PS Review of Traditional and New Maturity Indicators: Differences and Complementarities*

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Abstract

A review of how maturity is assessed will address some of the strengths and limitations of the tools traditionally used. It will introduce some correction algorithms as well as new tools or techniques that can effectively complement the geochemist or basin modeler tool kit.

Following a partial review of vitrinite reflectance and vitrinite equivalence for pre-Devonian organic matter, Tmax issues are addressed when dealing with high maturity samples. Some corrections that can be simply applied by any geoscientist are proposed with the scientific reasoning behind them.

If ethane and propane carbon isotopes have proved to be extremely good indicators of maturity levels, calibration is needed for each shale formation and each basin before the absolute carbon isotope values are used as an Ro (vitrinite) equivalent or as a liquid phase predictor (dry gas, wet gas, retrograde gas…). Issues found using methane carbon isotope need to be kept in mind, especially in absence of ethane and propane isotope analyses for the same samples.

Butane and, to a lesser extent, pentane ratios are extremely good proxies for maturity. However, the usefulness of these ratios (iC4/nC4 and iC5/nC5) varies, depending on their source (e.g., isojars, isotubes or chromatography).

When dealing with hydrocarbon ratios (e.g., C3+/C1+) local permeability enhancement associated with secondary porosity (diagenesis or fracture related) may obliterate and overwhelm the maturity indicator. Such a case is demonstrated when hydrocarbon ratio changes are tied to features seen on image logs.

Understanding maturity can be efficiently enhanced by using quartz cement modelling as a complementary tool in case of hybrid shale (e.g., Lorraine shale). Thus, whereas all of the previously described tools deal with a maximum temperature reached during burial, quartz cement precipitation is time dependent and the fluid filling the pores has to be water at 80ºC or higher.

Discrepancy can naturally exist between the maturity of the organic matter (or shale) and the maturity of the fluid in the pore system. Upward migration as seen in the Bakken Formation is expressed by hydrocarbon more mature than predicted by the geochemistry of the surrounding shale. On the other hand, early migration and entrapment are expressed by lower maturity hydrocarbon than indicated by any geochemical analysis of the organic matter; i.e. retrograde gas in a reservoir where the organic matter indicates wet-gas or dry-gas domain.

Selected References

Chatellier, J-Y., and M. Chatellier, 2006, Data Mining and Exploratory Statistics to Visualize Fractures and Migration Paths in the WCBS, CSPG Annual convention, Calgary, AB, Canada.

Chatellier, J-Y., P. Flek, M. Molgat, I. Anderson, K. Ferworn, N. Lazreg, L. Ko, and S. Ko, 2013, Overpressure in shale gas: When geochemistry and reservoir engineering data meet and agree, *in* J-Y. Chatellier and D.M. Jarvie, editors, Critical Assessment of Shale Resource Plays: AAPG Memoir 103, p. 45-70.

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Review of Traditional and New Maturity Indicators

Differences and Complementarities

Abstract

A review of how maturity is assessed will address some of the strengths and limitations of the tools traditionally used. It will introduce some correction algorithms as well as new tools or techniques that can effectively complement the geochemist or basin modeler tool kit.

Following a partial review of vitrinite reflectance and vitrinite equivalence for pre-Devonian organic matter, Tmax issues are addressed when dealing with high maturity samples Some corrections that can be simply applied by any geoscientist are proposed with the scientific reasoning behind them.

If ethane and propane carbon isotopes have proved to be extremely good indicators of maturity levels, calibration is needed for each shale formation and each basin before the absolute carbon isotope values are used as an Ro (vitrinite) equivalent or as a liquid phase predictor (dry gas, wet gas, retrograde gas…). Issues found using methane carbon isotope need to be kept in mind, especially in absence of ethane and propane isotope analyses for the same samples.

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Keywords

Rock-Eval Tmax use and limitations

Stable carbon isotope of C2 and C3

In-situ gas at 1.5%Ro & overpressure

Quartz cement modelling

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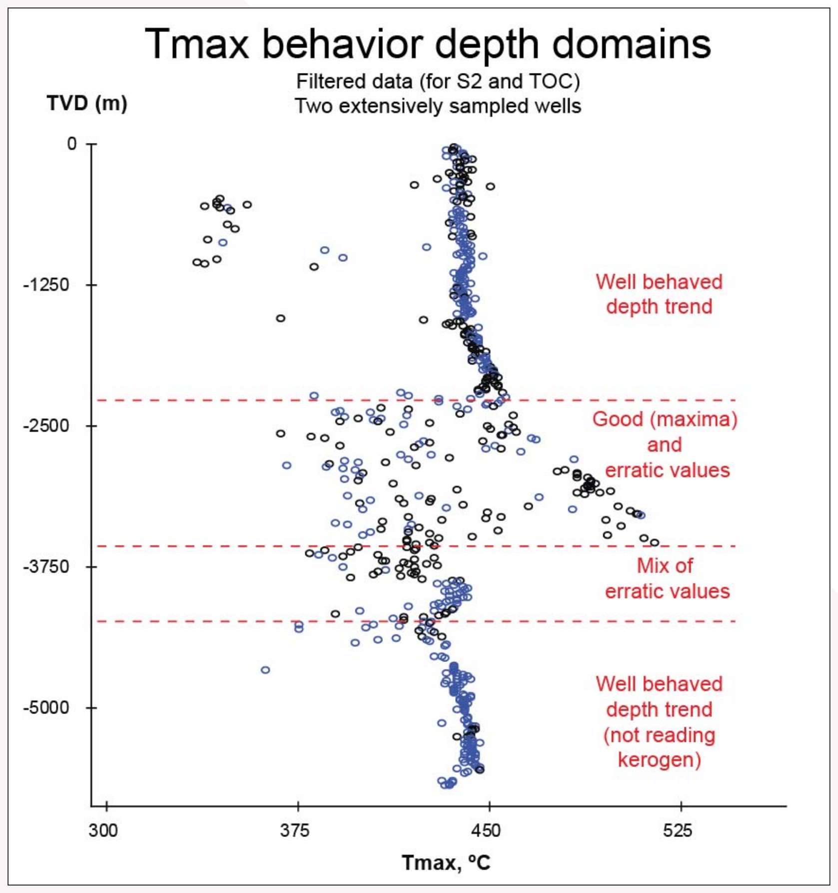
What can you do without vitrinite?



Chatellier et al. 2010, 2013 in press

1.1%Ro

Precipitation of bitumen

1.5%Ro

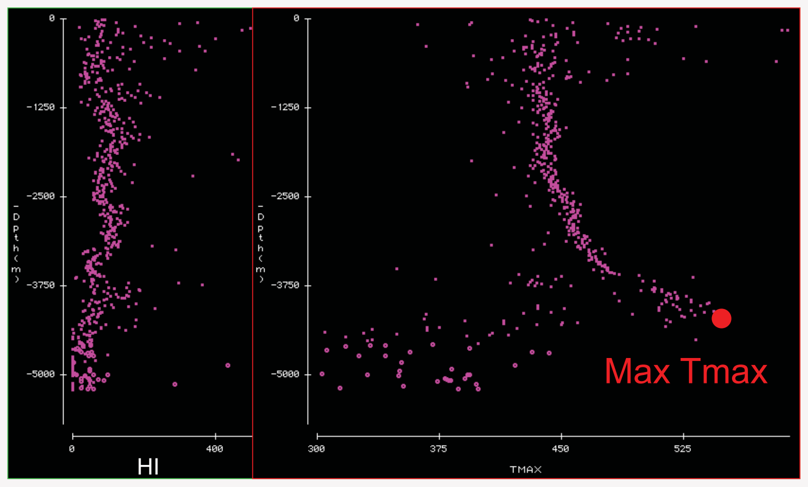
Tmax from Bitumen

The six vital steps to maximize your chance of success with Tmax

1) Look at the range of values obtained
2) Filter for S2 > 0.5 and TOC > 1%
3) Document and keep in mind the percentage of bad values
4) Use the Max, or 90%ile value of Tmax as most representative
5) Incorporate all Tmax values of shallower horizon
6) On a map incorporate all data and basement features

3-D mapping of the overpressure domain

16-25-047-21W5



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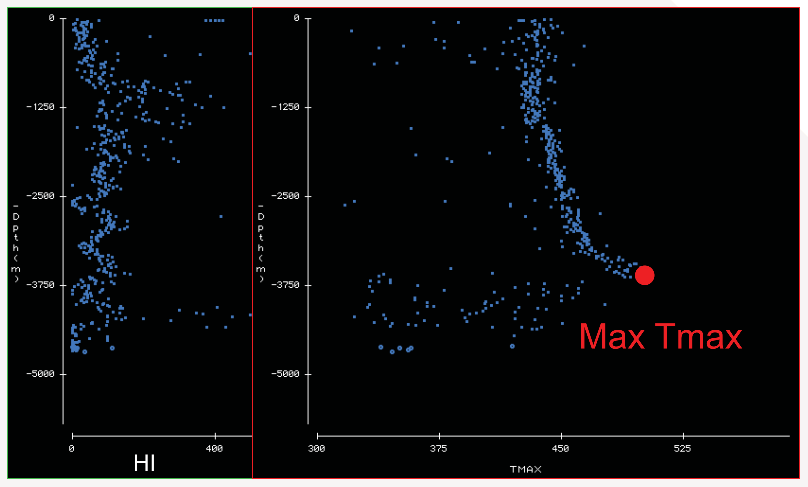

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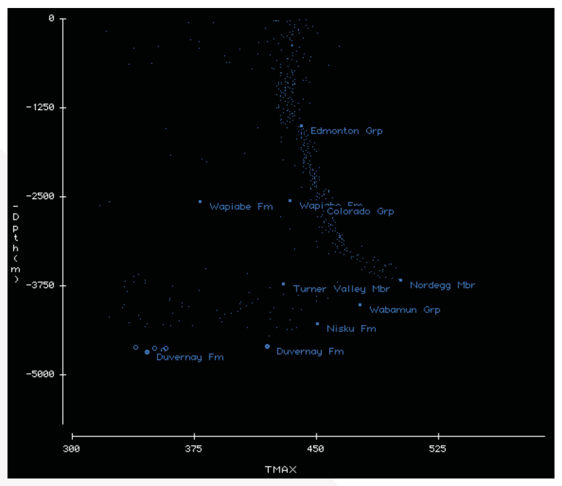
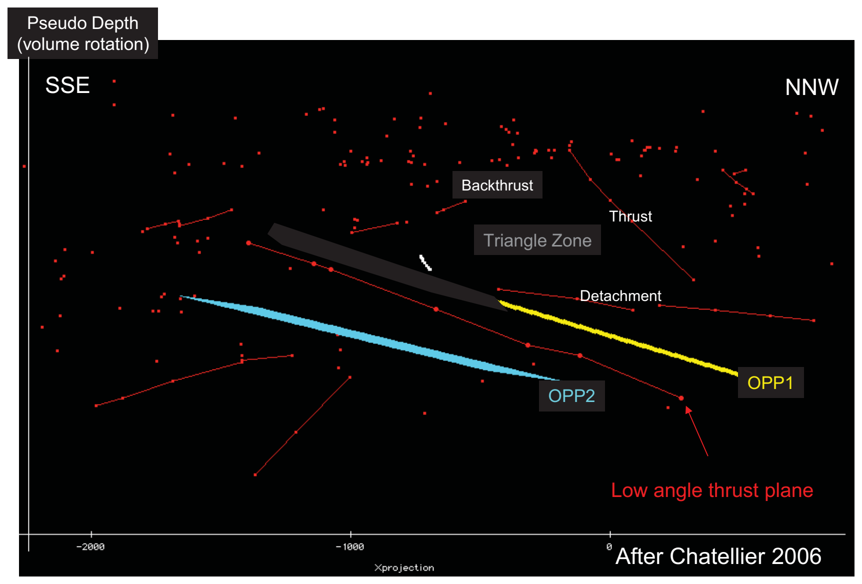
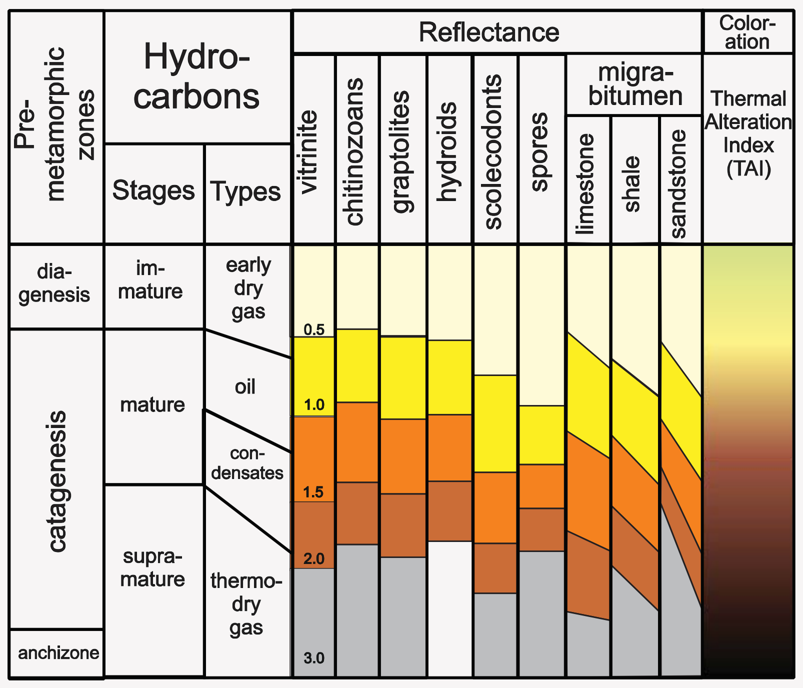


Mapping in 3-D all of the Tmax maxima as shown on the depth plots
Planes are then created using a least square algorithm (see projection to the right)



3-D projection of two overpressure planes
in Alberta (OPP1 and OPP2)
Based on GSC public domain data

Pre-Devonian rocks have no true vitrinite



Courtesy R. Bertrand (2013)

Formula for vitrinite equivalent

Courtesy R. Bertrand (2013)

$$R_{h\text{-}evi} = 0.8873 \cdot R_{h\text{-}chitinozoans} + 0.0124$$
$$R_{h\text{-}evi} = 0.9376 \cdot R_{h\text{-}graptolites} + 0.0278$$
$$R_{o\text{-}evi} = 0.9686 \cdot R_{o\ graptolites}^{\ 0.9819}$$
$$R_{h\text{-}evi} = 0.6493 \cdot R_{h\text{-}hydroids} + 0.2126$$
$$R_{h\text{-}evi} = 1.2038 \cdot R_{h\text{-}scolécodonts}^{\ 0.6824}$$
$$R_{h\text{-}evi} = 1.183 \cdot R_{h\text{-}migrabitumen\ (shale\text{-}marl)}^{\ 0.804}$$
$$R_{h\text{-}evi} = 1.2503 \cdot R_{h\text{-}migrabitumen\ (limestone)}^{\ 0.904}$$

Need specialized
Organic petrographer

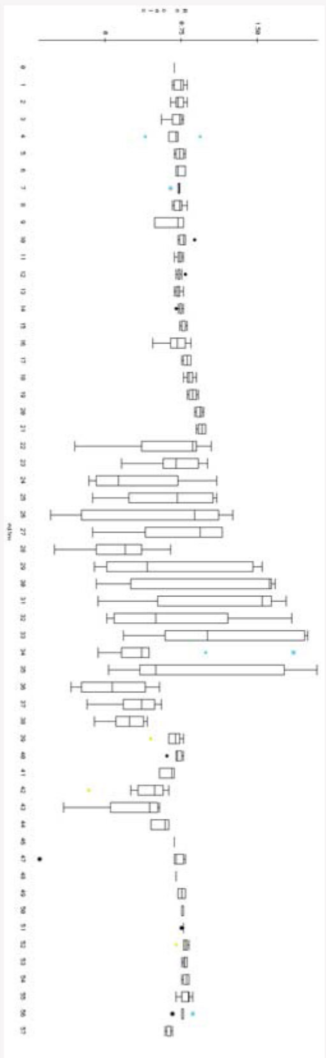
Tmax versus Transformation Ratio

Alberta Example

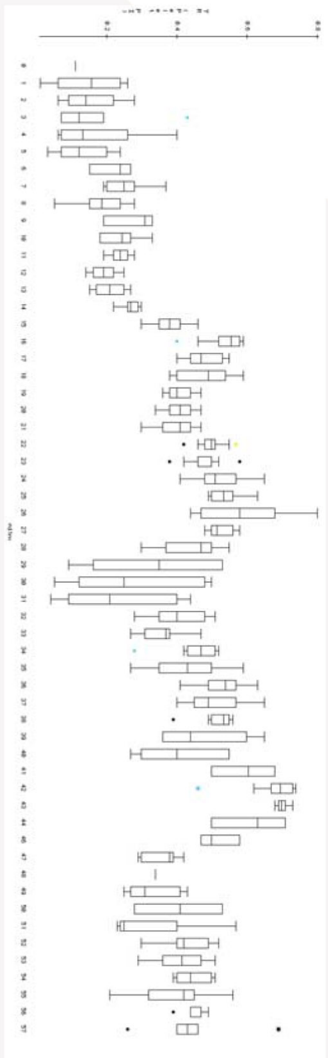
16-31-64-12W6

data from one single well

Ro calc (Tmax)



TR (Pelet)



Tmax can make good use of all of the data; it is not very sensitive to the source rock type

Tmax gets in trouble above 1.1%Ro when oil cracking generates bitumen as a bi-product

Tmax maxima best represent the maturity level reached; however, it fails beyond 1.5%Ro and gives unreliable values

Hence the importance to look at the maturity level up-hole at shallower depths

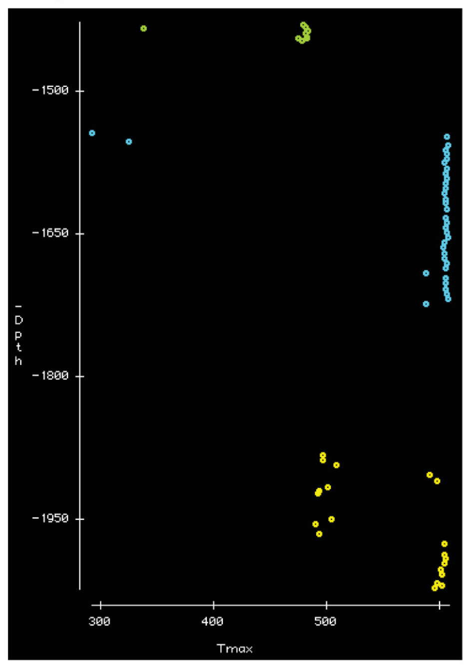
Transformation Ratios should only be used when comparing data from identical source rock types

For TR, it is recommended to have an original Hydrogen Index from low mature rocks

Quebec Example

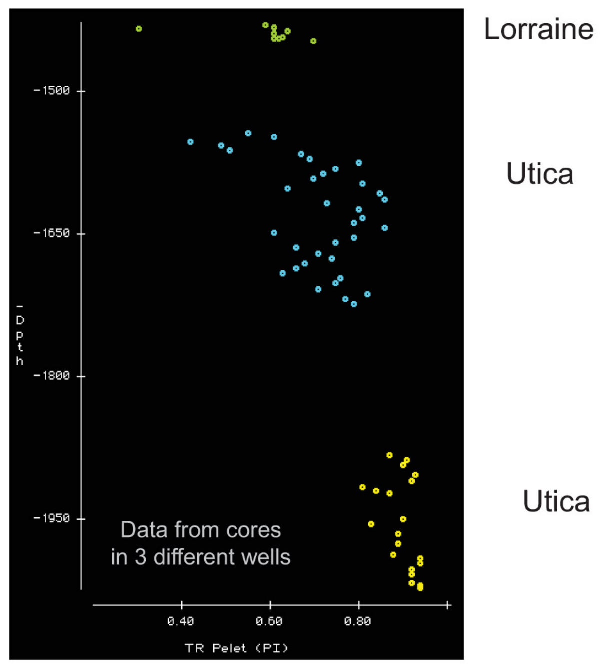
Tmax

Depth



TR (Pelet)

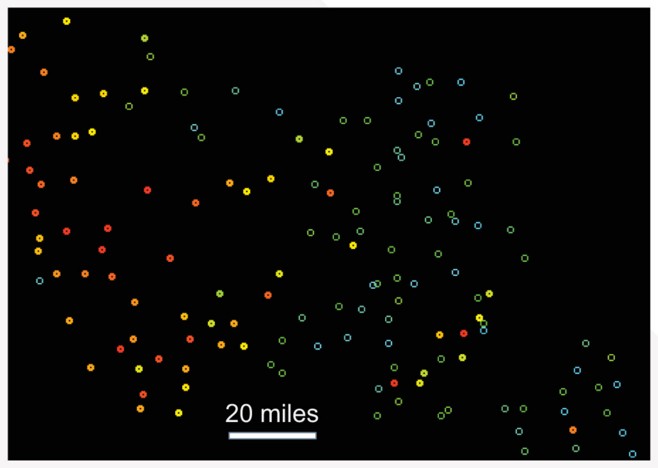
Depth



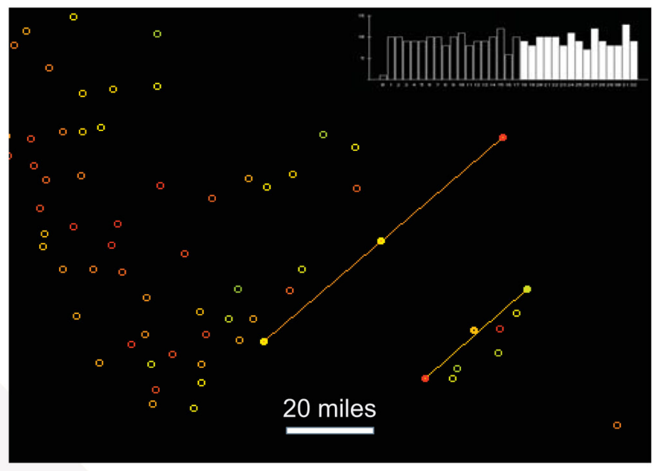
Tmax is inadequate as a tool to assess maturity levels in high maturity domains; on the other hand Transformation Ratio delivers acceptable maturity values and depth trends for high maturity levels

Unspecified North American Example

Transformation Ratios in a type II North American shale



unfiltered



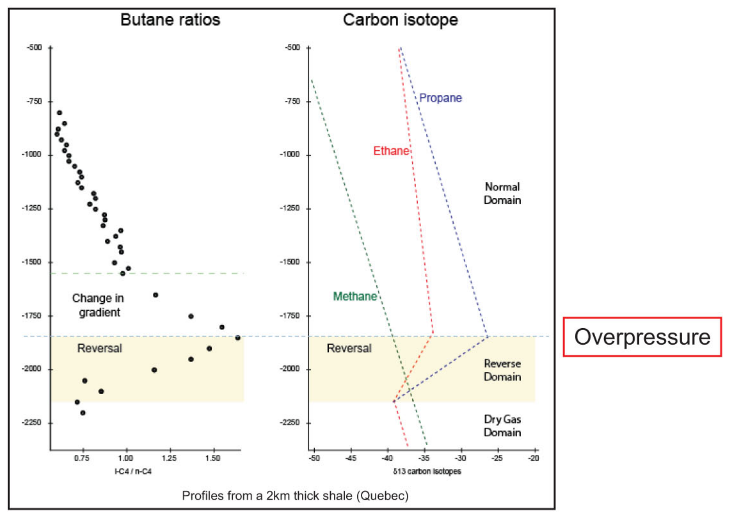
filtered

TR can be very useful to reveal structural elements. In the present example a horst at time of maximum burial is characterized by much lower maturity levels than surrounding rocks and rocks to the West

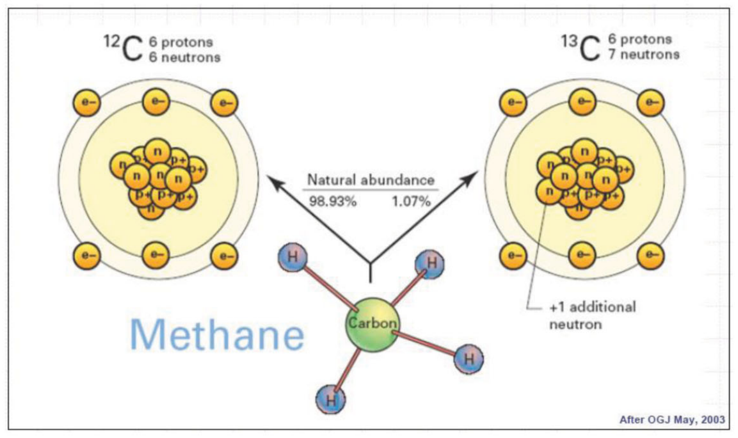
The lineaments drawn on the map on the right are parallel to deep-seated faults marked by high Nitrogen levels

Isotope Reversal and Shale Dehydration

Butane Ratio = a potential substitute for isotope profiling

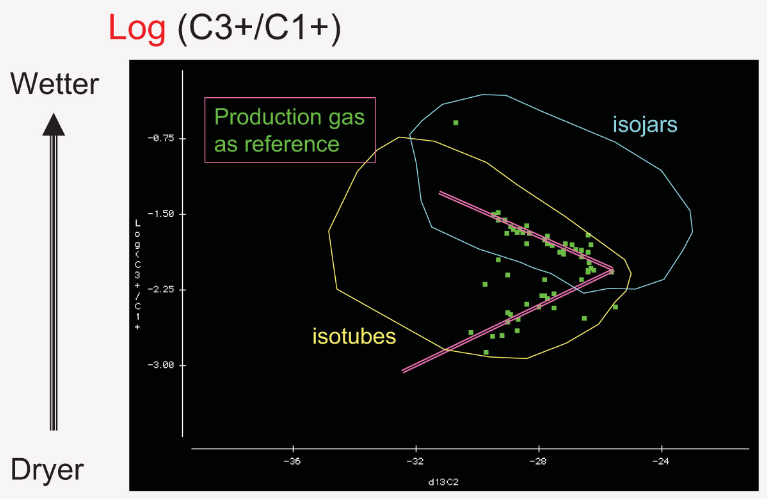


A graphical representation of carbon isotopes



Wetness versus Ethane Isotope

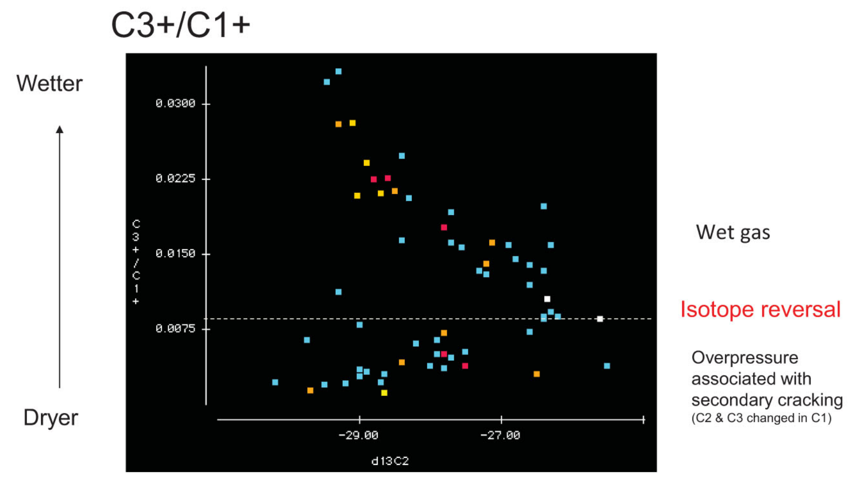
Montney Shale example



C2 Carbone isotope

Isojars exhibit higher wetness than Isotubes.

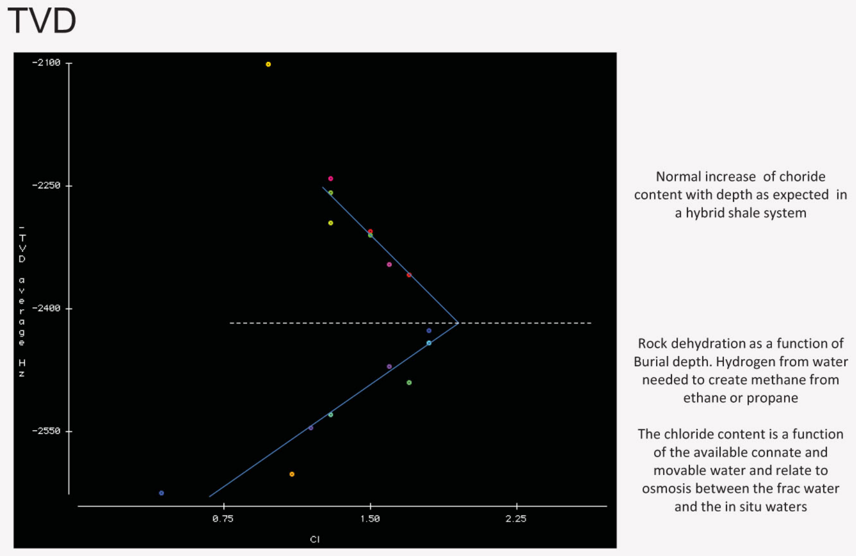
Isojars and isotubes from open fractured shale plot on top of the very well defined trend made up of produced gas compositions



C2 Carbone isotope

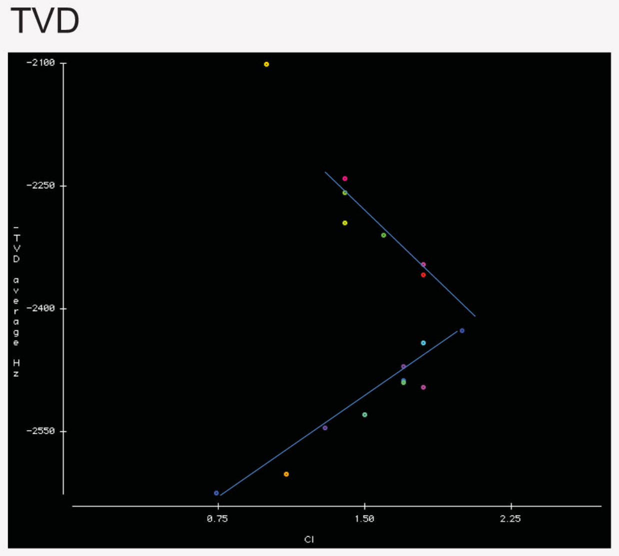
Dehydration in the Dry Gas Domain as seen by Flow Back Water from Montney Shale

Flow back water Chloride composition (~500m3)



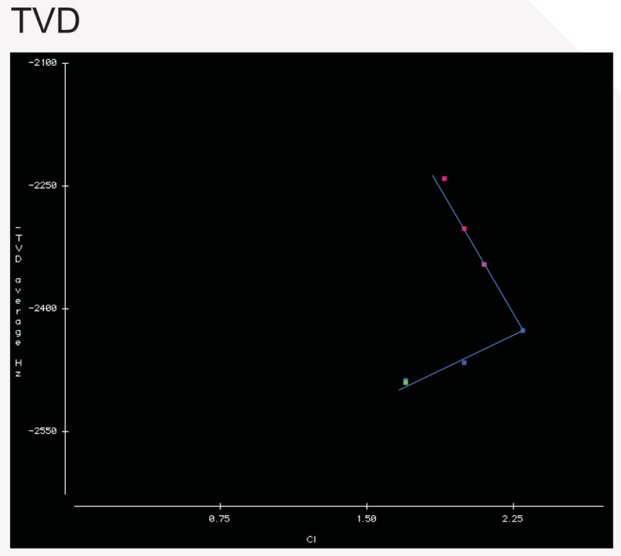
Chloride

Flow back water Chloride composition (~1000m3)



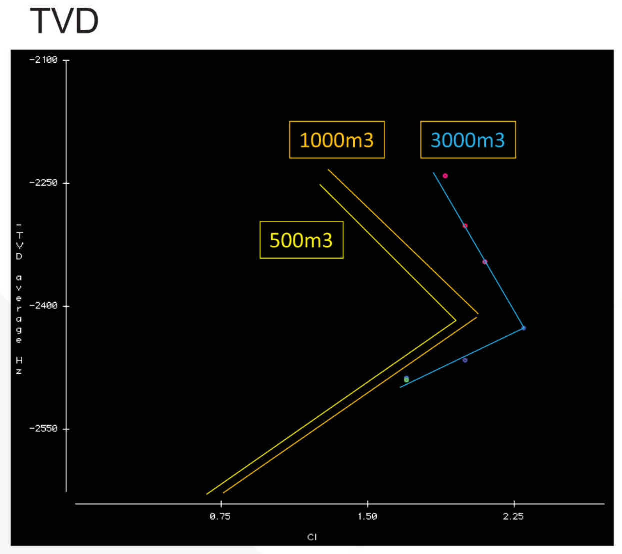
Chloride

Flow back water Chloride composition (~3000m3)



Chloride

Flow back water Chloride composition



Chloride

Salinity of flow back water increases through time. Plots of such changes as a function of volume recovered against TVD depth reveal interesting patterns:

1) There are two well defined trends with opposite gradients; this is a reversal reminiscent of the isotope reversal or of the iC4/nC4 reversal
2) The increase of salinity through time (increase in flow back volume recovered) is faster above the reversal than below
3) The salinity increase is a function of the water saturation as transfer of salinity is through osmosis; chloride being transferred to the fresher flow back water
4) The decrease in chloride content is the expression of the dehydration of the shale as hydrogen is extracted from the interstitial water to generate methane:

$C_2H_6 + 2H \Rightarrow 2CH_4$

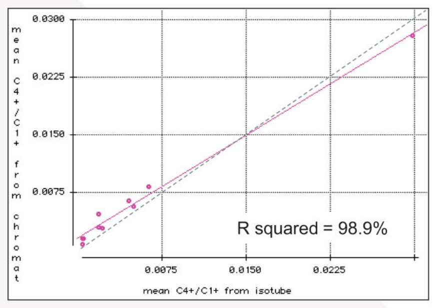
TALISMAN ENERGY

T.S.I.

Observations worth keeping in mind

Conventional Gas Chromatography

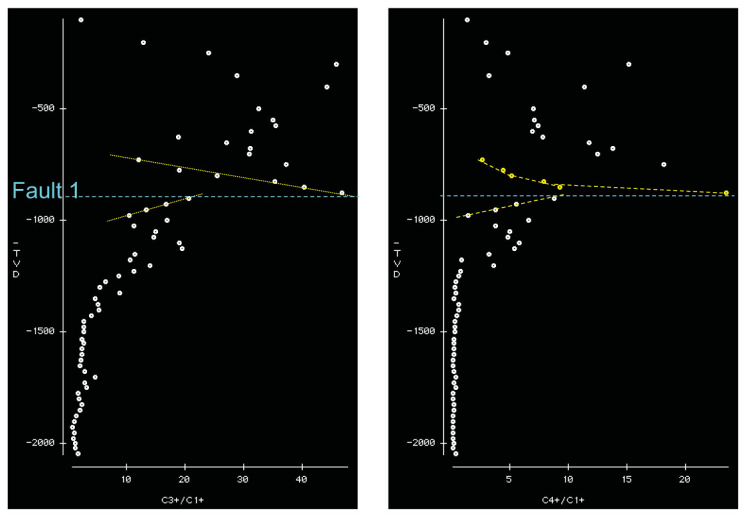
C4+/C1+ Chromat vs Isotubes



This is a comparison between two averages:
- C4+/C1+ from chromatography (~1300 data points)
- C4+/C1+ from isotubes (~6 to 7 points data points)

Conventional gas chromatography is deemed reliable to characterize the wetness of gases in the wet gas and retrogade gas domains: they give the same results as the isotubes

Fault affecting isojar data

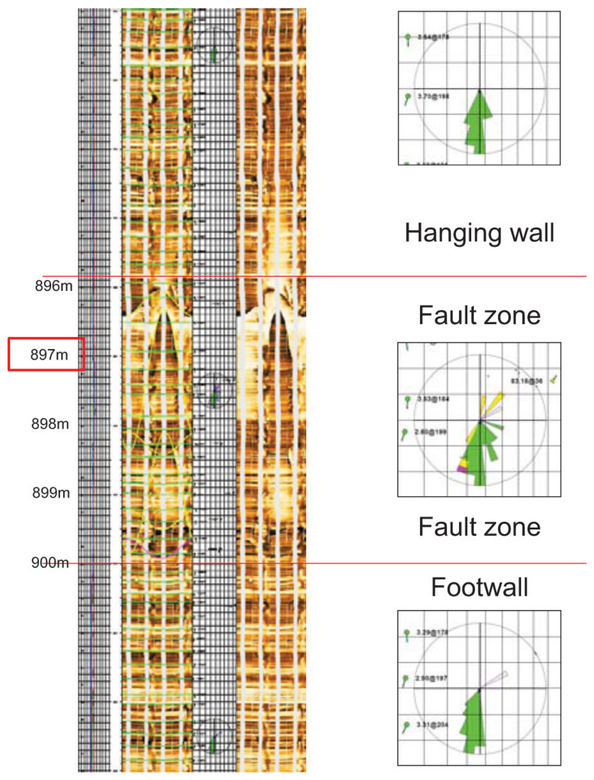


A reverse fault is present around 897m depth.

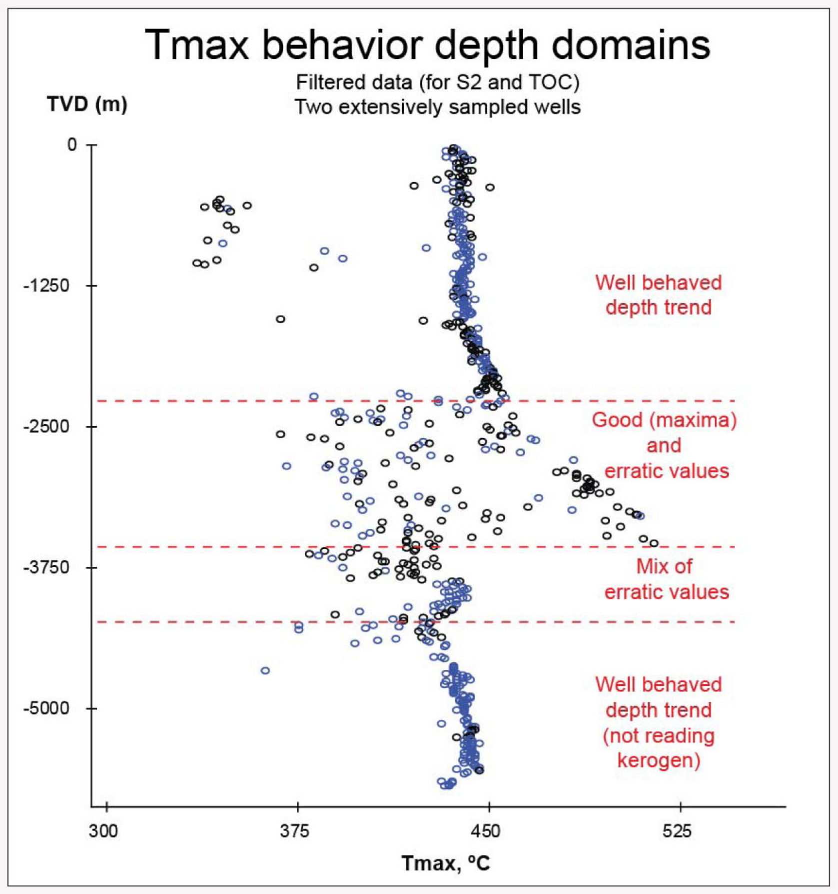
The fault is well defined and recognizable on :
- the FMI Image log

The pattern of C3+/C1+ or C4+/C1+ is linked to the presence of the fault. Increase in C4+/C1+ is interpreted as an increase in fracture permeability.

FMI of the reverse fault around 897m



Oil-cracking-derived overpressure



Chatellier et al. 2010, 2013 in press

1.1%Ro

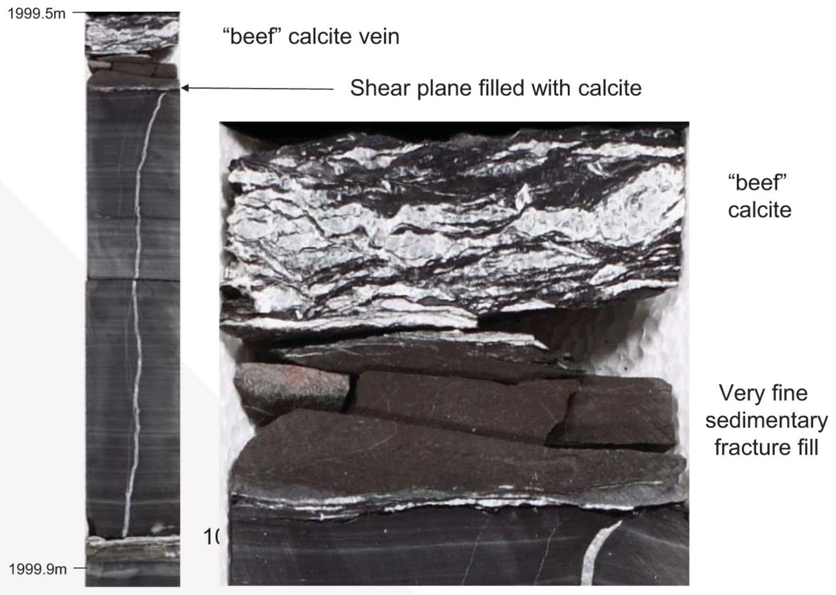
Precipitation of bitumen

1.5%Ro

Tmax from Bitumen

Beef Calcite Generation

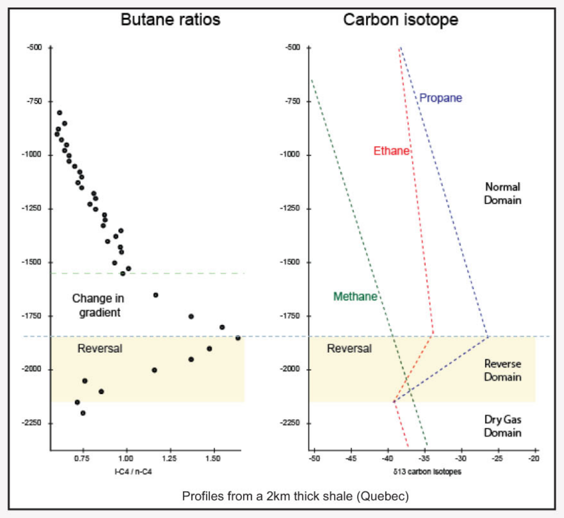
Beef Calcite in Utica Shale associated with oil cracking

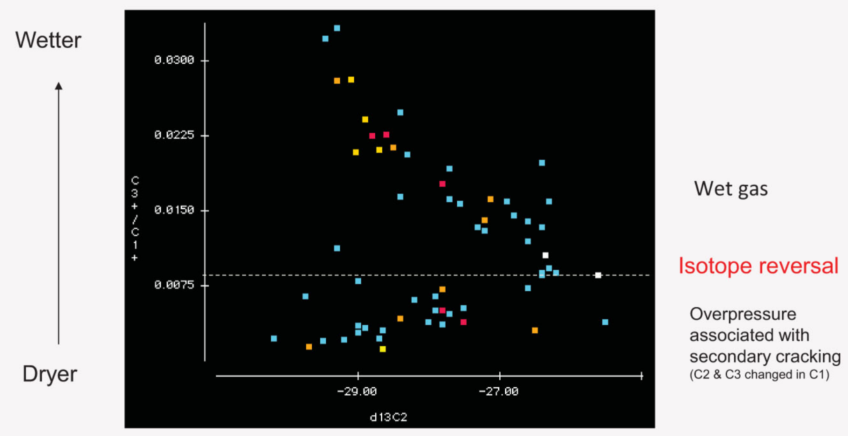


Typical habitus of beef calcite (expansion seams)
Above calcite-filled shear fractures.

Oil cracking and beef calcite precipitation is post-thrusting in the St Lawrence Lowlands. The horizontal calcite layers cross-cut a fold.

Isotope reversal and in-situ gas-generating source rocks





C2 Carbon isotope

Present day TOC of 1.5% seems sufficient to generate in-situ gas

The isotope reversal as well as the volume of gas in the Utica Shale, the Lorraine Shale and the Montney Shale confirm that they have generated in-situ gas despite their present day 1.5% TOC (possibly insufficient to generate oil)

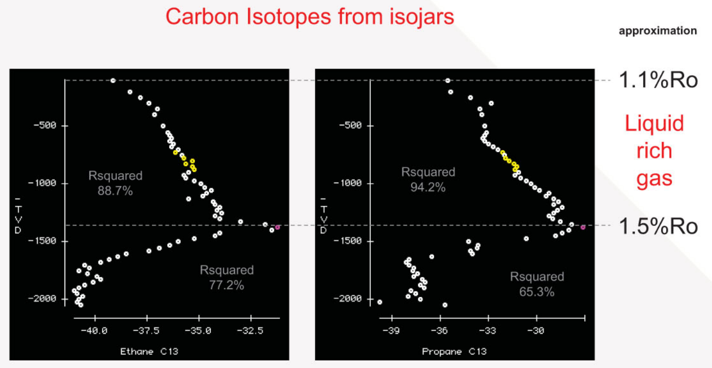
Complementary observations and conclusions

Various expressions of isotope behavior above and below the isotope reversal

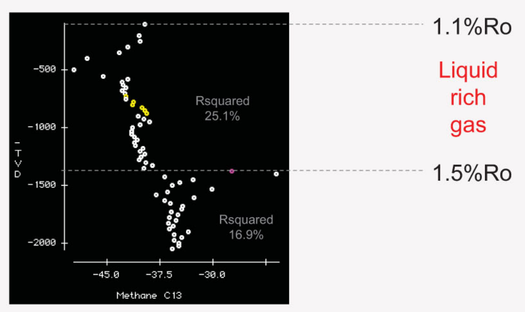
Examples from Quebec St Lawrence lowlands from released data

Testing isojar data set from Well 1

Carbon Isotopes from isojars



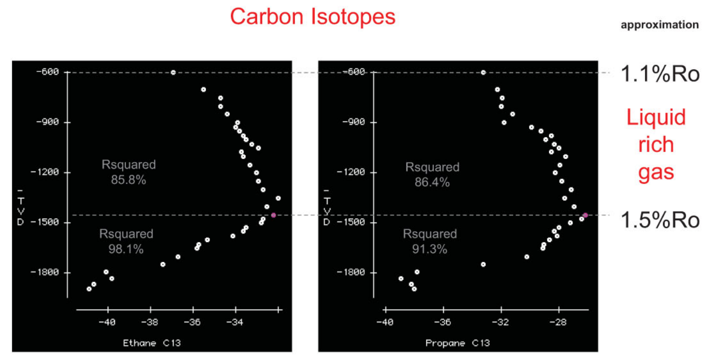
Very well defined trends in the liquid rich domain



Alteration of Methane isotope at and below reversal

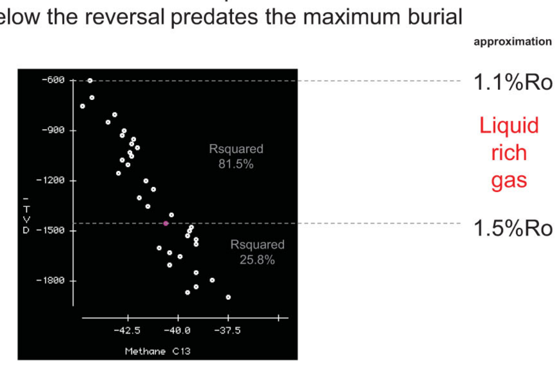
Testing isojar data set from well 2 Hz

Carbon Isotopes



Well defined trends in the liquid rich domain

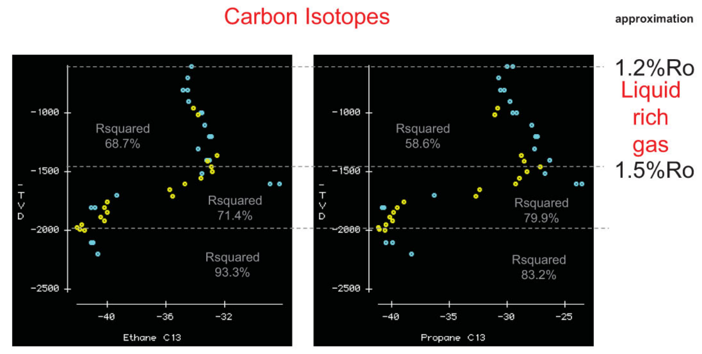
Major fault below the reversal predates the maximum burial

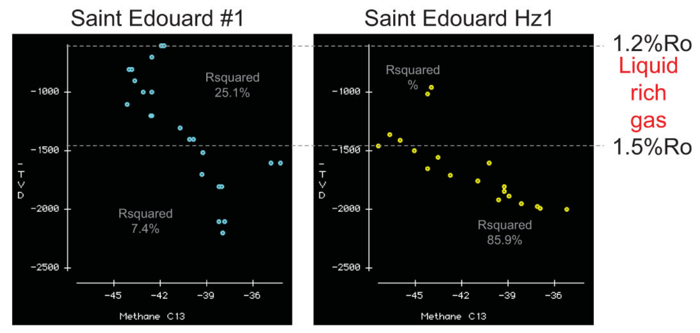


Alteration of Methane isotope at and below reversal

Testing isojar data set from well 3 and 3Hz

Carbon Isotopes

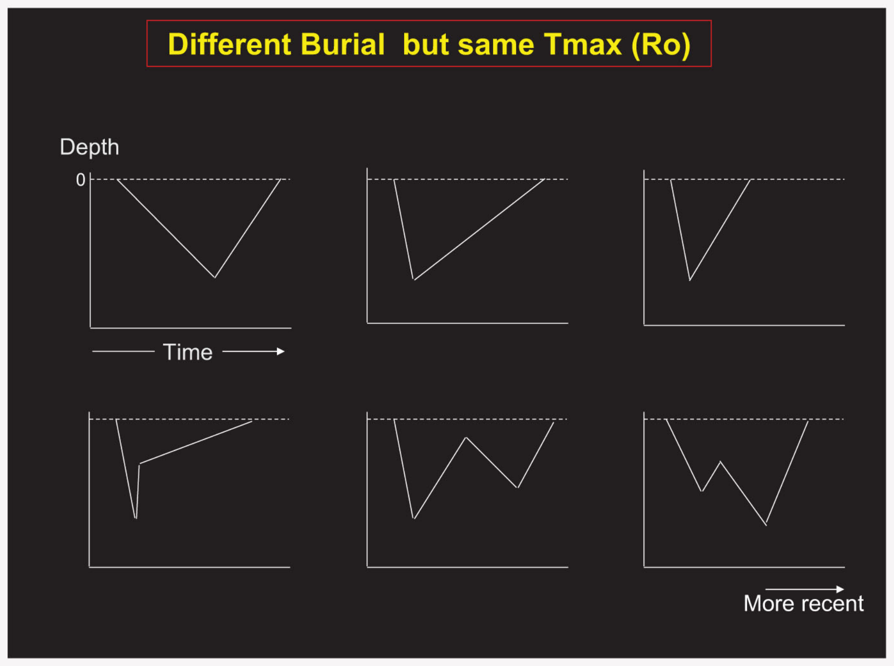




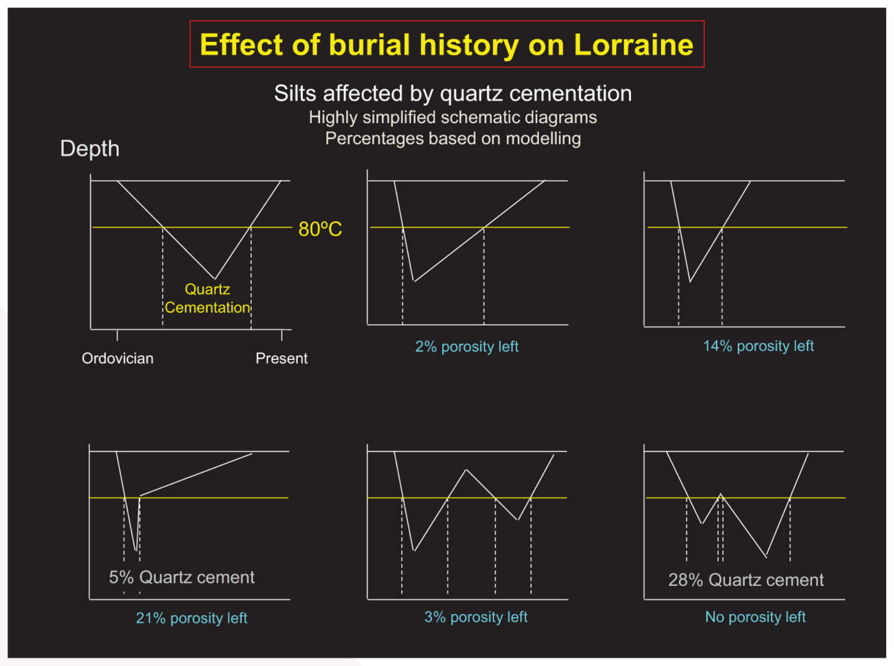
Methane isotope more negative isotope expression associated with interference from the vertical well (30m away)

Maturity indicators only tell one side of the story: The maximum "cooking" Level

Quartz cement can discriminate between various tectonic scenarios



Each of these scenarios has an identical maximum burial



Each of these scenarios has a very different history.
Quartz cement can be modelled, predicted and verified.
Hydrocarbon generation and migration can also be modelled.

Conclusions

- Tmax can be used when using maxima, range and adequate filtering
- Ethane and propane isotopes are extremely useful but calibration is needed for each shale and each sub-basin
- Open fractures and well interferences can alter gas and isotope composition
- Overpressure occurs at time of oil cracking and can be associated with beef calcite
- Overpressure occurs at a pressure controlled depth and is characterized by isotopic and composition reversals
- Basin modelling and quartz cement modelling can help refine our understanding some of our hydrocarbon reservoirs

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