SPE Workshop:
Petrophysical Challenges in Reservoir Life Management

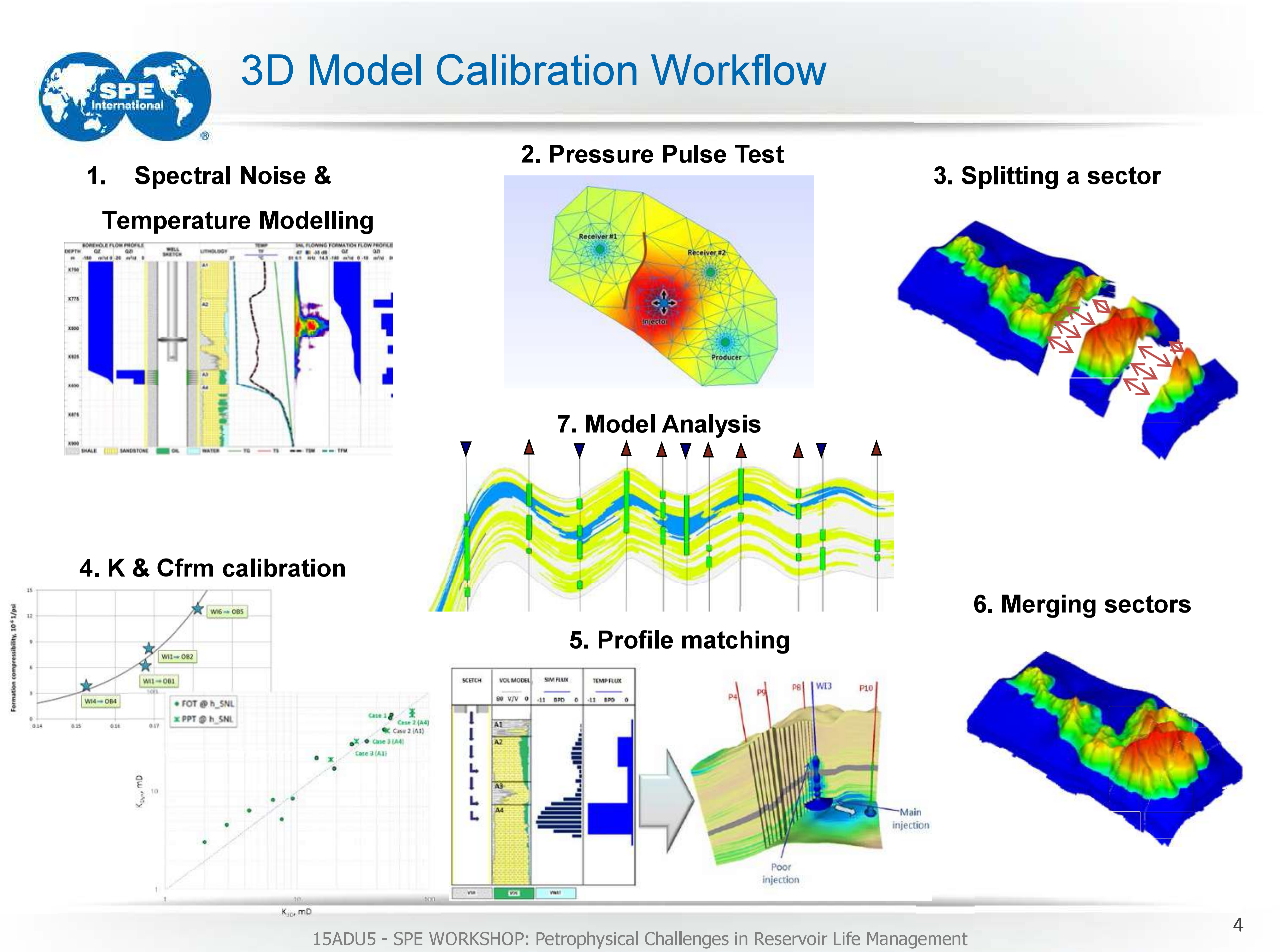
27 – 29 April 2015
Dubai, United Arab Emirates

Calibrating 3D models in multi-layer formations with production logging and pressure test data

Dr. Arthur Aslanyan
TGT Oil & Gas Services

Agenda

1. 3D Model Calibration Workflow
2. Field Summary
3. Data Acquisition
4. Model Calibration
5. Comparison Analysis
6. Production Optimization



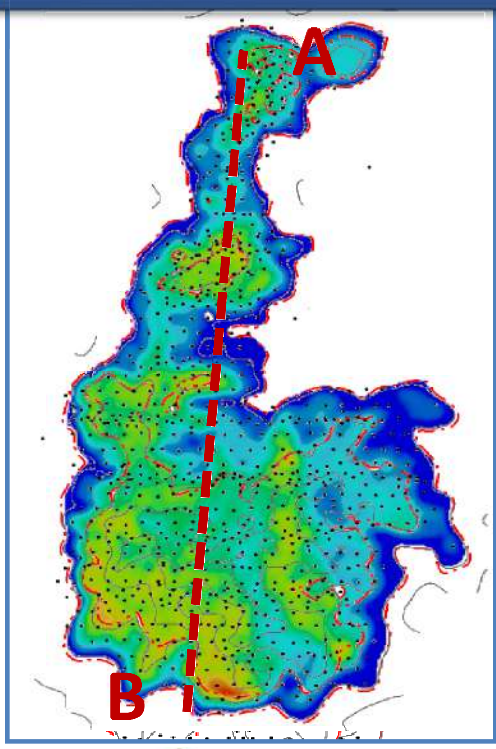
This presentation illustrates how reservoir flow profiles and cross-well pressure tests can be integrated to calibrate a 3D model. Three data acquisition techniques were used in this study: spectral noise logging, temperature modelling and pressure pulse testing. The data were acquired in a sector of a large oil field and, after calibration, a sector model was integrated into the main field model. It is generally believed that calibrated data should not be changed in further dynamic modelling, which makes it less flexible but more physically realistic.

The model parameters that need a solid field-wide calibration in the first instance are formation compressibility and permeability. Regular compressibility and permeability modelling is based on core data and core-calibrated open-hole logs, which do not reflect the full complexity of large rock masses between wells. Cross-well pressure tests can be used to calibrate the correlation of these parameters with porosity for various lithofacies and to extend the field-proven permeability and compressibility to the entire model grid. Importantly, pressure testing can be used for permeability and compressibility analysis only if the well flow profile is known, which requires reservoir-oriented surveys, such as spectral noise and temperature logging. Cross-well pressure tests can also verify various features between wells, such as conductive or sealing faults, fracture corridors, pinch-outs and barriers, which can be used as reliable supplementary data for a 3D model.

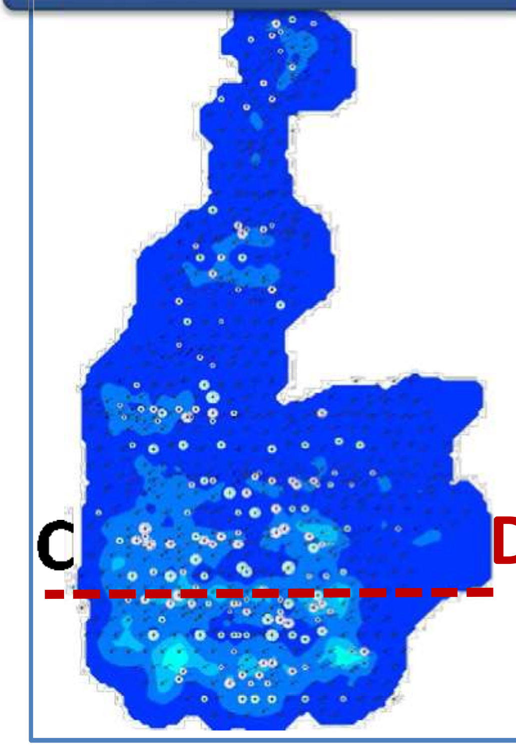
Overall, well profiling and cross-well pressure testing constitute a 3D data acquisition framework for 3D model calibration.

Field Summary

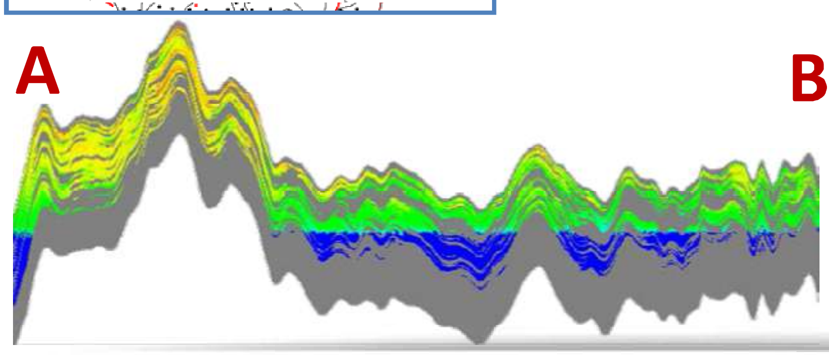
Initial Saturation

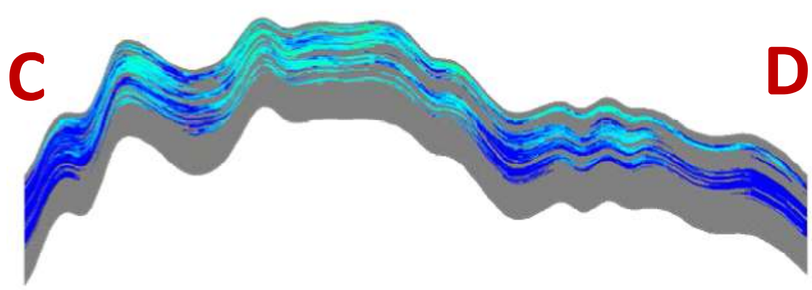


Current Saturation



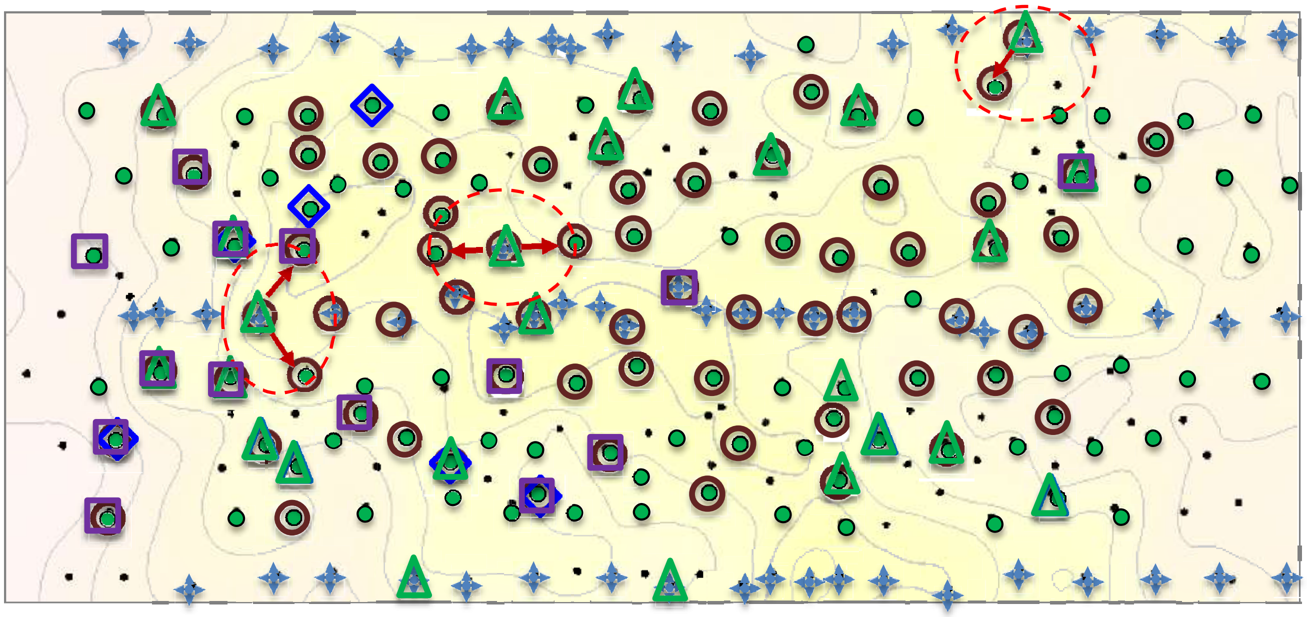
Location	Western Siberia
Formation	Jurassic Sandstone
Porosity	15% – 19%
Permeability	15 – 50 mD
Wells	1000
Depletion	Waterflood
Water Cut	95%





The study was carried out for a West Siberian oil field with a porosity ranging between 15% and 19% and high shale content. The permeability ranges between 15 mD and 50 mD. A core study found that water flooding can ensure 50% oil displacement efficiency. The field has been producing for almost 34 years with 610 producers and 255 injectors for pressure support. When the average water cut reached 95%, the recovery factor was 15% below expectations.

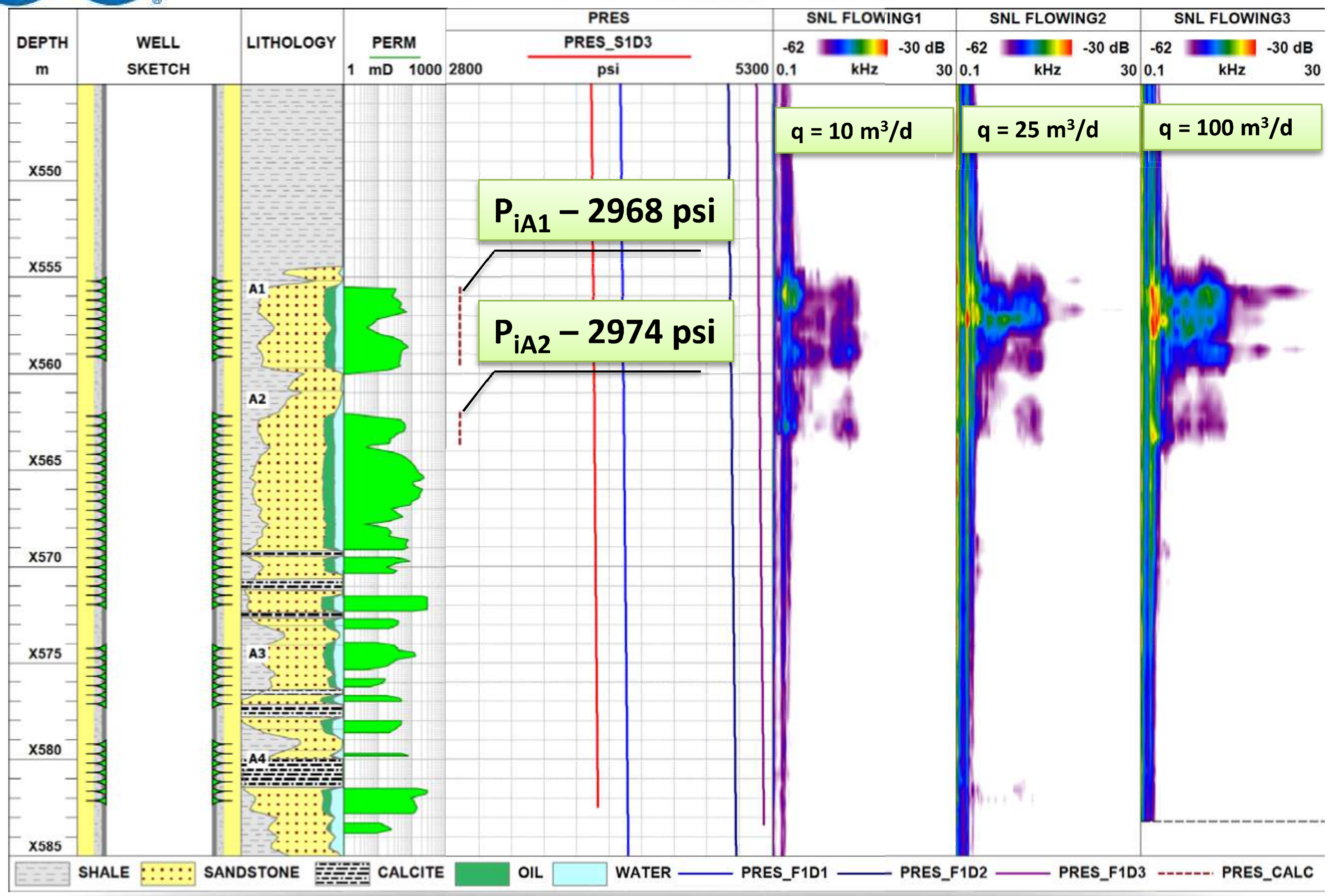
The maps and cross-sections of the 3D model suggest that the field is swept uniformly and there is not much oil left behind. There were attempts to explain low recovery by assuming that the initial oil displacement efficiency was overestimated by non-representative core samples although there was no clear indication of that. However, new flow-profile data and cross-well pressure tests have shown that the sweep is far from uniform and there are some development opportunities for bypassed and low-mobility oil. On the other hand, the calibrated pulsed neutron surveys suggested 50% oil displacement in swept zones, in full compliance with initial core-based displacement estimates. This provided a new vision of field performance and opened the way for redevelopment.



1	High Precision Temperature & Spectral Noise Logging	HPT & SNL	71
2	Pulsed Neutron-Neutron	PNN	6
3	Pressure Transient Test	PTT	25
4	Pressure Pulse Test	PPT	5
5	Multi-barrier Corrosion Logging	MID	15

Water flooding was by linear drive and the sector model contained 150 wells including 90 producers between three dividing rows of 60 injectors.
All wells are completed with 5" liners, 2.5" tubing and up to four perforation intervals across four major pays, with tubing shoes above the top perforations.
Producers are operated with rod pumps but were put on nitrogen lift during the survey campaign.
The data acquisition campaign took seven months and included:
71 spinner-based Multiphase Production Logging surveys
71 Spectral Noise Logging surveys
71 static and transient High-Precision Temperature Logging surveys
71 numerical models of multiphase-flow and temperature profiles
Six pulsed neutron surveys and 25 pressure transient tests
Five pressure pulse tests
15 through-tubing multi-barrier corrosion logging surveys
All data were acquired with 1-11/16" OD downhole memory tools through 2.5" tubing.

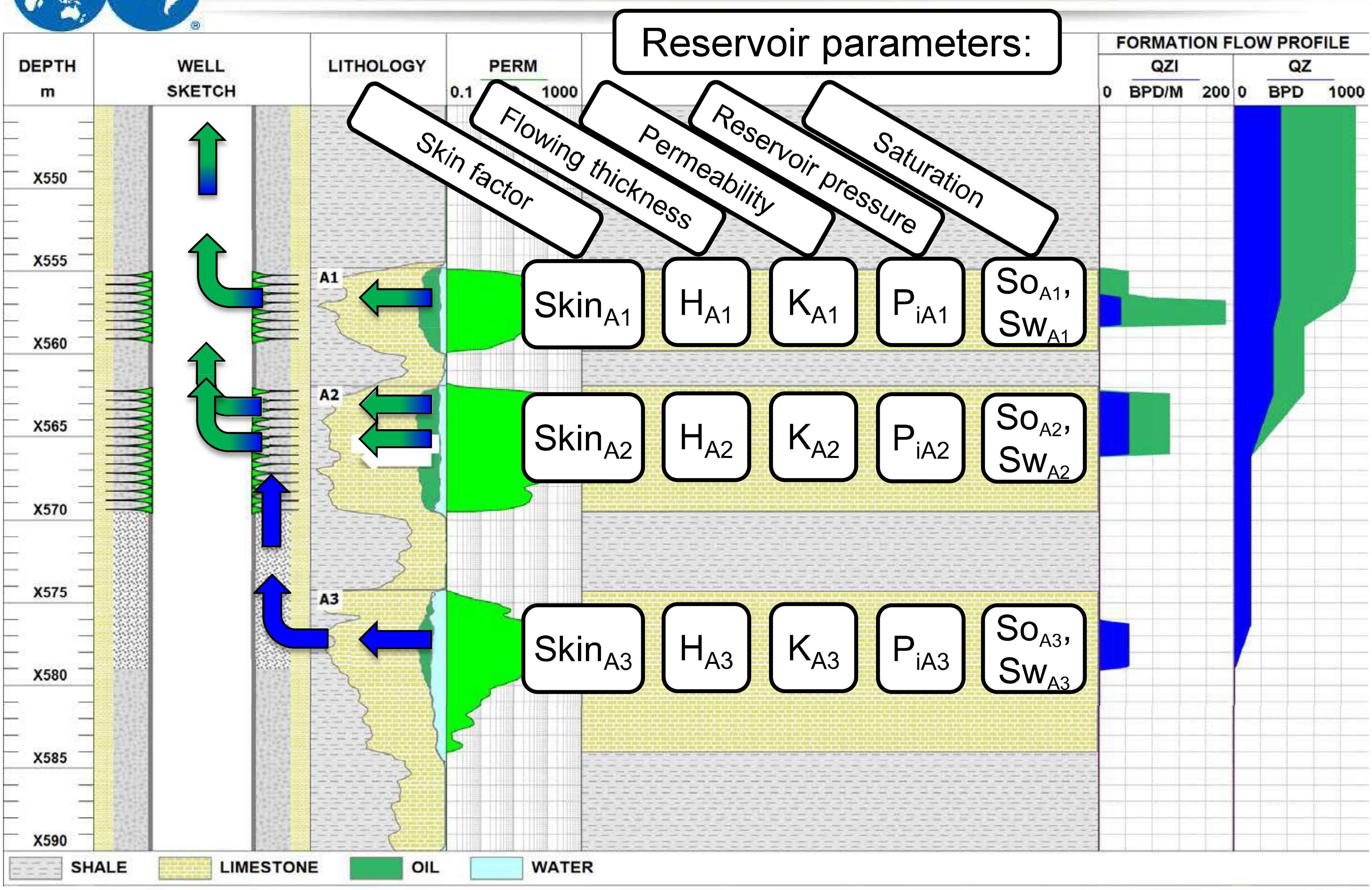
Multi-Rate SNL



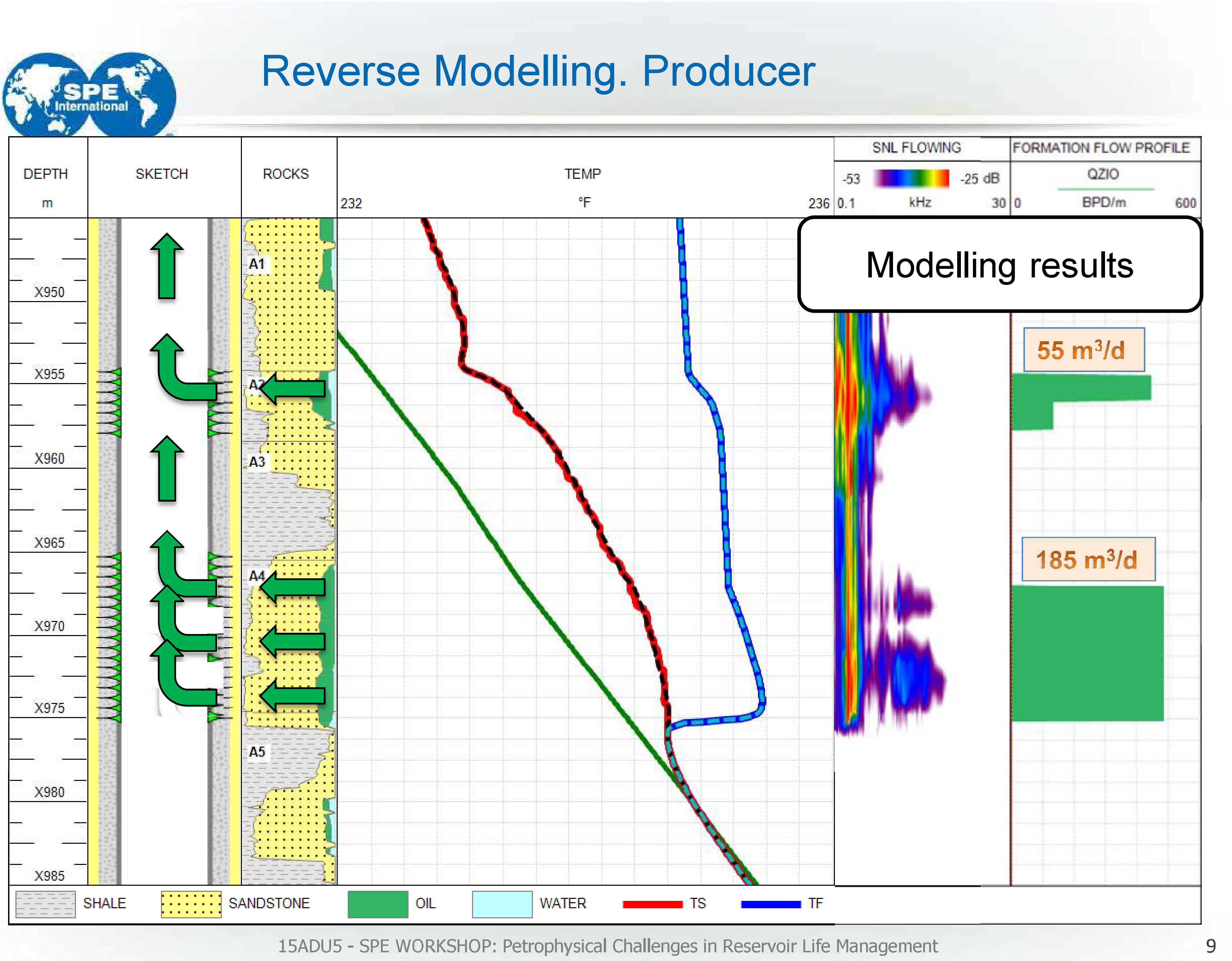
Spectral noise logging data indicated which of the four pays, and what parts of them, were actually flowing during the survey. This provided initial information about the non-uniformity of the well flow profile that was then integrated into the model used to determine the field-wide flow geometry and residual saturation. In the above case, the flow profile was highly non-uniform and injection was mainly into the A1 unit, some of it into the upper part of the A2 Unit and almost nothing into the rest of the A2 Unit and the A3 and A4 Units. SNL was performed at different rates to find out how the flowing thickness depended on the differential pressure and to optimise the flow rate for each well individually.

The ratio of noise volumes recorded at different flow rates depends non-linearly on the ratio of these flow rates, and this phenomenon can be used to estimate the formation pressure in each flowing streak independently by mathematical modelling. This provides a valuable input for 3D model calibration.

TERMOSIM ™ Inputs. Producer



Spectral noise logging data alone cannot quantify flow and its composition in every streak.
Once the location, thickness and pressure of every flowing streak are known from an SNL survey, they are fed into the multiphase flow temperature simulator TermoSim that can adjust skin factors for each flowing streak to match temperature and multiphase logs.
Fitting is performed automatically using parallel multi-core computing and provides the Formation Flow Profile that shows the flow distribution between active streaks.
In most cases, the formation flow profile differs from the conventional PLT profile recorded with a mechanical spinner due to its low sensitivity to low flow rates and behind-casing complications that the spinner cannot capture.
In this field, the difference between the formation and borehole flow profiles was found to be substantial in 70% of producers and 90% of injectors.
The integration of these data into a 3D model led to a substantial revision of the field-wide flow geometry and enabled the identification of poorly-swept zones.

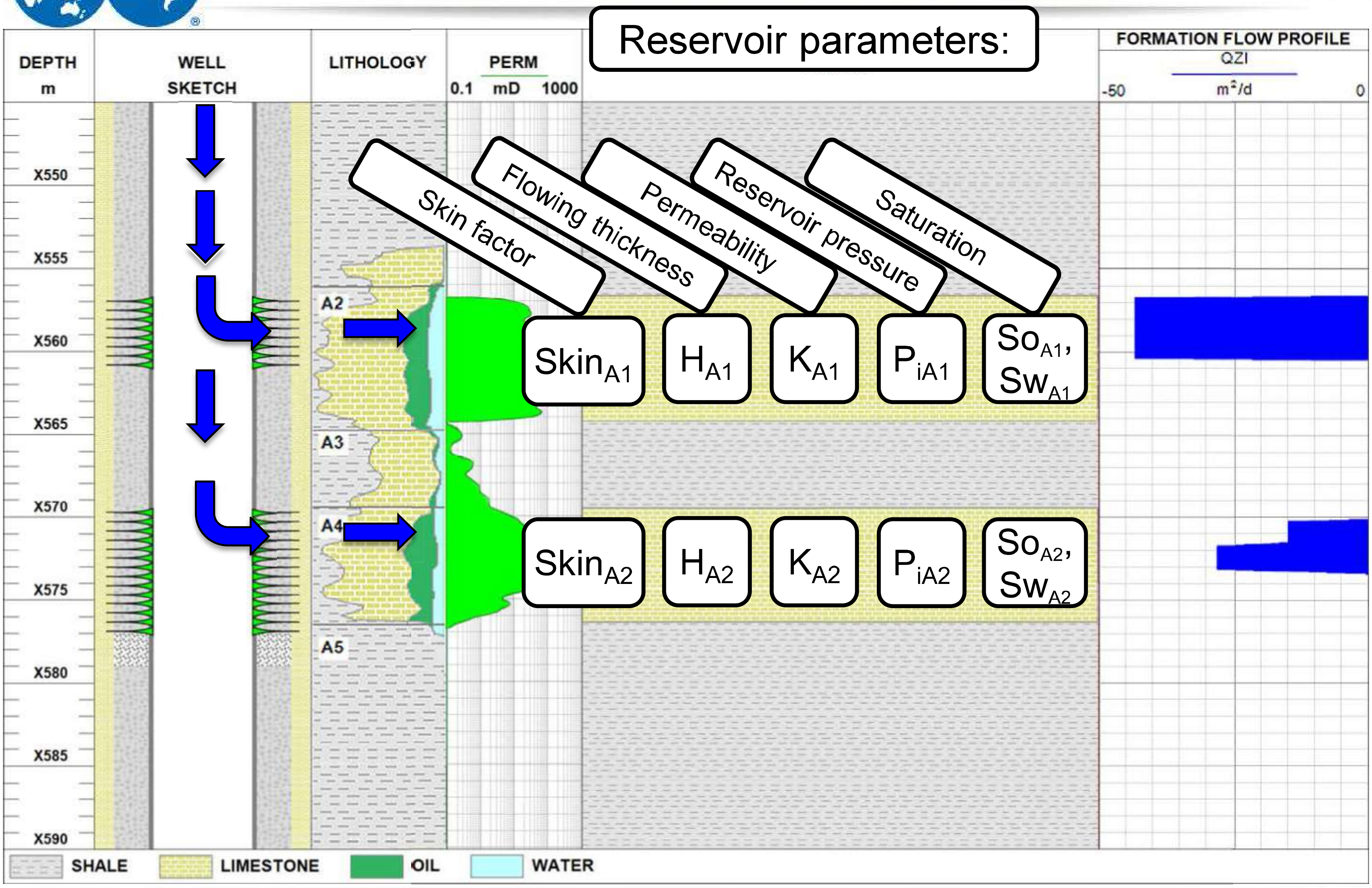


TermoSim is a numerical fine-grid simulator for producers and injectors operating in time and space with a resolution of minutes and feet. It simulates multiphase mass flow in multiple porous streaks and blends the outputs into borehole flow. In parallel, it simulates heat transfer within flowing streaks, between porous streaks and overlying and underlying rocks. Heat exchange between borehole flow and rocks is numerically simulated taking into account well completion components including tubing, casing, cement and various fillings in between.

It takes millions of iterations, high-power parallel computing and smart optimisation algorithms to achieve a proper match with temperature logs at different times. In the past years, it took weeks, required high skill and diligence and was not practical.

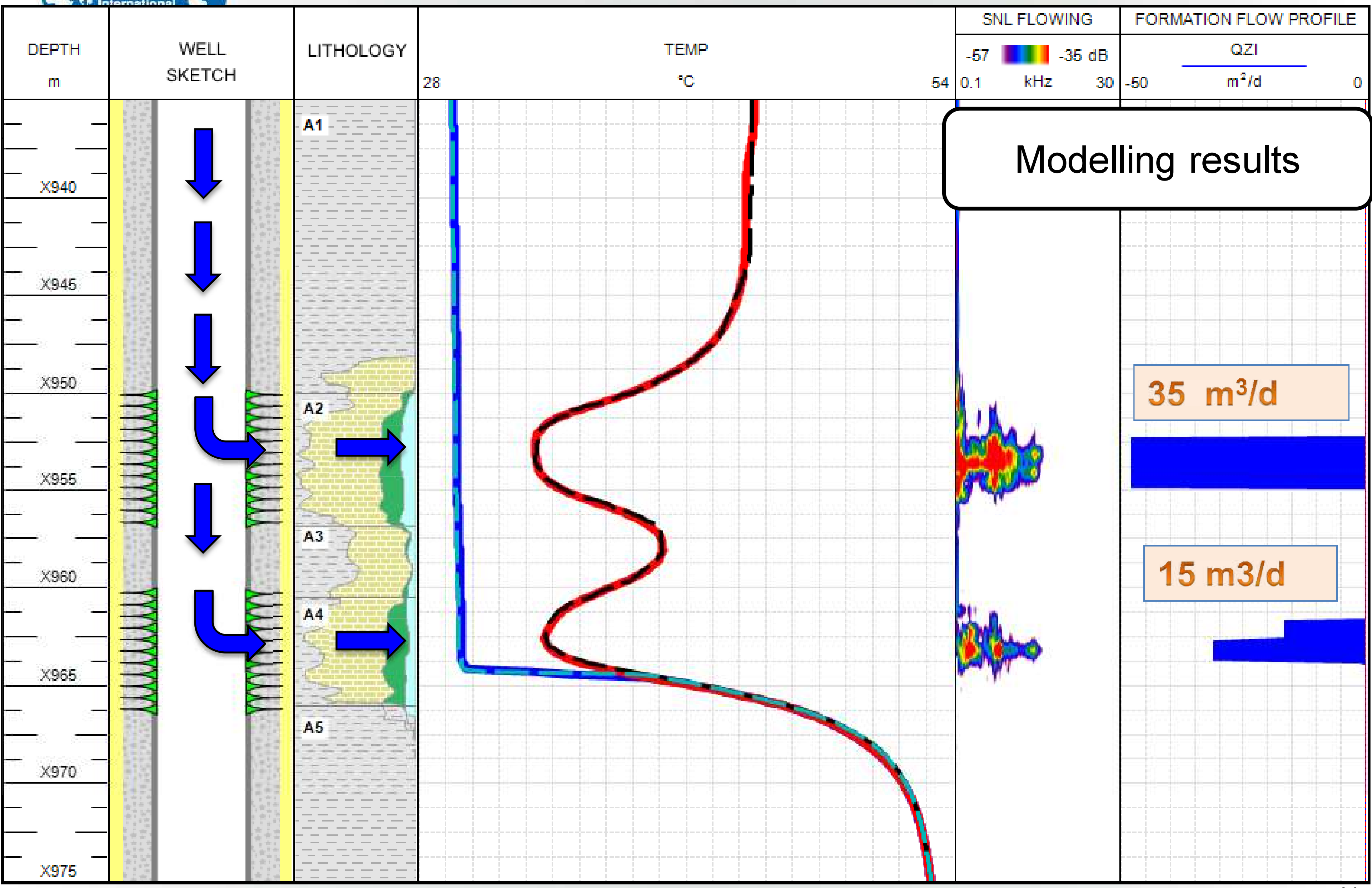
However, with the advent of high-power computing and new optimisation algorithms, it now takes less than an hour, and this technique is a practical and scalable solution.

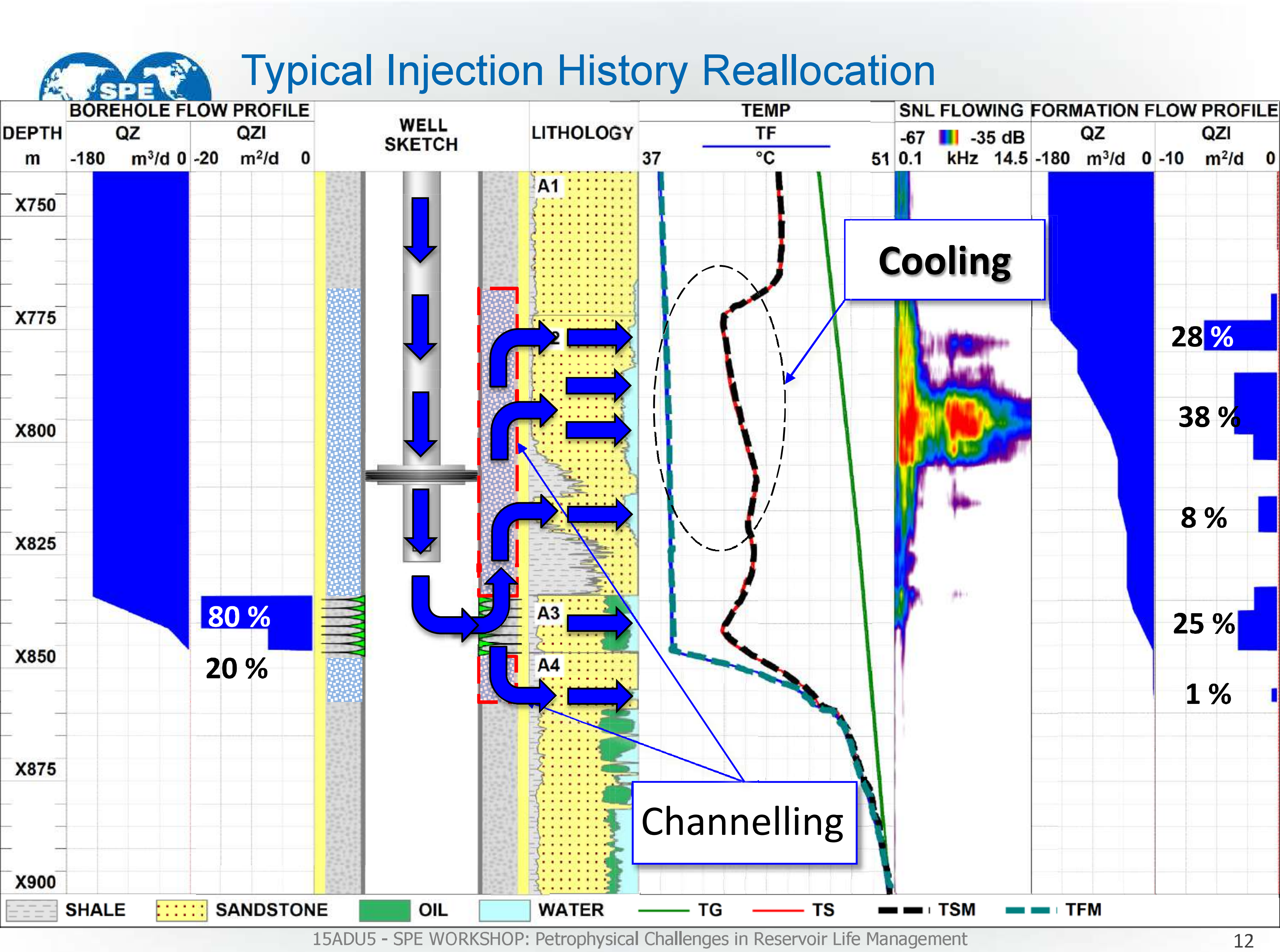
TERMOSIM ™ Inputs. Injector



Temperature models for injectors differ from those for producers and have specific inputs, such as surface temperature variations.
The main challenge in this field is that the formation is 3000 metres deep, and surface temperature variations do not reach it.
In this case, the formation temperature is not related to the flow rate and temperature logging is inefficient in flow quantification.
Nevertheless, temperature perturbations can be artificially generated.
Shutting in a well for a short, pre-calculated period of time and then opening the well to flow can generate a temperature pulse depending on the flow rate across each flow streak and allowing TermoSim to perform fitting and determine the injection flow profile.

Reverse Modelling. Injector





This figure illustrates a typical injection-related complication.

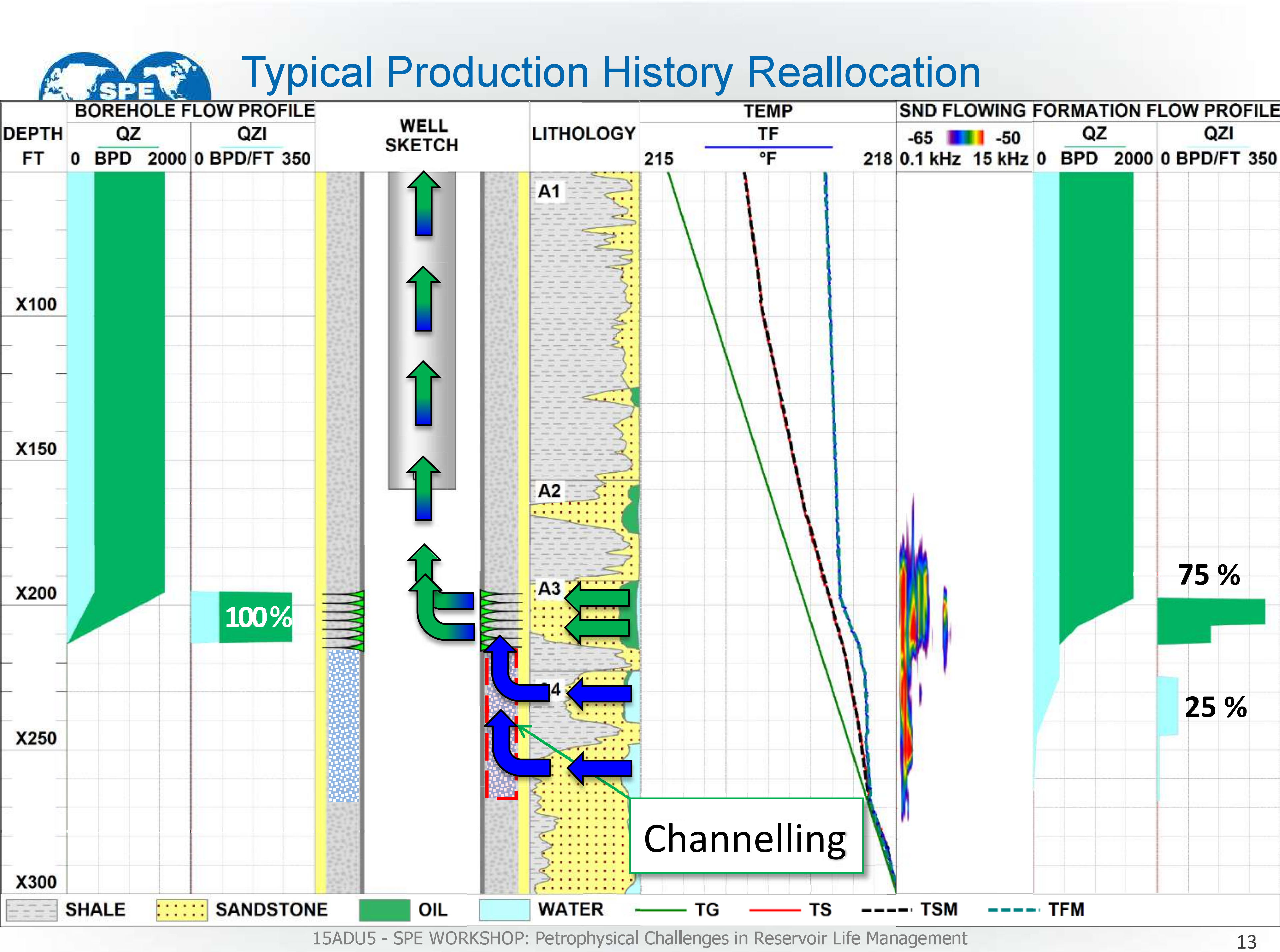
The A3 Unit is the only perforated pay and PLT suggested regular injection through the perforations, as seen in the Borehole Flow Profile on the left.

However, HPT-SNL clearly indicated flow in the A1 Unit above the perforated pay, as seen in the Formation Flow Profile on the right.

The SNL log shows formation noise in several streaks of the A1 Unit and the temperature log indicates cooling between them.

TermoSim modelling suggested that 70% of fluid was lost above the A3 Unit over at least 10 years, meaning that the injection distribution in the 3D model should be corrected accordingly.

Notably, this finding resulted from a cheap slickline through-tubing survey.



This figure illustrates a typical complication in a producer.

The A3 Unit is the only perforated pay and PLT suggested regular production from the perforations, as seen in the Borehole Flow Profile on the left.

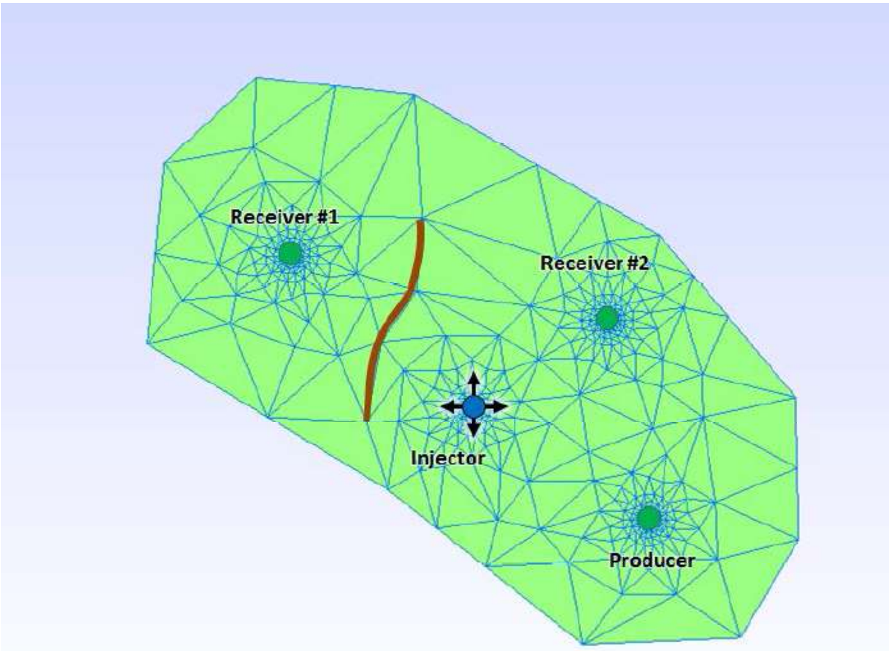
HPT-SNL and TermoSim modelling suggested 25% unwanted production from the watered A4 Unit.

Generally, HPT-SNL cannot reliably verify the fluid type behind the casing, unless it is a gas that shows up sharply in temperature and noise logs. However, it would be logical to assume that 25% of water production at the surface and 25% unwanted production from the watered A4 Unit below the pay is hardly a coincidence and that all water came from the A4 Unit by channelling, while the A3 Unit was still oil-saturated and water from injectors did not reach this location.

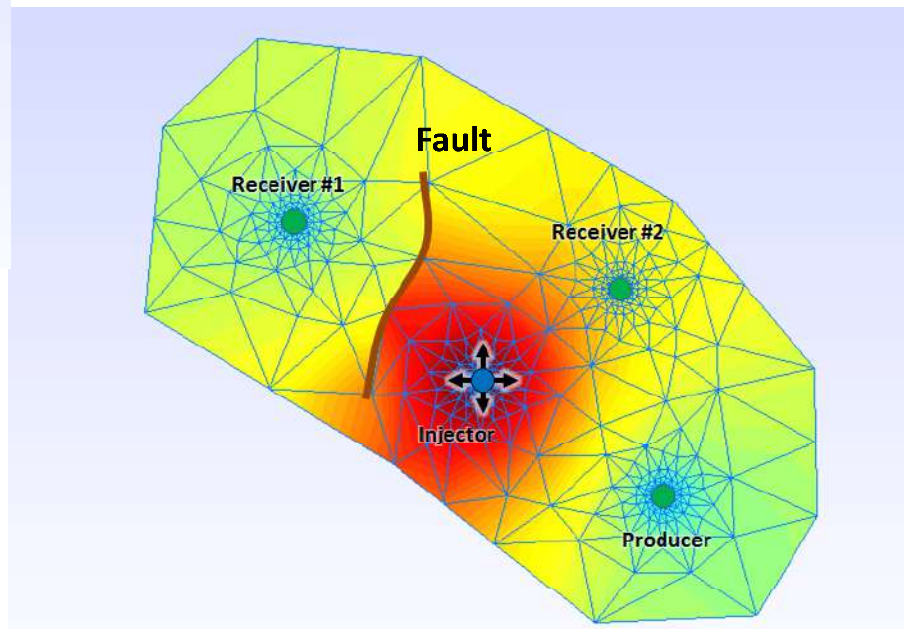
This is another valuable input for 3D model calibration.

Pressure Pulse Test – Basics

Before PPT



PPT results



Cross-well interference testing is a powerful reservoir characterisation technology.

This figure illustrates numerical pressure simulations for a selected field sector including two generating wells and a receiving one.

Pressure diffusion in time clearly proves that it contains encoded data on boundaries and heterogeneities.

Additionally, it contains information on formation permeability and compressibility between wells, which makes pressure interference testing (PIT) different from pressure transient analysis (PTA).

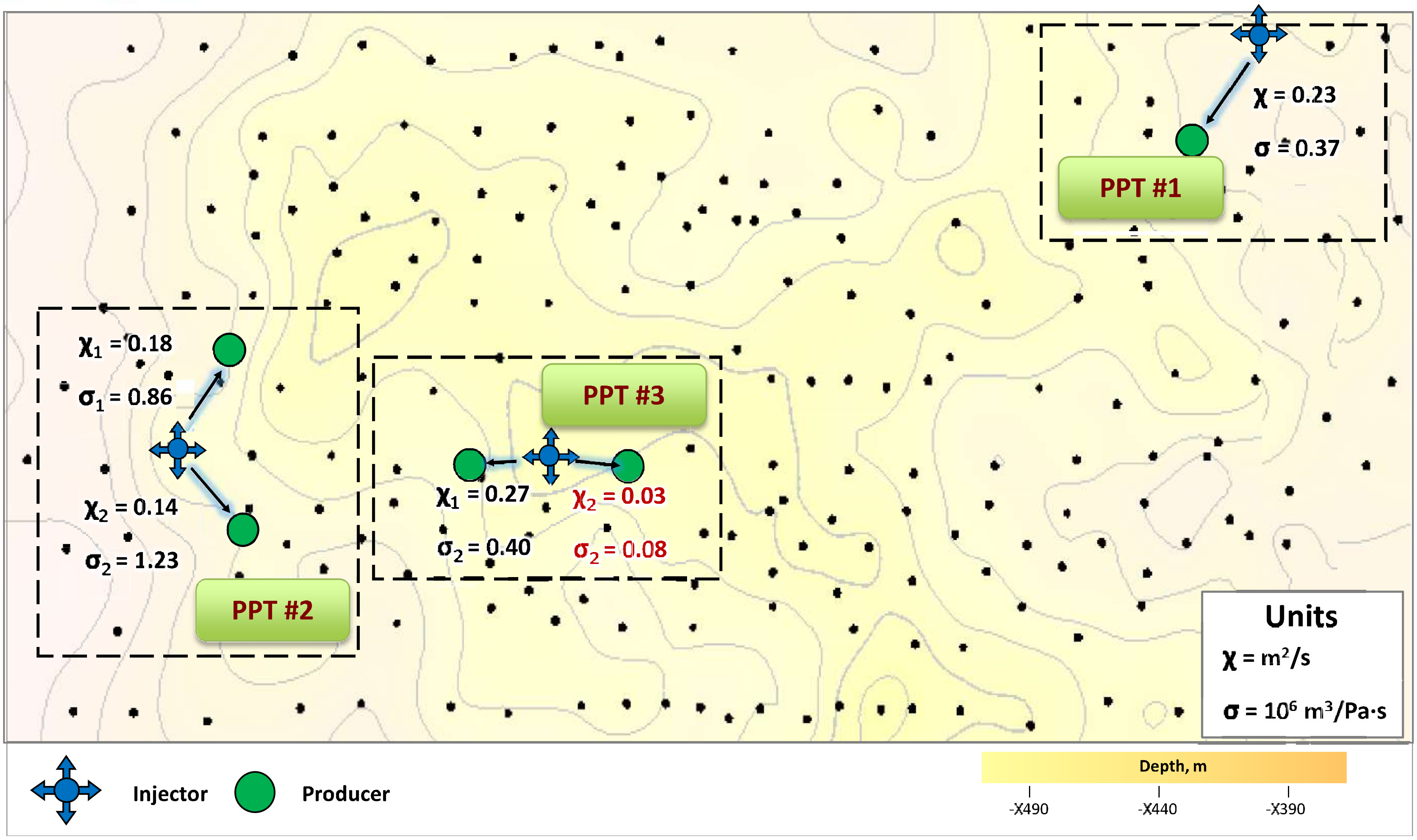
In PTA, pressure response fitting can verify formation transmissibility as well as a combined parameter that includes skin factor and hydraulic diffusivity, each of which should be found independently to find the other one.

In PIT, pressure response fitting can verify skin factor, transmissibility and hydraulic diffusivity independently, which is an advantage over PTA.

The current technique is to pulse wells in a certain pattern and record complex pressure responses in different wells, which is called pressure pulse testing (PPT), and then create an optimisation loop for formation parameters between wells that would be most consistent with pressure responses recorded in all wells.

This obviously requires a powerful parallel computing system and smart optimisation algorithms.

PPT Interpretation



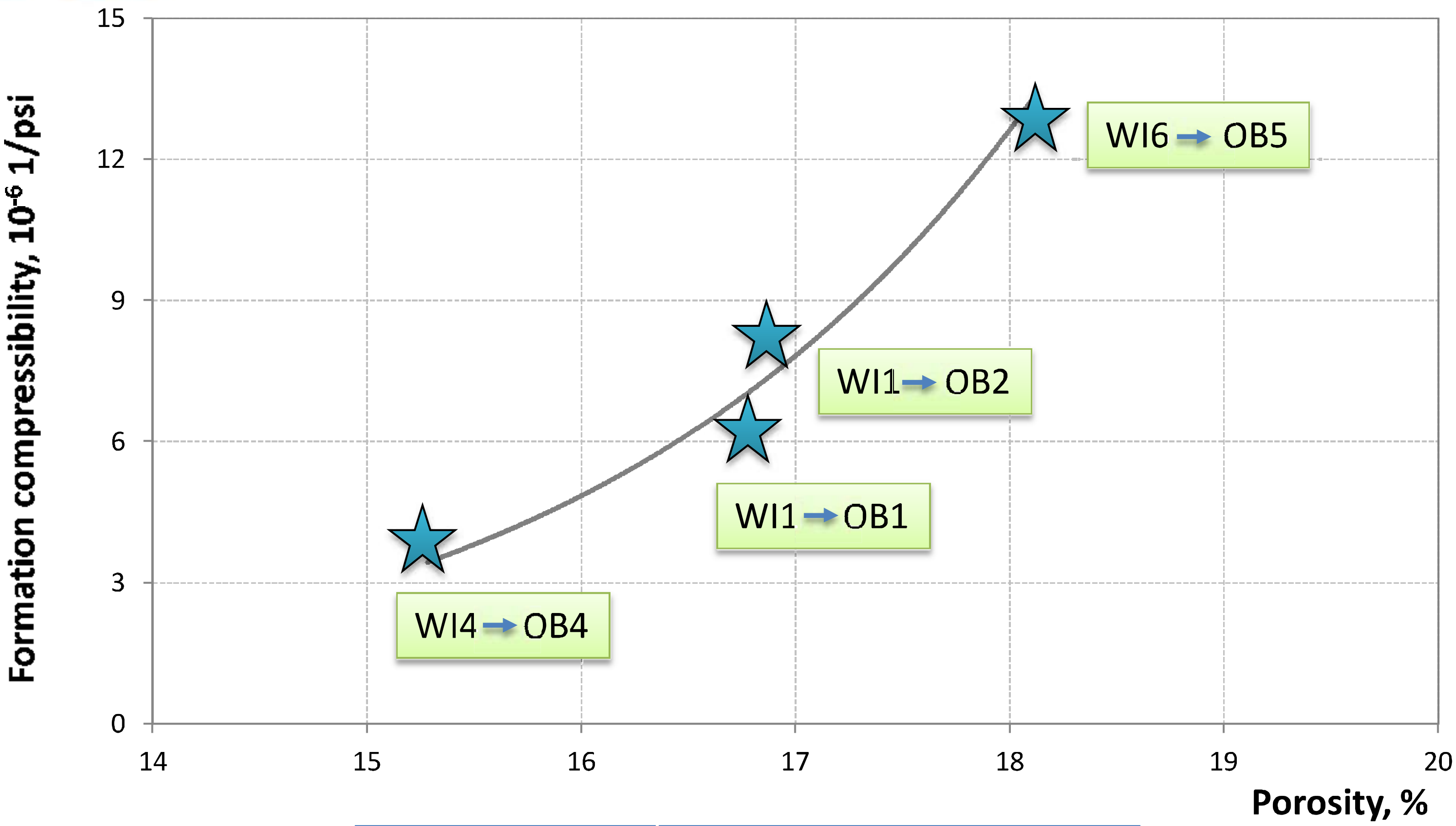
In this study, three pressure pulse tests were performed in aquifer and water-flushed areas in which the fluid saturation was known.

The flowing thickness was controlled through HPT-SNL.

The only unknowns for pressure diffusion were transmissibility and hydraulic diffusivity that can be translated into formation permeability and compressibility.

A PPT campaign was carried out in four intervals between wells, i.e. at four data points to correlate formation permeability, compressibility and porosity, and calibrate the 3D model.

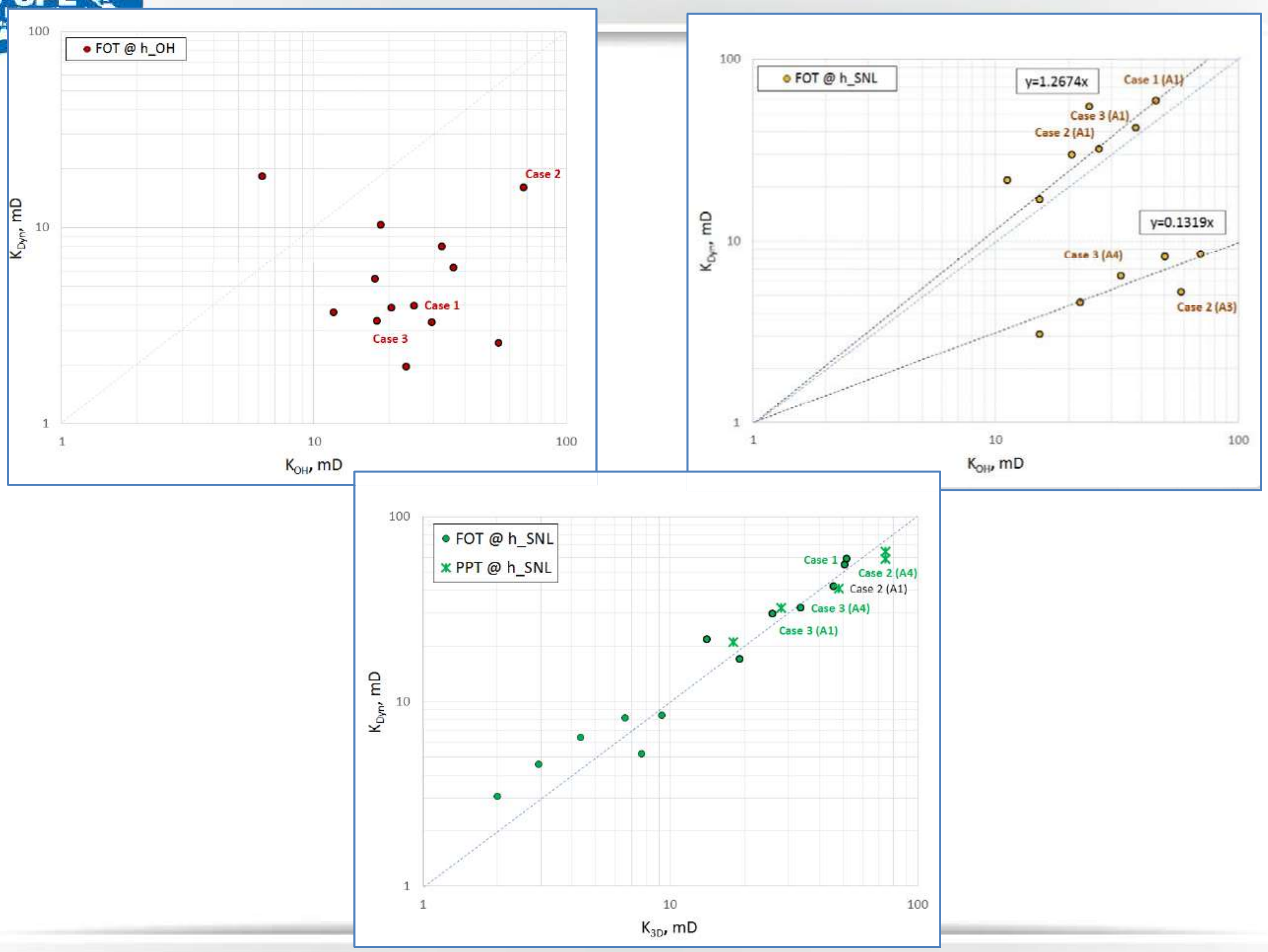
Dyn Compressibility vs Porosity



Data Source	C_{FORM}
FROM CORE	N/A
FROM PPT	$0.0023 \cdot e^{0.48 \cdot \Phi}\ 10^{-6}$ 1/psi

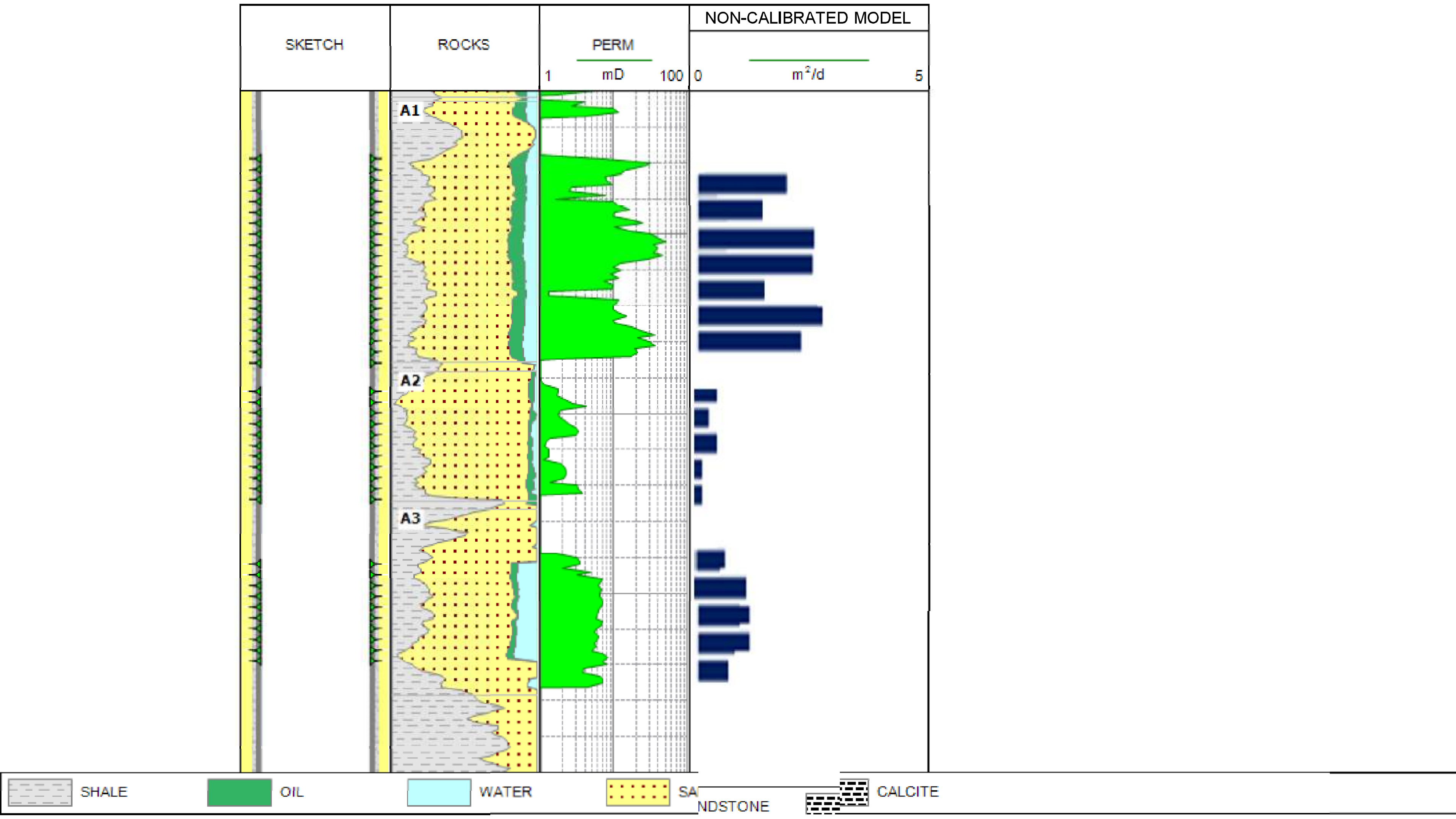
The first parameter to calibrate is compressibility.
The only method other than core analysis that can determine formation compressibility is cross-well interference testing, as it can assess transmissibility and hydraulic diffusivity independently.
This figure shows four data points for determining compressibility vs. porosity that can be simulated by a simple exponential correlation. Note that the rock porosity varied during the PPT survey narrowly between 15% and 19% while the compressibility varied between 3 Mpsi^-1 and 15 Mpsi^-1.
It means that the compressibility cannot be assumed to be constant throughout the field, at least in a model in which porosity variation is taken into account.
Interestingly, not a single test in this particular field was done on core compressibility, and original information on formation compressibility for the field development plan was sourced from the same formation of the neighbouring field, and it was assumed to be constant at 3 Mpsi^-1.
In many fields, this led to substantial errors in compressibility estimation and to corresponding errors in the pressure response to a material balance.

Dyn Permeability vs. OH Permeability



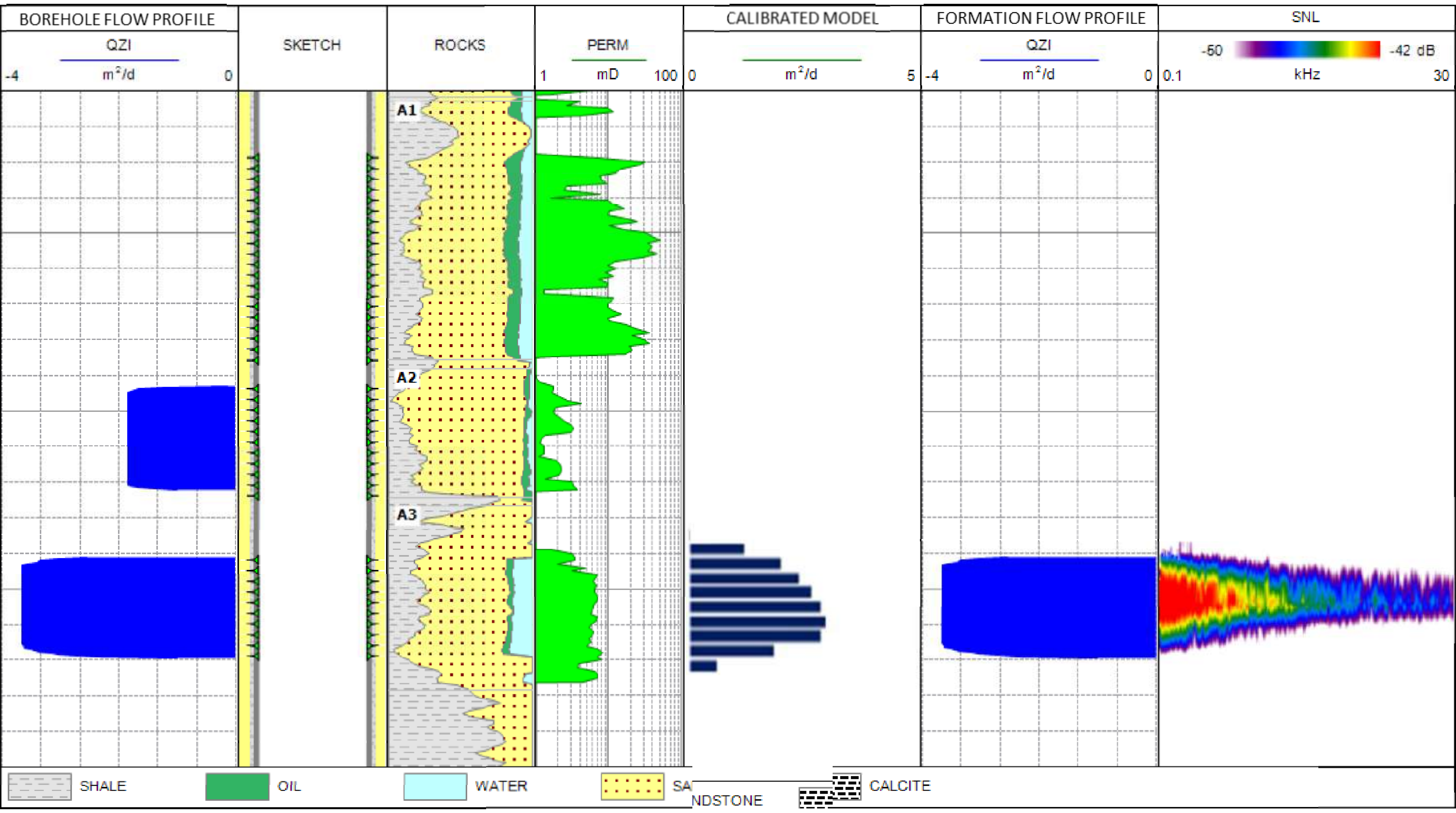
Permeability is the next parameter used in calibration.
Once compressibility has been calibrated, dynamic permeability data can be acquired from both PTA and PIT, which gives a lot of useful information for proper porosity-permeability correlation.
The only difference is that PIT can determine permeability from hydraulic conductivity using flowing thickness, while PTA requires manual input of flowing thickness, as it determines permeability from transmissibility.
Fig. P1 shows that the PTA permeability calculated using the open-hole thickness does not reasonably correlate with the open-hole permeability calibrated on core data. The same PTA using the same transmissibility divided by the SNL flowing thickness provides a better correlation, as seen in Fig. P2 showing two facies with different correction factors for macroscopic features.
Applying these corrections ensures a good correlation between the PTA permeability and the corrected open-hole permeability, as shown in Fig. P3.
Fig. P4 shows that the PPT permeability indicated by green stars confirms this correlation. The main advantage of the new corrected permeability model is that it has been calibrated to a macroscopic field-wide pressure diffusion response, not just to core analysis data.
Notably, core analyses are still important, as they provide useful information on the spatial distribution of porosity and permeability for variogram modelling.

Injection Profile Calibration



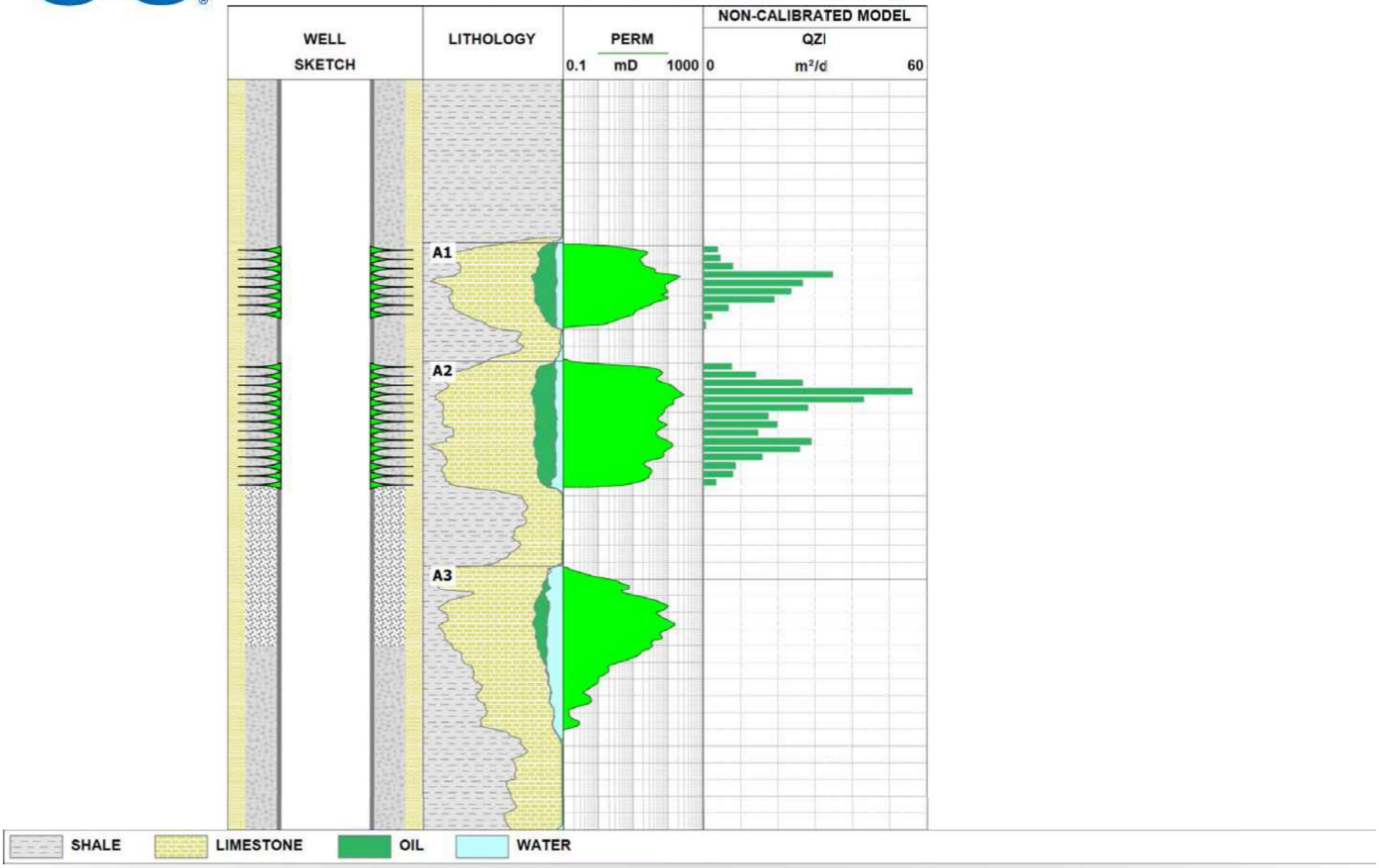
The next step in model calibration is flow profiling.
The flow profile based on open-hole data is given in the NON-CALIBRATED MODEL log data panel.
PLT data show that only two pays received water, as seen in the BOREHOLE PROFILE log data panel, which is different from the original open-hole model.
It would be erroneous to assume that PLT data actually show what is happening in the reservoir and use them for model calibration.

Injection Profile Calibration



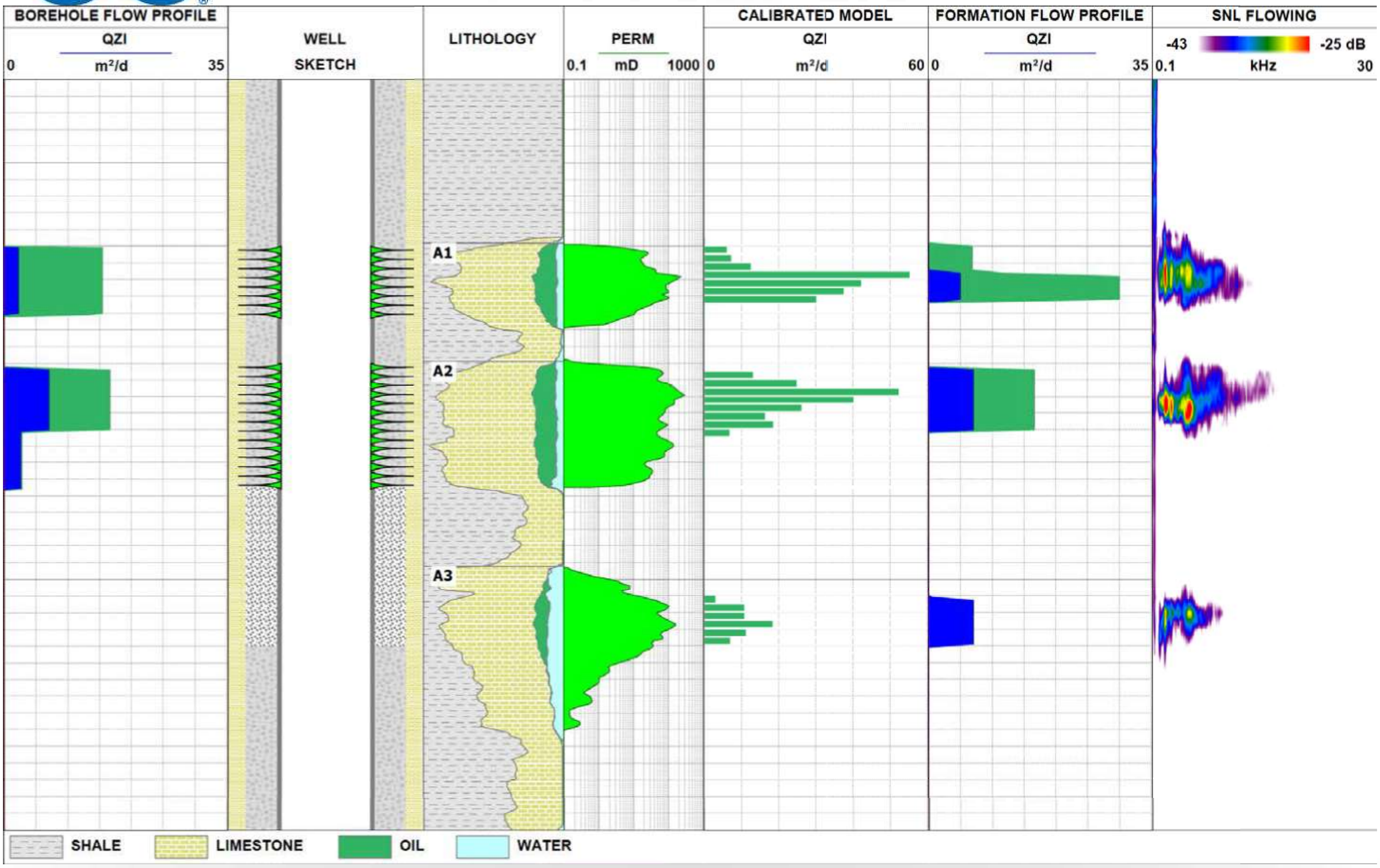
Unlike PLT, the HPT-SNL survey is reservoir-orientated, so it can see into the reservoir. In this case, it suggested that only the A3 Unit was flowing and that part of the flow was distributed behind casing through the A2 Unit perforations, which is captured by PLT but is misleading as to where this fluid came from. The actual reservoir flow profile is shown in the FORMATION FLOW PROFILE log data panel and a corresponding computer model is shown in the CALIBRATED MODEL log data panel.

Production Profile Calibration



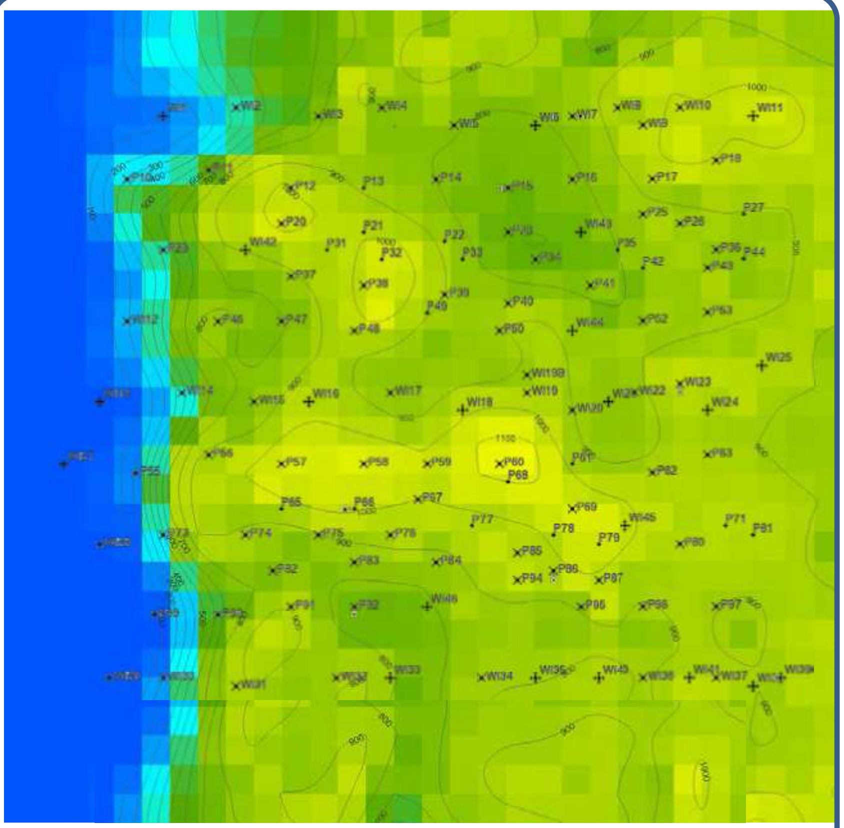
Surprises of this sort are often encountered in producers. In this case, PLT provided a fair match to what was expected from open-hole logs: two perforated pay units, A1 and A2, were producing oil and injected water.

Production Profile Calibration

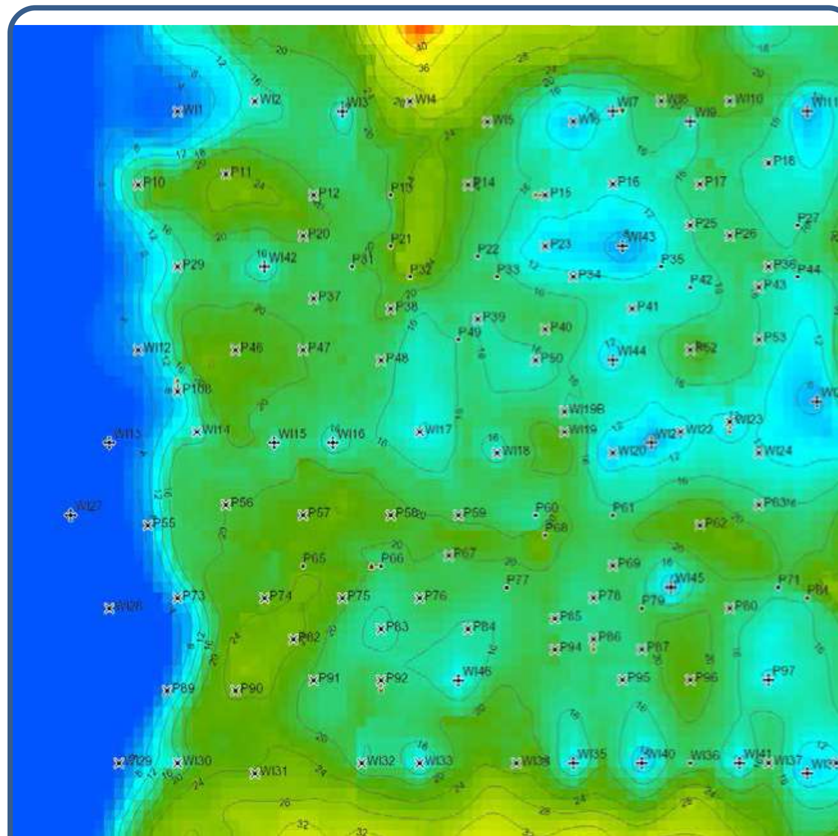


In reality, there was unwanted water production from the unperforated A3 Unit through behind-casing channelling.

Unit A1+A2

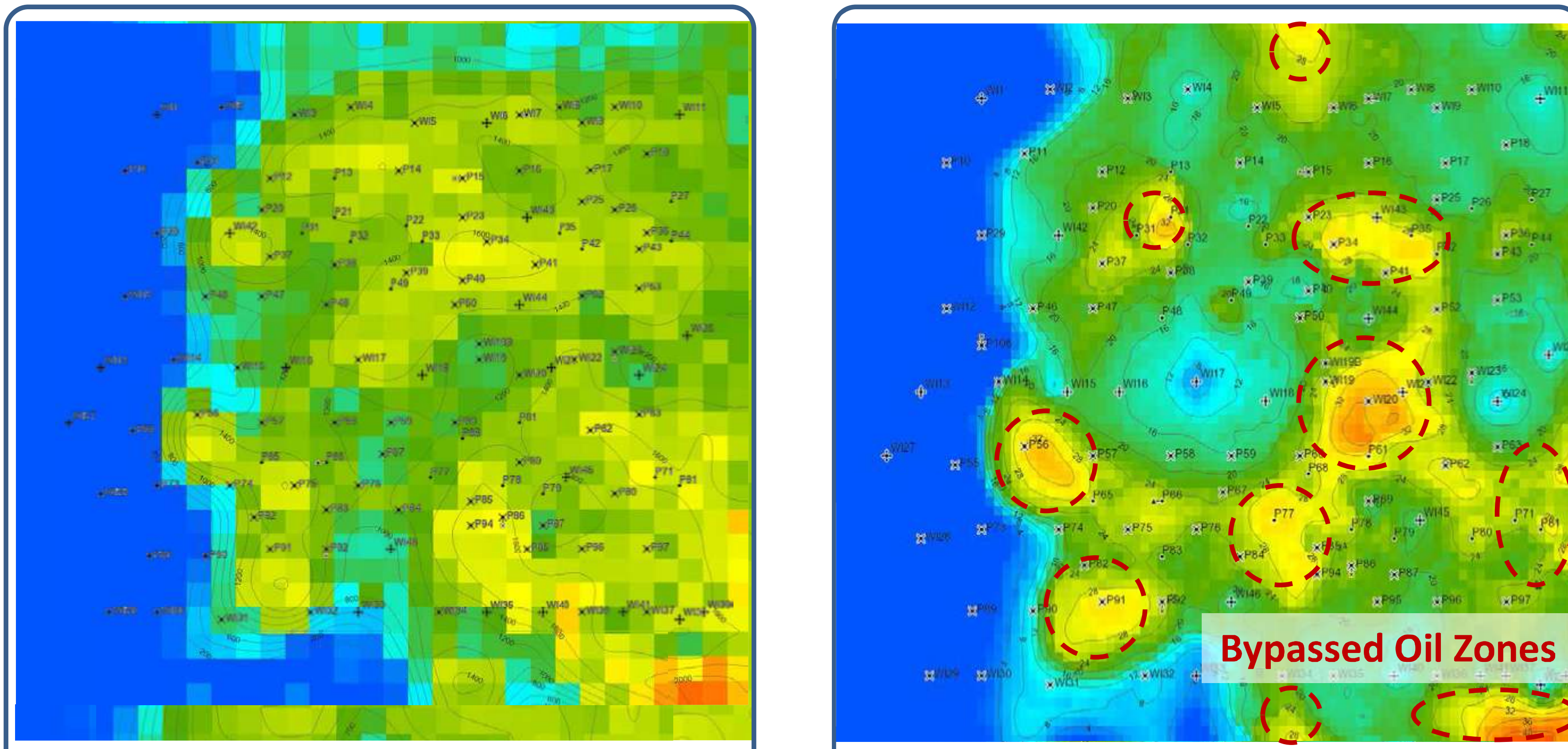


Non-Calibrated Model



Calibrated Model

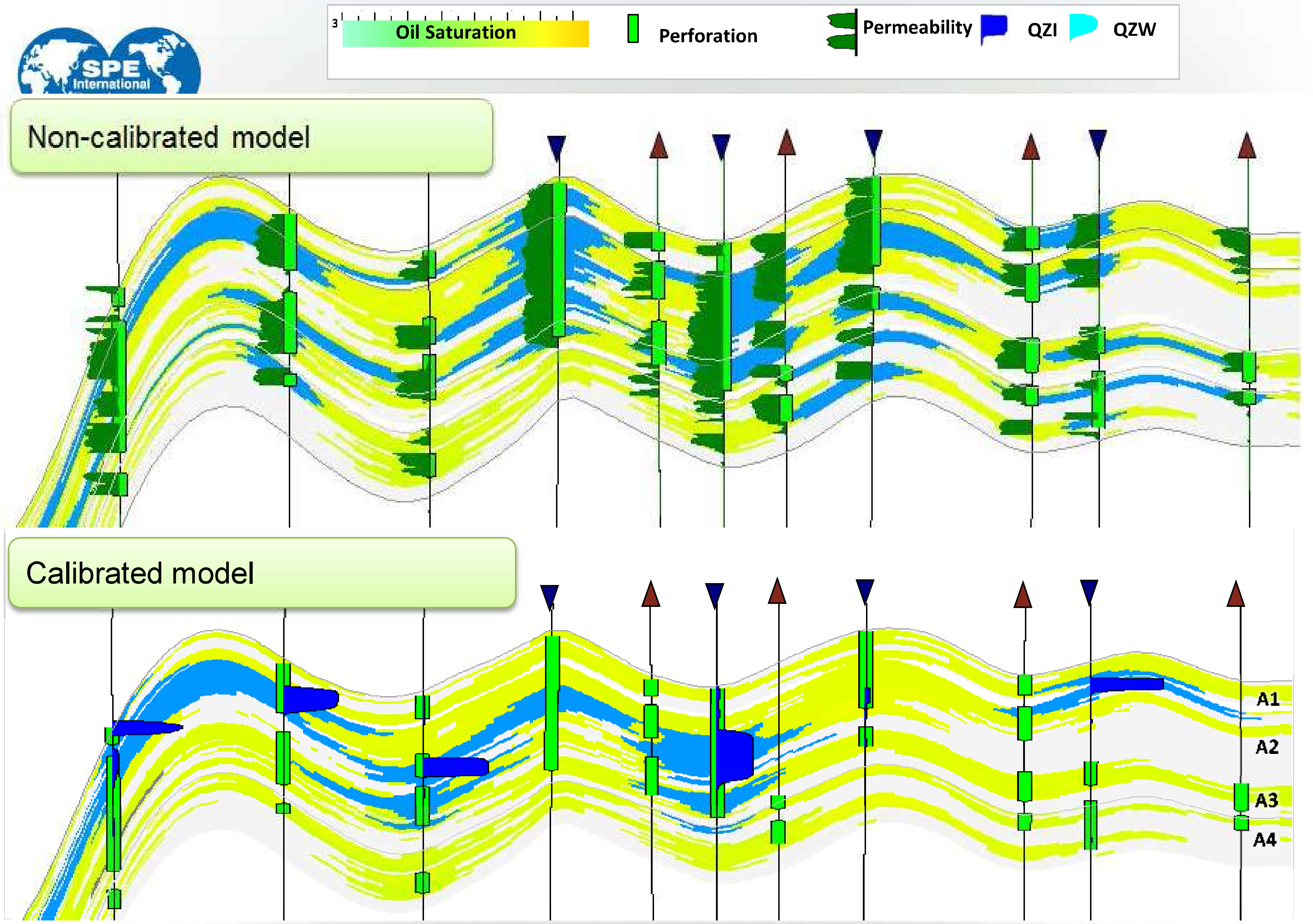
A comparative analysis of calibrated and non-calibrated models of the upper formation comprising the A1 and A2 Units revealed a substantial difference between them.
The non-calibrated model shows uniform depletion, while the calibrated one shows a patchy, non-uniform sweep with a lot of bypassed or lagging oil.



Non-Calibrated Model

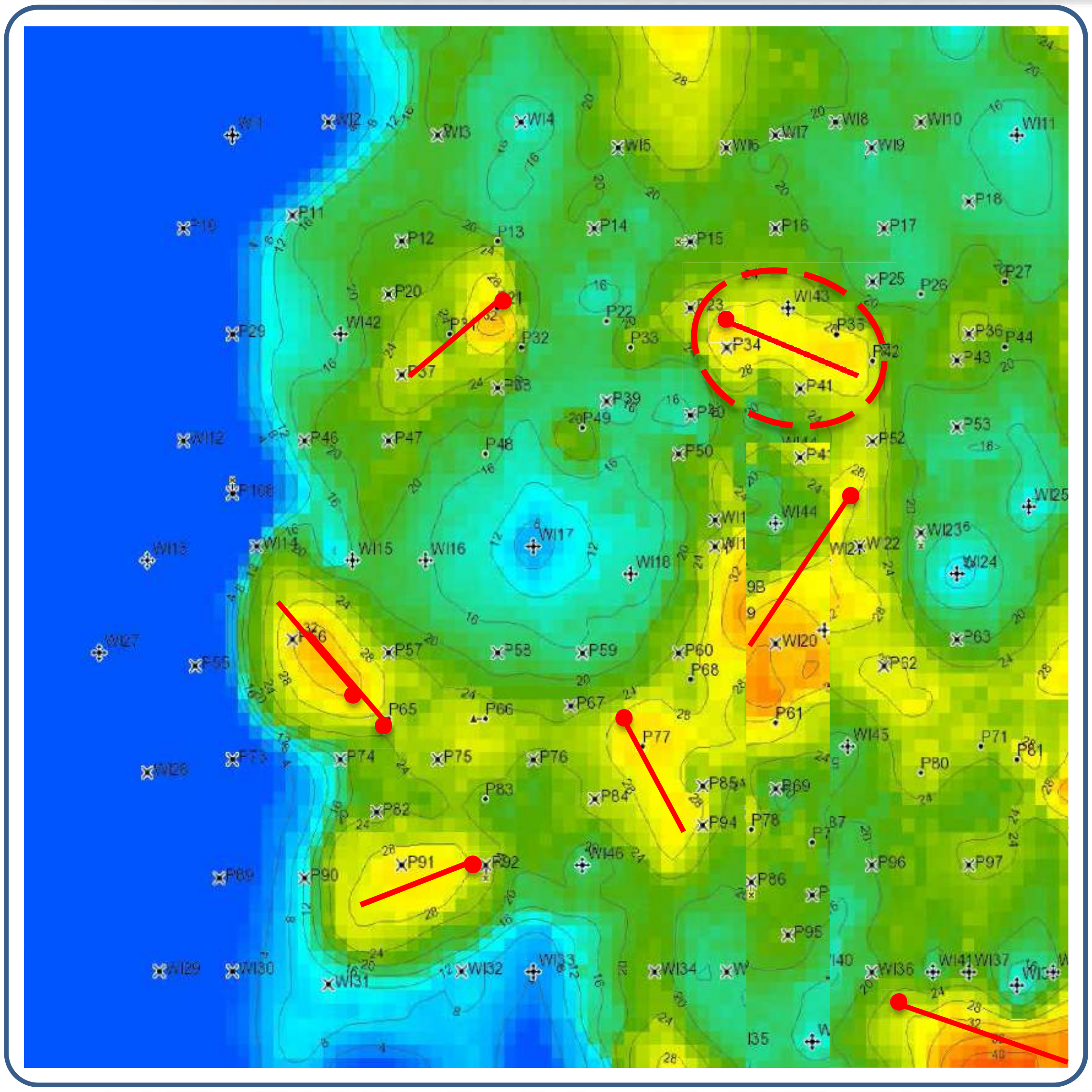
Calibrated Model

The contrast is higher for the lower formation comprising the A3 and A4 Units.



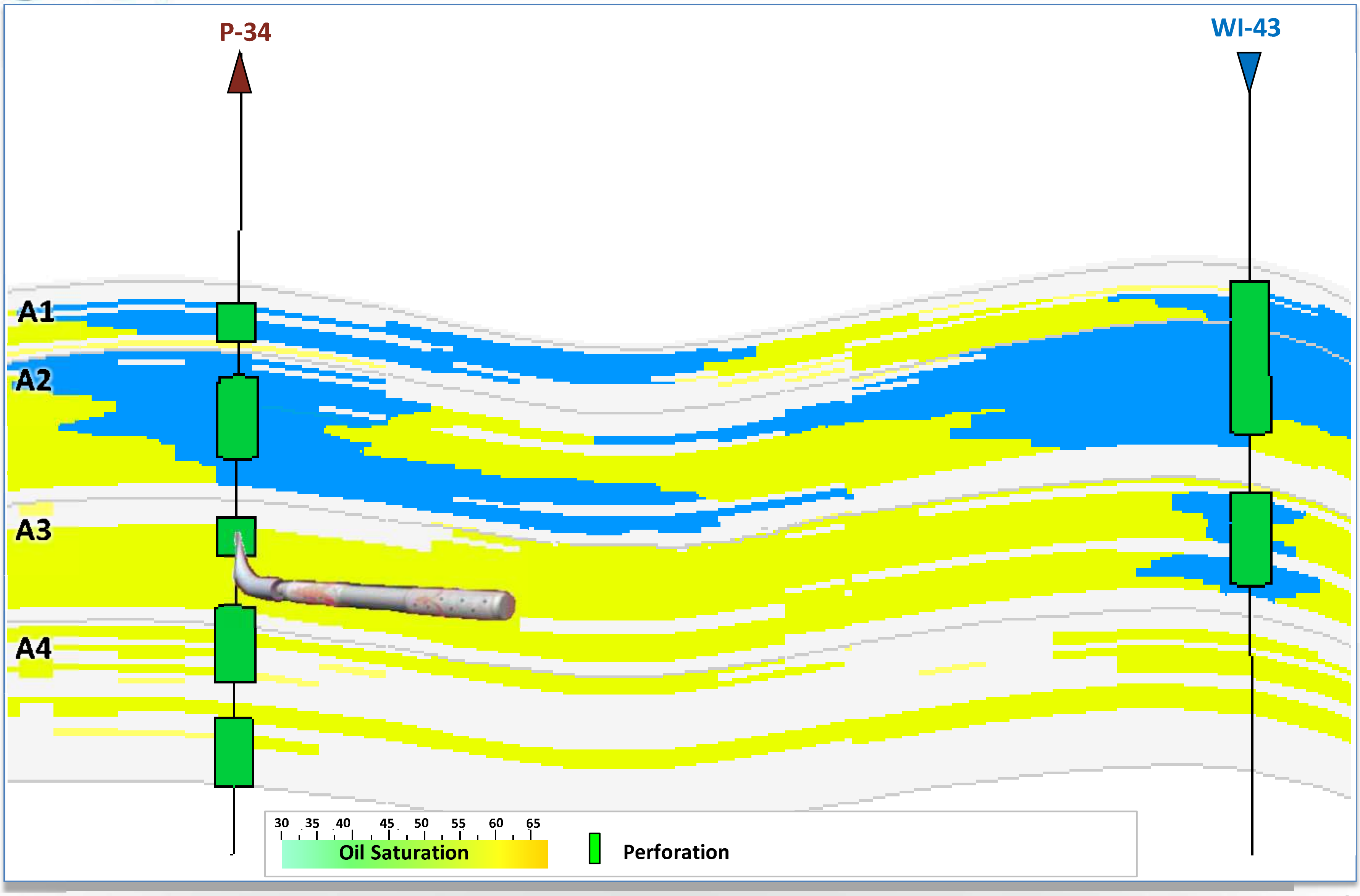
This cross-section illustrates the difference in residual oil distribution and displays bypassed oil zones.
Note that injection flow dominates in the A3 Unit that apparently has better reservoir qualities relative to the overlying and underlying units.
This led to short-circuiting in the A3 Unit and loss of flow circulation in other units with consequent 15% recovery delay.

Sidetracks – Map View



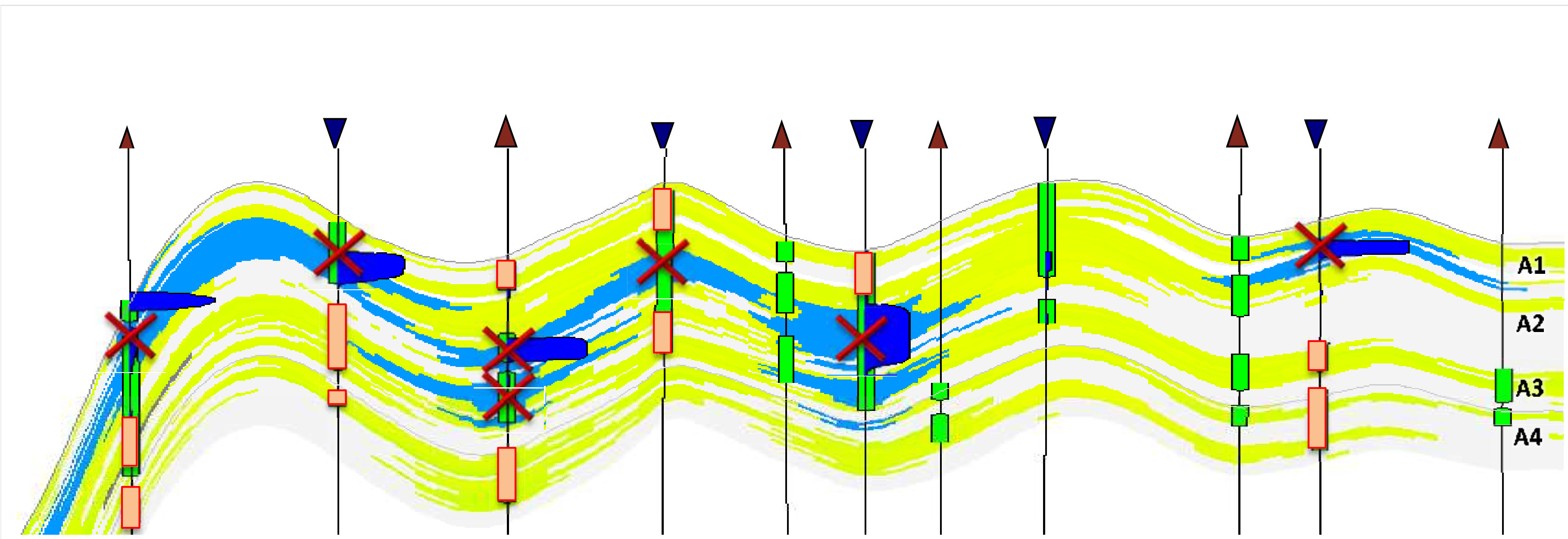
The calibrated model suggests that a sidetrack drilling plan should target bypassed and low-mobility oil.

Sidetracks – Side View



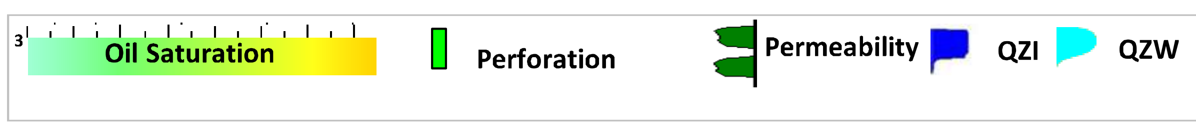
A side view of one of the proposed sidetrack trajectories.

Workovers – Water Shut-off & Perf/Acid



- Water shut-off

- Perf/Acid



A cross-section indicating water shut-off and stimulation jobs to reduce circulation in the A3 Unit and reinforce the A1, A2 and A4 Units.

Thank You