A Collaborative Approach to Seismic Interpretation for Offshore Field Development—A Case Study*

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Abstract

Santos operates several gas fields in the offshore Otway Basin in water depths around 100 m. The gas is reservoired in late Cretaceous sandstones with porosities typically of 18–25% and permeabilities typically of 10–700 mD at approximately 1800 mss depth. A 3D seismic survey was acquired across the fields and initial exploration and development wells were located using a time migrated 3D volume. A recent development well drilled on the interpreted crest of the field delivered lower productivity than expected with indications of produced water from an unknown source. This result indicated greater complexity than originally envisaged: to address this it was decided to reprocess the seismic volume using Pre-Stack Depth Migration (PSDM) and, at the same time, establish a multi-disciplinary team to take an integrated approach to understanding the field. This paper discusses how a collaborative approach, combining holistic 3D structural interpretation, rock physics modelling, fluid dynamics (incorporating petrophysical and SCAL data), and production data elicited new ideas to explain the field performance and identify further development opportunities.

Introduction

It is considered that the full complex nature of some hydrocarbon fields only becomes apparent under production. Often a field that has been perceived as a single tank does not live up to the expectations and requires further investigation. The answer often lies beyond the scope of any one subsurface/surface discipline. Such fields can be better understood with more data, new technologies, fresh ideas, and multi-disciplinary collaboration. This case study addresses the integrated use of geology, geophysics, petrophysics, rock physics, and production.

The case study comes from a Santos Ltd (STO) operated Henry Field in the offshore Otway Basin. The field was discovered in 2005. The initial development well, drilled in 2008, did not produce the expected volumes. The poorer than expected gas production and the unexpected water production required another review of the field. A new multi-disciplinary development team was created and given the task of understanding the well and field performance and the locating an optimal target for further field development.

Geology

The Otway Basin is located in south-eastern Australia and extends from Cape Jaffa in southeast South Australia to the northwest tip of Tasmania (Figure 1). The basin is about 500 km long and covers an area of about 155,000 km^2, 80% of which lies offshore. Maximum sediment thickness in the basin is about 10,000 m. It is one of a series of Late Jurassic-Tertiary basins that developed along the southern margin of Australia during the breakup of eastern Gondwana (Willcox and Stagg, 1990; Norvick and Smith, 2001).

The Otway Basin has a relatively complex tectonic history, comprising two periods of rifting separated by 10-15Ma. The first rift event, oriented northwest–southeast, occurred during the Late Jurassic-Early Cretaceous (Tithonian-Berriasian) and was responsible for the development of a series of large east-west to northwest-southeast striking half-graben structures (Willcox and Stagg, 1990; Cockshell, 1995; Cockshell et al., 1995; Perincek and Cockshell, 1995). The second rift event occurred during the Late Cretaceous (Turonian-Maastrichtian), but this time the extension was oriented northeast-southwest (Willcox and Stagg, 1990), with the locus of extension shifting offshore to the south. This extension ended in the Late Maastrichtian with the onset of seafloor spreading in the Southern Ocean between Australia and Antarctica (Cande and Mutter, 1982; Lavin, 1997). The late Cretaceous reservoir of the case study is interpreted to have been deposited in a restricted marine environment and is composed of inter-bedded fine-grained lithic sandstone, carbonaceous mudstones, and thin coals or carbonaceous stringers.

Field History

A development well (Well 2) was drilled in 2008; it was not placed in the same high amplitude band used to locate Well 1. Well 2 instead targeted the updip structure with the assumption that the whole structural trap updip of Well 1 would contain a connected gas volume. A horizontal well was considered the optimal development strategy, and a pilot well was drilled to define the location of top reservoir in the new location. The horizontal Well 2 intersected gas saturated sand but also encountered cemented sections of reservoir related to previously un-mapped faults. Consequently the well came online with significantly less than expected initial rates which declined further on production.

Material Balance demonstrated that Well 2 only saw an Original Gas In Place (OGIP) of approximately one third of the original volumetric estimate for the field. In addition Flowing Material Balance analysis (FMB) showed that Well 2 is attached to a volume of less than one tenth the originally estimated OGIP but with access to another larger volume of unknown size and by transmissibility of unknown scale. In late 2009 it also became apparent that this field was responsible for producing small volumes of water identified at the plant by $CaCO_3$ scale. It is evident that the understanding of the field and its physical properties was flawed and the development sub-optimal. Questions for the field redevelopment were summarised as follows:

- Is the initial estimate of OGIP correct?
- Can Well 2 develop all the remaining OGIP?
- What is the optimal location for additional development wells if required?
- What is the source of the produced water?

In order to answer these questions a new integrated subsurface team was created and the seismic volume reprocessed using Pre-stack Depth Migration (PSDM).

Seismic Data

Well 1 and 2 were drilled on the structural interpretation of the PSTM 3D seismic data. However, the structural complexity (which comes from two episodes of rifting that are oblique to each other (Figure 3a)) and stratigraphic complexity (as the reservoir sands are sandwiched between two regional unconformities) required better imaging. A decision to invest in more advanced seismic processing techniques was taken in 2013 and the PSDM 3D seismic data became available in 2014. The PSDM data provided better Signal to Noise (S/N) ratio and also preserved the low frequency part of the signal (Figure 3b). The low frequency part of the signal bandwidth is essential for defining AVO effect as it is more susceptible to the pore fluids.

Structural Interpretation

Structural interpretation was undertaken on the PSDM seismic data with the following objectives:

- Provide a robust structural interpretation of the reservoir that can be taken into static modelling.
- Explain the structural setting near Well 2.
- Provide detailed intra field fault mapping to avoid future Well 2 scenarios.

With the objective of getting most of the intra field faults into the structural interpretation, the seismic volume was interrogated carefully and horizons/faults were interpreted in the inline, crossline, and random (using traverse) directions. In addition a dip steered similarity cube (Figure 3a) was used to aid in fault interpretation.

The fact that faults follow a fractal pattern is well published in literature (Turcotte, 1990, Barton and Zoback, 1990, 1992; Davy et al., 1990; Scholz and Cowie, 1990; Marrett and Allmendinger, 1991; Walsh and Watterson, 1992; Gauthier and Lake, 1993; Pickering et al., 1996) and the log-log plot of “maximum fault throw” against “cumulative number of faults” should be straight line (e.g. Peacock and Sanderson, 1994). This plot can be also be used to find out if faults are missing from the seismic interpretation – especially those below seismic resolution. For this case study in the maximum throw range of 6 m-175 m the correlation coefficient of the power log curve is, as predicted, a straight line (Figure 4). This gives confidence that the fault density in the field is adequately mapped. The reason for the falling off of the straight line at fault throws of less than 6 metres (Figure 4) is that throws of this magnitude are beyond seismic resolution. The falling off of faults above 200 metres throw is that these faults are too large to be encompassed in the field area and are only partially present or not present at all.

The horizontal section of Well 2 encountered significant sections of cemented reservoir related to faulting. Examination of the drill cuttings revealed that well had intersected at least three carbonate cemented intervals that have been attributed to fault zones whereas only one fault could be interpreted from detailed inspection of the seismic data. So the most plausible explanation was thought to be the presence of a wing crack (or edge crack) system. Wing cracks are developed as a result of stress concentration at the tips of faults. So the well could have intersected one major fault (which can be seismically imaged) and multiple associated-wing cracks (Figure 5).

One other observation was that the faults intersected at Well 2 were 50-75 m away from the faults interpreted in the seismic data (Figure 5). This positioning error in the seismic data can be attributed to migration (seismic processing) error. The magnitude of the error can be used for better future well placements with regards to the PSDM seismic volume fault interpretation.

Rock Physics and Seismic Attribute Analysis

To better understand the seismic attributes a fresh Rock Physics study was undertaken. The scope included the following:

- Wedge modelling.
- AVO half space modelling for reservoir fluids (Brine and Gas).
- Generation of AVO facies maps from PSDM gathers.

Wedge modelling was undertaken to investigate whether the loss of amplitude towards the crest of the structure (Figure 2) could be explained by a thinning reservoir. The wedge model showed a tuning thickness of circa 25 m (Figure 6a). The model of sand thinning towards the crest of the structure was also a good fit with the geological understanding of the area. As the reservoir deposition was syn-rift, the thicker sands should be present near the then active faults where there would be more accommodation space. Furthermore the reservoir has been broadly classified into two units: an upper unit (Unit 1) with higher Net to Gross (N/G) and lower unit (Unit 2) with lower N/G. Analysing the proportional horizon slices from the top to the base of the reservoir (Figure 6b) it became evident that the good quality Unit 1 is predominantly present near the faults. The reason for this is that the channels flowed into the accommodation space created on the downthrown side of faults and deposited good quality reservoir sands while the overbank or fine grained sediments would be deposited away from the faults towards the shoulder of the half graben.

A summary of the geological model of the reservoir that evolved was that the thicker sands are present in the high amplitude zones close to the major growth faults. The good quality Unit 1 reservoir is interpreted to be absent in the crestal areas of the field to the southwest because of erosion by the overlying unconformity (Figure 2). The inferior N/G Unit 2 is present over the crest but it is less than 25 m thick (tuning thickness).

An AVO half space model was created using parameters from wireline log data. The model demonstrated that gas sands would have a Class II AVO response but for brine sand it would be Class IIP AVO (Figure 7, ASEG polarity). So the change in polarity from near angle negative amplitude to far angle positive amplitude would be a wet sand scenario.

AVO facies mapping (Figure 8) at the reservoir level was completed using the PSDM seismic gathers. Most of the facies map could be explained with the already discussed scenarios. Region B which covers most of the field is yellow, representing a Class II AVO (gas sands).

The change in colour in Region D was interpreted to be due to brine-saturated sands below the Gas Water Contact (GWC) and the change in colour in Region A to the crest of the structure was interpreted to be sub-tuning effect from thin sands. Region C (blue in Figure 8) represents Class IIP brine sands in the middle of Region B gas sands and required further study.

The following models were proposed to explain the AVO response in Region C.

- **Brine sands**: The field is compartmentalised and has two GWCs. Well 2 intersected faults as it drilled from Region A into Region C, suggesting Region C could be an isolated pool cut-off by faults.
- **Thin sands**: Sub tuning effect like that of Region A.
- **Different facies**: Region C could be a different facies.

Fluid Analysis

Fluid analysis was achieved by using reservoir and fluid information to fit suitable regressions to SCAL derived pore entry pressure (Pc) and water saturation (Sw). The log derived porosity, permeability, and water saturation can then be used to estimate a log derived value for Pc (J). The SCAL regressions and the log derived Sw to Pc points can be cross plotted on the same graph. For the SCAL regressions the Free Water Level is fixed but for the Pc (J) values it remains a variable and is altered until the best fit to the SCAL regressions is obtained. In this way an estimate for FWL can be made from the log values in each well.

For the Henry Field there were 3 SCAL samples in the reservoir and these were used in the laboratory SCAL tests to derive Air-Brine and Mercury Injection values for Sw and Pc. The regressions were fitted to the data as shown in Figure 9 and Figure 10. It is noted that the Air-Brine data plotted so close together that a single regression fitted all the data.

The up-scaled log values were then used along with Facies information and each well was investigated for possible free water levels (FWL).

Well 1 FWL

Well 1 is the discovery well in the field and also the well, which was cored, and therefore the origin of the SCAL data. If this well's petrophysically derived values are reasonably accurate then a good estimate of FWL should be obtained. Figure 11 shows the well values (red point) fitted to the SCAL data which gives an estimate of FWL at -1842 m TVDss.

Well 2 FWL

Well 2 is the horizontal development well. When data from this well is plotted against the SCAL derived functions the following is apparent:

- The averaging of the logs in a horizontal well causes more uncertainty in the log values as seen in the greater scatter (Well 1 plot (Figure 11) cf. Well 2 plot (Figure 12)).
- The longer length of the well means there are more log-derived points as apparent on the plot (Well 1 plot (Figure 11) cf. Well 2 (Figure 12)).
- The estimate of FWL is shallower than that in Well 1 (Figure 13).

Discussion with the JV resulted in questioning the use of the horizontal well for FWL estimation. Concerns were raised on to the validity as follows:

1. As demonstrated by (Maggs et al., 2014) high angle and horizontal wells geometric effects, proximity to bed boundaries, and anisotropy create problems in log analysis and result in over estimation of Sw.
2. The Mercury injection SCAL tests are not as accurate as the Air-Brine and appear to have different results and should not be used.
3. The phi-k relationship from Coates exponents was different in both wells and therefore a single relationship derived from core should be used to generate permeability.
4. The poorer quality reservoir should be excluded because the effect of bound water will skew the results especially in the horizontal well where this rock will be affected by point 1.

Given the uncertainty in Well 2 petrophysical values the question arises as to the possibility of obtaining a reasonable fit of FWL.

FWL

In order to understand if the FWL interpreted for Well 1 and Well 2 could be reconciled to a similar value, both wells were plotted together (Figure13). It is clearly evident that when Well 2 fits the SCAL regressions then Well 1 is plotting negative. However, with concerns about the validity of the method it was re-done using only Air-Brine, a common phi-k relationship to generate the permeability log and removal of all but the higher porosity sand. The results can be seen in (Figure 14). They show that it is still difficult to plot both wells on the same FWL although the magnitude of estimates of FWL is now closer being approximately 20 metres difference. It is not possible to say from this if there is a FWL difference or if the difference on the plot is due to log value uncertainty.

Compartments

It is not clear if compartments are due to faulting and this led to the investigation of other possible explanations. A reasonable second option was proposed which segregated the field into compartments using lateral facies variation sand trends that were derived from seismic attributes to delineate these trends away from well control. Currently two base case models are carried the first separates the field into compartments by faulting and the second which separates the field by lateral facies variation.

Production Issues

In 2010 water production at the gas plant was indicated by $CaCO_3$ scale. Over time it became clear that Henry Field was producing small amounts of formation water. The investigation showed that when Henry Field produced there is a spike in $CaCO_3$. Well 2's choke had also scaled up and during its replacement in 2013 samples of the scale were taken and analysed, showing it was 70% $CaCO_3$. It was not; however, clear if this produced water was from shallow aquifers or from the reservoir. A review of the casing and cementing of Well 2 revealed potential pathways to shallower aquifers since the cement plugs were not fully pressure tested.

Conclusion

The real success of this case study lies in collaboration. Individual subsurface disciplines have significant uncertainty but when they are integrated the optimal solution can emerge. The following list notes the key observations from each discipline.

Geophysics
- Well-2 encountered faults in Region C.
- Region C shows Class IIP AVO – interpreted as brine sands. But Class IIP AVO could also be lateral facies variation effect.

Fluid Analysis
- The saturation height function of both wells could be best explained using a dual FWLs model. But there are uncertainties in core measurements and petrophysical analysis.

Production
- Well-2 produces formation water. But the water could have come from shallower aquifers via a poor cement job.

Each individual discipline had an alternative explanation for Region C but after looking at them as a whole the most optimal solutions were fault bounding compartments and facies defined compartments. Based on the new interpretation of the field, further development drilling options are currently being assessed.

Acknowledgements

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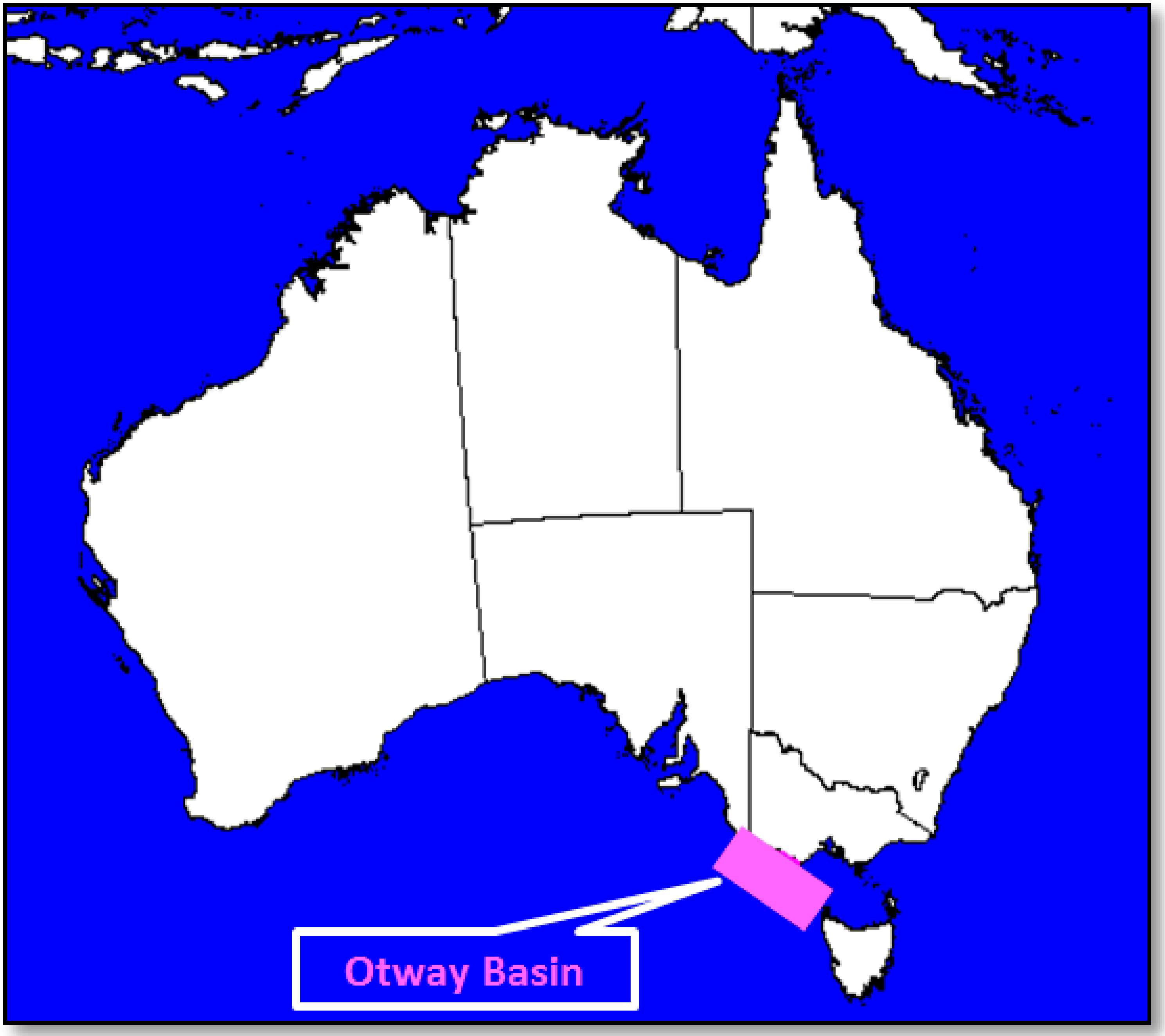


Figure 1. Otway basin location map

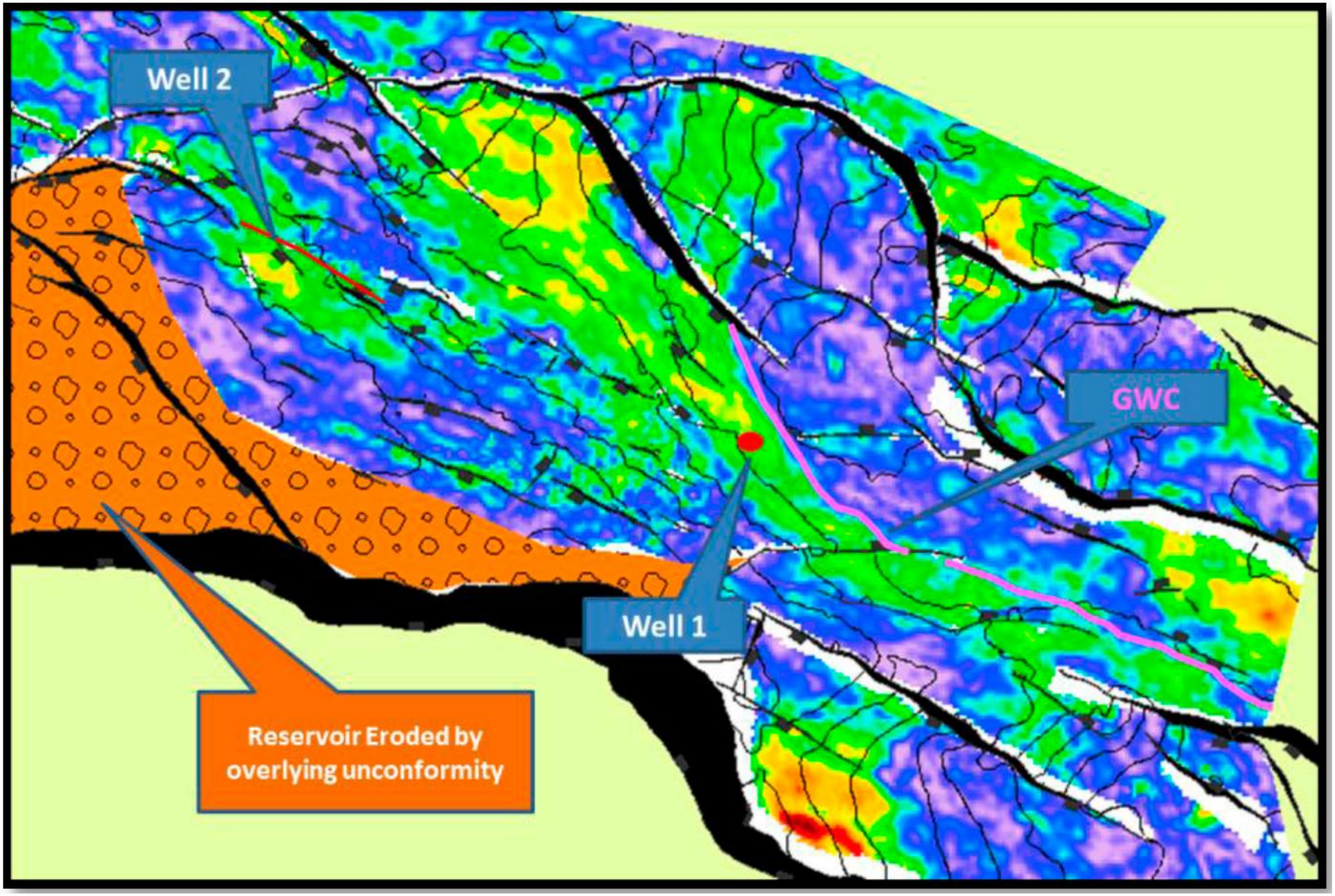
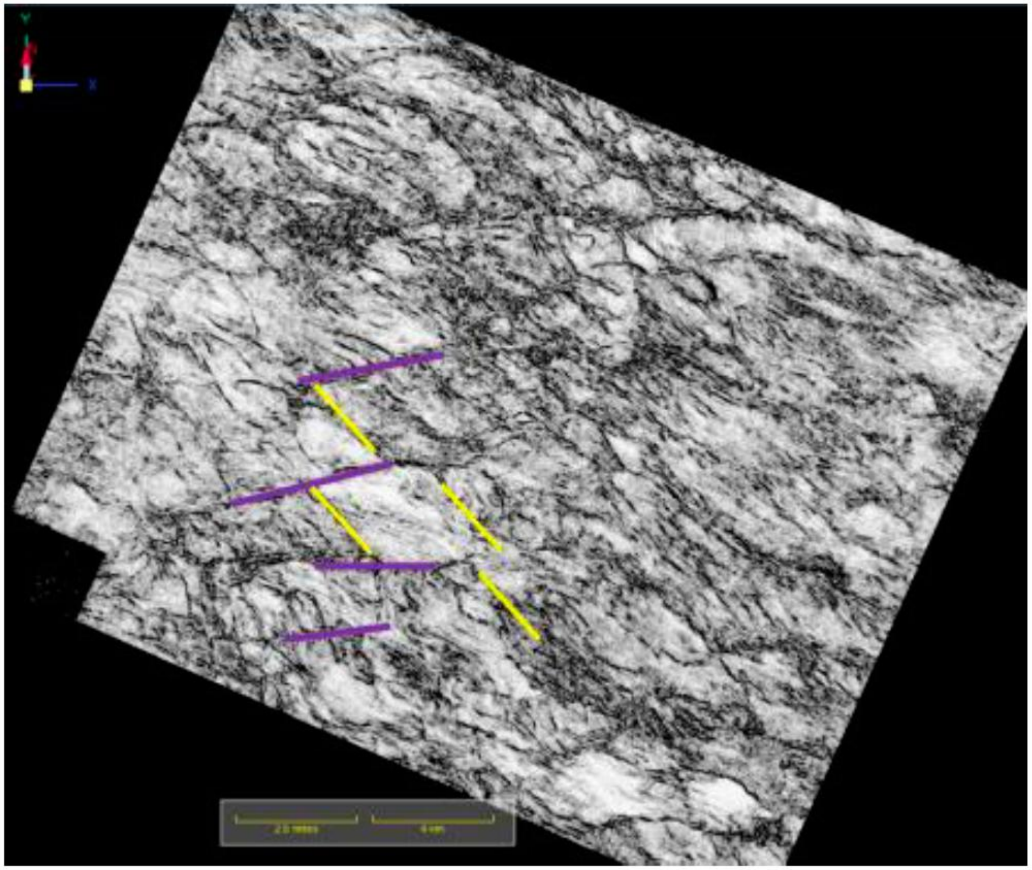
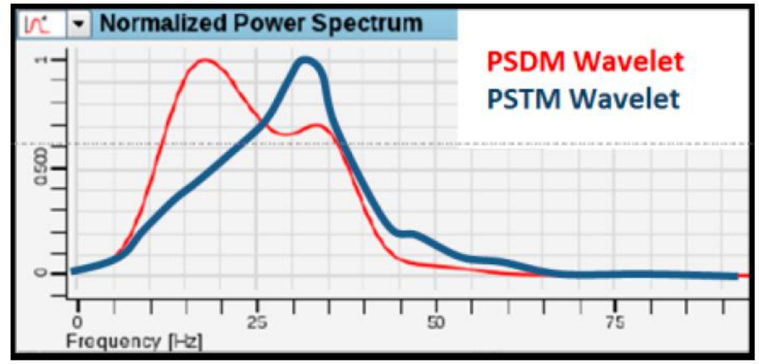


Figure 2. Reservoir RMS amplitude map and TWT contours.



a



b

Figure 3. a) Oblique fault fabric evident from a time slice off the Dip steered Coherency cube ; b) PSDM processing has preserved low frequency signals.

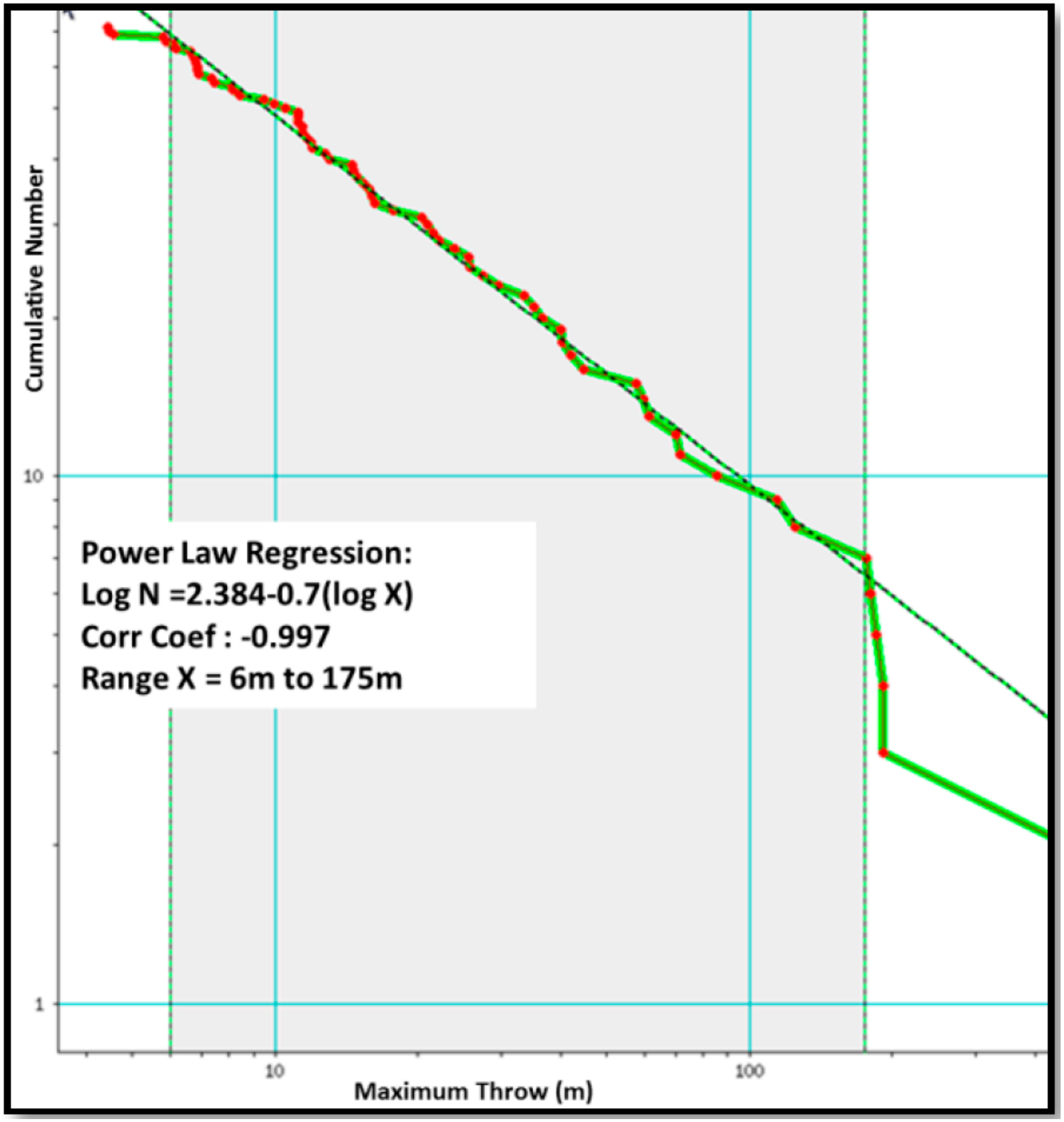


Figure 4. Log-Log plot of Maximum fault throw vs. Cumulative number

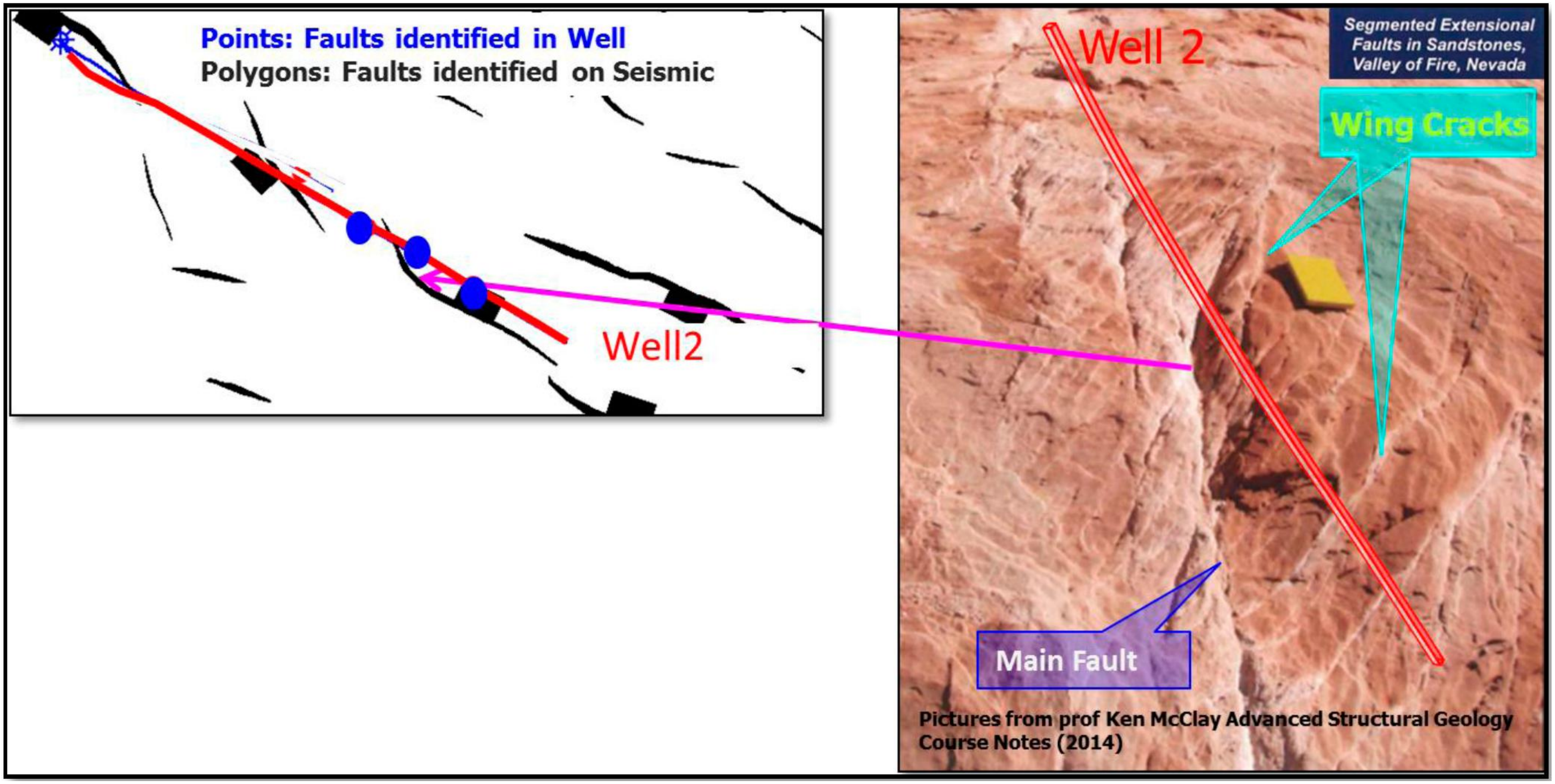


Figure 5. Schematic diagram showing the model of Well 2 intersecting a wing crack system

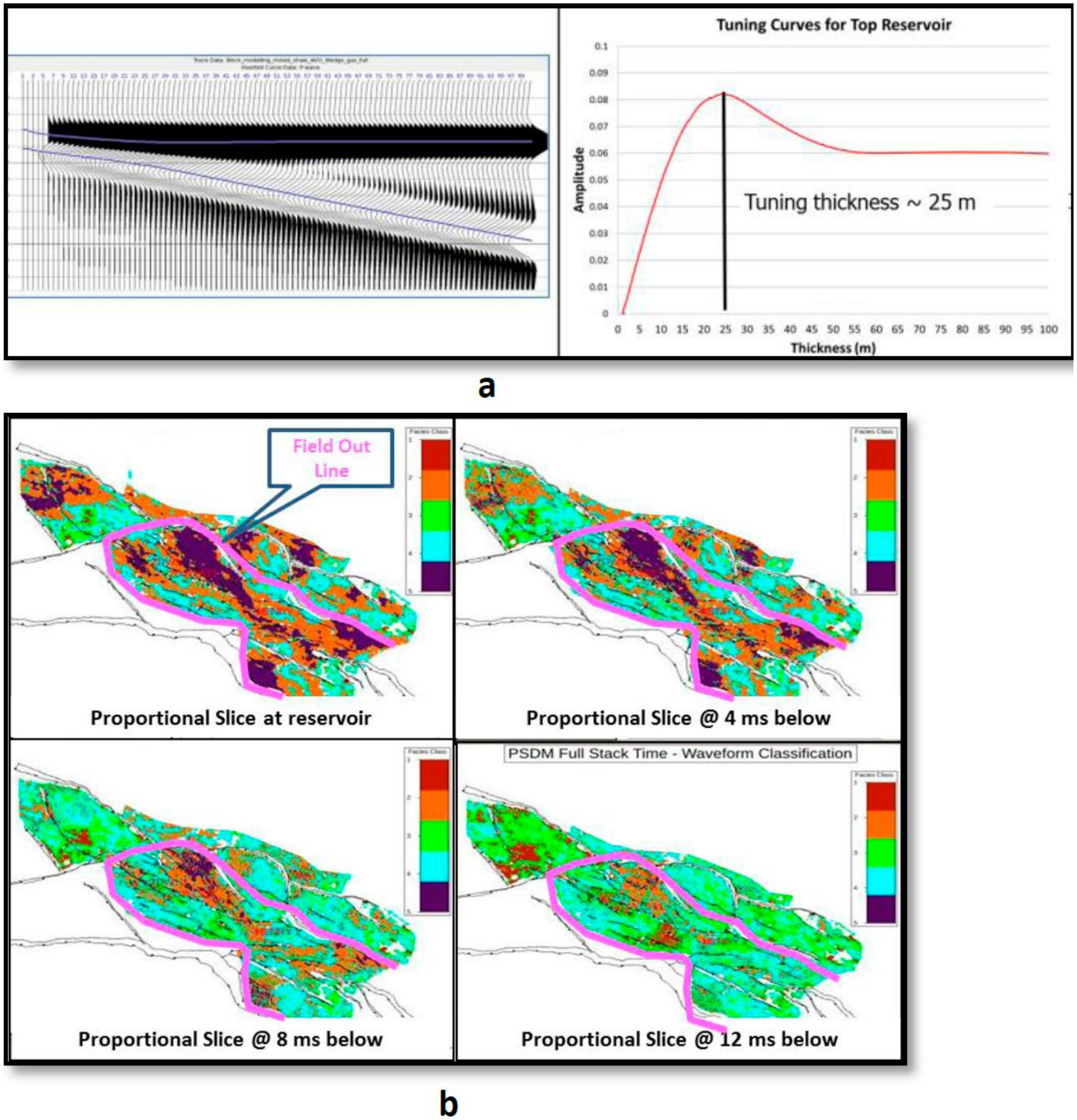


Figure 6. a) Wedge Modelling showing tunning thickness ~ 25m ; b) Proportional slices from top of reservoir to top of basement are showing the change in facies. This change has been interpreted as the change from Unit 1 reservoir rocks to Unit 2 reservoir rocks.

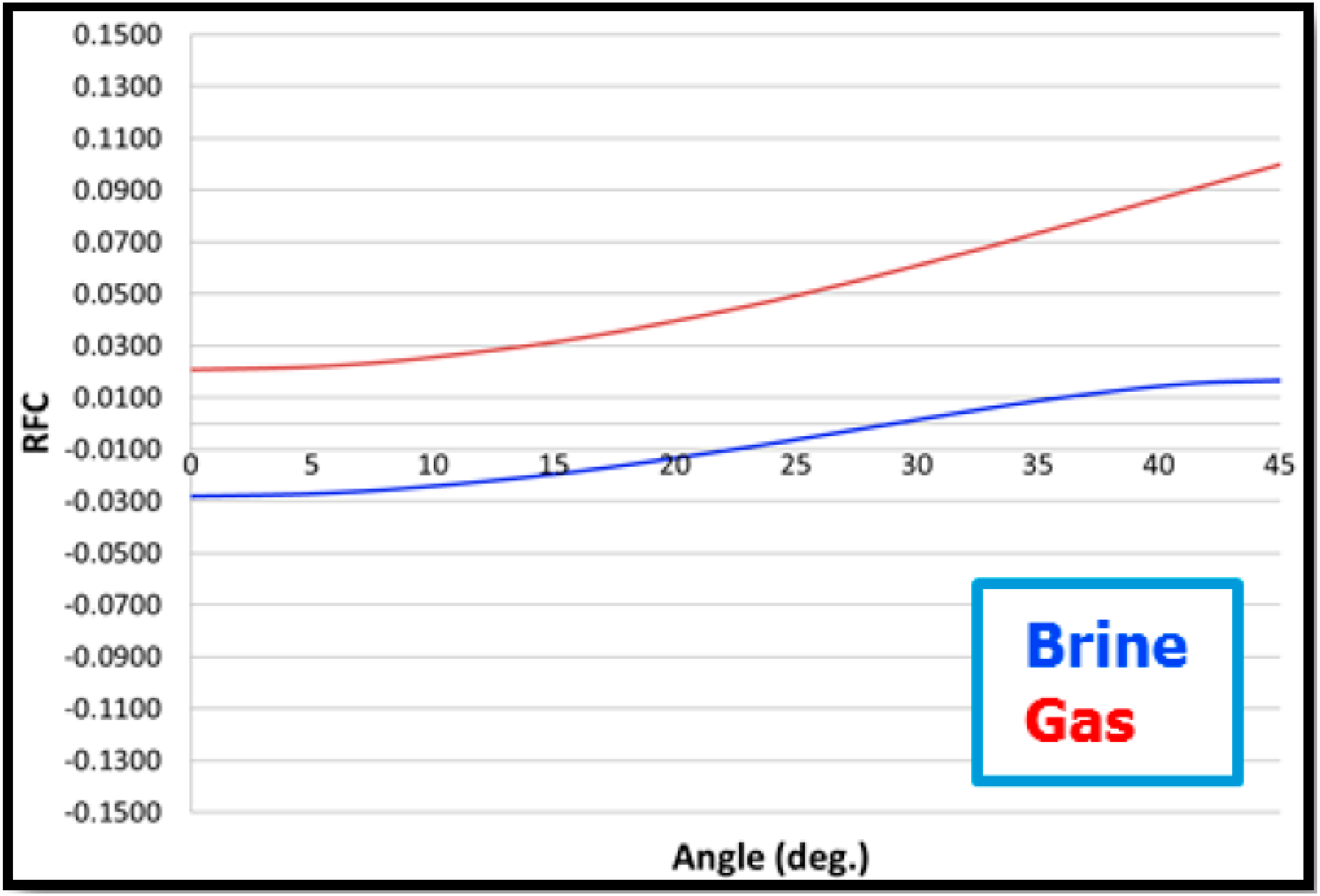


Figure 7. AVO Modelling (ASEG polarity), Gas Class II & Brine Class IIP

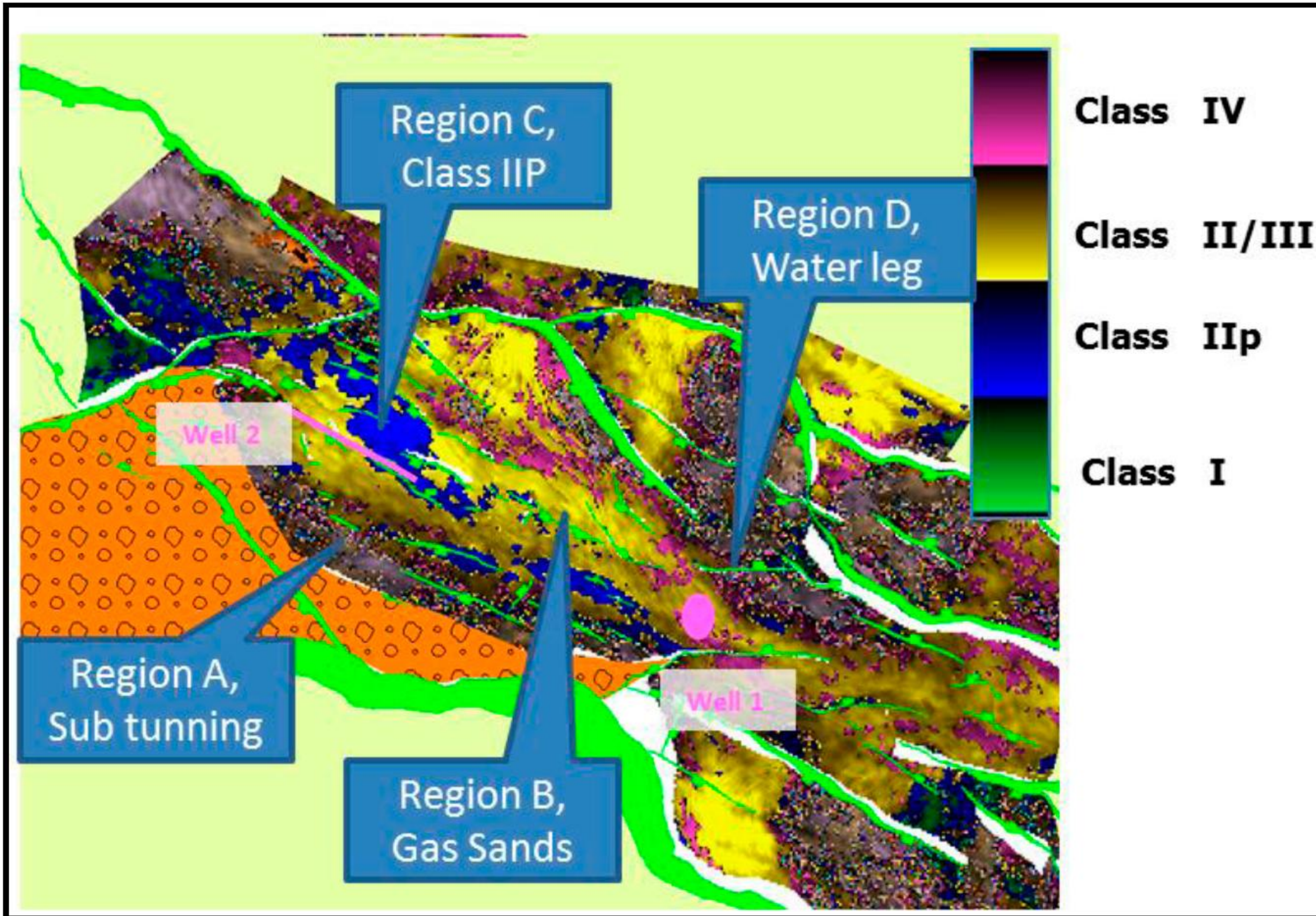


Figure 8. AVO Facies Map of the reservoir based on PSDM seismic

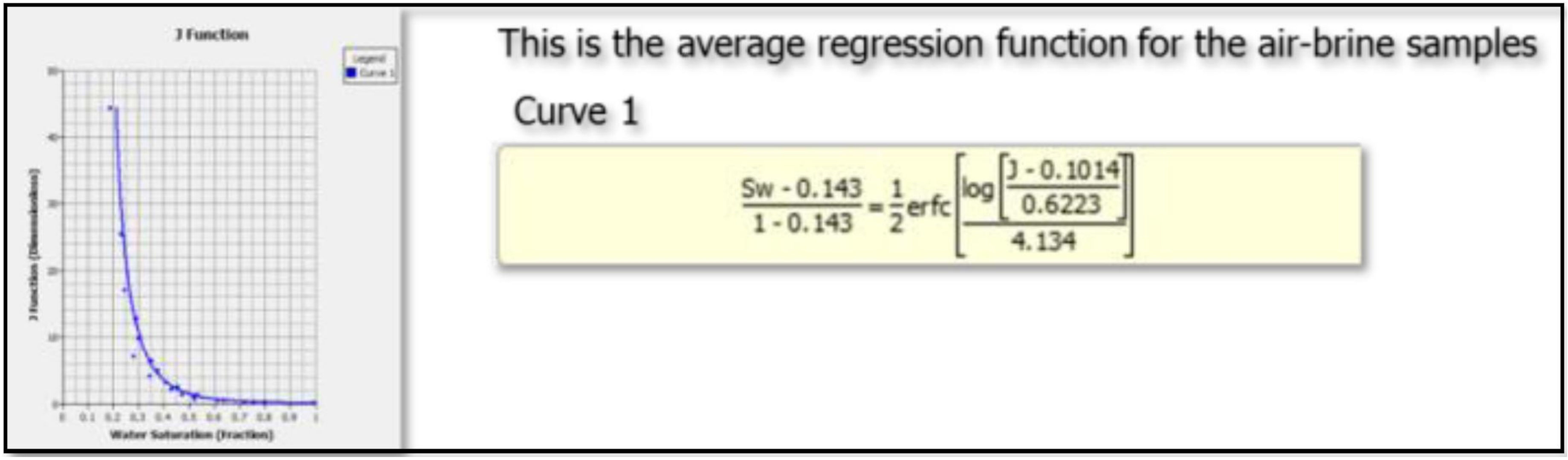


Figure 9. Air-Brine regression from Geo2FlowTM

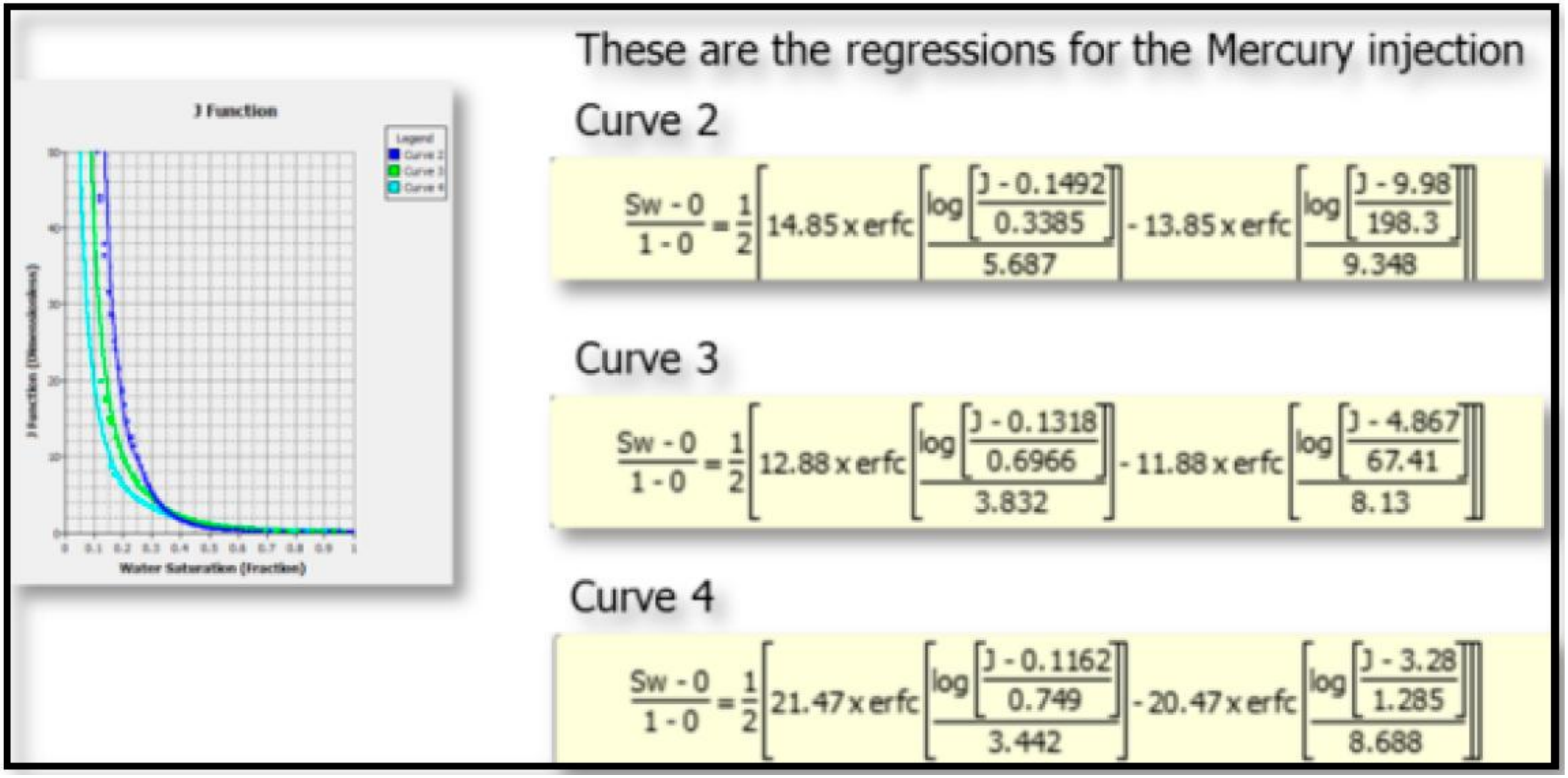


Figure 10. Mercury-Injection regressions from Geo2FlowTM.

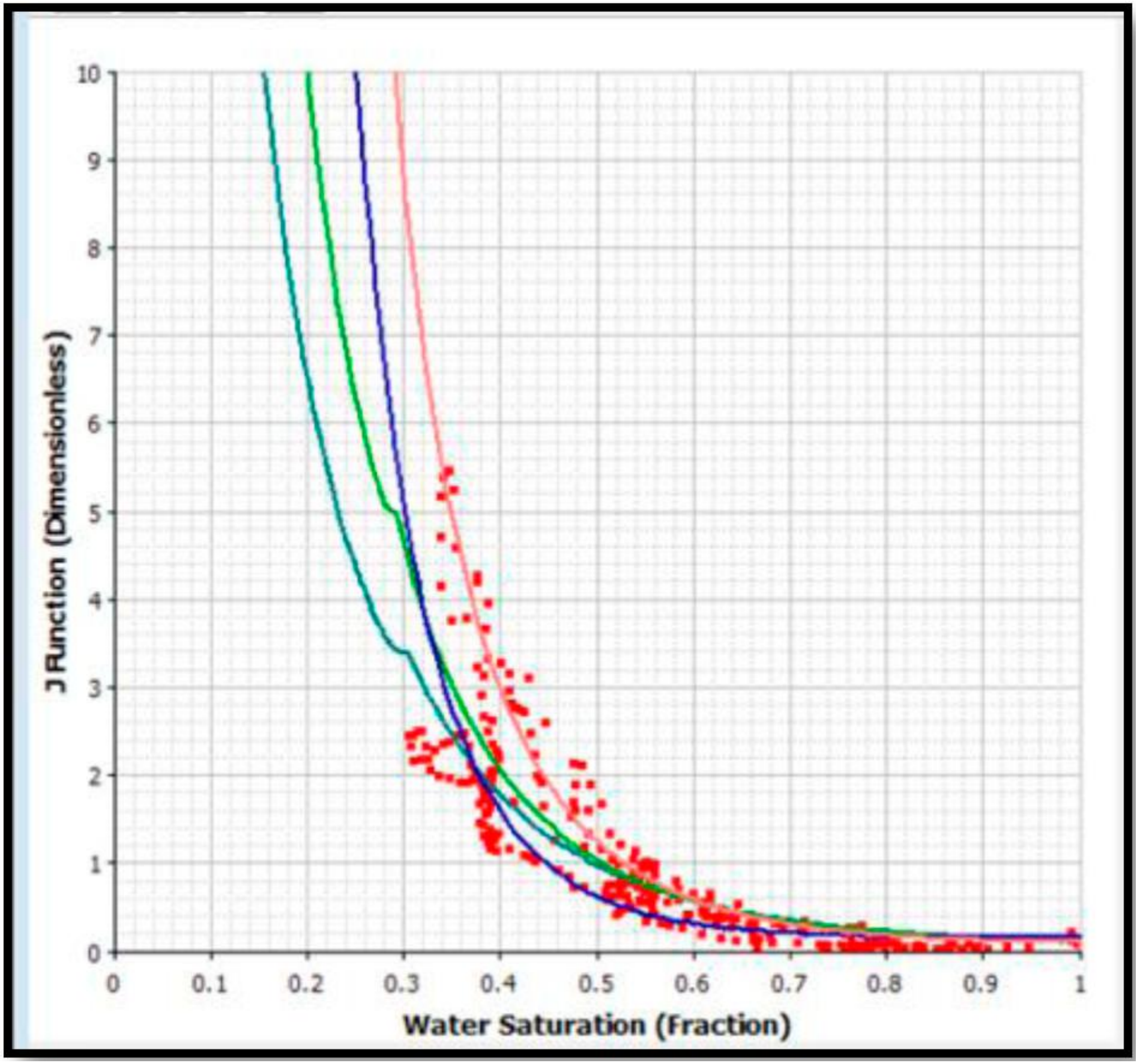


Figure 11. Well 1 plot of log to SCAL.

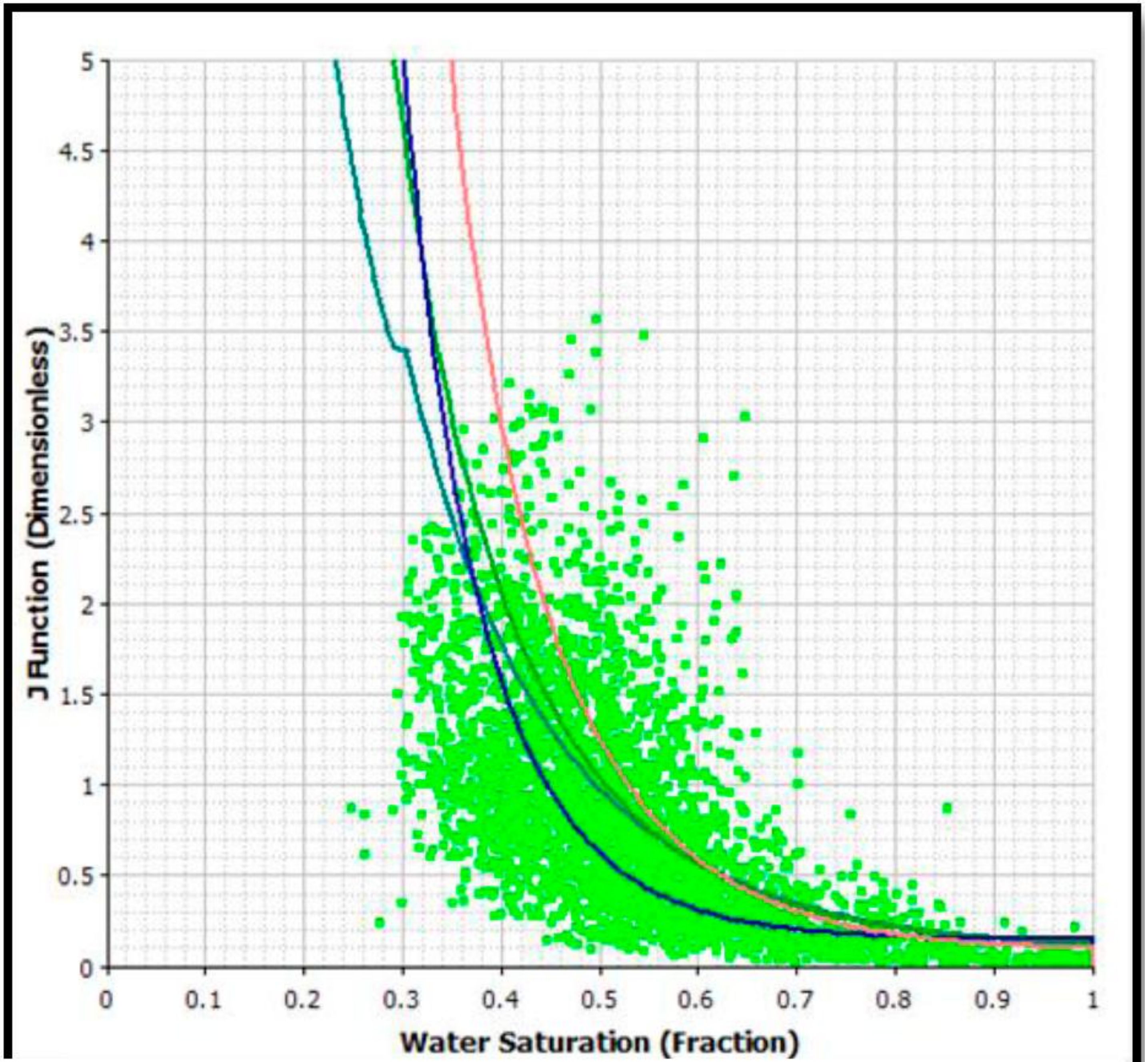


Figure 12. Well 2 plot of log to SCAL.

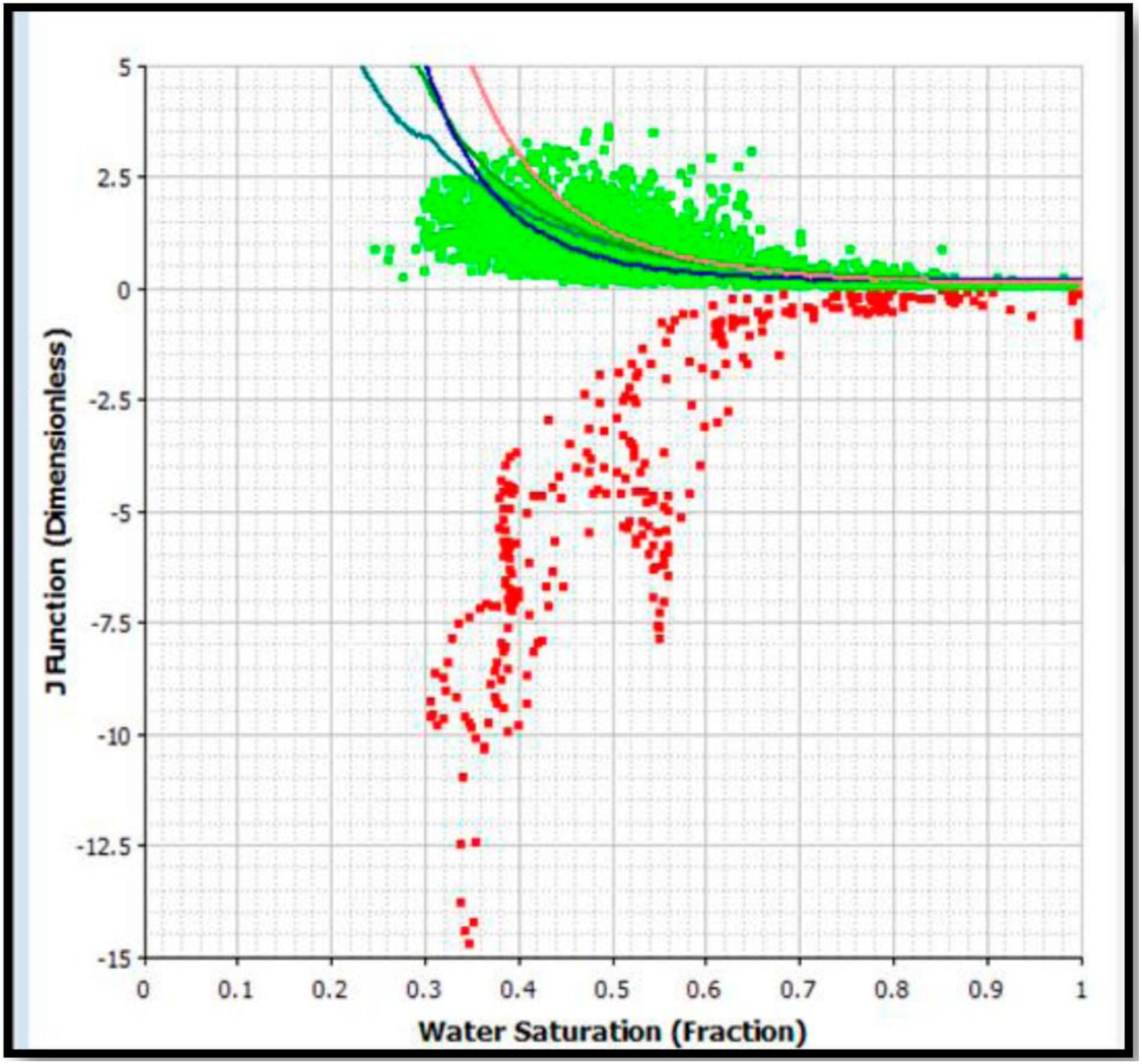


Figure 13. Plot of Well 2 and Well 1 petrophysical data and SCAL regressions.

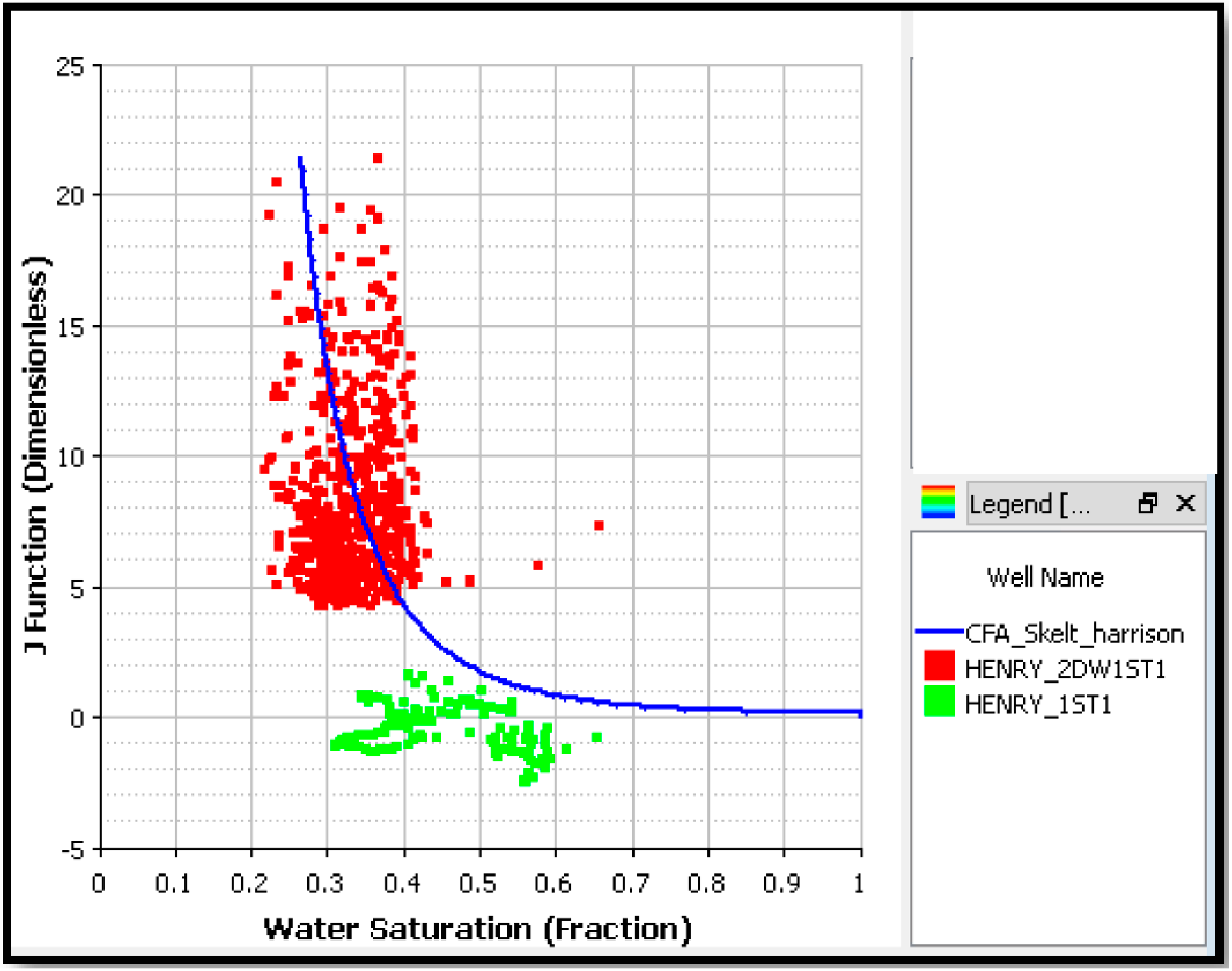


Figure 14. Plot of Well 2 and Well 1 petrophysical data and SCAL regressions.