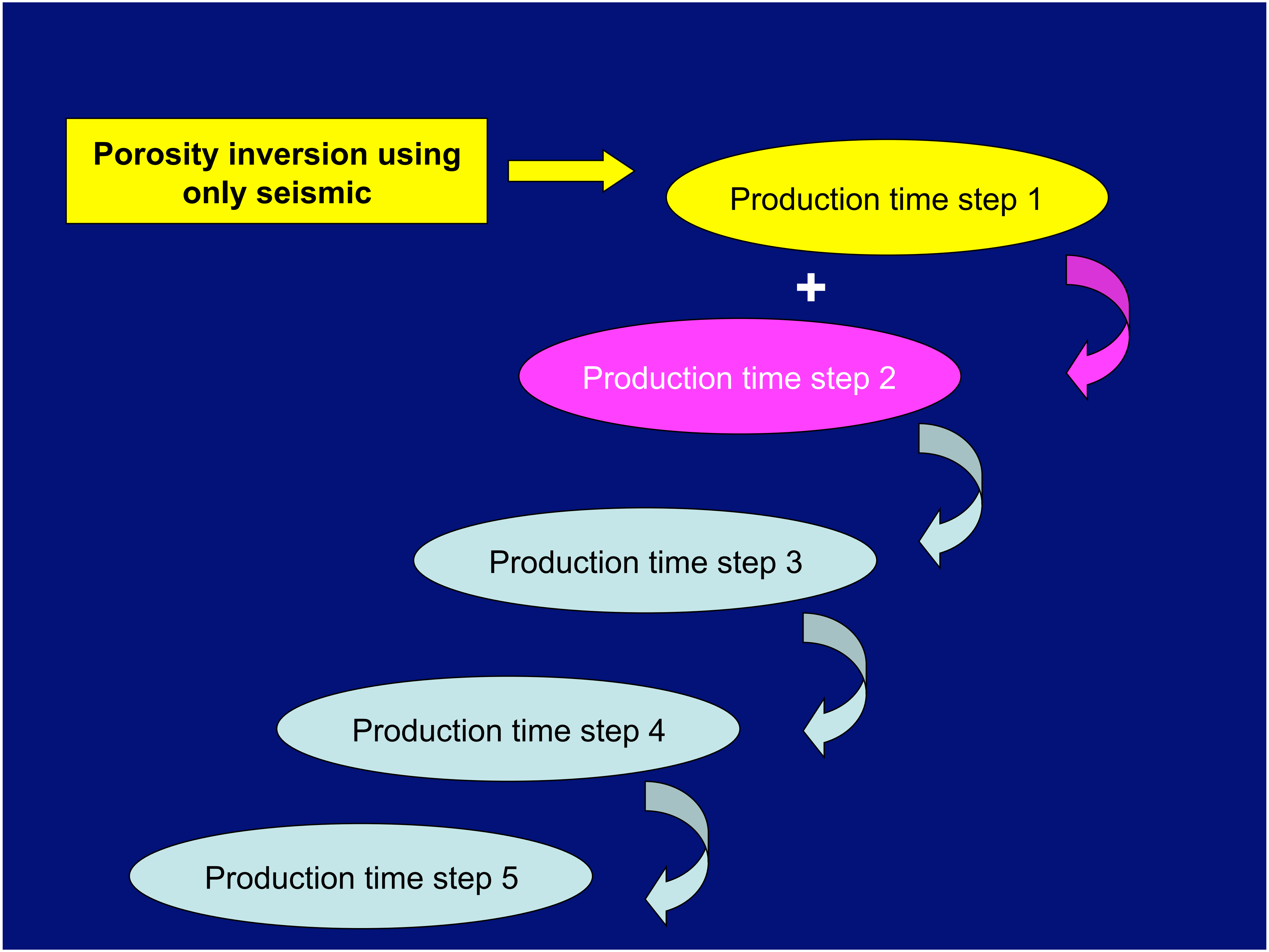
Input porosity based on seismic & production



Sw (True) - Sw using inverted porosity assuming permeability – porosity relationship

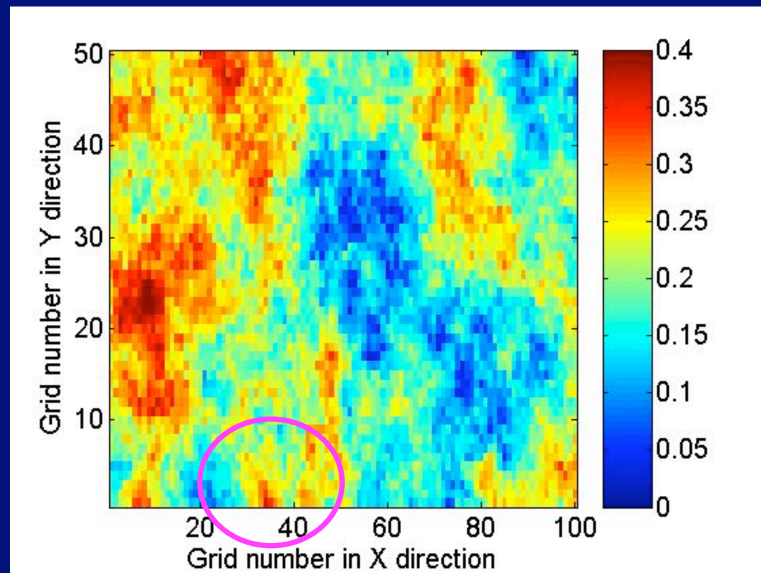


Sw (True) - Sw using inverted porosity assuming permeability – porosity relationship


Porosity inversion using only seismic
Production time step 1
+
Production time step 2
Production time step 3
Production time step 4
Production time step 5

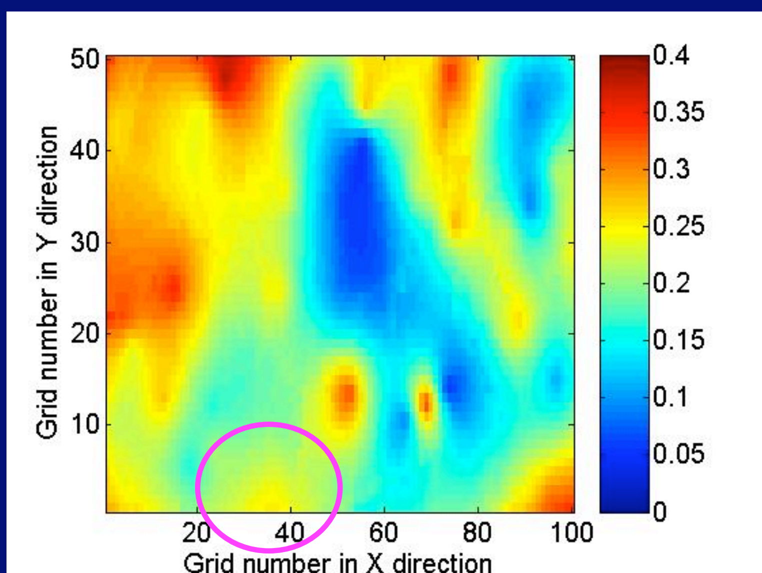
Assimilating time lapse data for time step 2

True porosity

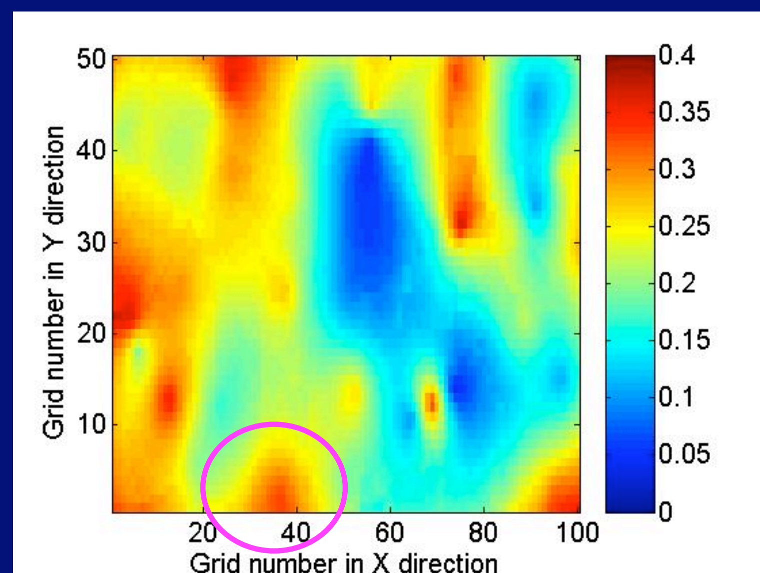


Seismic only

Seismic & Reservoir simulation



Inverted porosity (constant Sw=.2)

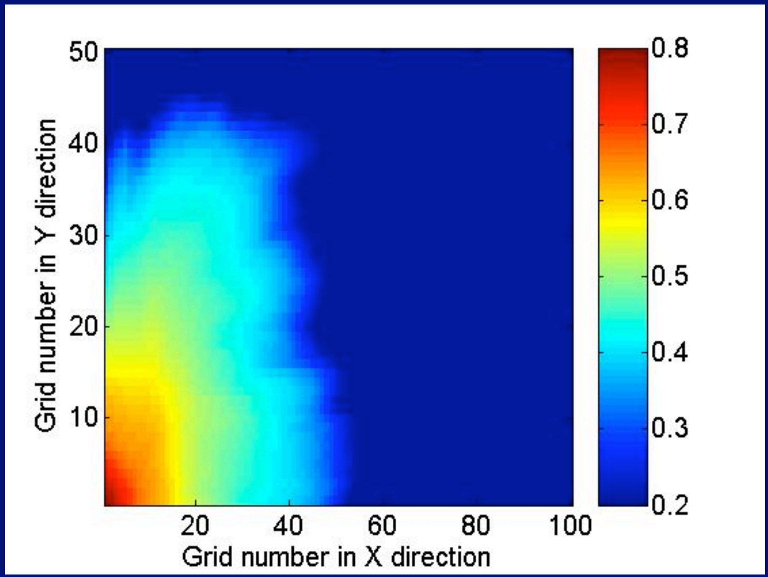


Inverted porosity for time step 2

Comparison of reservoir simulation results

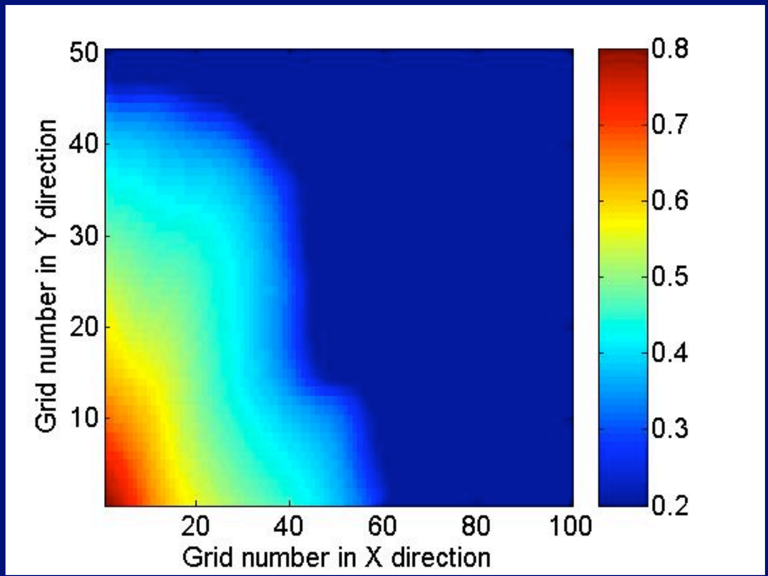
Saturation distribution at production time step 2

True Saturation

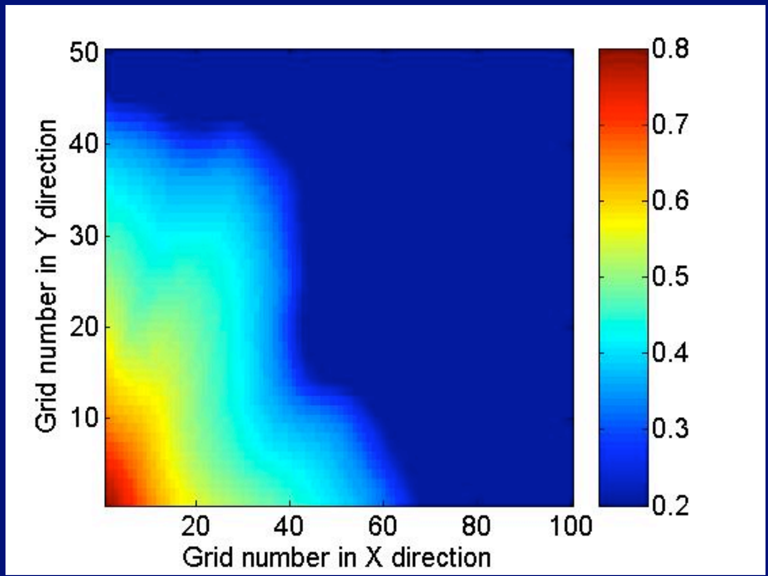


Input porosity based only on Seismic

Input porosity based on seismic & production



Sw using inverted porosity assuming permeability – porosity relationship

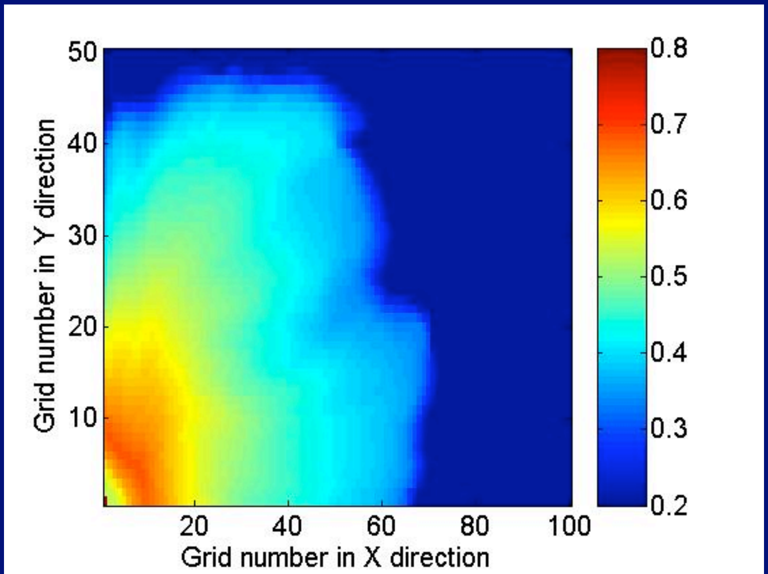


Sw using inverted porosity assuming permeability – porosity relationship

Comparison of reservoir simulation prediction

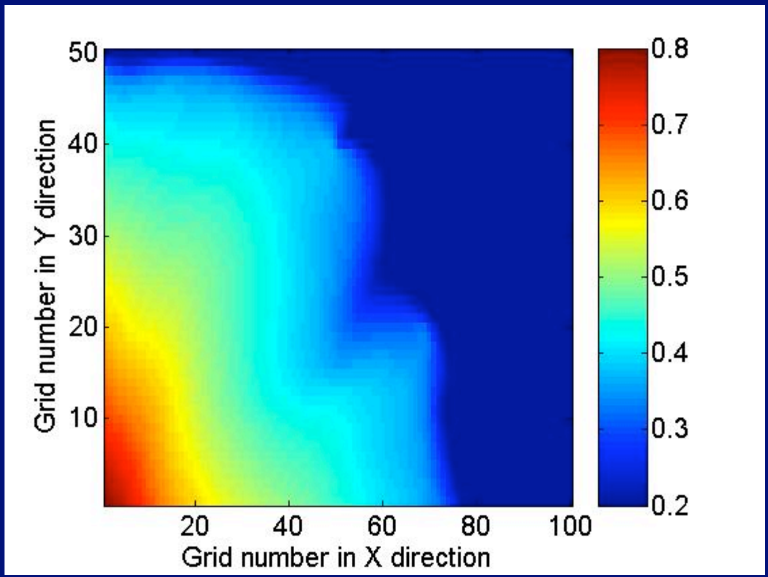
Prediction of saturation distribution at production time step 3

True Saturation

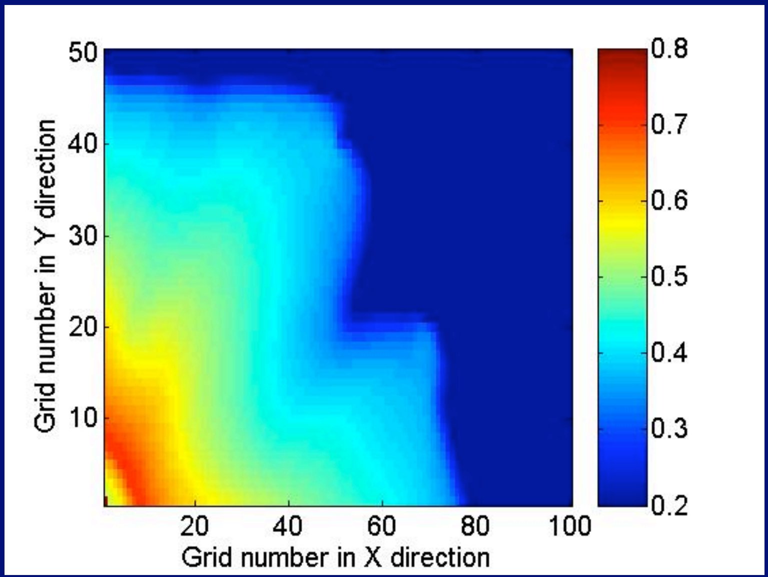


Input porosity based only on Seismic

Input porosity based on seismic & production



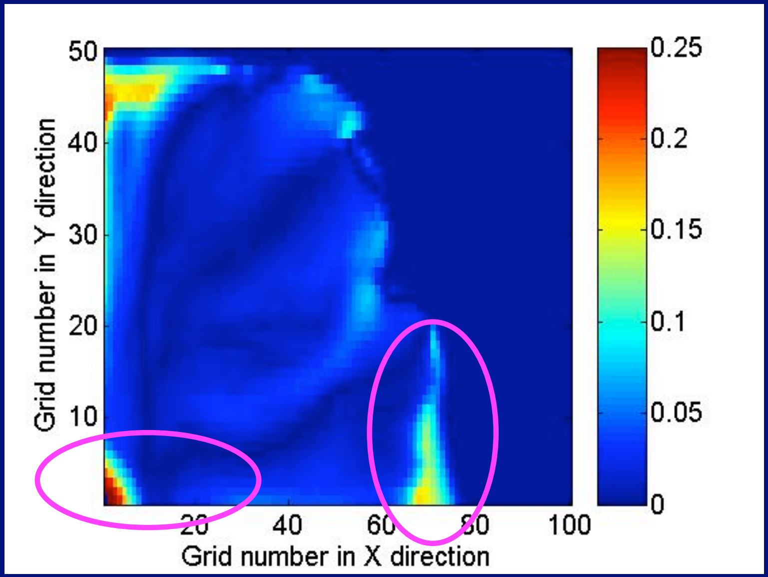
Predicted Sw **using inverted porosity assuming permeability – porosity relationship**



Predicted Sw **using inverted porosity assuming permeability – porosity relationship**

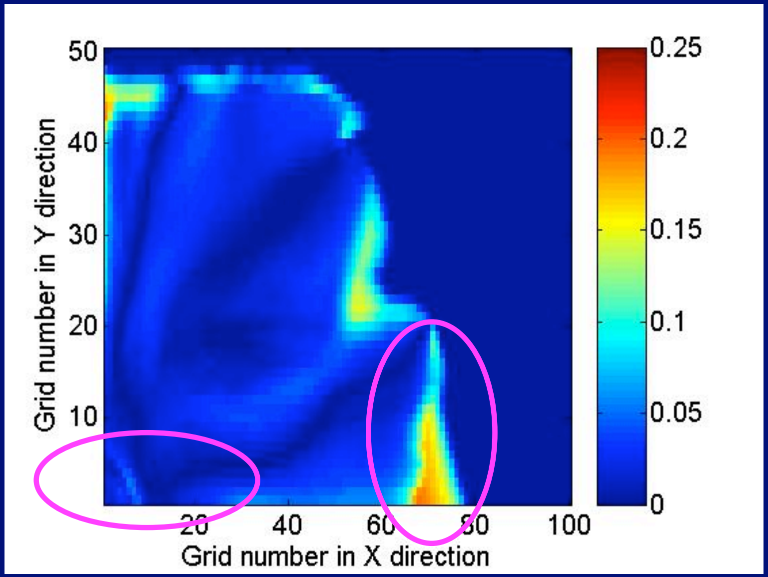
The error of predicted saturation distribution at production time step 3

Input porosity based only on Seismic

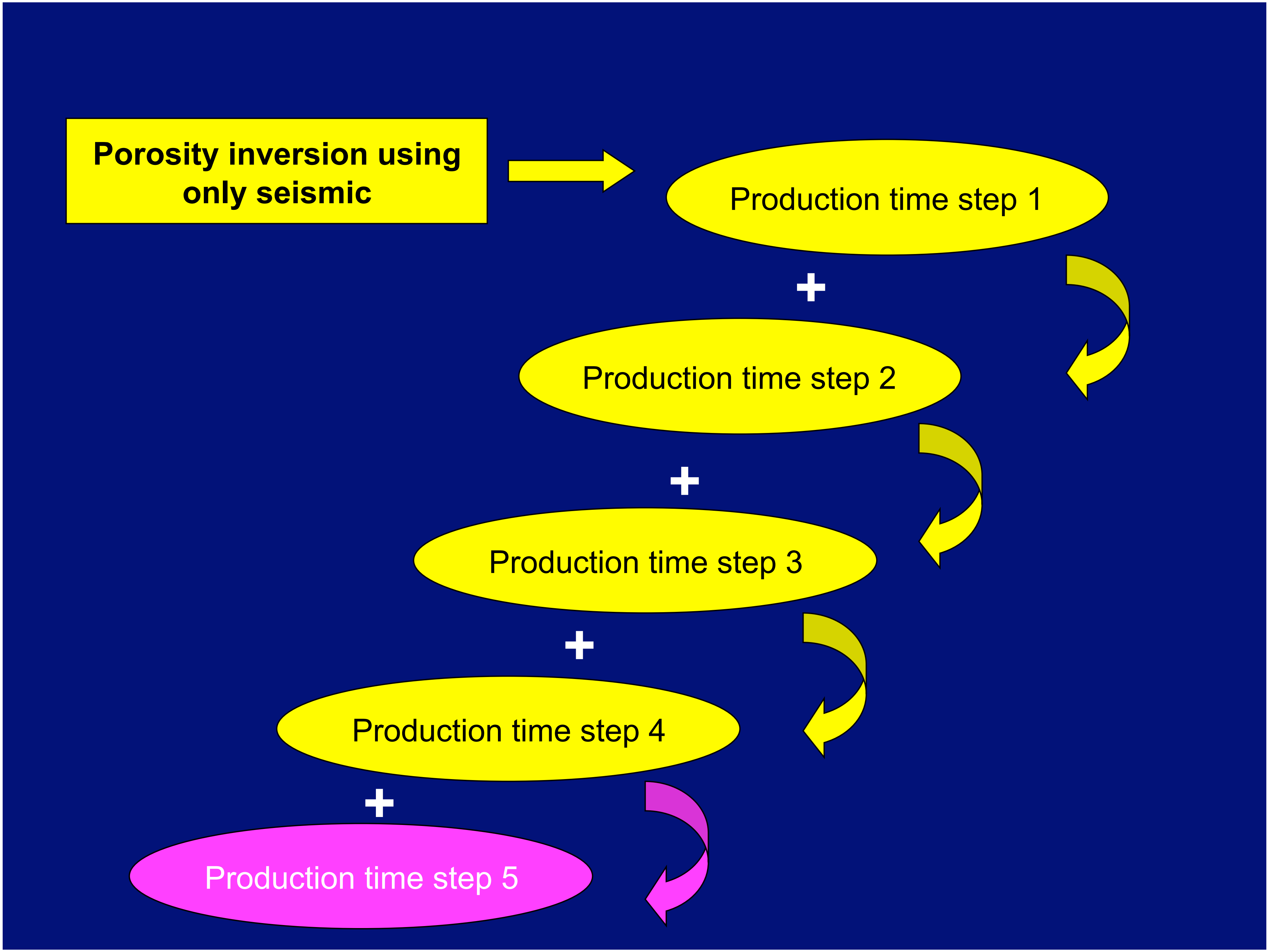


Sw (True) - Sw using inverted porosity assuming permeability – porosity relationship

Input porosity based on seismic & production

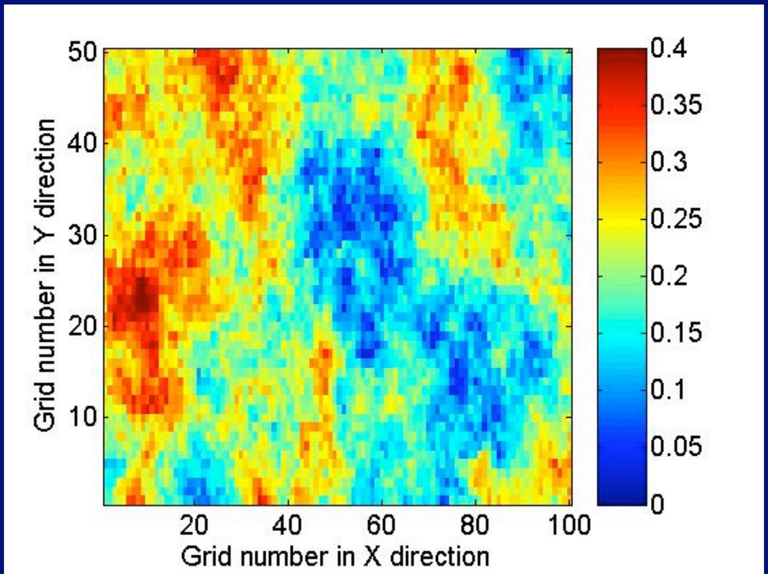


Sw (True) - Sw using inverted porosity assuming permeability – porosity relationship

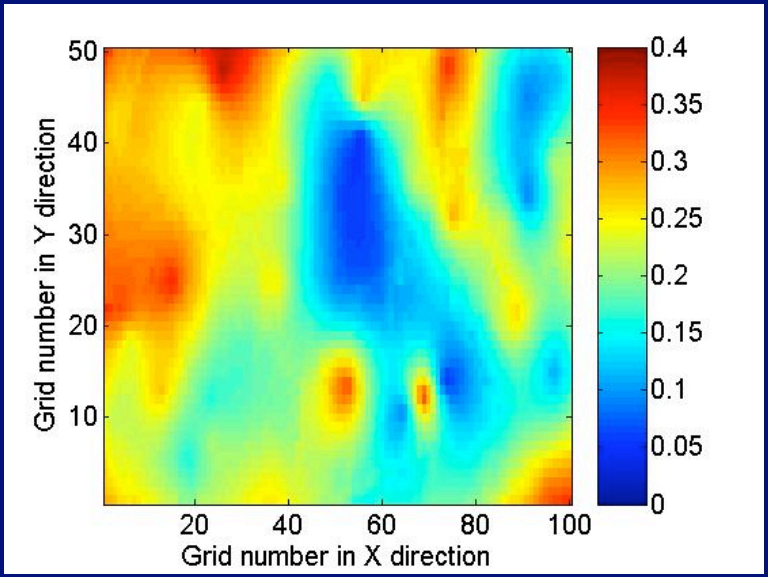

Porosity inversion using only seismic
Production time step 1
+
Production time step 2
+
Production time step 3
+
Production time step 4
+
Production time step 5

Assimilating time lapse data for time step 5

True porosity

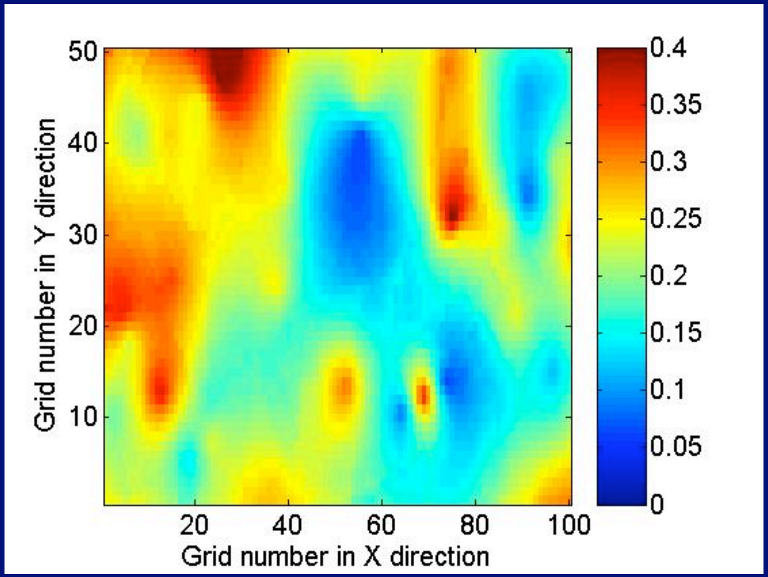


Seismic only



Inverted porosity (constant Sw=.02)

Seismic & Reservoir simulation

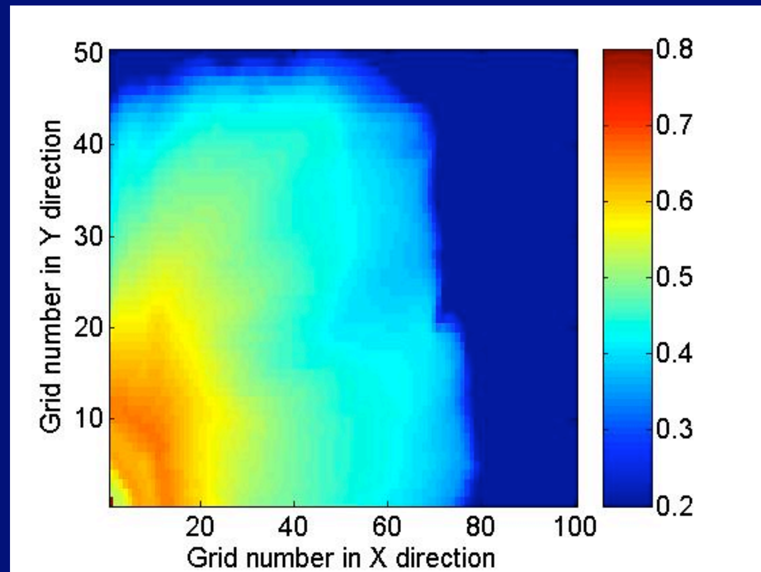


Inverted porosity for time step 5

Comparison of reservoir simulation results

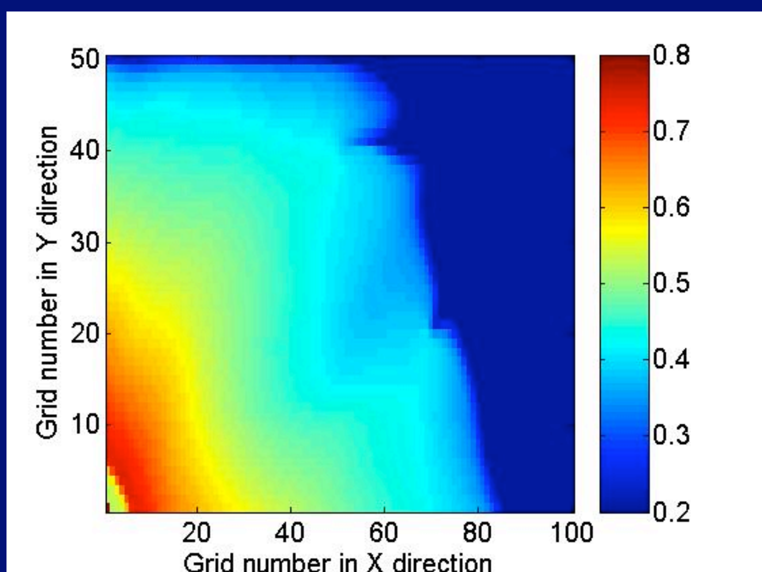
Saturation distribution at production time step 5

True Saturation

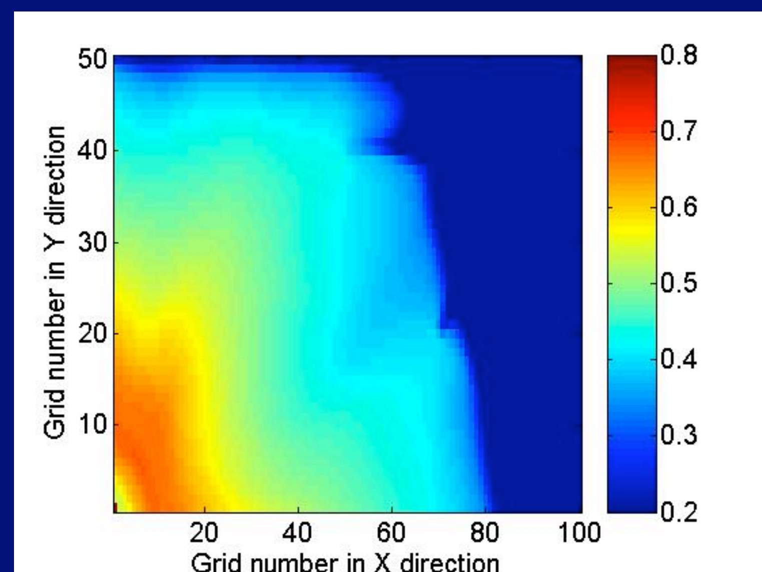


Input porosity based only on Seismic

Input porosity based on seismic & production



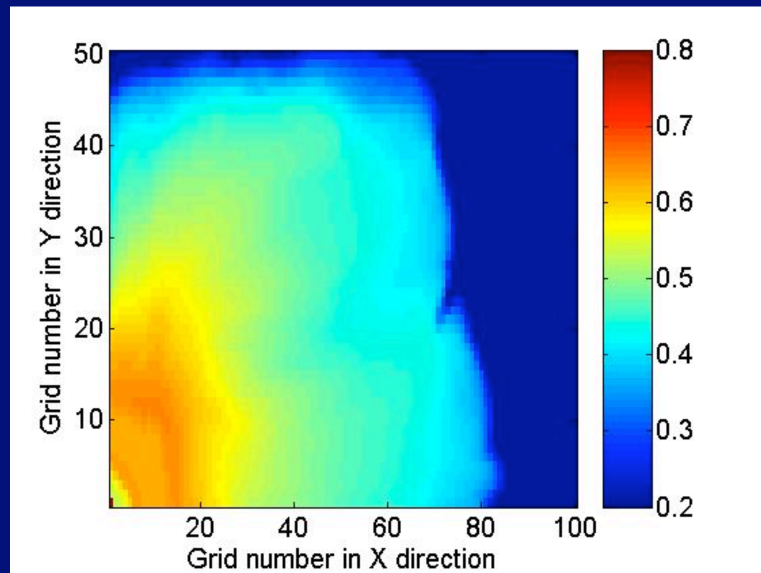
Sw using inverted porosity assuming permeability – porosity relationship



Sw using inverted porosity assuming permeability – porosity relationship

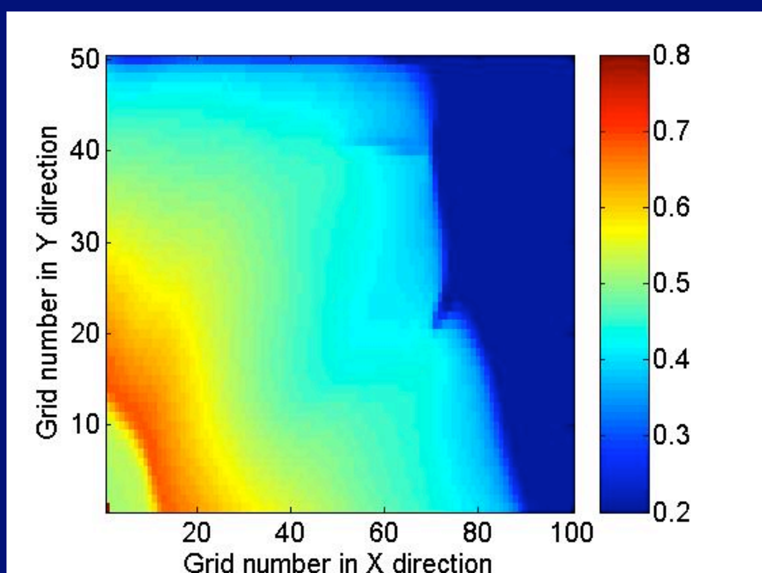
Comparison of reservoir simulation prediction

Prediction of saturation distribution at production time step 6



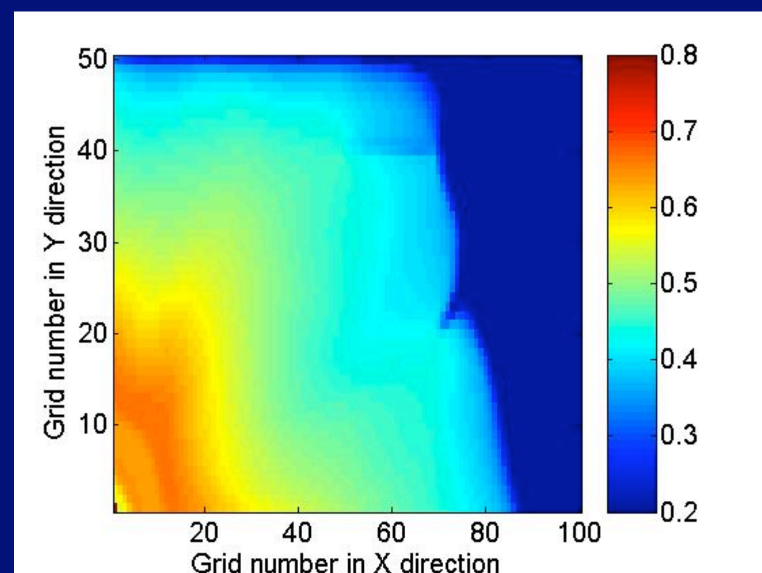
True Saturation

Input porosity based only on Seismic



Predicted Sw **using inverted porosity assuming permeability – porosity relationship**

Input porosity based on seismic & production

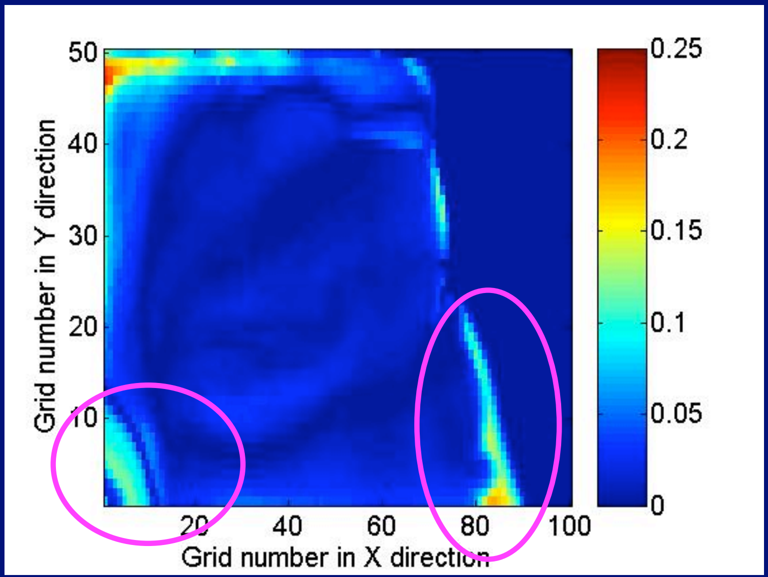


Predicted Sw **using inverted porosity assuming permeability – porosity relationship**

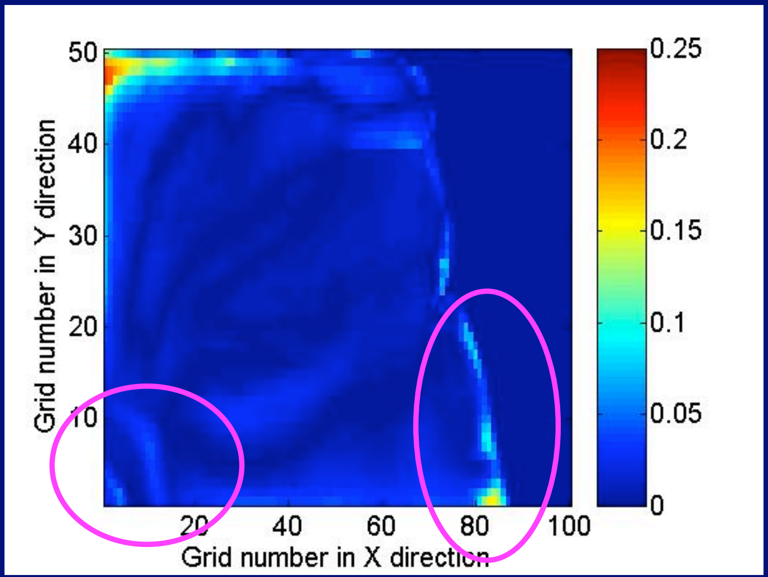
The error of predicted saturation distribution at production time step 6

Input porosity based only on Seismic

Input porosity based on seismic & production



Sw (True) - Sw using inverted porosity assuming permeability – porosity relationship



Sw (True) - Sw using inverted porosity assuming permeability – porosity relationship