Comparing Completions to Geology in the Cardium Formation - North Central Pembina*

Andrew Wiseman[1], Federico Krause[1], and Christopher DeBuhr[1]

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Abstract

The Cardium Formation has been the subject of extensive study since Socony Mobil Oil first struck oil in the Pembina area in 1953. Interest in the formation waned during the 1990's; however, with refinements in horizontal drilling and multistage hydraulic fracing techniques, interest has been rekindled. New drilling targets are thinner, lower quality reservoirs that require a greater understanding of subtle variability of reservoir quality and geometry. We use petrophysical, petrological and production analysis techniques to define a geological framework, characterize the reservoir interval, and examine the effectiveness of different completion techniques. Well logs from over 800 wells and core analyses from 440 wells were used to map the formation and identify conglomeratic intervals. Ten cores were logged to characterize lithofacies. Grain size, XRD, EDX, and CL analyses were conducted on each lithofacies. New and innovative Variable Pressure Environmental Field Emission Microscopy techniques were developed to identify and observe difficult-to-image clays and to conduct rock-fluid interaction experiments. Subsurface mapping revealed that only datums below the sandstones provide a realistic basinward-dipping geometry, and 3 upward-cleaning sandstone clinoforms were identified. The upper clinoforms have their thickest sandstone intervals in more basinward positions than the underlying clinoforms, indicating basinward progradation. Petrological findings include XRD and BSE identification of kaolinite, illite, and mixed layer kaolinite-smectite clays. Quartz overgrowths have been shown to increase grain size and completely occlude porosity within some sandstone-filled burrows. Comparisons between lithofacies and grain-size analyses have revealed a clear inverse relationship to water saturation, such that as grain size increases and shale content decreases, water saturation also decreases. This relationship holds despite the very slight grain-size difference observed between lithofacies.

A total of 126 horizontal wells were used for production analysis. Wells were grouped and compared based on pay thickness, number of fraced stages, and completion fluid. While no positive correlation between pay thickness and production has been observed, there is a strong correlation between completions technology and 1st year production. This is best demonstrated by a 39% increase in 12-month cumulative production in wells with greater than 20 fraced stages.

References Cited

Krause, F.F., K.B. Deutsch, S.D. Joiner, J.E. Barclay, R.L. Hall, and L.V. Hills, 1994, Cretaceous Cardium Formation of the Western Canada sedimentary basin: Calgary, Alberta, Canada, Alberta Research Council, Edmonton, Alberta, Canada: Canadian Society of Petroleum Geologists, Calgary, Alberta, Canada, Chapter 23.

Krause, F.F., and D.A. Nelson, 1984, Storm event sedimentation: Lithofacies association in the Cardium Formation, Pembina area, West-Central Alberta, Canada: Canadian Society of Petroleum Geologists Memoir 9, p. 485-511.

Website

Alberta Geological Survey, Geological Atlas of the Western Canada Sedimentary Basin: Website accessed October 5, 2013. http://www.ags.gov.ab.ca/graphics/atlas/fg23_04.jpg

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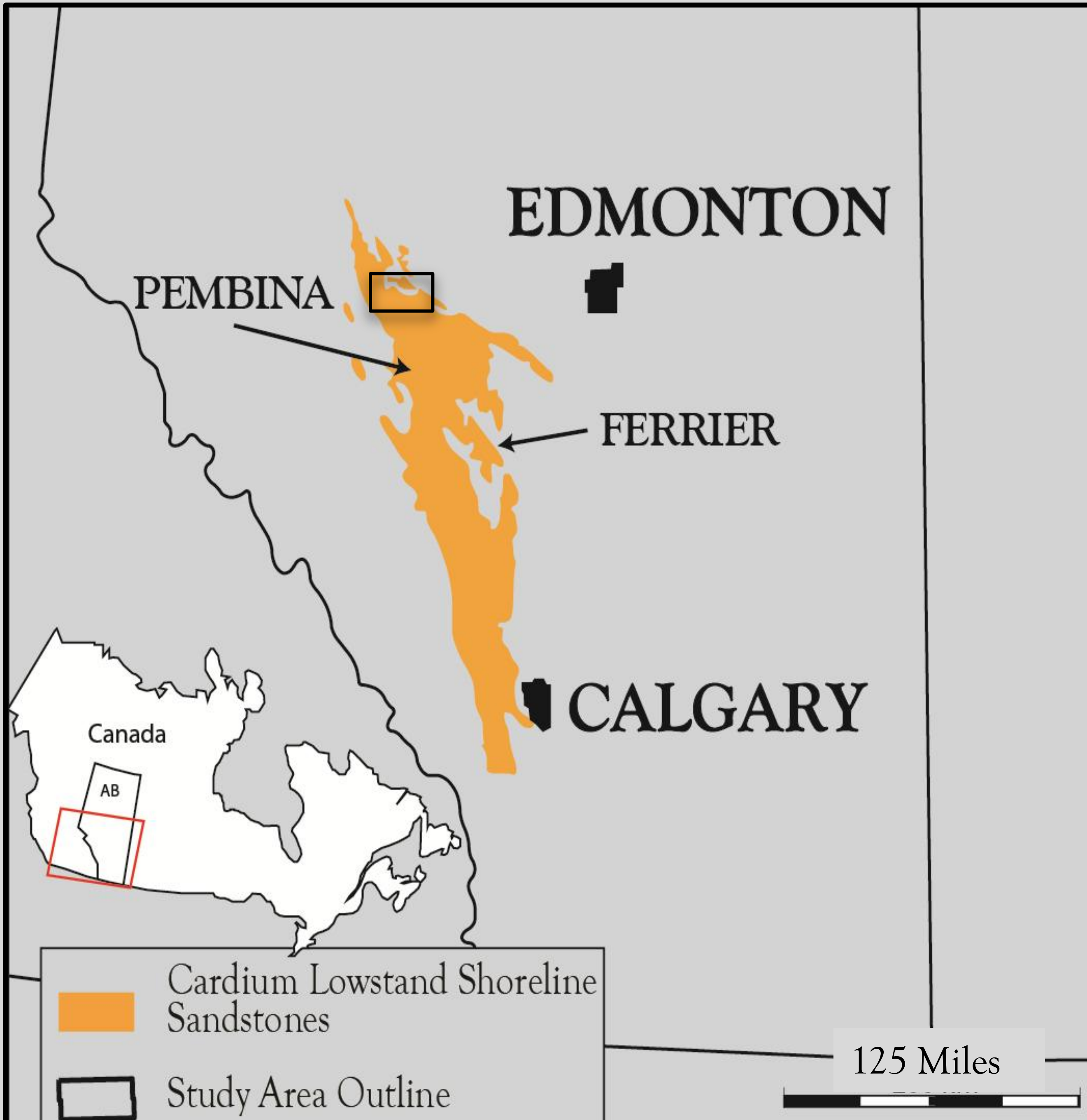
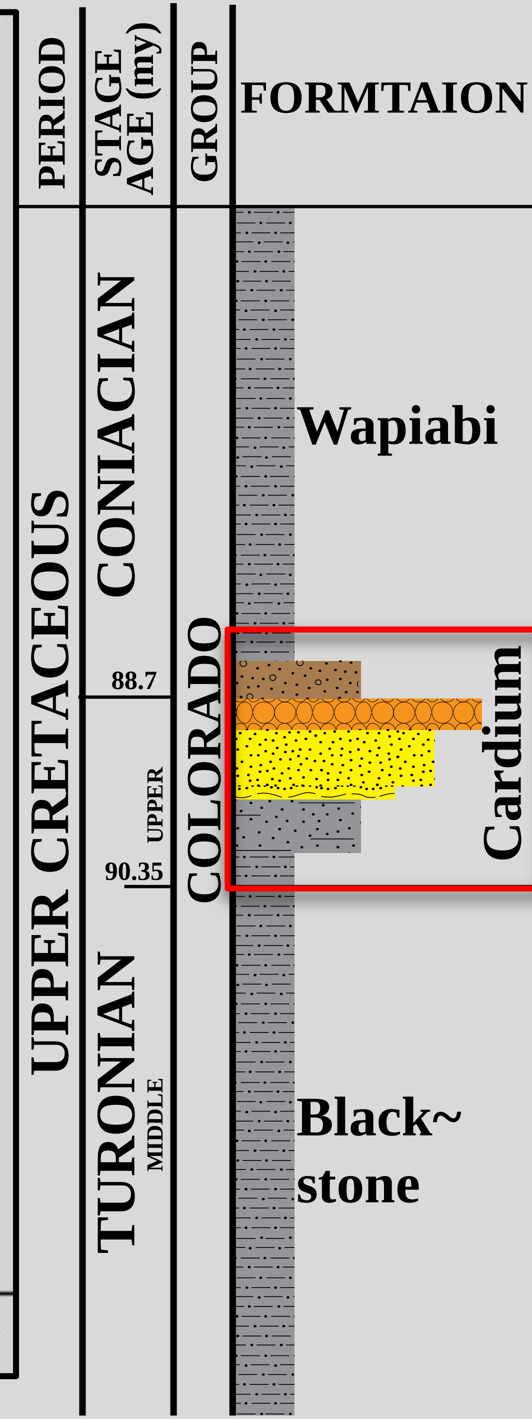
UNIVERSITY OF CALGARY

O T C

AGENDA

- **STUDY AREA INTRODUCTION**
  - Importance of Study Area
- **GEOLOGY**
  - Geological Mapping
  - Porosity/ Permeability trends
  - Clay mineralogy
  - Fluid Sensitivity
- **PRODUCTION**
  - Geology
  - Completions





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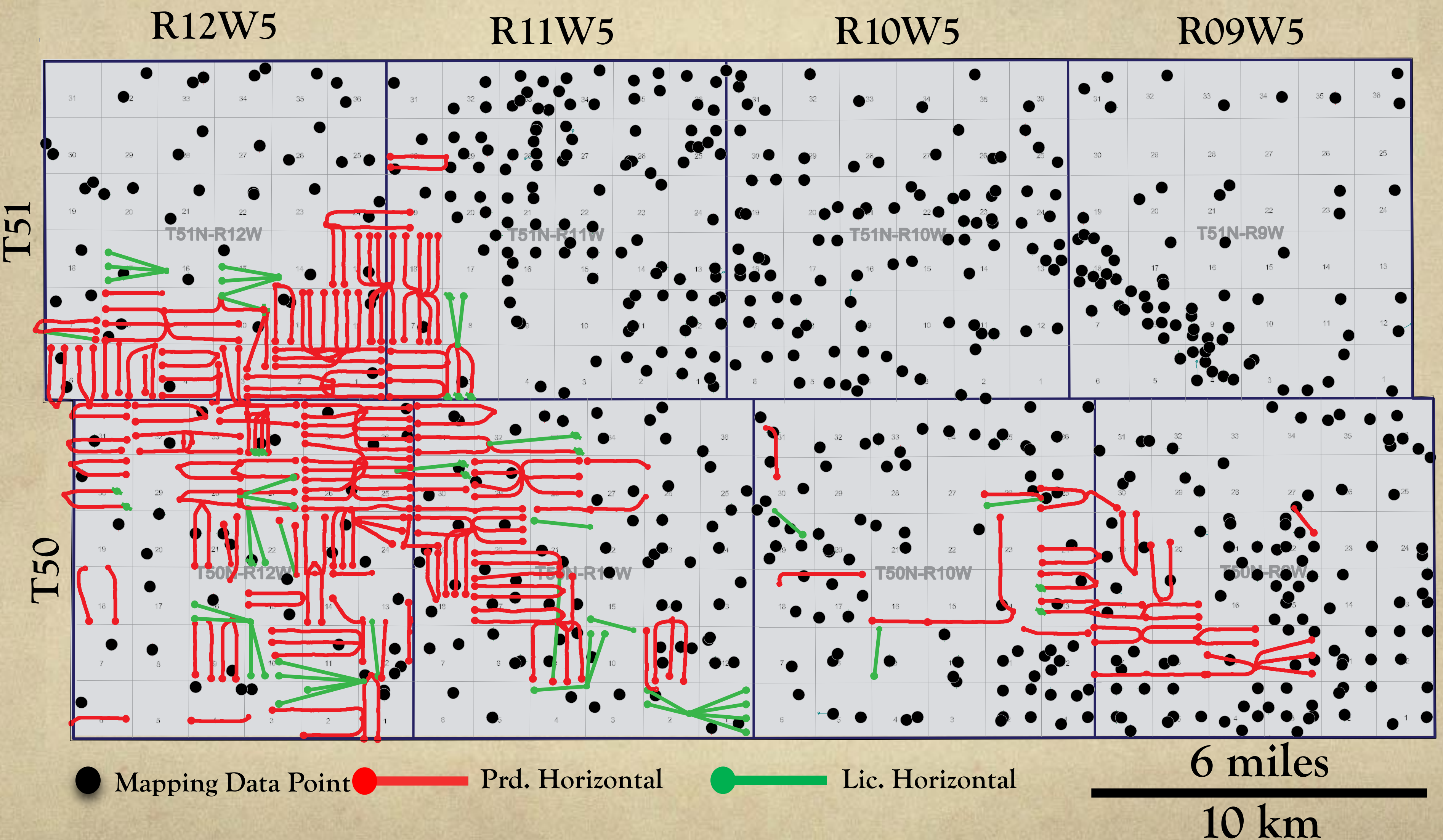
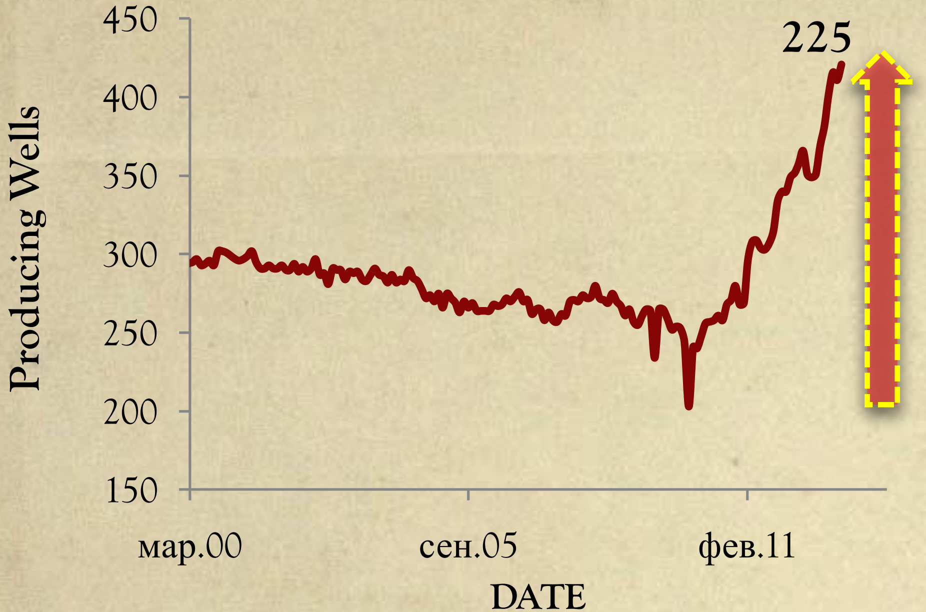
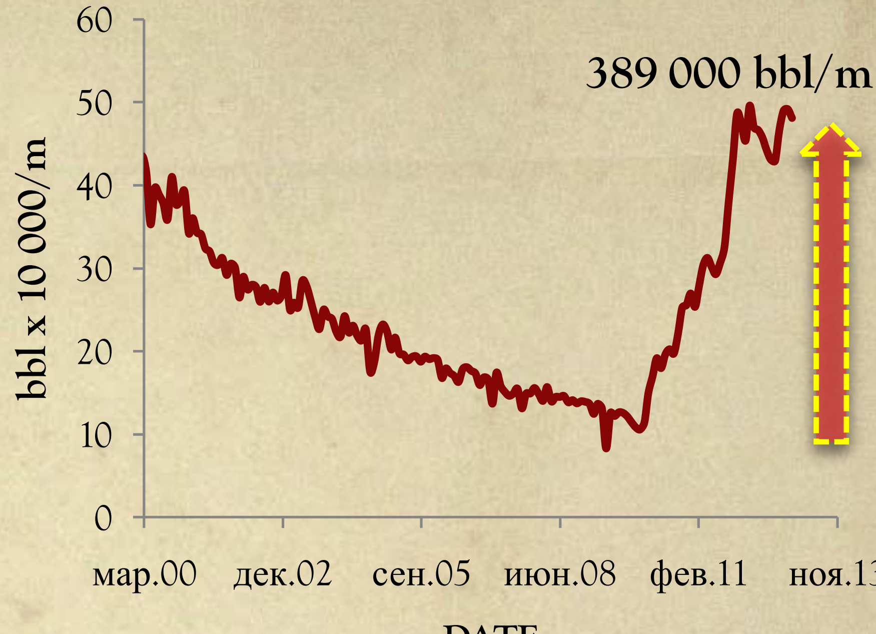
STUDY AREA

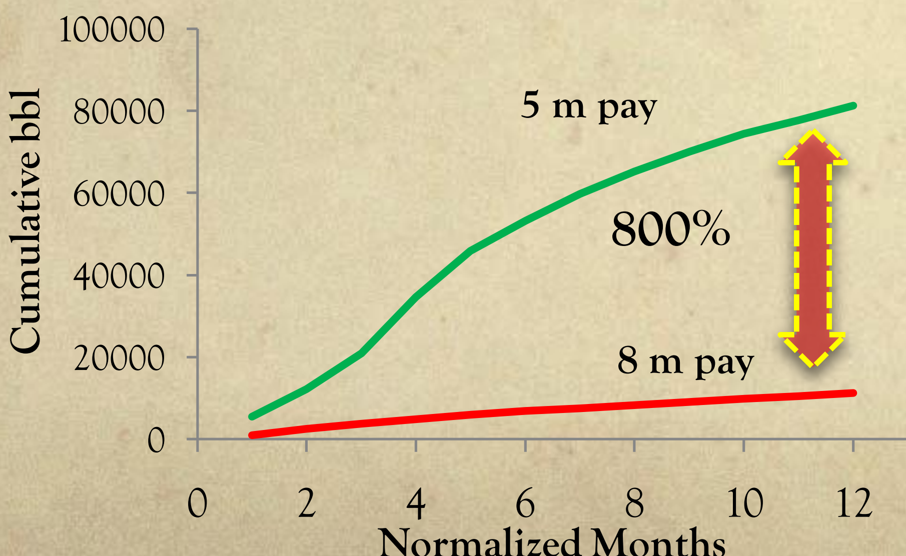


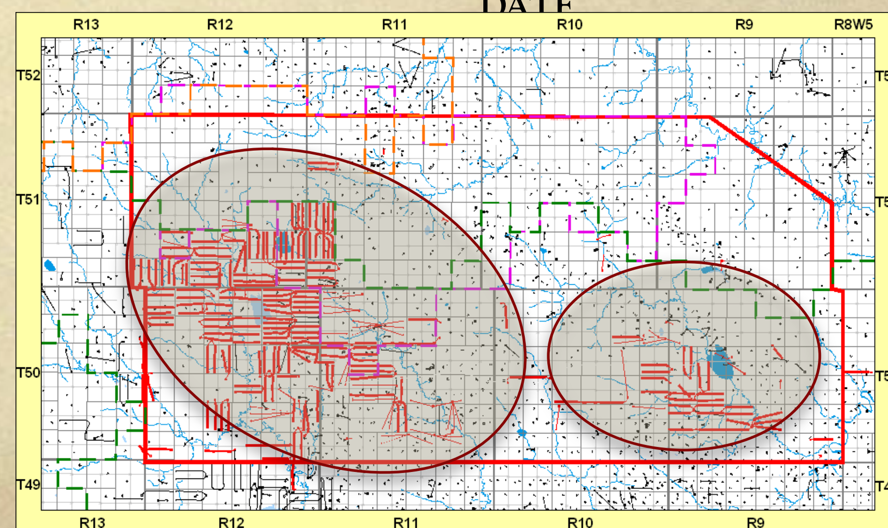
R12W5
R11W5
R10W5
R09W5
T51
T50
T51N-R12W
T51N-R11W
T51N-R10W
T51N-R9W
T50N-R10W
Mapping Data Point
Prd. Horizontal
Lic. Horizontal
6 miles
10 km

WHY SHOULD I CARE?





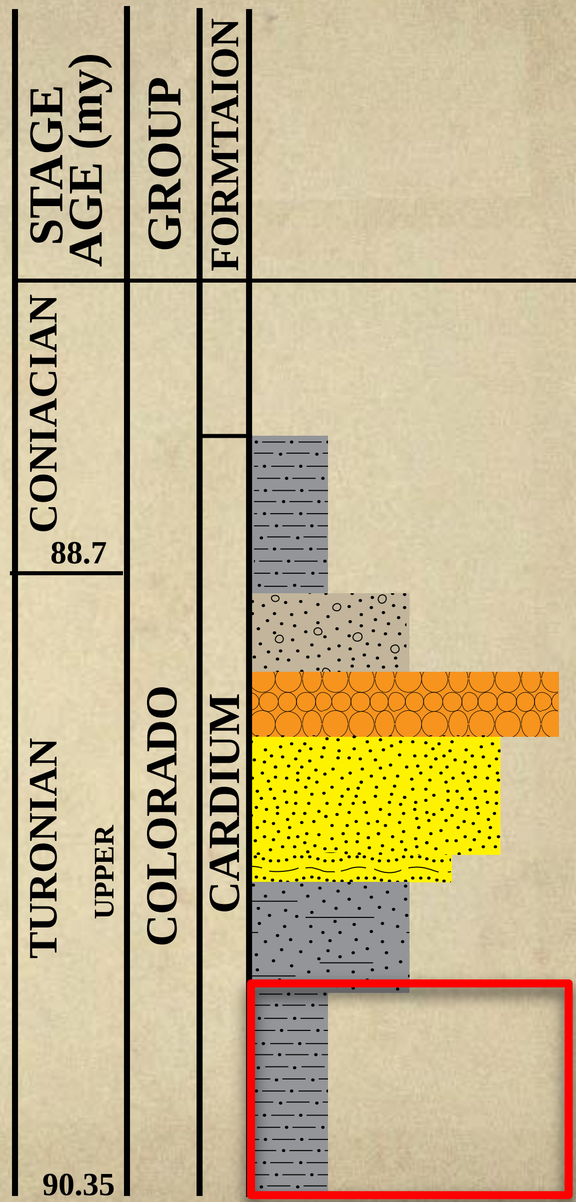




GEOLOGY

LITHOFACIES

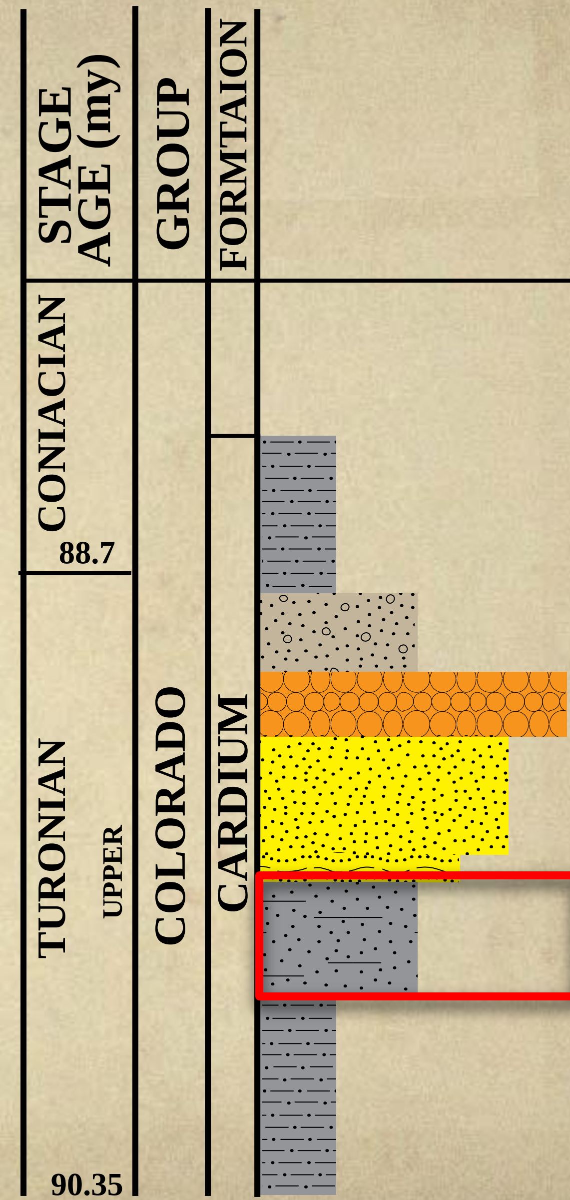
- 6 Lithofacies Identified
  1. Dark Grey Shale & Wacke



Modified from Krause and Nelson, 1984

LITHOFACIES

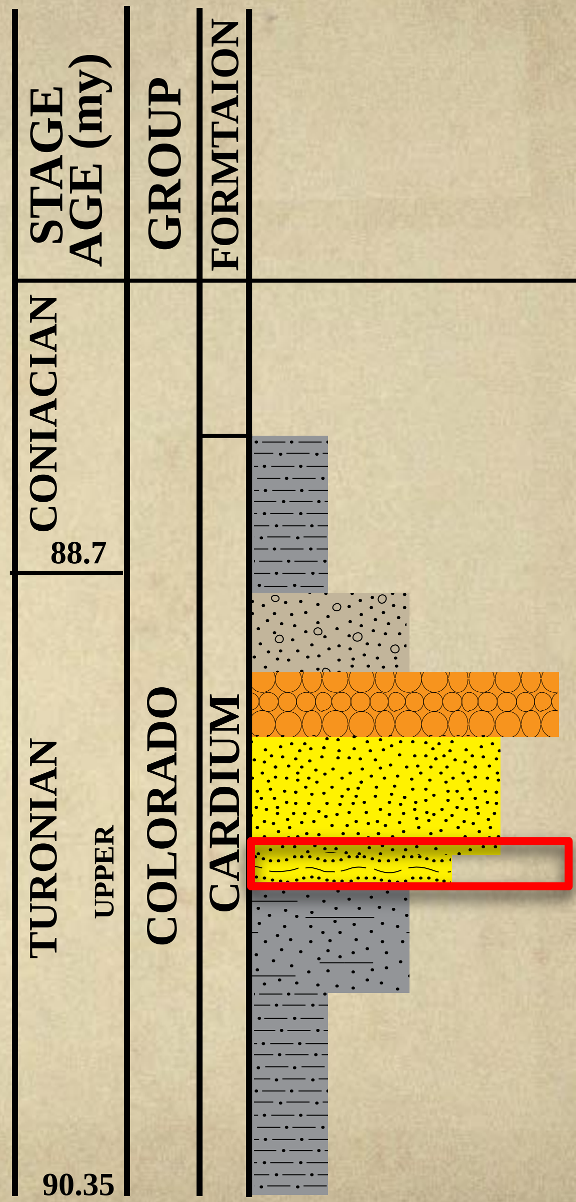
- 6 Lithofacies Identified
  1. Dark Grey Shale & Wacke
  2. Bioturbated Wacke



Modified from Krause and Nelson, 1984

LITHOFACIES

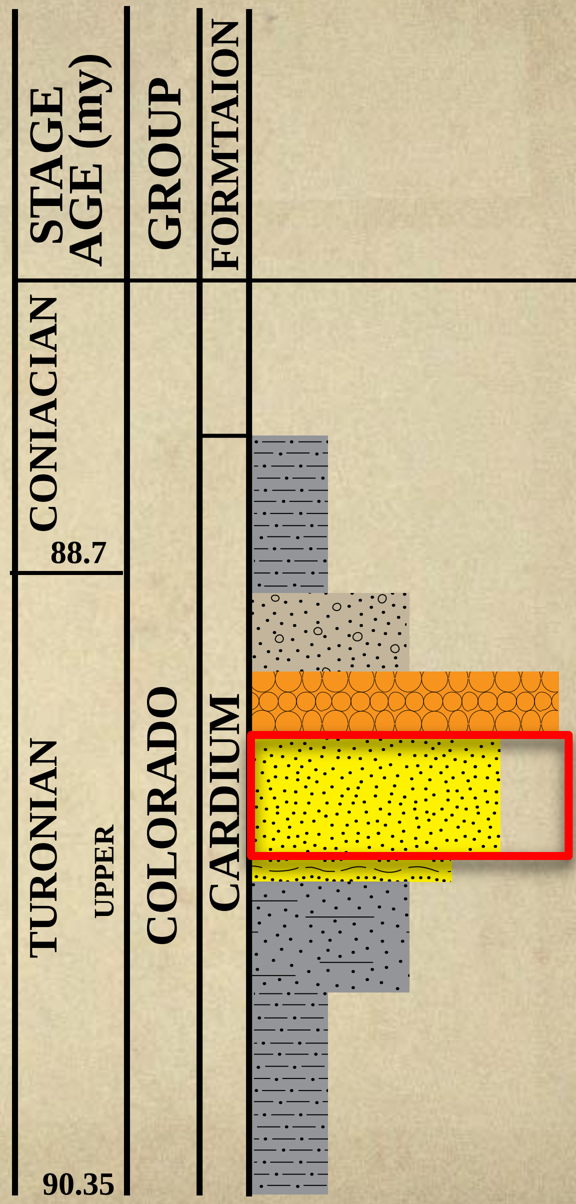
- 6 Lithofacies Identified
  1. Dark Grey Shale & Wacke
  2. Bioturbated Wacke
  3. Thinly interbedded VF-grained SS & muds



Modified from Krause and Nelson, 1984

LITHOFACIES

- 6 Lithofacies Identified
  1. Dark Grey Shale & Wacke
  2. Bioturbated Wacke
  3. Thinly interbedded VF-grained SS & muds
  4. Medium to thick-bedded, VF-F-grained SS



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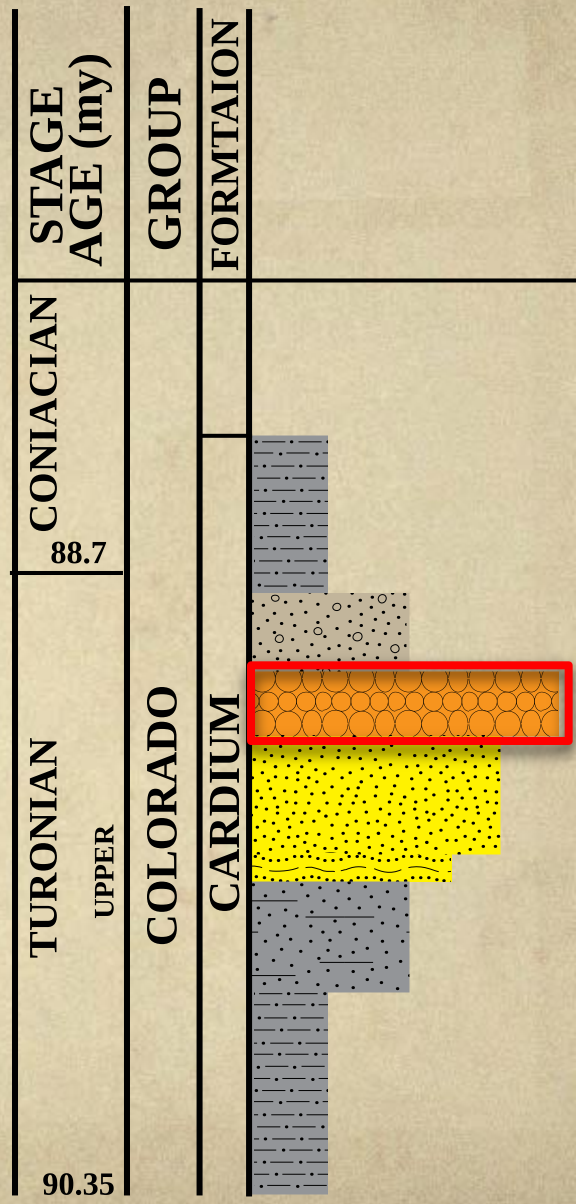
  5. Conglomerate



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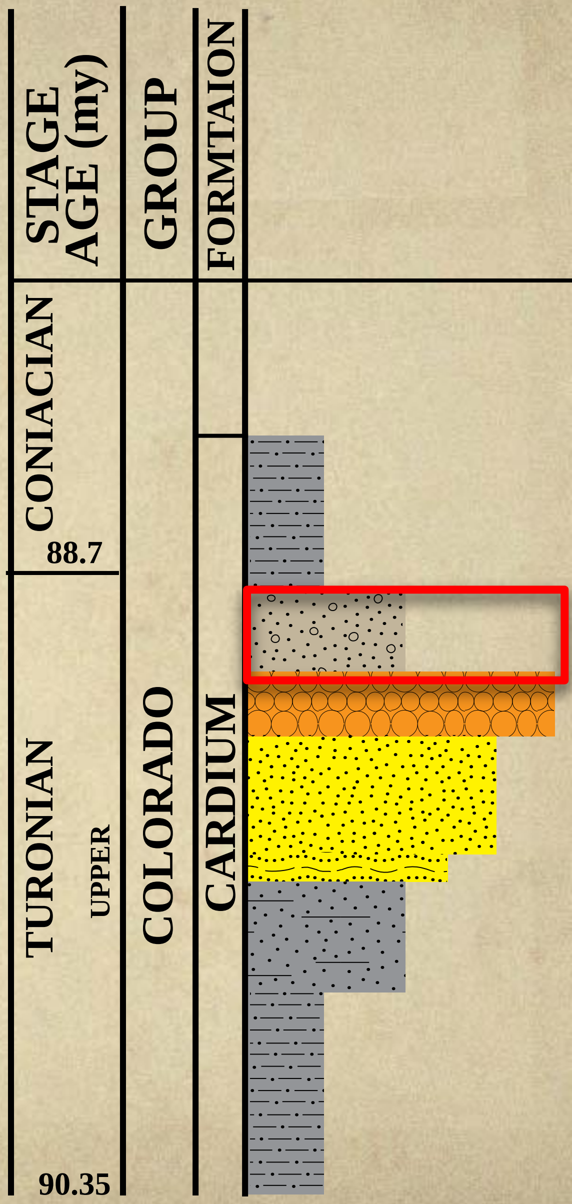
  5. Conglomerate
  6. Pebbly Mudstone



Modified from Krause and Nelson, 1984

CONVENTIONAL RESERVOIR

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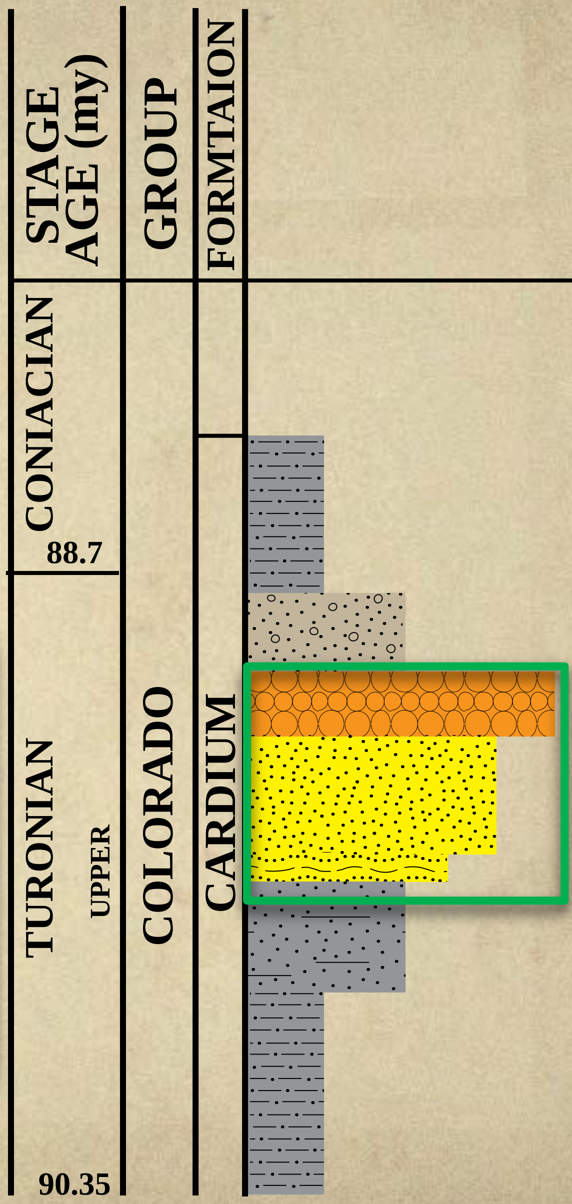

Modified from Krause and Nelson, 1984

UNCONVENTIONAL RESERVOIR

- 6 Lithofacies Identified
  1. Dark Grey Shale & Wacke
  2. Bioturbated Wacke
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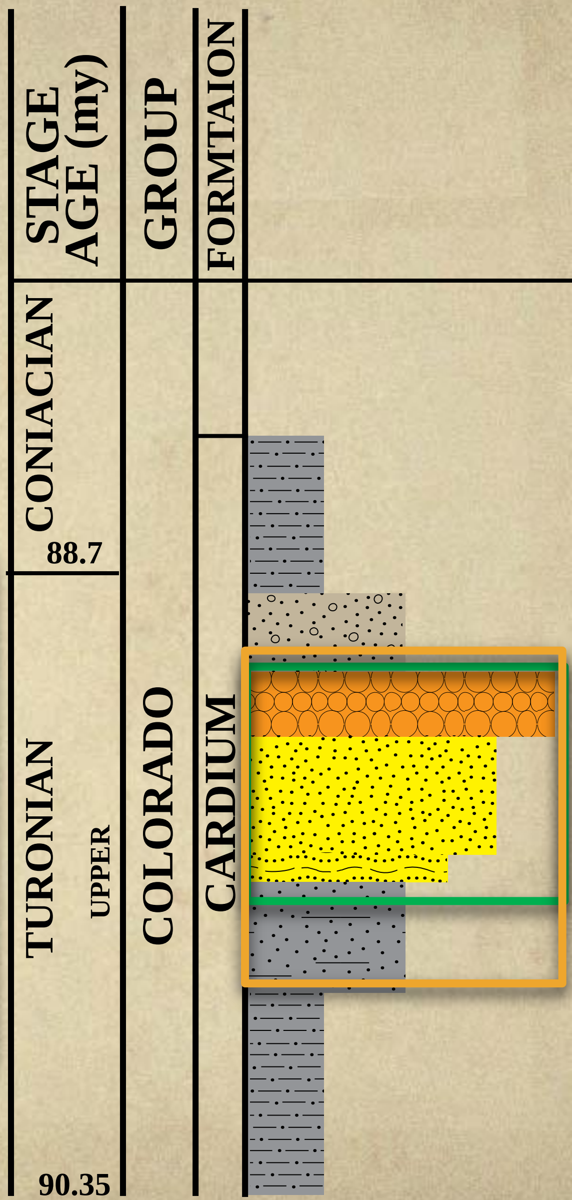
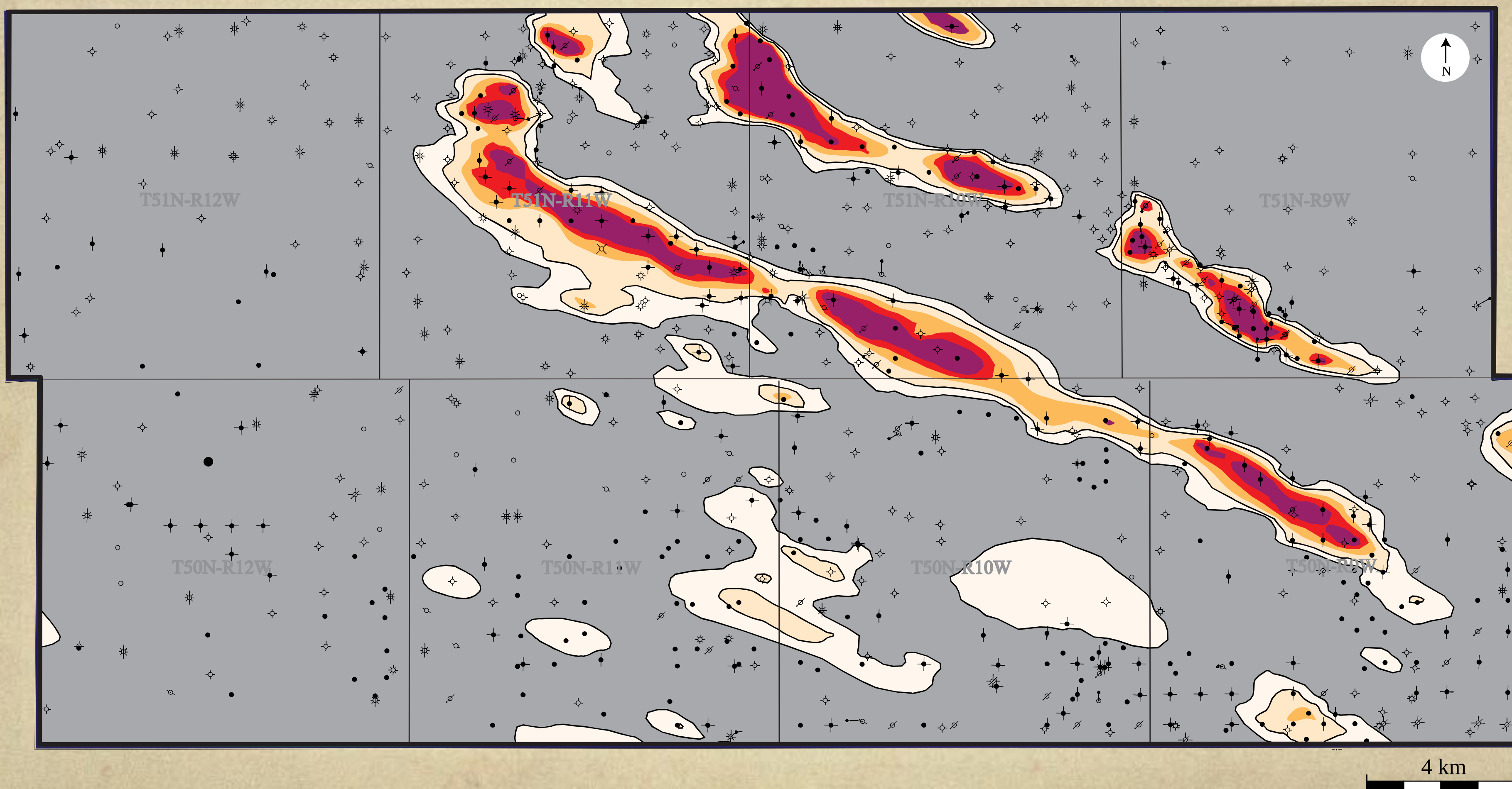
  4. Medium to thick-bedded, VF-F grained SS
  5. Conglomerate
  6. Pebbly Mudstone



Modified from Krause and Nelson, 1984

CONGLOMERATE



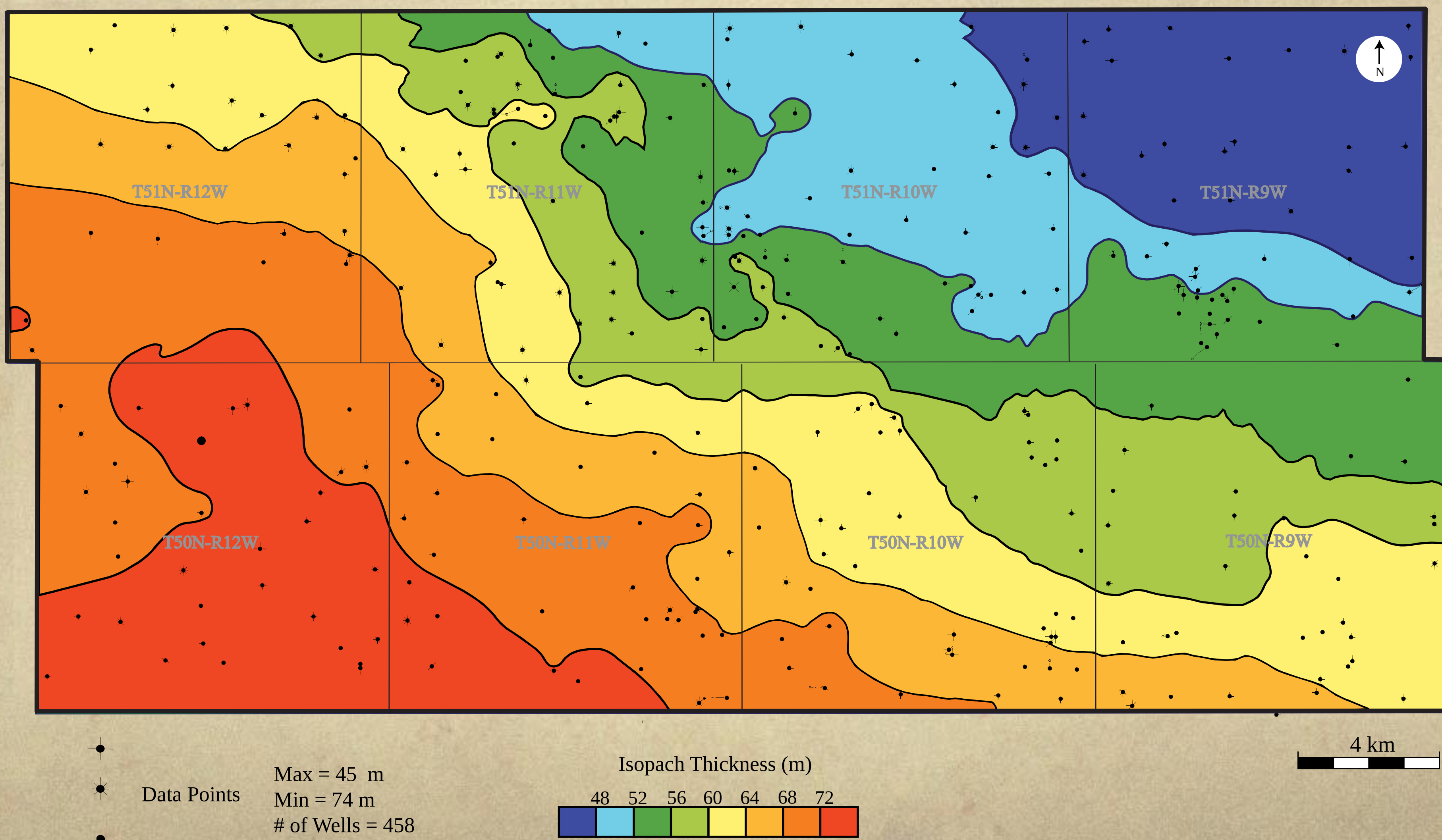
Data Points
@
Well locations

Max = 17.6 m
Min = 0 m
# of Wells = 1086
W CGL = 277

Conglomerate Thickness (m)

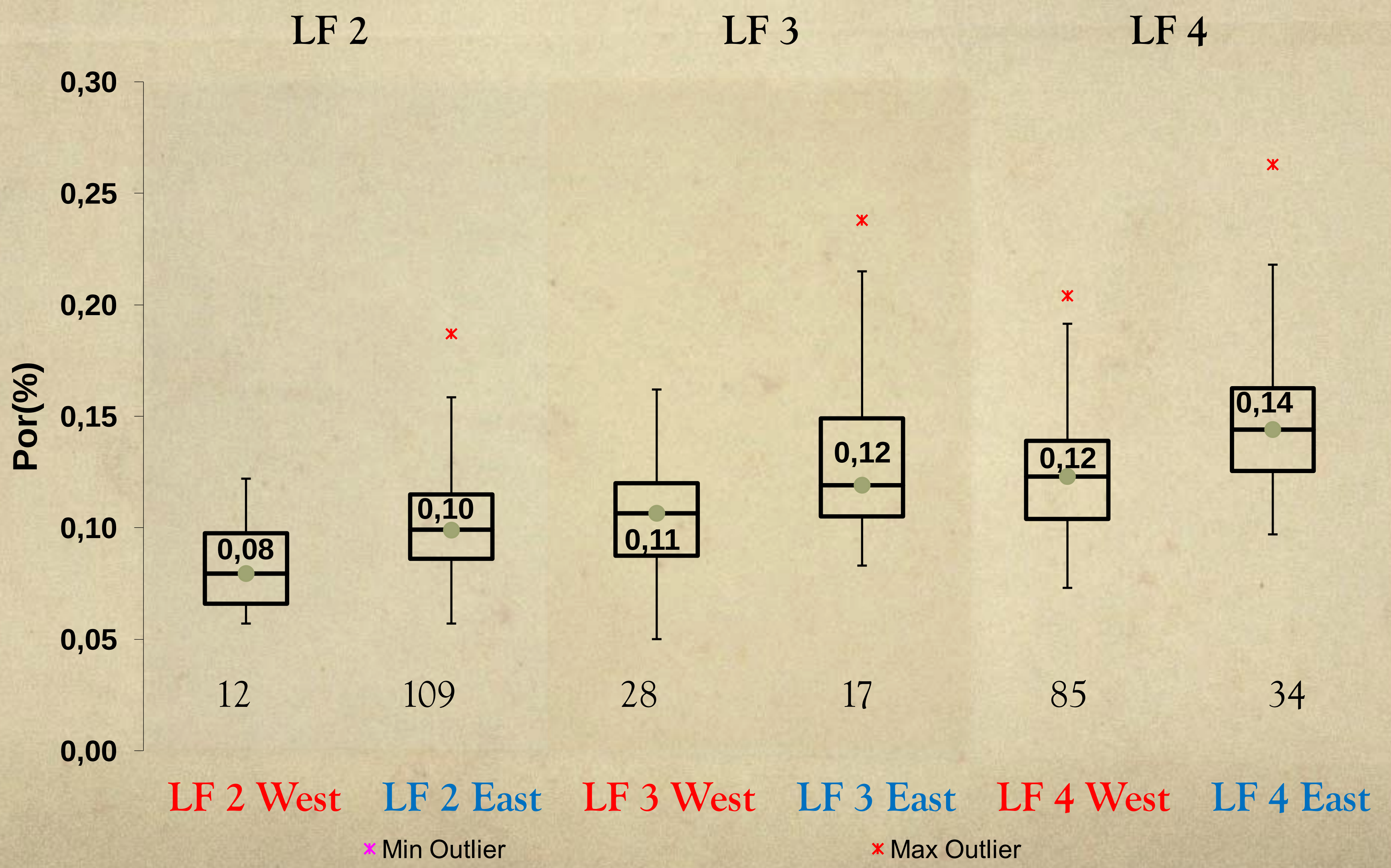
STRATIGRAPHIC MAP

Russian Marker – Cardium SS

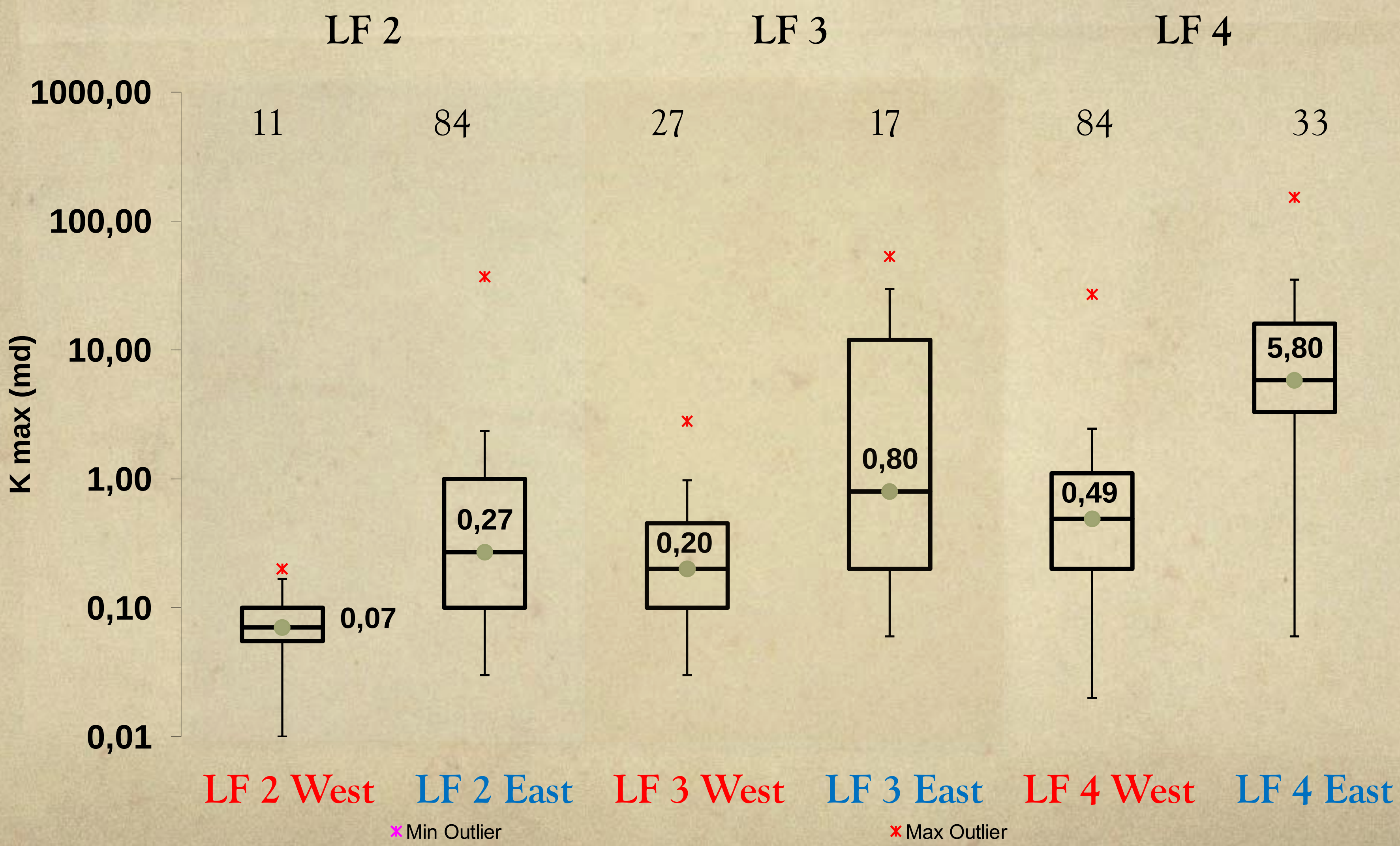


POROSITY
&
PERMEABILITY

POROSITY VARIABILITY



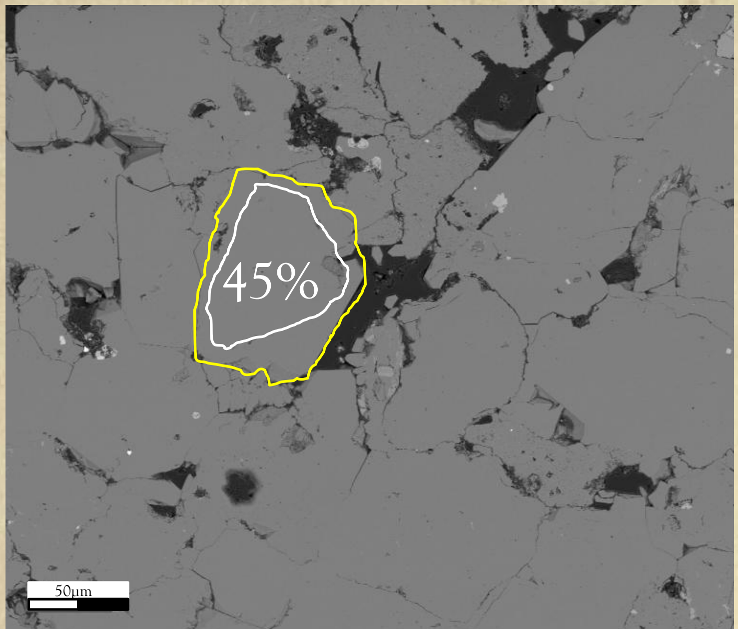
PERMEABILITY VARIABILITY

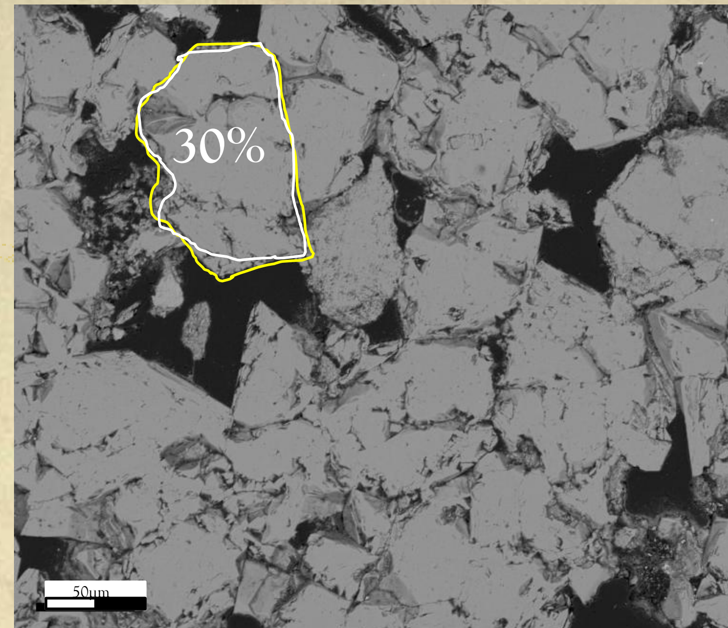


13-04-50-12W5
WEST

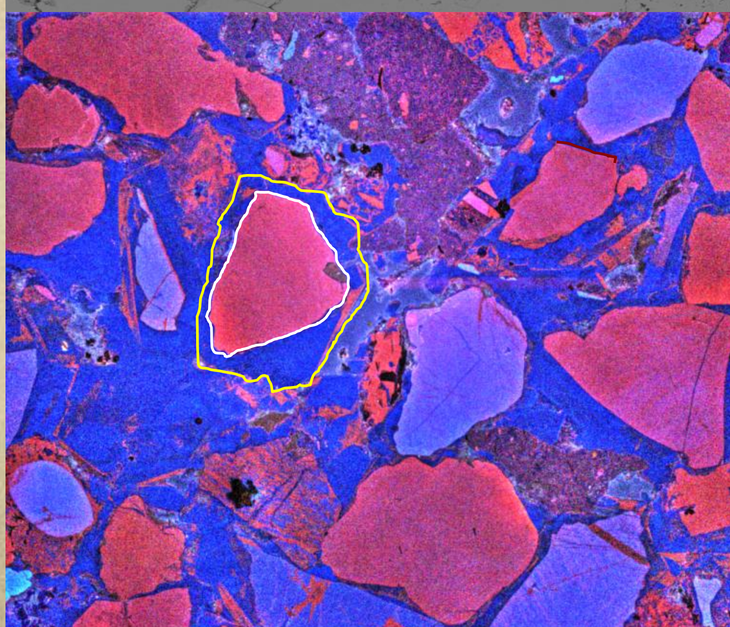
10-15-50-9W5
EAST

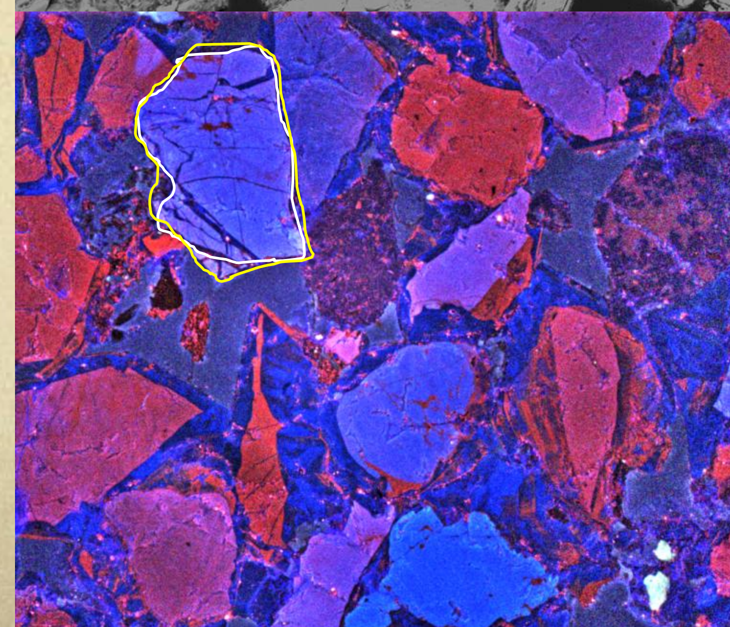
BSE





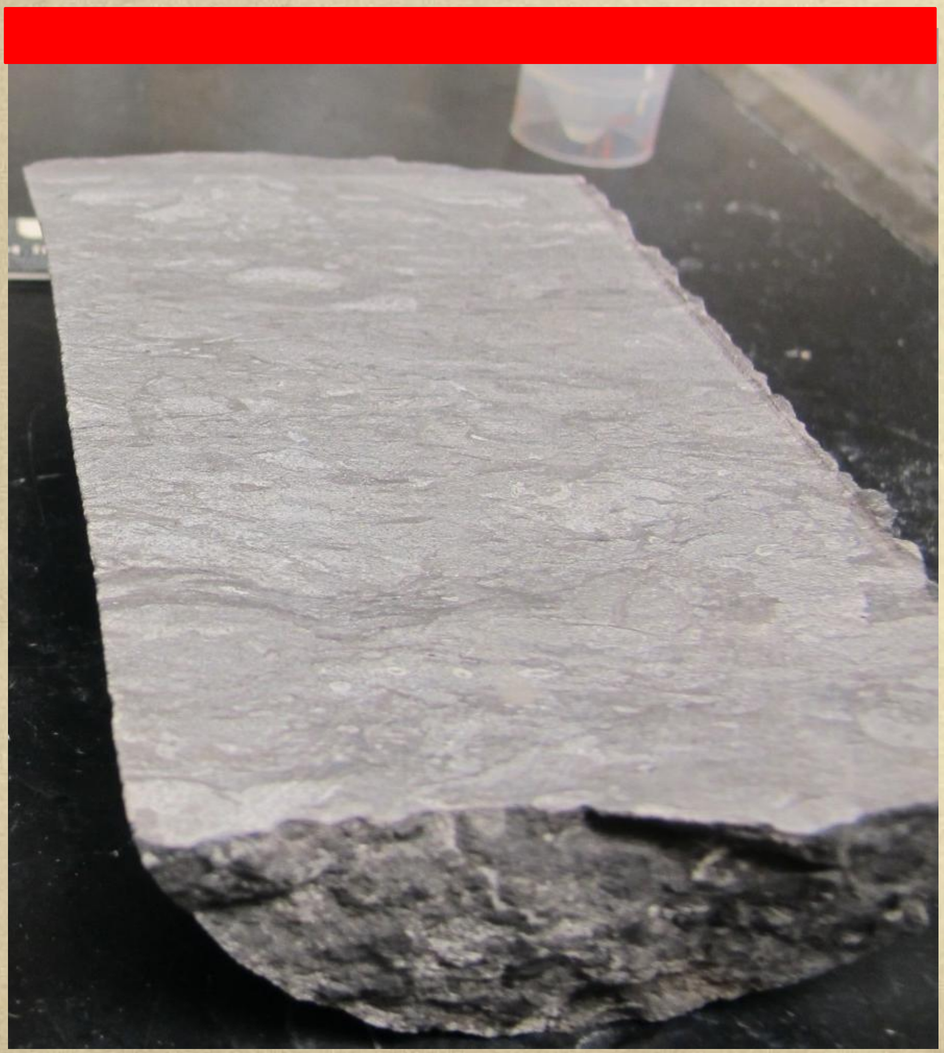
CL





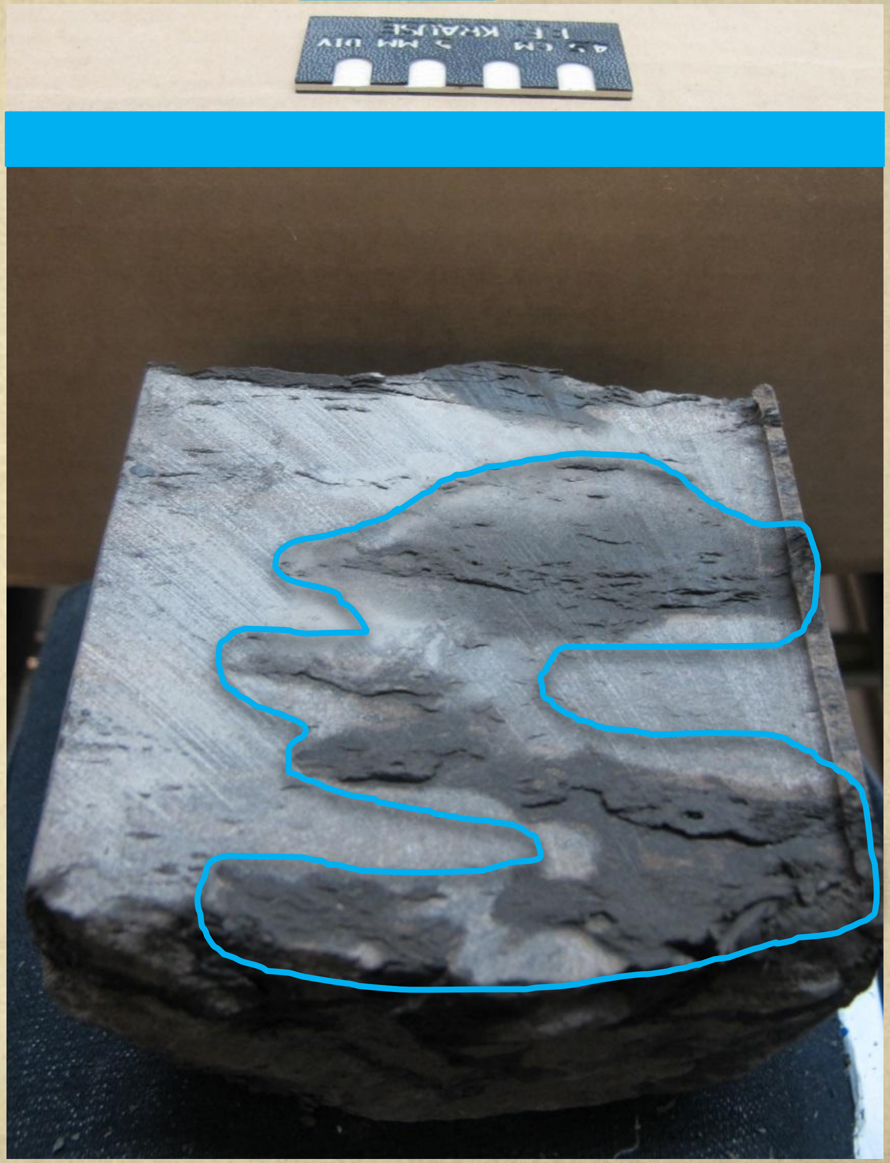
CLAY MINERALOGY
&
FLUID SENSITIVITY

4-22-50-12W5
WEST

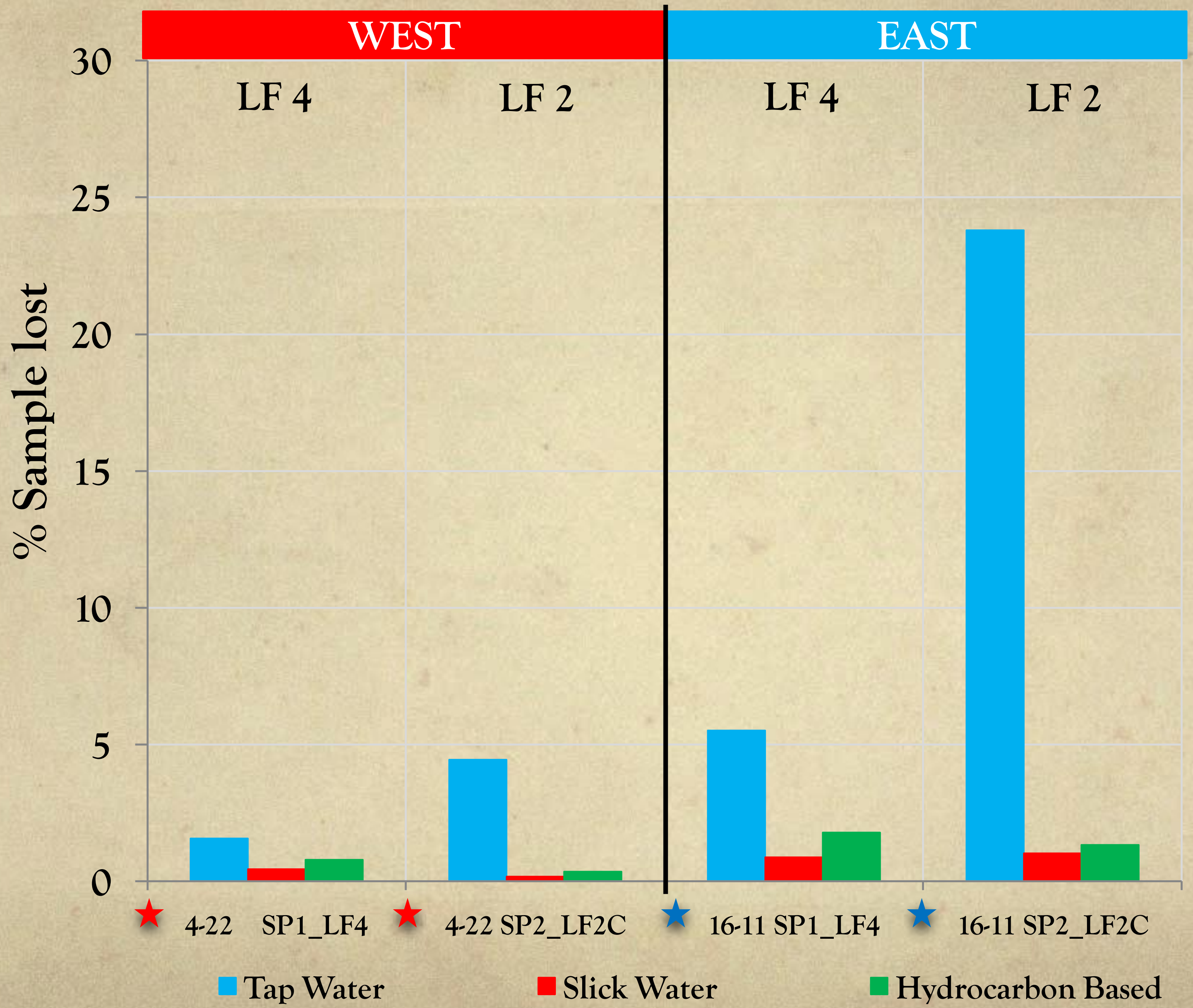


Little/no swelling clay

16-11-50-9W5
EAST

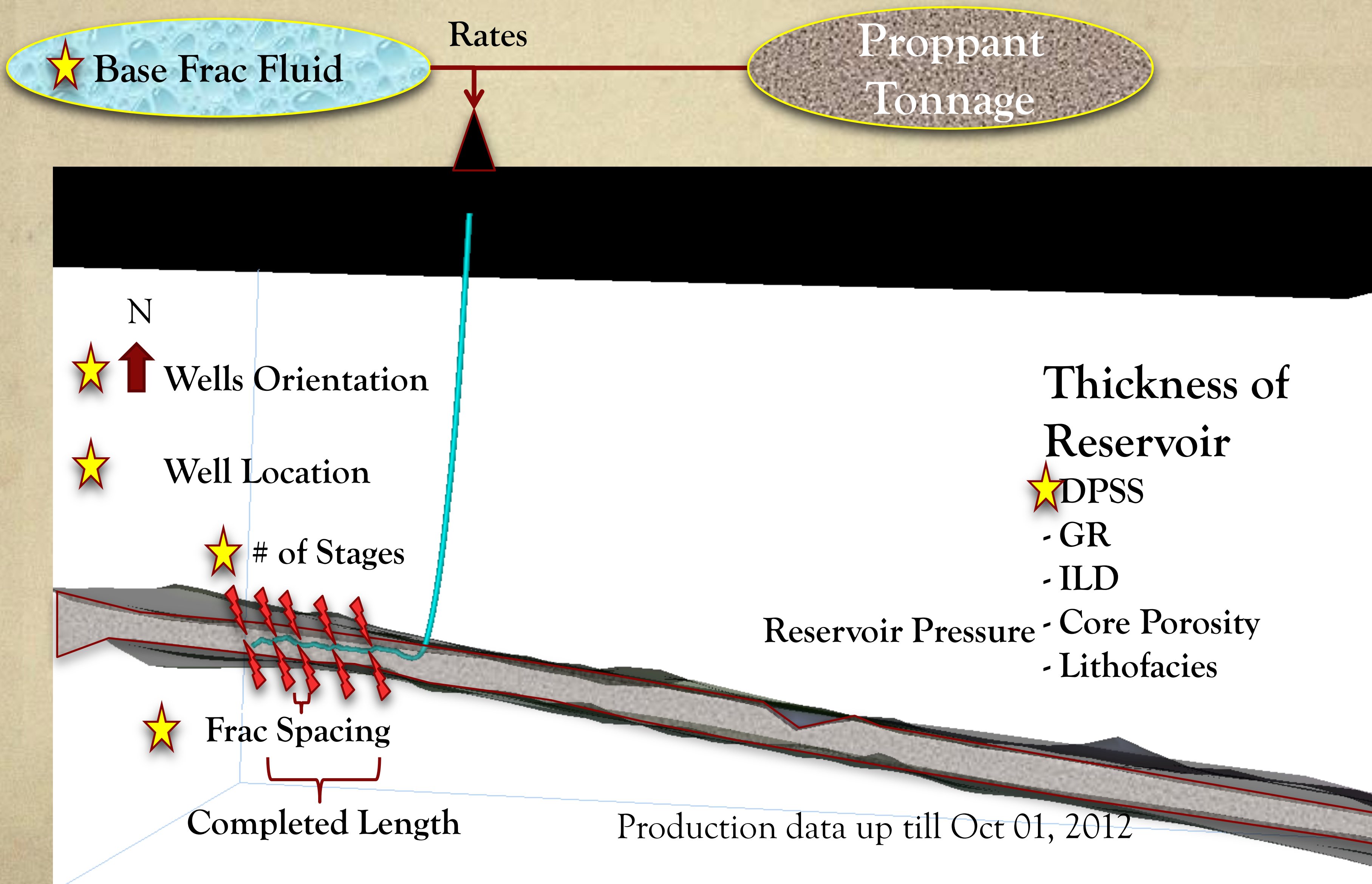


Common swelling clay



WEST
EAST
LF 4
LF 2
LF 4
LF 2
% Sample lost
30
25
20
15
10
5
0
4-22 SP1_LF4
4-22 SP2_LF2C
16-11 SP1_LF4
16-11 SP2_LF2C
Tap Water
Slick Water
Hydrocarbon Based

PRODUCTION ANALYSES



METHODS

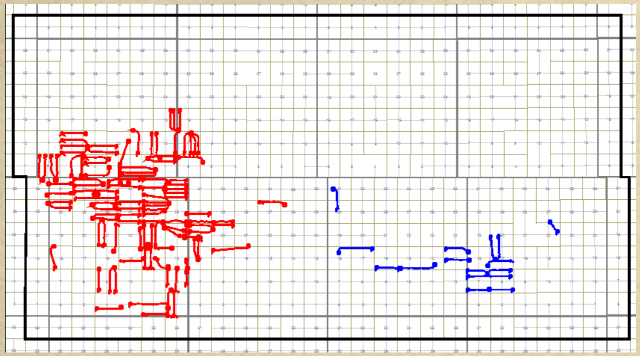
- Production data - geoSCOUT© up to Oct, 2012
- Completions data – Canadian Discovery

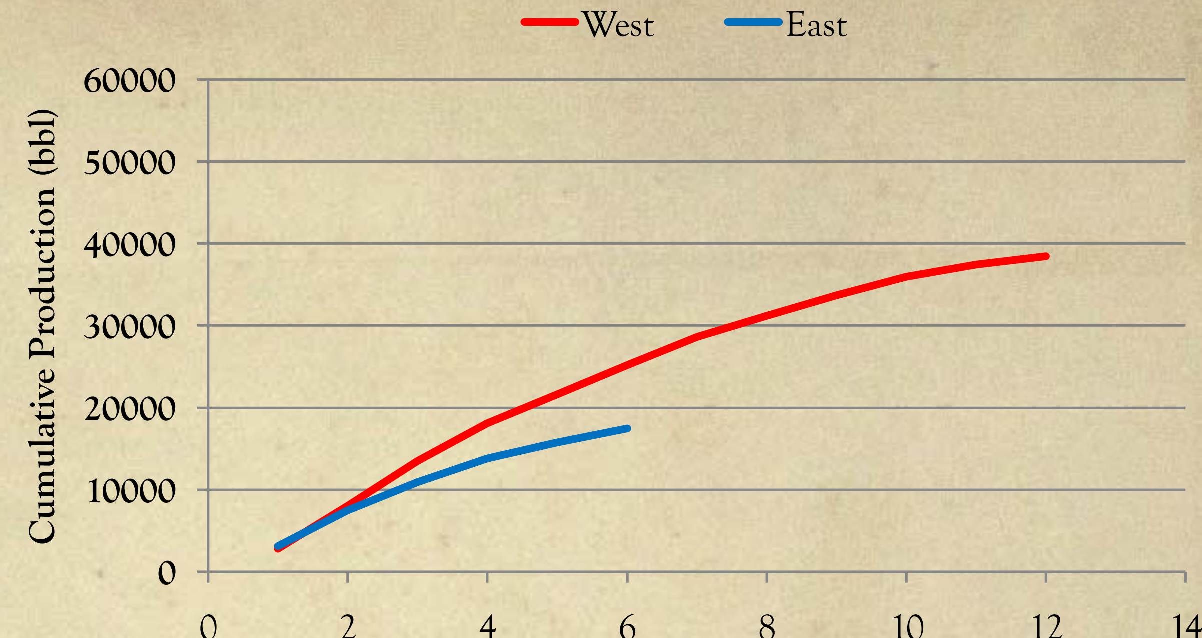
Well Completions & Frac Database®

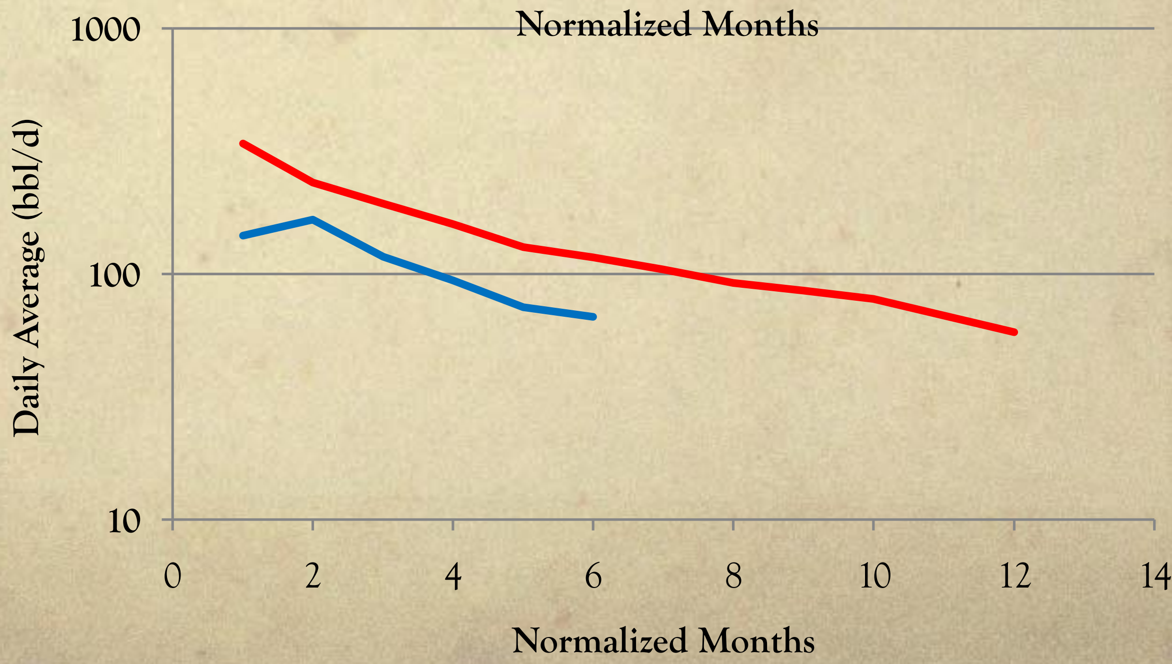
- Production averages calculated until well counts dropped below 4
- When well counts were sufficient production was calculated for the 1st 12 months

EAST vs. WEST

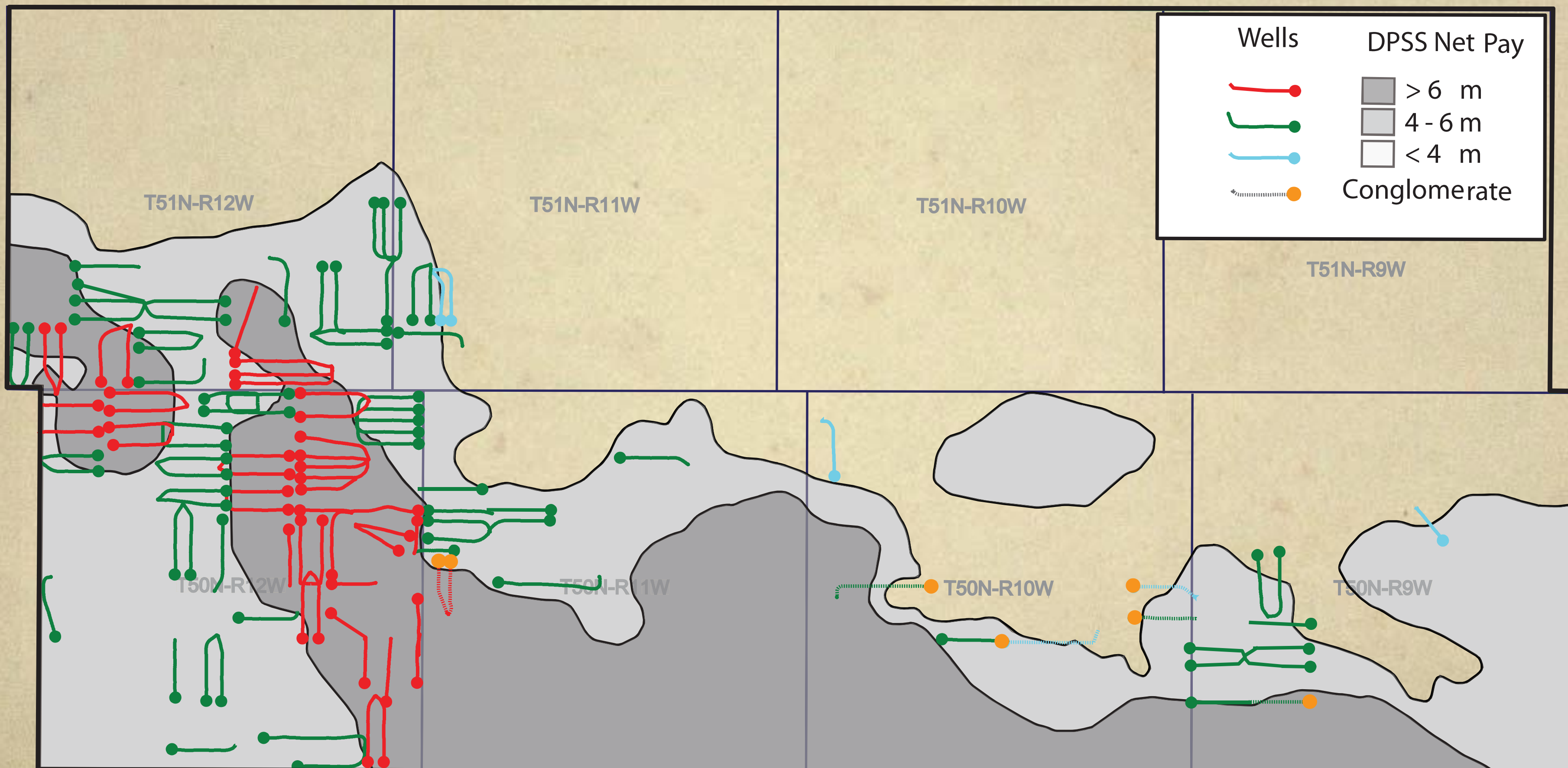
- West wells outperform east wells





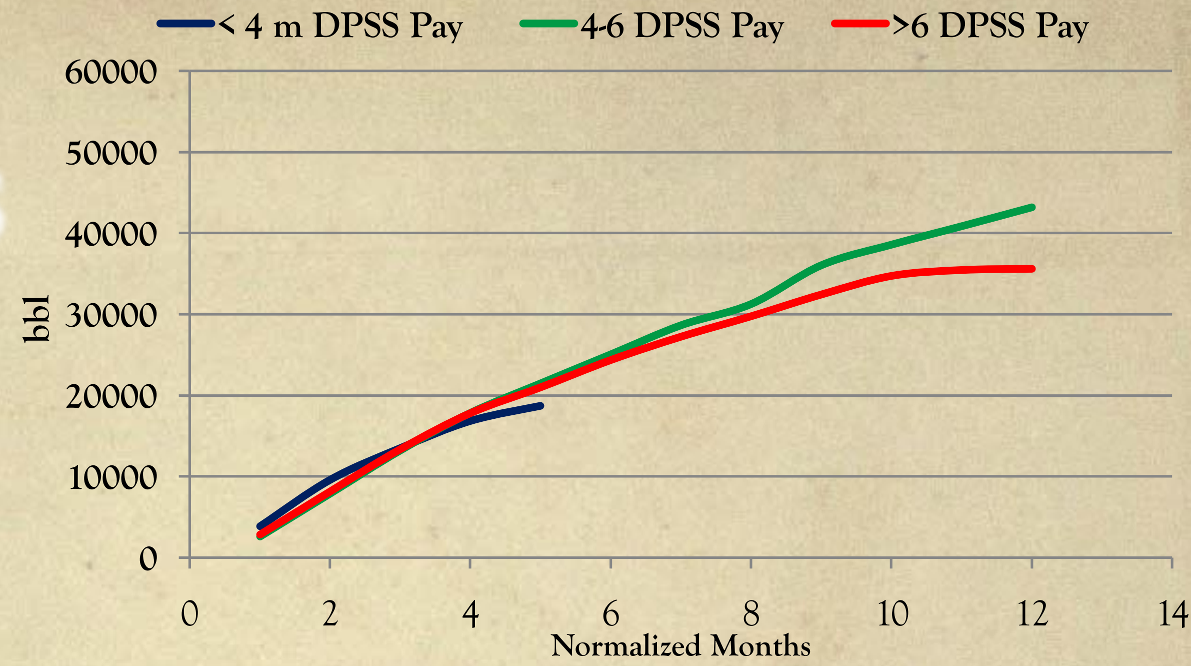


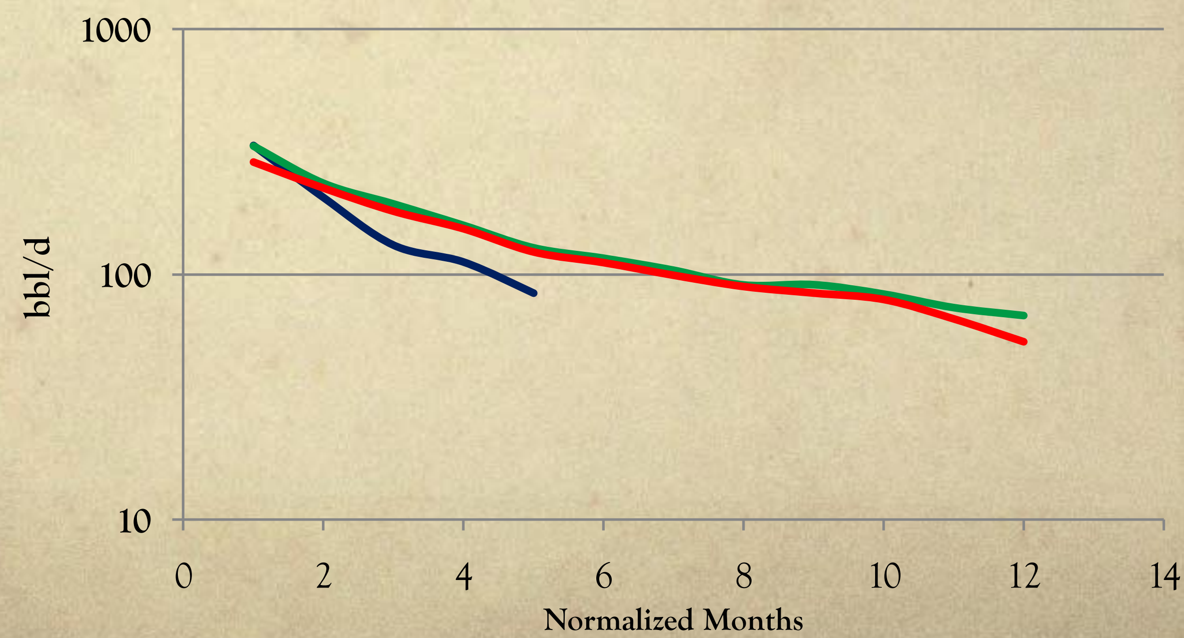
NET-PAY THICKNESS 6% DPSS

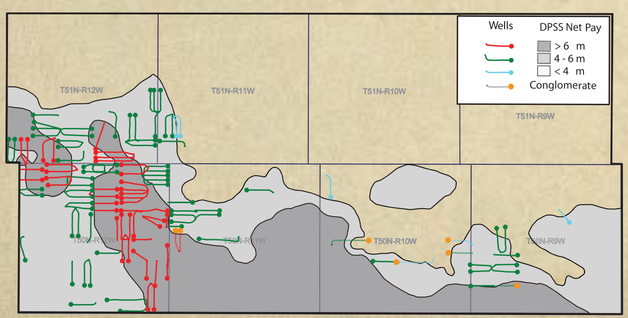


NET-PAY THICKNESS

- Thickest pay ≠ best well
- Lower limit of reservoir thickness

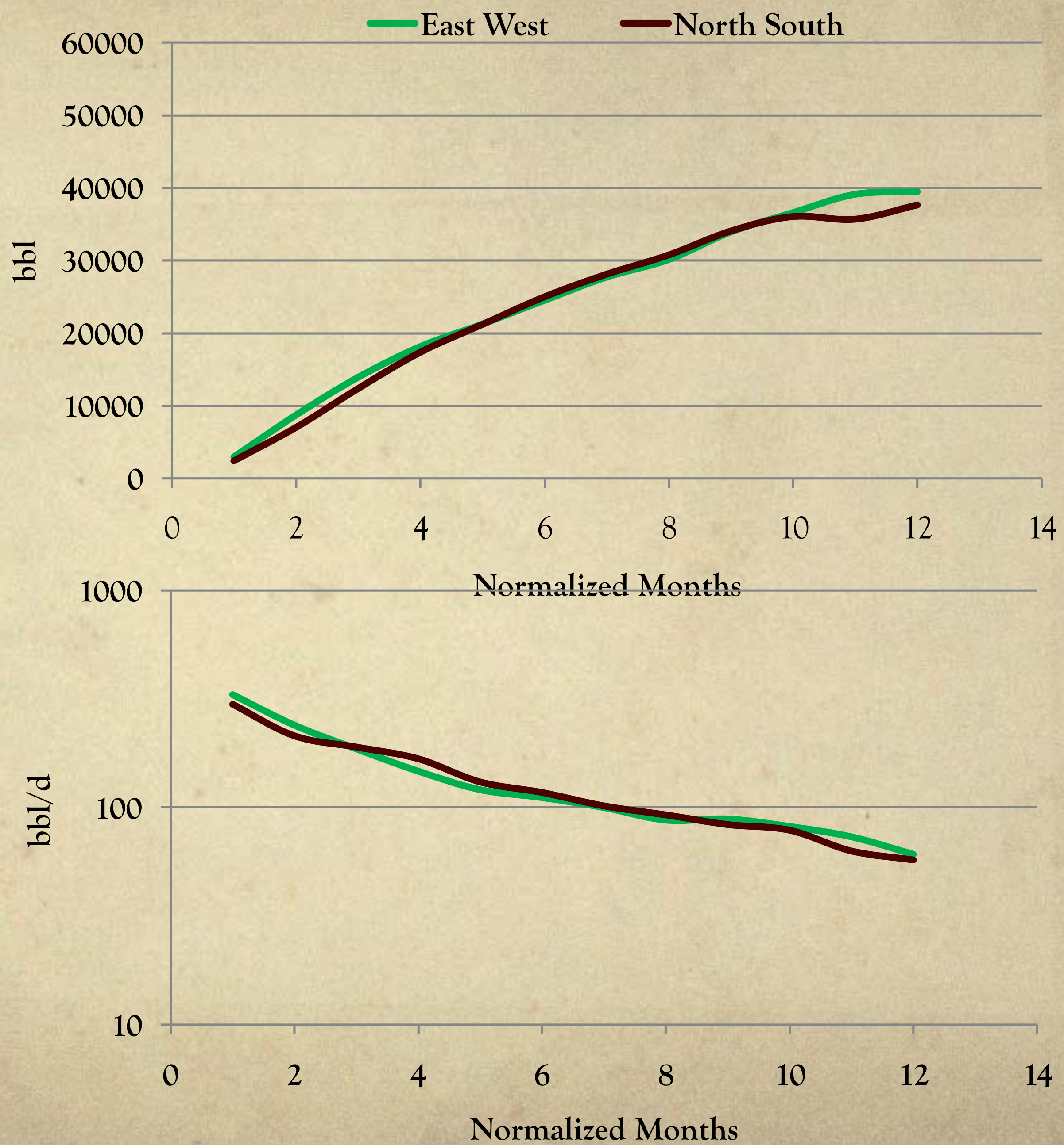






ORIENTATION

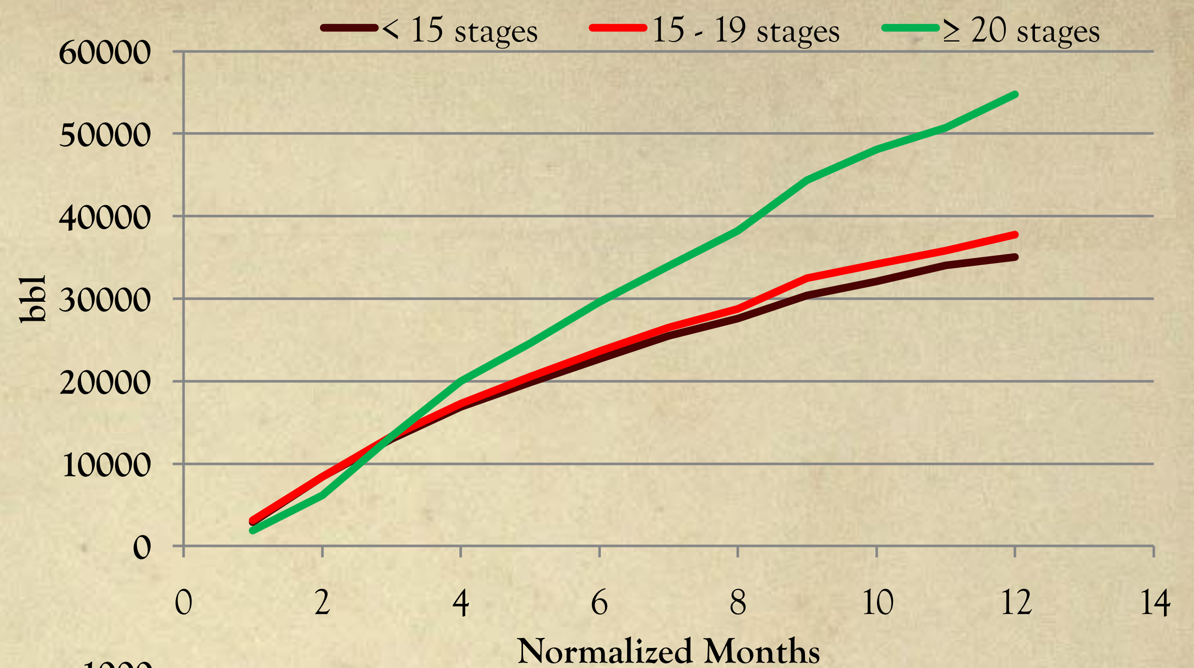
- Average pay thicknesses are similar
- **Orientation appears to have little impact on production**

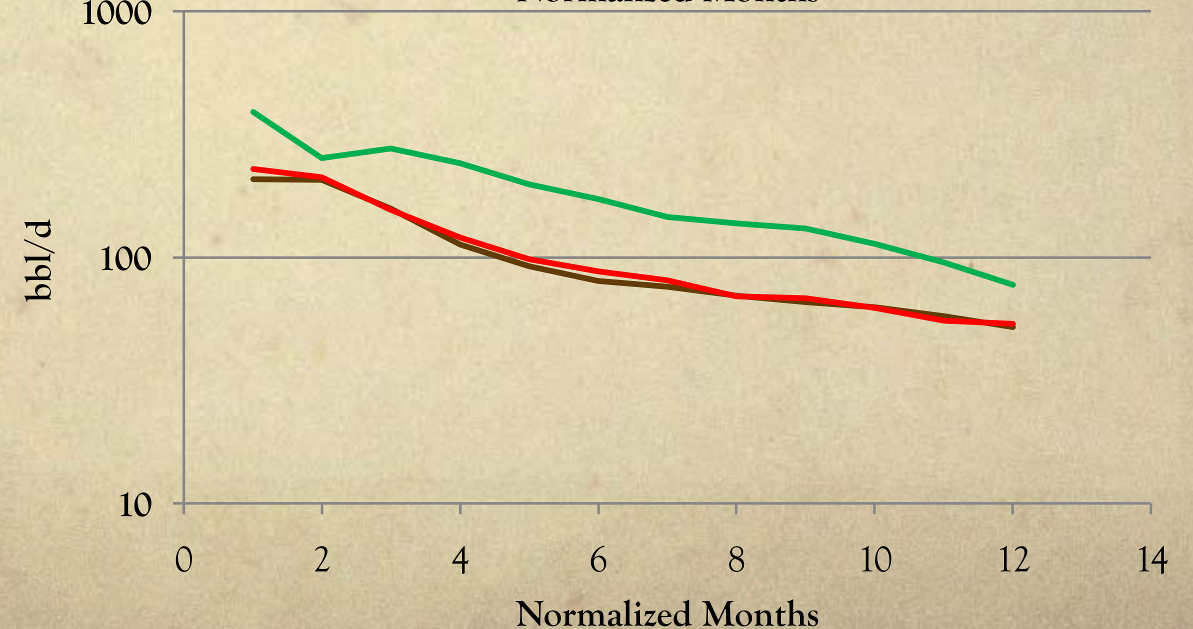


OF STAGES

- Wells with ≥ 20 stages are dramatically outperforming wells with <20
- 12 months

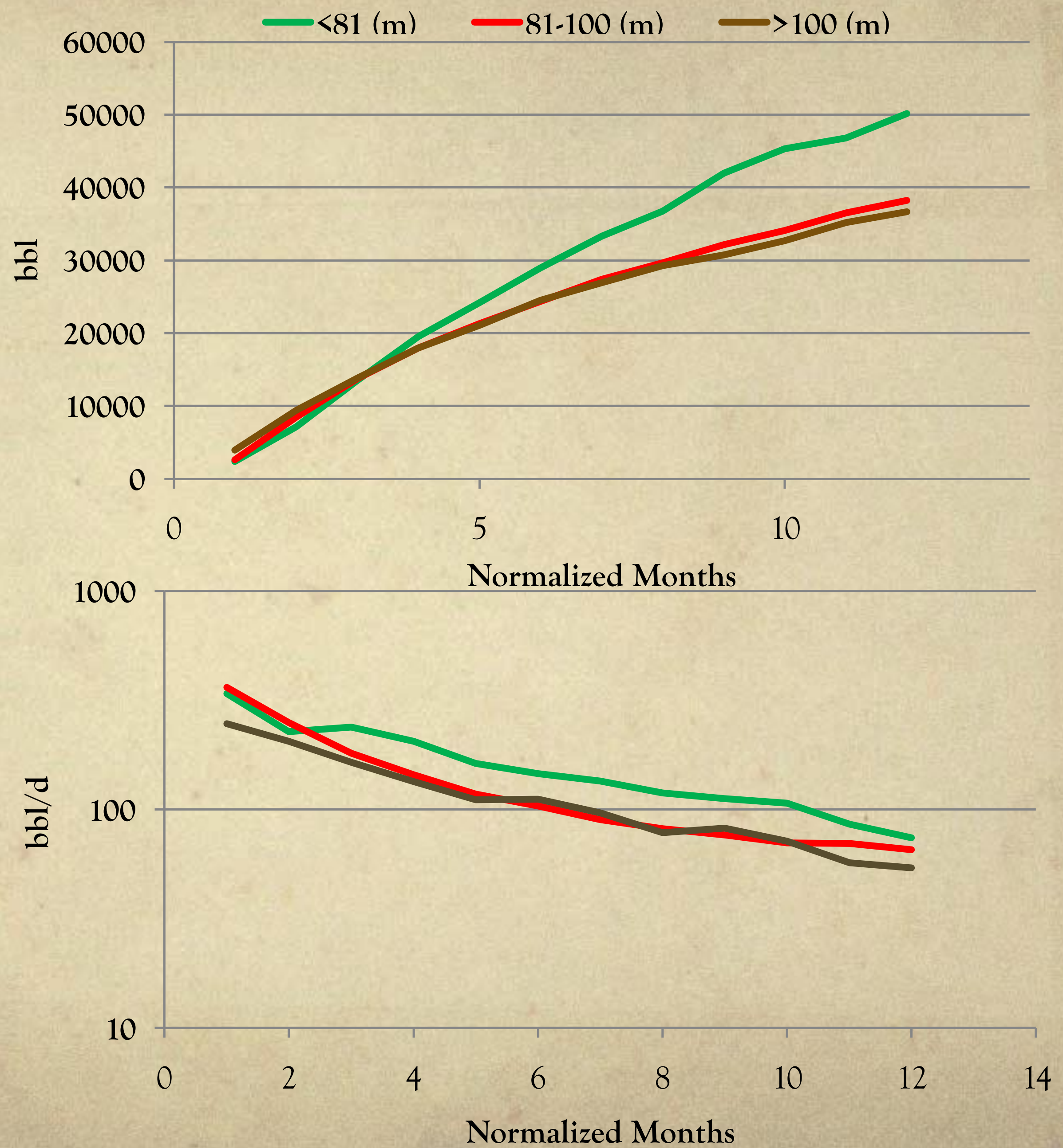
  19 000 bbl





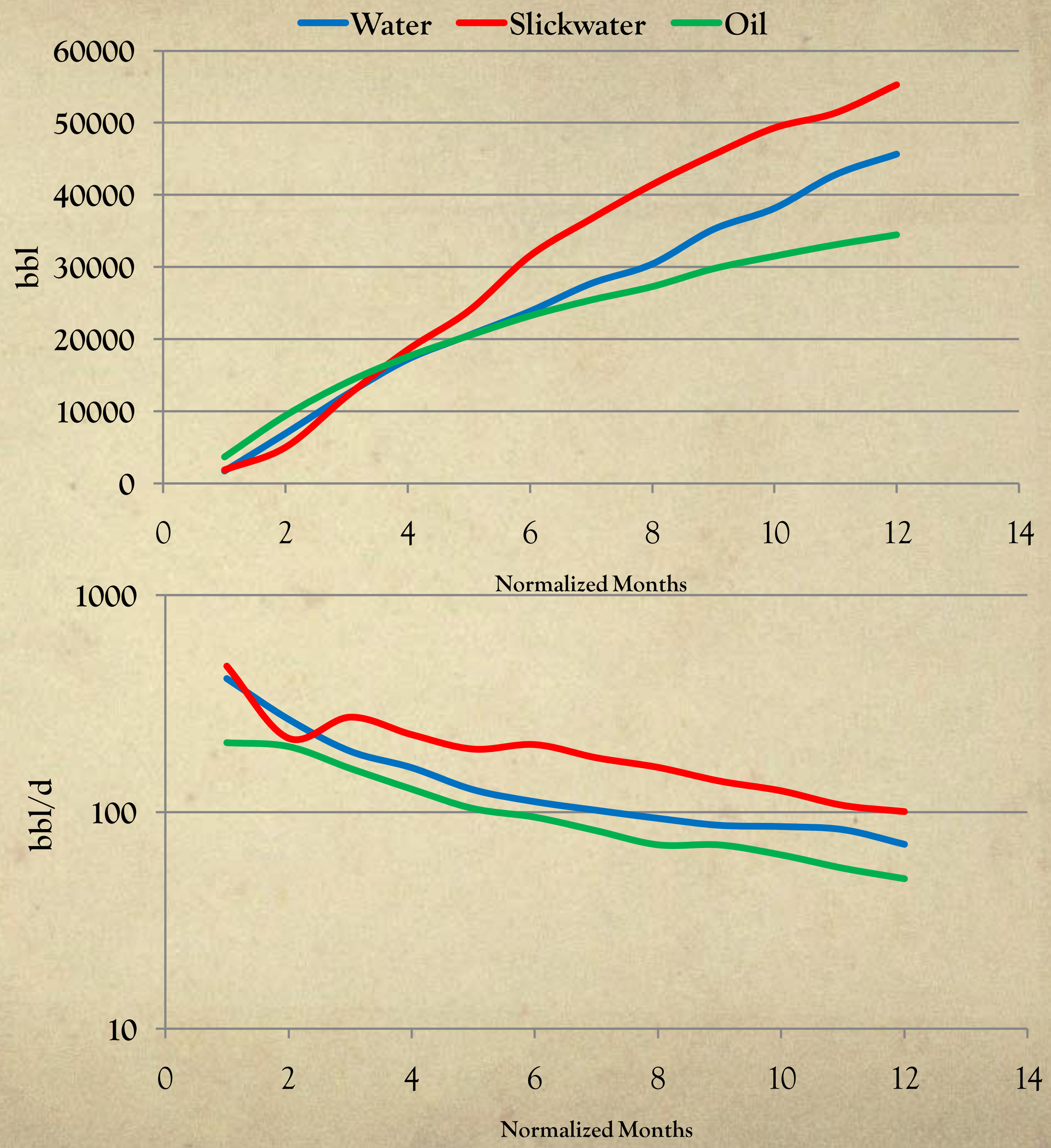
FRAC SPACING

- Only wells 1200-1800m in length
- **Frac spacing below 80 m displays best performance**



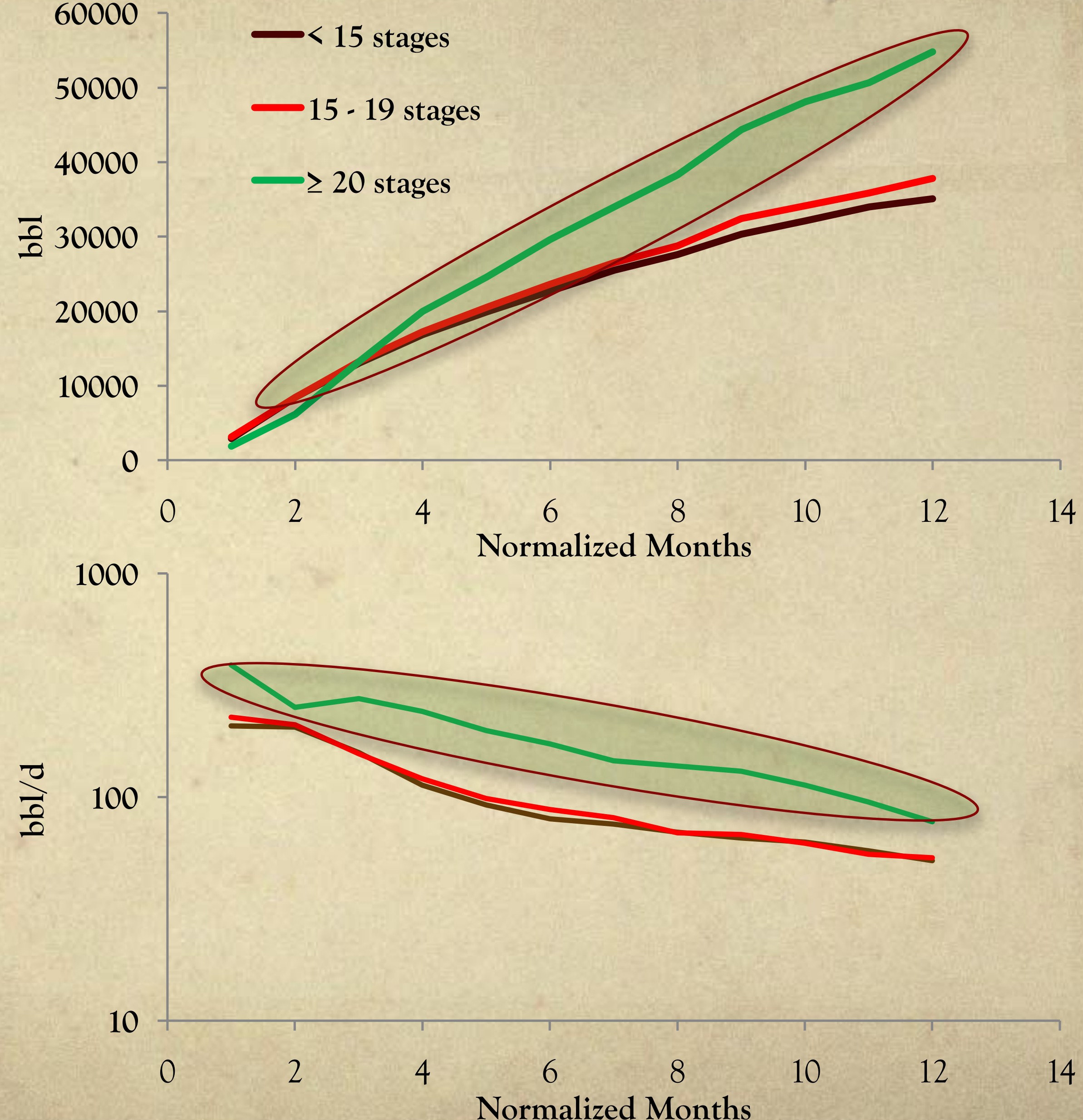
BASE FLUID

- Slickwater wells **appear** to be performing the best

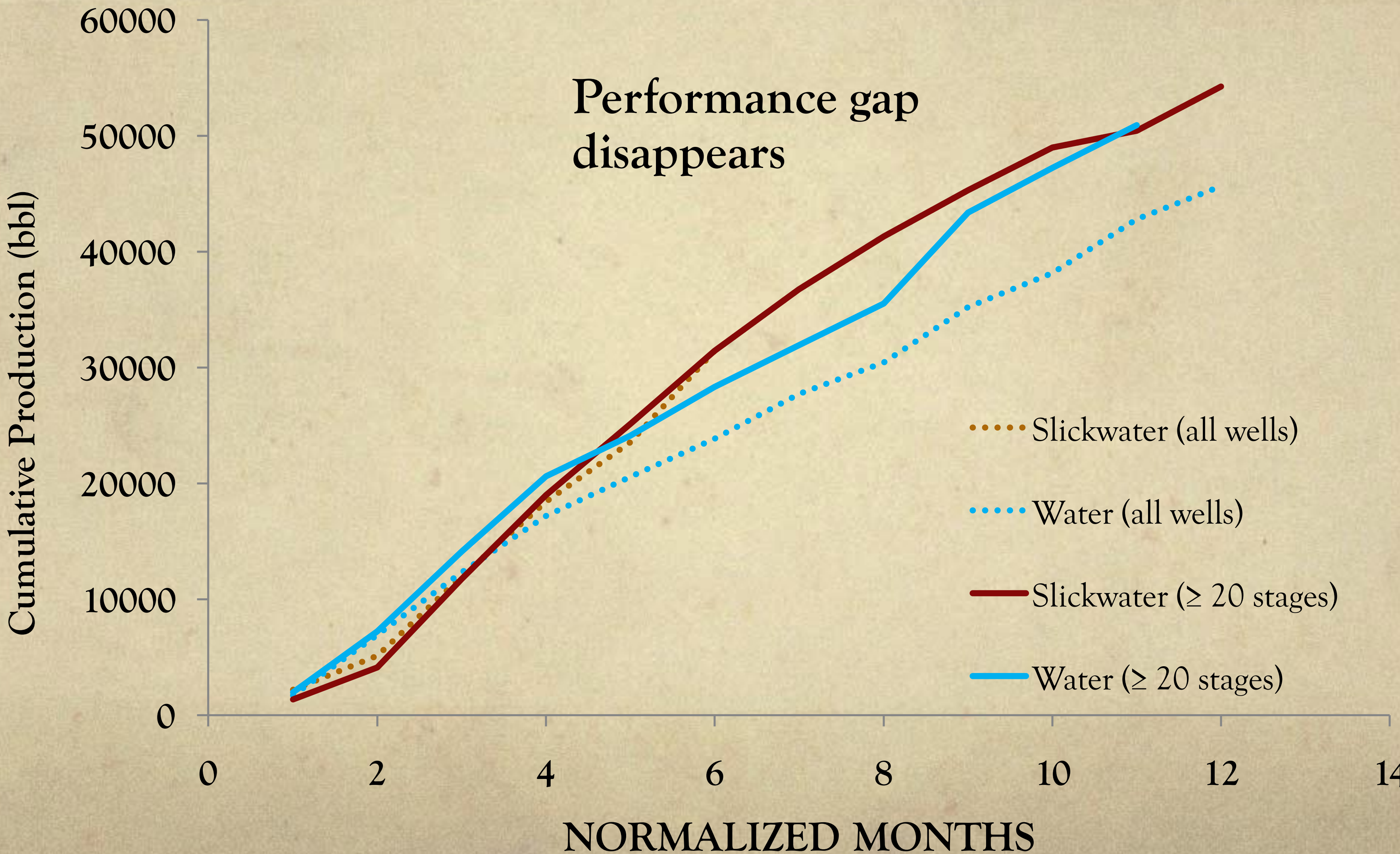


OF STAGES

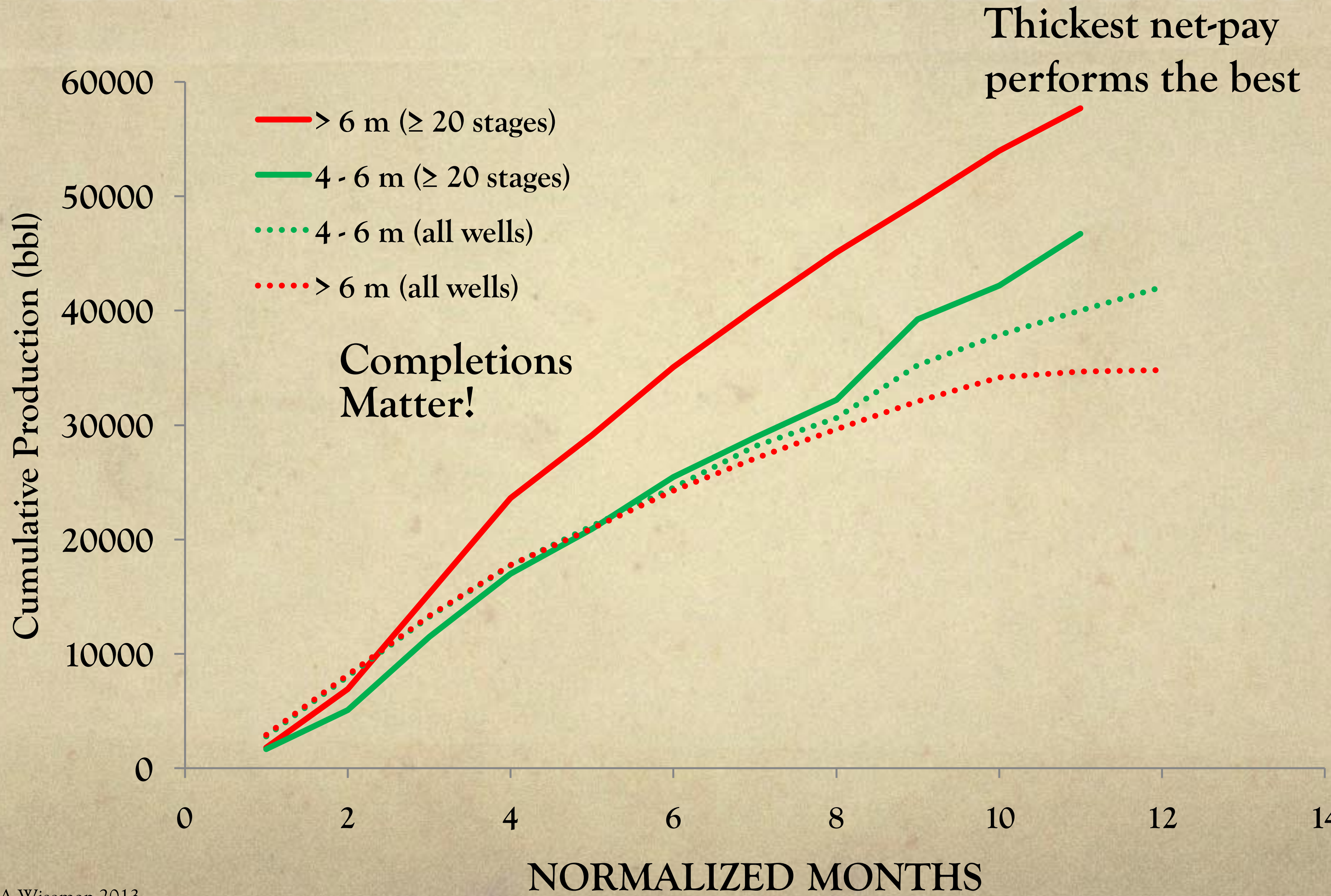
- Slickwater wells are dominantly ≥20 stages



≥20 STAGES vs BASE FLUID



≥20 STAGES VS DPSS THICKNESS



CONCLUSIONS

- Geology impacts well performance

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  - Reservoir properties vary across the study area
    - Lithofacies - Por and Perm

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CONCLUSIONS

- Geology impacts well performance
  - Reservoir properties vary across the study area
    - Lithofacies – Por Perm
    - Clay mineralogy / Fluid Sensitivity
    - Lower net-pay limit
  - Density logs are effective when completions are considered

CONCLUSIONS CONT.

- Completions impact well performance

CONCLUSIONS CONT.

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  - Number of fraced stages appears to have largest impact on wells productivity
    - 19 000 bbl

CONCLUSIONS CONT.

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CONCLUSIONS CONT.

- Completions impact well performance
  - Number of fraced stages appears to have largest impact on wells productivity
    - 19 000 bbl
  - A frac spacing of 80 m or less is optimal
  - Well bore orientation has little impact
  - Slickwater and Water-based fracs are both performing

ACKNOWLEDGMENTS

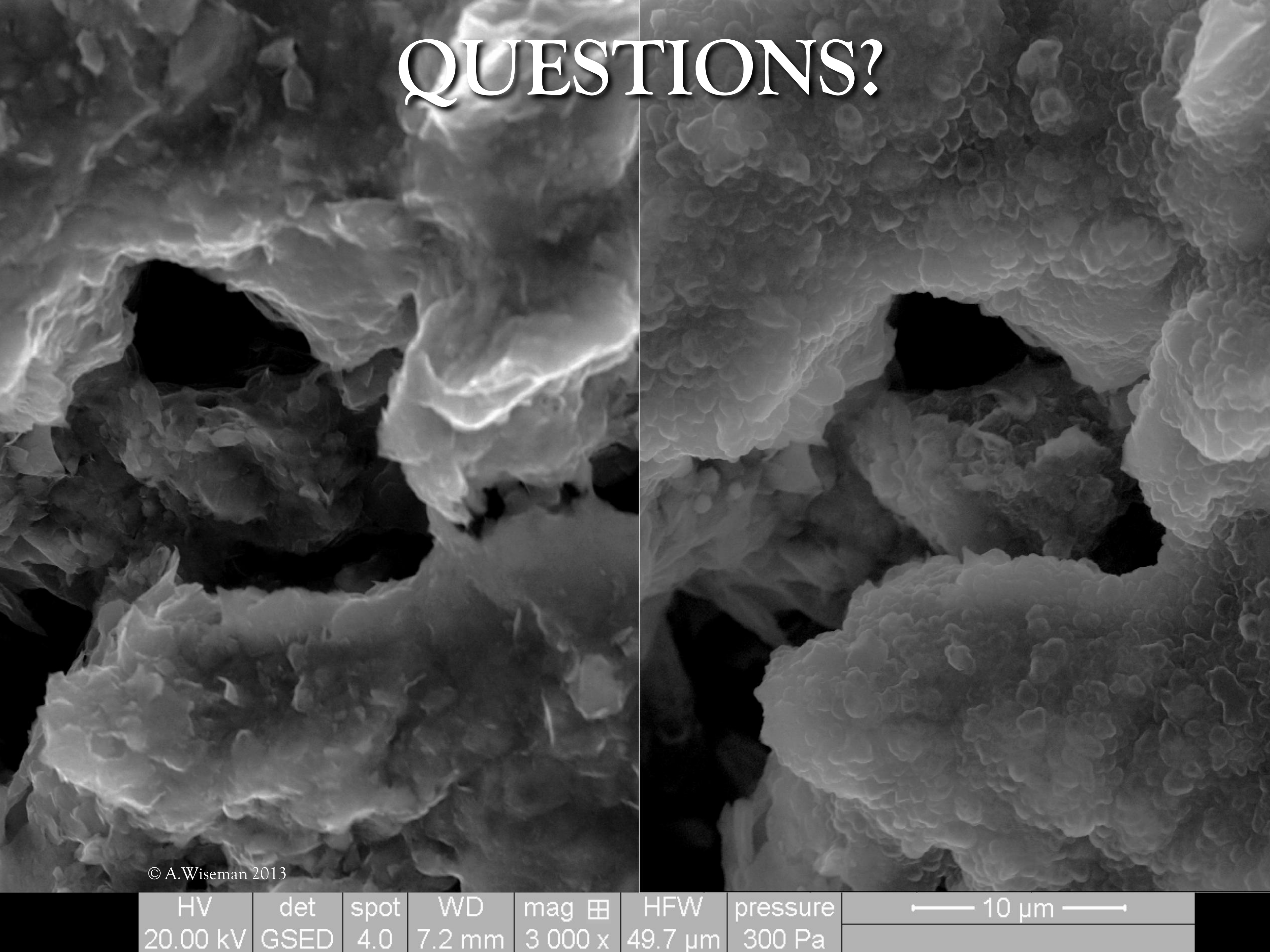
- TIGHT OIL CONSORTIUM
- UNIVERSITY OF CALGARY
- PETROBAKKEN ENERGY LTD.
  - Don Keith, Parker Moores, Matt Franks, Rainer Czypionka, Christian Viau
- FACULTY OF GRADUATE STUDIES
- IFFAEM
- TRICAN LABS

References

Krause, F. F., Deutsch, K. B., Joiner, S. D., Barclay, J. E., Hall, R. L., Hills, L. V., . . . Shetsen, Irina. (1994). *Cretaceous Cardium Formation of the Western Canada sedimentary basin*. Calgary, AB, Canada | Alberta Research Council @Edmonton, AB @CAN (CAN): Canadian Society of Petroleum Geologists, Calgary, AB.

Krause, F. F., Nelson, D. A., (1984) Storm event sedimentation: Lithofacies association in the cardium formation,
pembina area, west-central alberta, canada, Canadian Society of Petroleum Geologists pp. 485-511

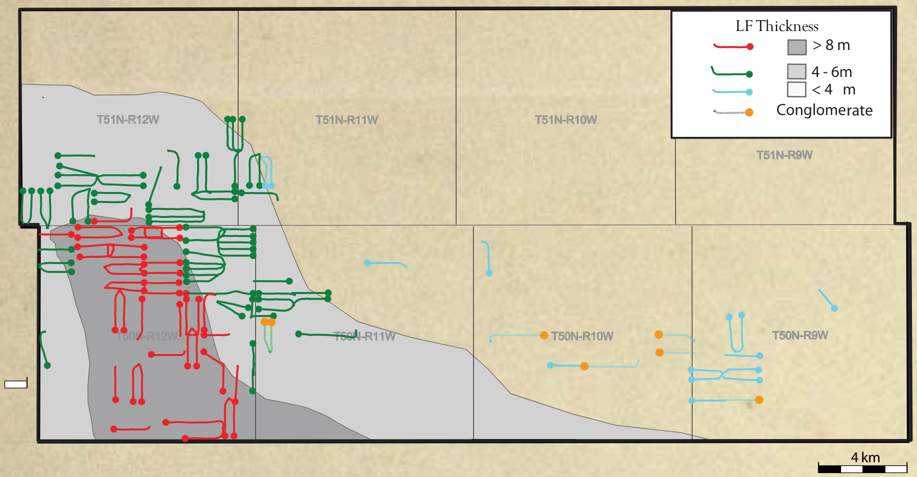
QUESTIONS?


© A.Wiseman 2013
HV 20.00 kV
det GSED
spot 4.0
WD 7.2 mm
mag 3 000 x
HFW 49.7 µm
pressure 300 Pa
10 µm

Addendum

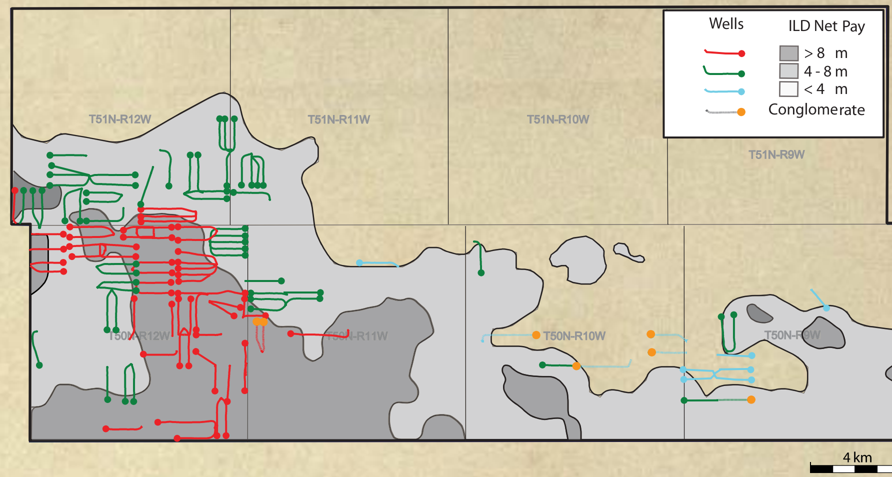
Thickest is the best?

Lithofacies Thickness



2 000 bbl

Resistivity



5 500 bbl

Phih

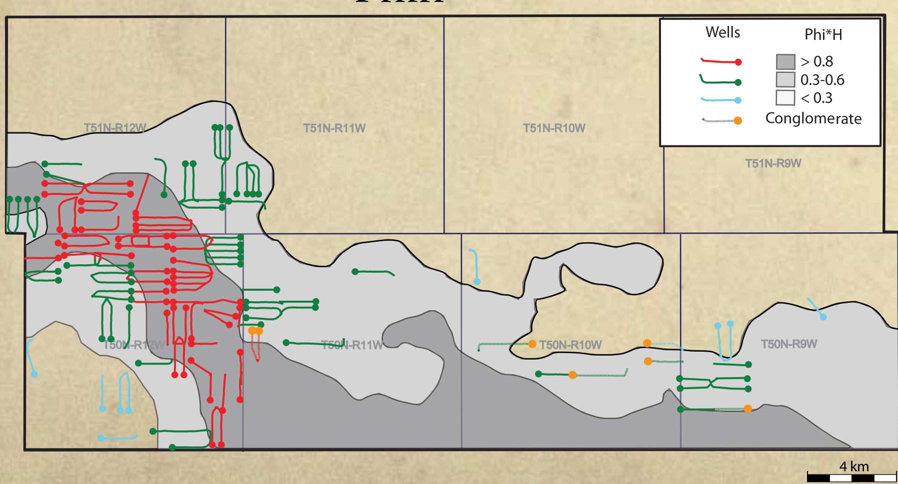
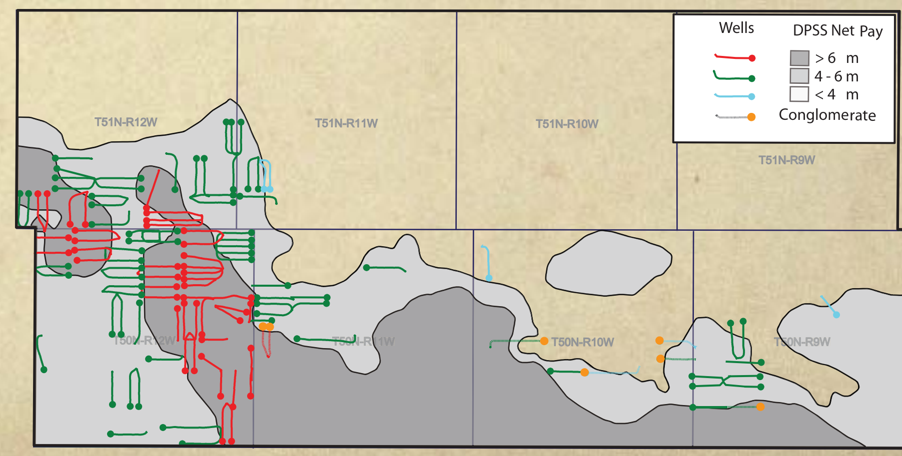


Figure 6: Phi*H quality map showing horizontal wells used for production analyses colored based on Phi*h quality groupings and loca-

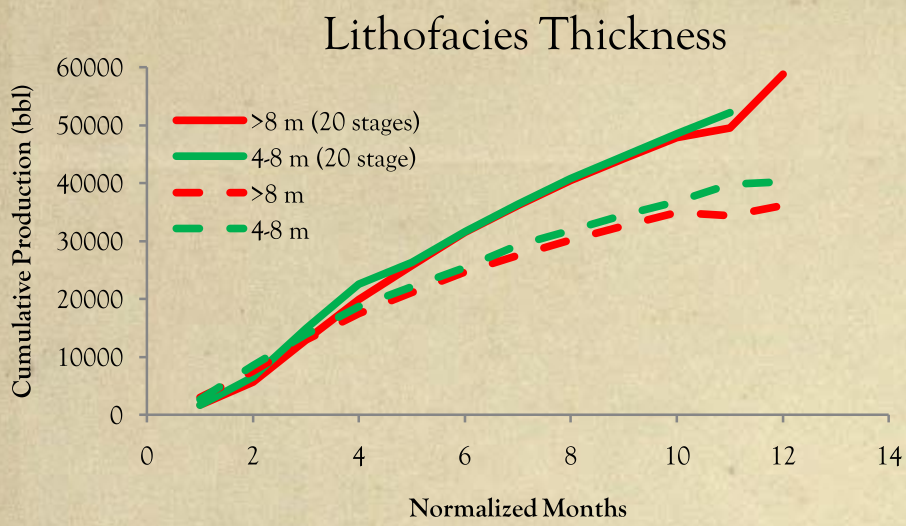
5 000 bbl

DPSS

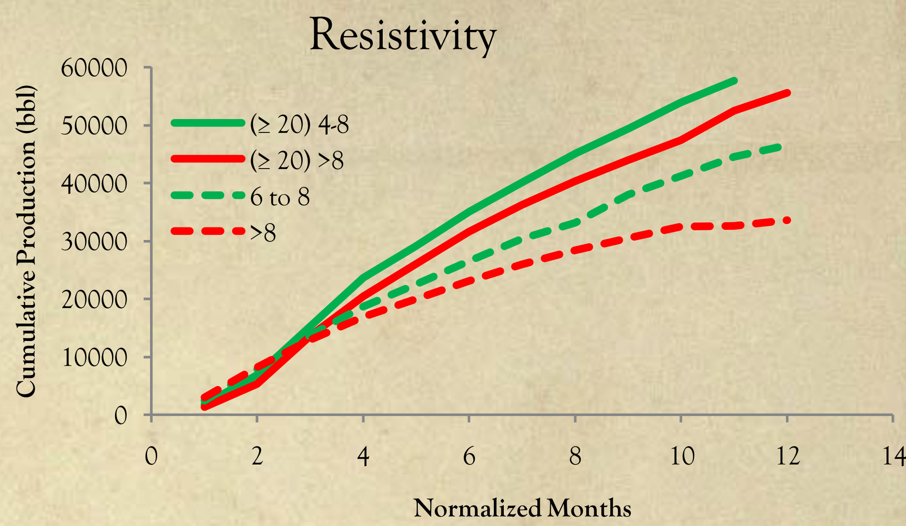


11 000 bbl

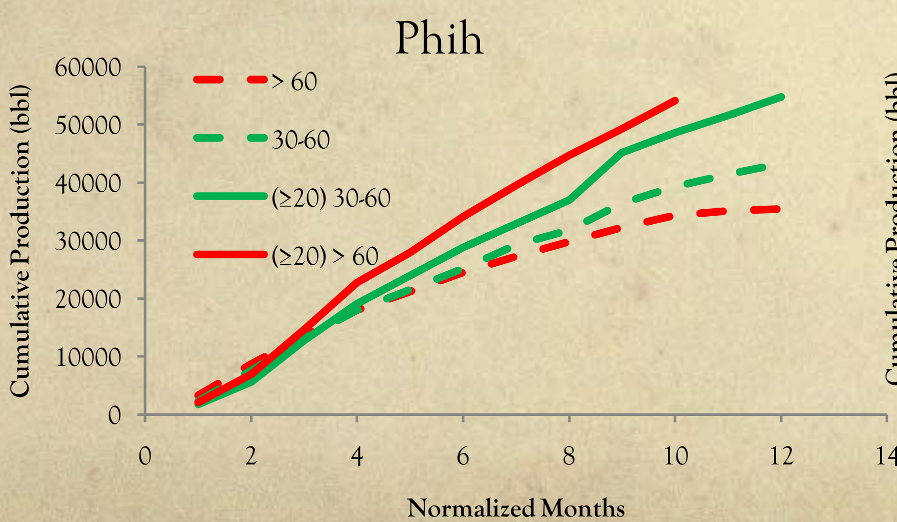
Thickest is the best?



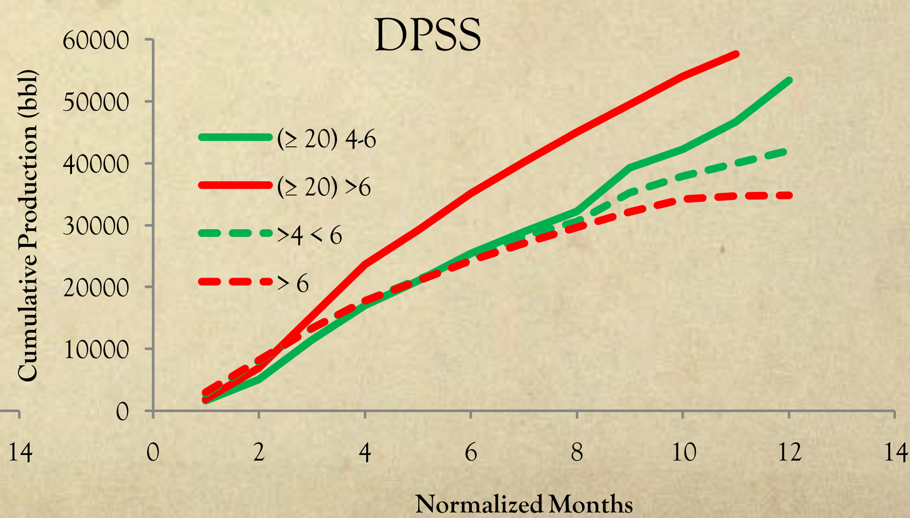
2 000 bbl



5 000 bbl

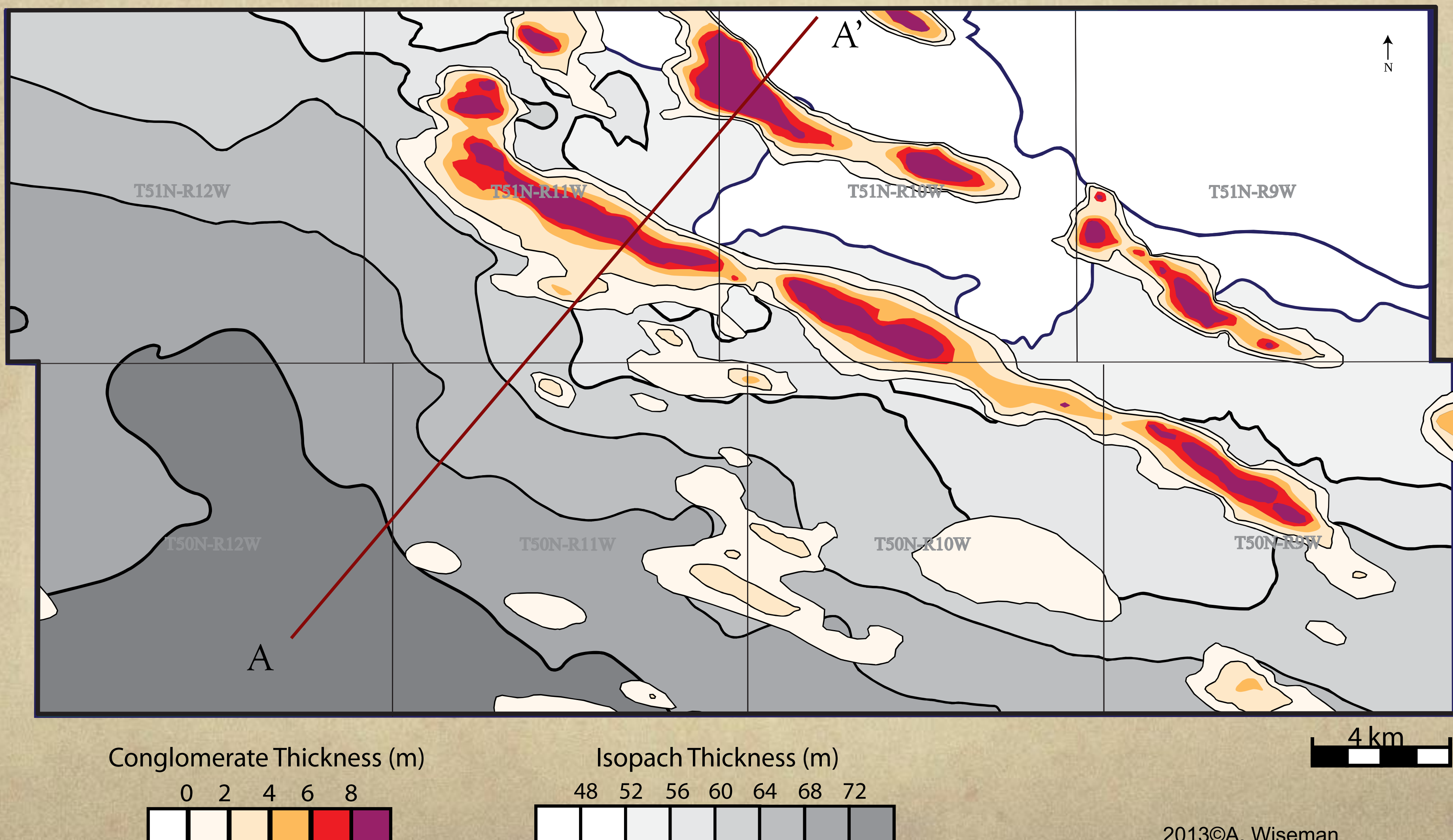


5 500 BBL

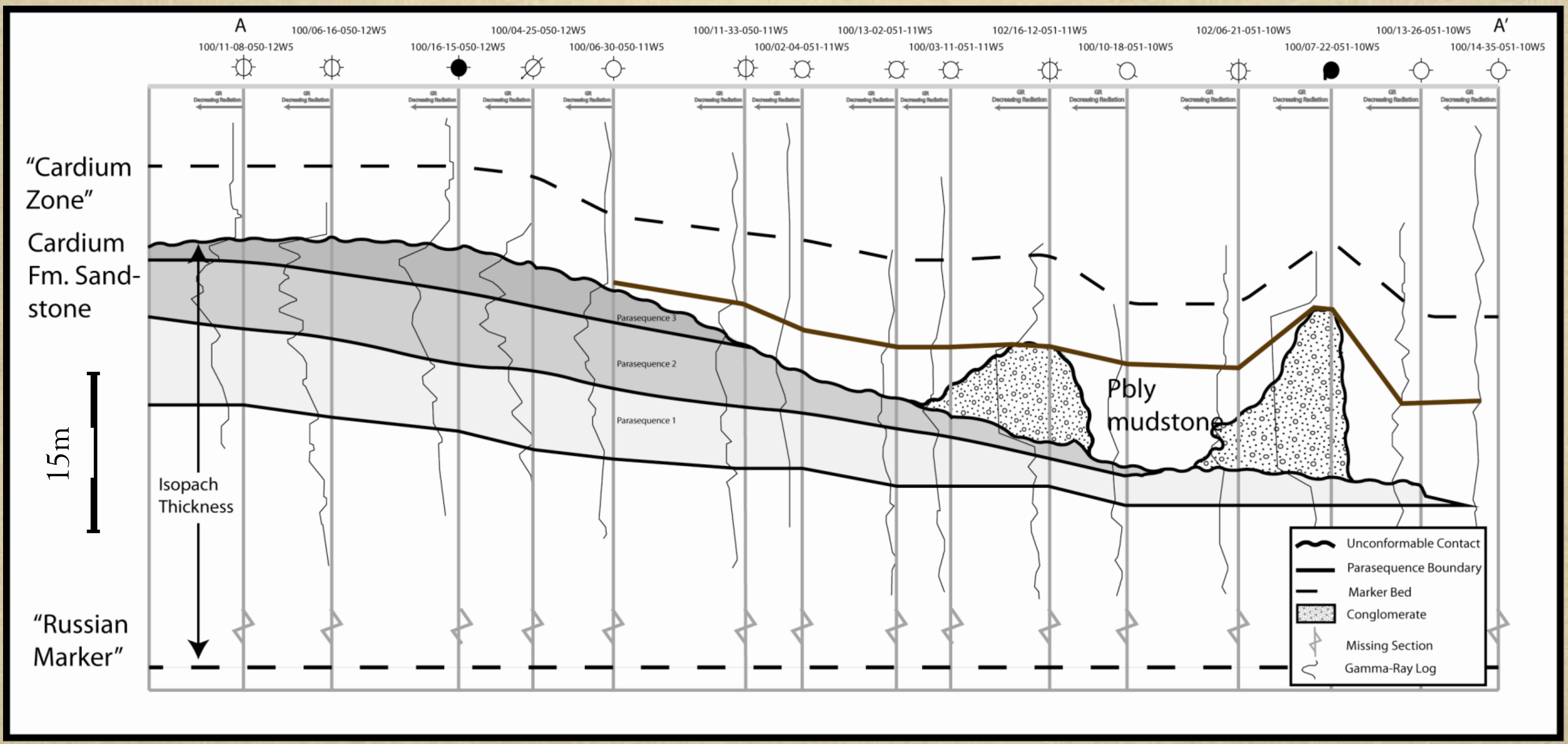


11 000 bbl

STRATIGRAPHIC MAP & CONGLOMERATE



INTERNAL STRATIGRAPHY



PAY CUT-OFFS

Petrofacies	Por (%)		K max (md)		SW (%)	
Ohm*m	Value	Count	Value	Count	Value	Count
< 20	0.08	84	0.08	64	0.48	78
20-30	0.11	549	0.4	486	0.23	500
> 30	0.12	418	0.61	393	0.19	387

DPSS %	Por (%)		K max (md)		SW (%)	
< 6	0.08	84	0.11	109	0.31	107
6 to 12	**0.11**	316	**0.42**	313	**0.19**	288
> 12	**0.12**	160	**0.48**	159	**0.09**	157