Primary or Secondary Organic Pore Network and Parallel Adsorption Sites in Shale: Dependency on Organic Facies and Maturity in Selected Canadian Source Rocks*

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Abstract

An evaluation of selected source rocks from the Mississippian marine Banff-Exshaw or Bakken and Triassic Montney/Doig formations from Alberta (Western Canada) and the Mississippian lacustrine Horton Group shale sequences from New Brunswick (Eastern Canada) were evaluated, based on the issue of maturity or facies dependency of methane adsorptions, the changes in primary or secondary organic pores in shale, and primary migration of oil within various kerogen networks. The amount of adsorbed and free liquids or gases and primary migration of oil within kerogen network are related to the changes of organic facies (labile versus inert) and organic maturity (oil or gas phase). This data illustrates a close relationship with the neoformed liquid hydrocarbons, change in the proportion of adsorbed and free oil and gases, and the changes in kerogen networks within various shale plays. The selected adsorption and desorption capabilities in selected kerogen Type I, II, II-III shale and carbonate source rocks indicate the possible presence of parallel gas and liquid adsorptions within the labile phases in different phases of advanced maturity. They show changes in both primary and secondary pores within the organic matter of various kerogen types. This data also suggests the possible implications of multilayer adsorptions where adsorptions are pressure- and temperature-dependent. The maturation time sequences of oil and gas adsorptions within various macerals (organoclasts) species change to free oil or gas phases. This process also defines the timing and volumetric changes of primary versus secondary pores in various macerals in shale. This data may also define the path of oil migration within the maceral pore structure for enhanced production within shale.

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June 2, 2015

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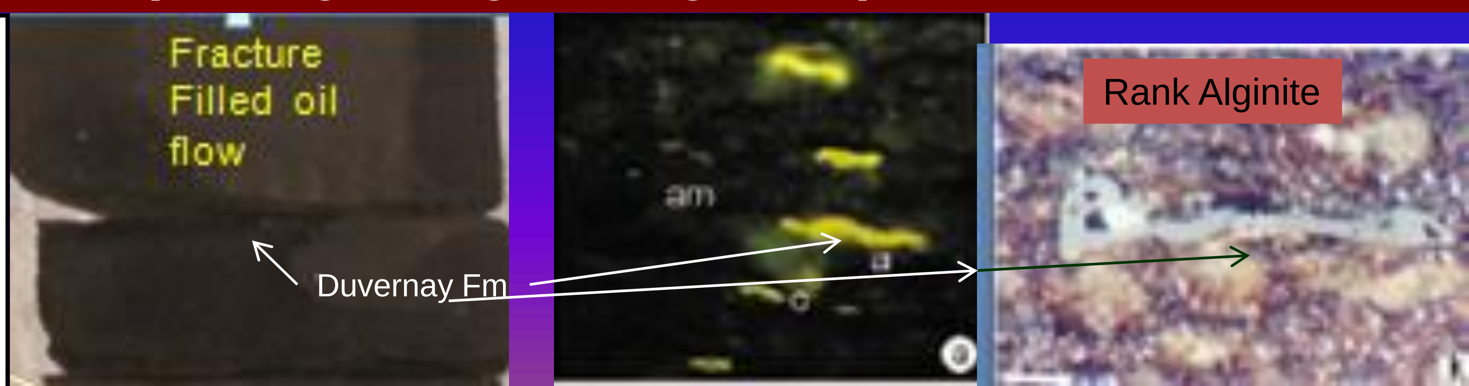


Biogeneic Gas, Shale Oil, Condensate and Shale Gas

Are Nothing But a Maturation Transition of Various Oil /Gas Prone Organic facies

Same Source Rock can Generate Four Sequences of Hydrocarbone

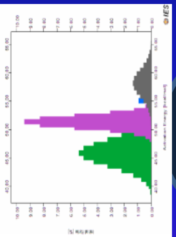
Pores developed in kerogen or bitumen network is a process of continuous change

Biogenic Gas	Shale Oil	Condensate + Wet Gas	Shale Gas
Immature (0.2-0.45% Ro)	Mature (0.45- 0.9% Ro)?	Mature (0.9- 1.4% Ro)	Overmature (1,4- 3.0% Ro)

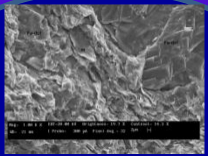
SR Potential

TOC : 1.0 -10%
Hydrogen Index > 250
(mg HC/G TOC)
PI- 0.01 to 0.03)

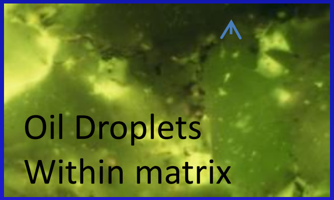
Kinetics

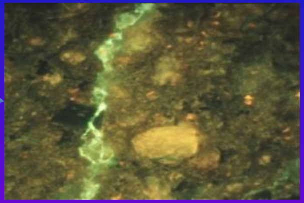


Organic Facies



Mineralogy





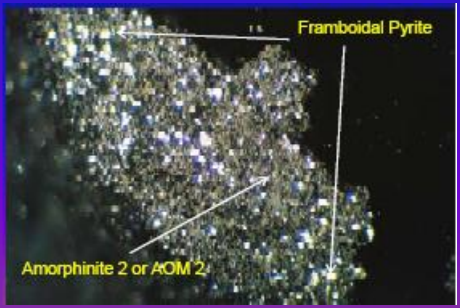
Duvernay
Condensate
API: >45º

Oil Droplets
Or vein within
Source matrix

Original
Type I to II
kerogen

Original
Type II
kerogen

TOC: <2.0%
Hydrogen Index
<100 mg HC/g TOC
PI> 0.15



Organic Pores and Current Status on Organic Pores in Shale Microfabric

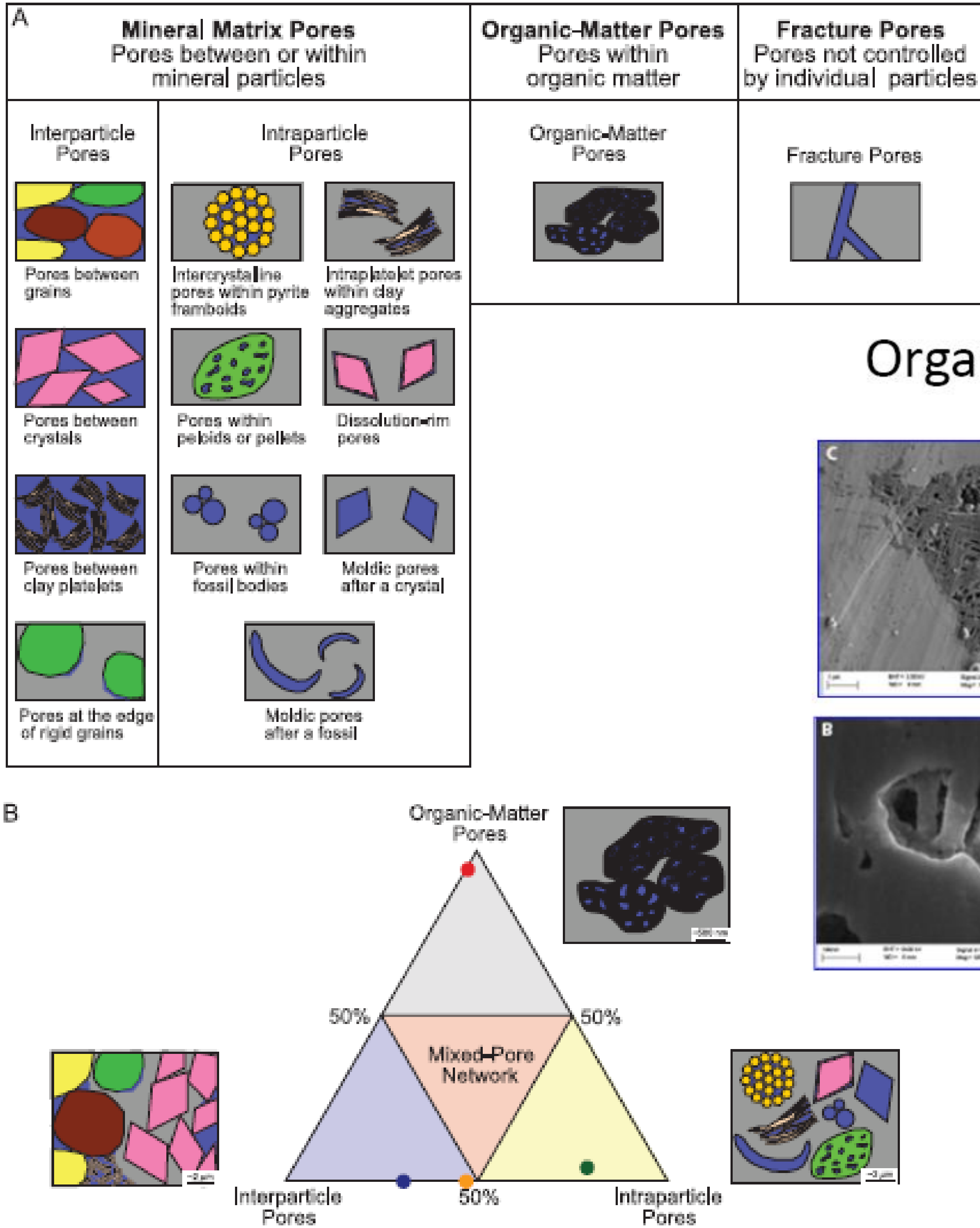
Next to microfacture porosity, organic pores are the most efficient ways for oil and gas migration in globules from a shale micro-fabric and defining "sweet spots" in shale for both types of petroleum systems

Since 1960s, Organic pores have been identiied by the Organic Petrologists working with solid bitumen (Jacob, 1984, 1985; and later continued by other researchers in organic petrography (Bertrand, 1993; Cardott 1993; Landis and Castano, 1996)

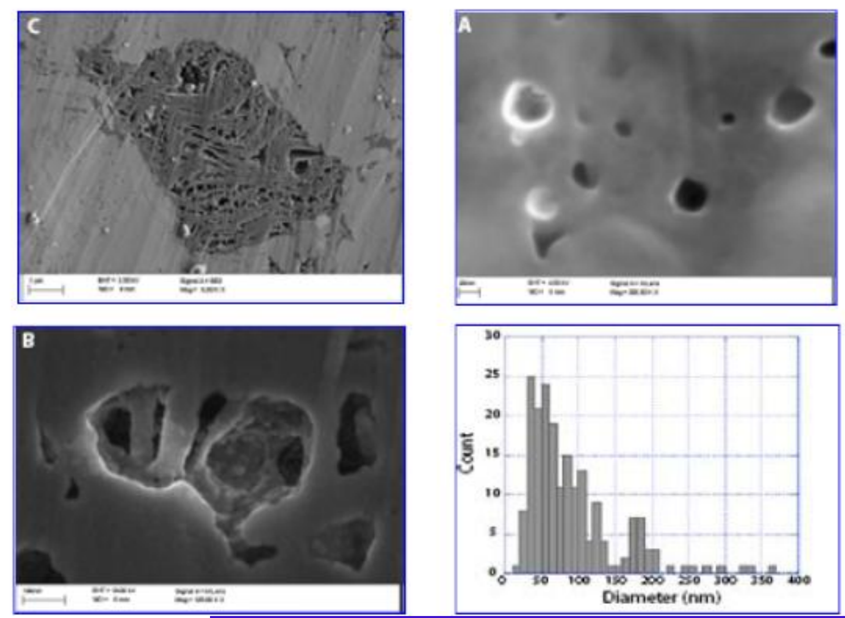
Until 2012, other geoscientists studied shale pores based on ultrafine polished pellets by SEM of the pore distribution of the organics using the association of minerals and organics in comprehensive studies (Loucks et al., 2009, 2011, 2012; Weatherford Lab scientists, 2009, 2013)

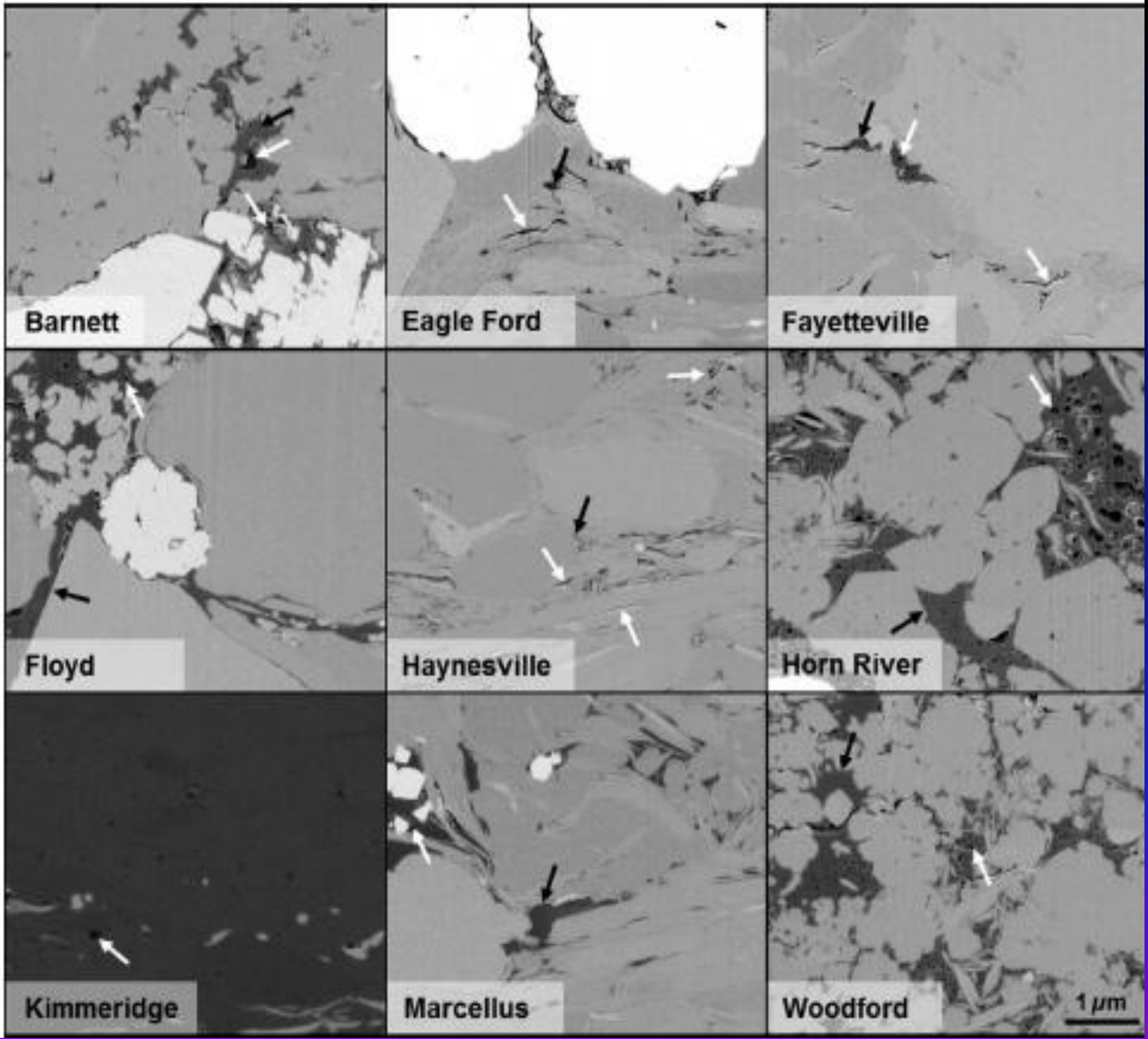
Since 2010, organic petrography was used to identify organic pores in shale for shale gas evaluation and in association with organic adsorption and pores related to macerals (Curtis et al. 2009, 2011,2012; Mukhopadhyay, 2010, 2012; Cardott et al 2015; Sanei et al. 2013; 2015)

Porosity of shale
(after Loucks et al., 2009; 2012)



Organic Porosity Development





Backscattered images shows pore distribution from various North American shales, with British shale

Courtesy: M. Curtis et al.2012 (AAPG Bulletin)

Concept on porosity distribution in shale based on organic petrological Identification (combination of maceral and minerals)

Criteria of Pore Formation within Maceral and Maceral Mineral Groundmass

Factor 1: Density differences within (a) various maceral species and (b) macerals and minerals

Factor 2: Differential adsorption criteria for various macerals and minerals at various stages of maturity

Factor 3: Maturation and formation of secondary macerals as solid and liquid bitumen and rank-liptinites

Mukhopadhyay, 2010, 2012, 2015

Concept of Porosity and Organic Porosity in Shale based on Lab and Organic Petrological Identification (Mukhopadhyay 2010 and 2015)

Pores in both Primary and Secondary Macerals or Organoclasts visible in Incident Light Microscopy, TEM and SEM

- **Micofracture Porosity: Determination on core surface (millimeter scale)**
- **Primary Maceral Pores present during OM deposition for all three maceral groups but mainly dominant in inertinite (fusinite, zooclast cell filling) (mainly in micrometer scale but also in nanometer scale)**
- **Secondary Organic Pores (both in solid bitumen and kerogen microfabric (nanometer to micrometer):**

(a) early mature stage (solid and liquid bitumen phases) (0.3 to 0.6% Ro)

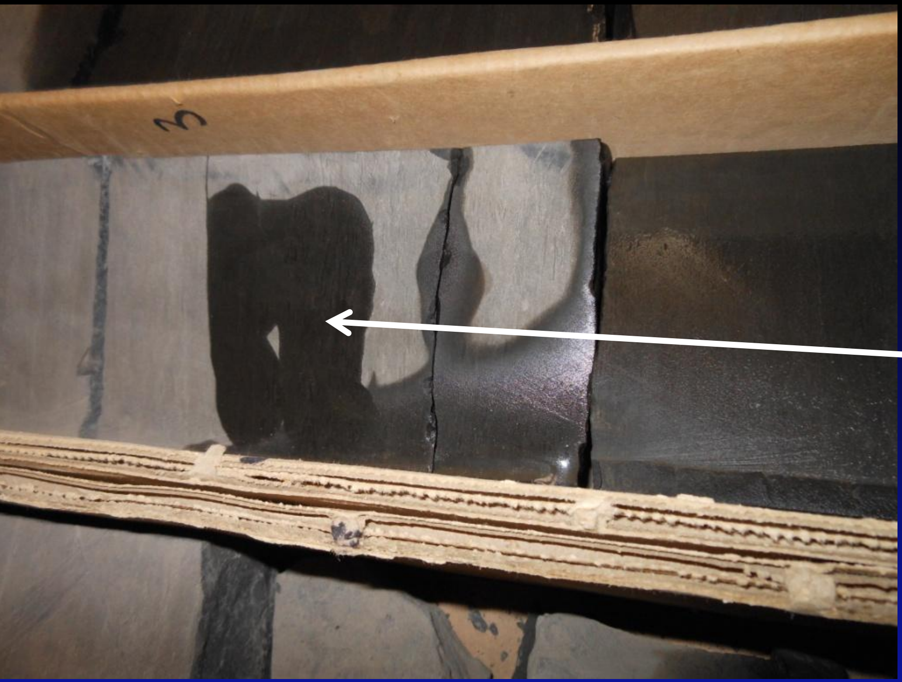
(b) main oil phase (destruction of the oil bubbles) and other ways (0.6 to 1.1%)

(c) main phase of condensate and wet gas stages (0.9 to 1.6% Ro)

(d) main phase of dry gas zone s (1.6 to 3.0% Ro)

(e) gas destruction zone: destruction of pores in rank –alginite, rank-amorphous liptinite (including oil), and vitrinite (3.0% tp 4.5%)

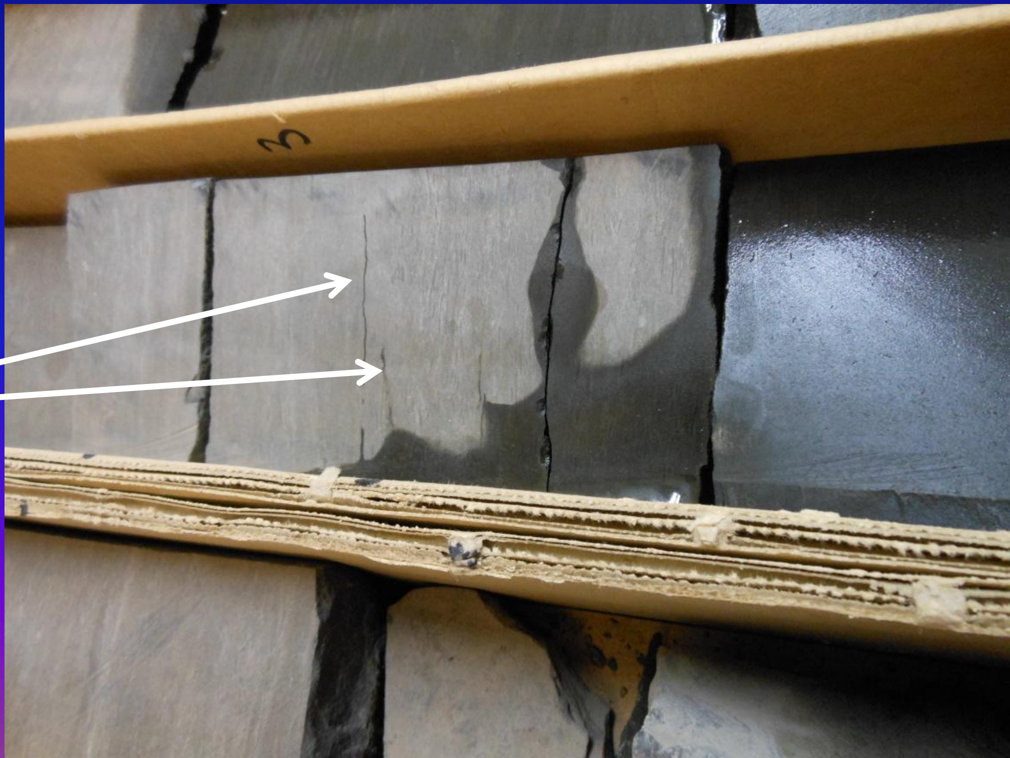
Fracture Porosity in Western Canadian Shale Testing with Acetone within Shale Core from Duvernay Fm, Western Canada



Acetone is poured in shale before drying

Acetone/Alcohol test for identifying fractures in laminated shale (Duvernay Fm; Western Canada)

Same portion of the shale after drying from Acetone showing distinct visible fractures



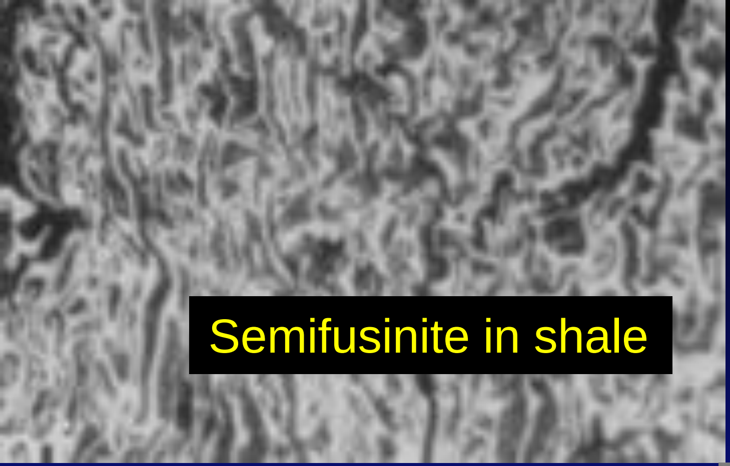
Monterey Type IIS SR is expelling heavy oil at Carpentaria Beach, California

Ro: 0.30%,
Deepwater Monterey Kerogen
Type IIS Source Rock

This heavy oil seepage area showed two different phases: early generation of heavy oil due to catalytic effect of organic sulphur within the organics and formation of solid bitumen (early generated bitumen) almost immediately due to bacterial degradation of the expelled heavy oil

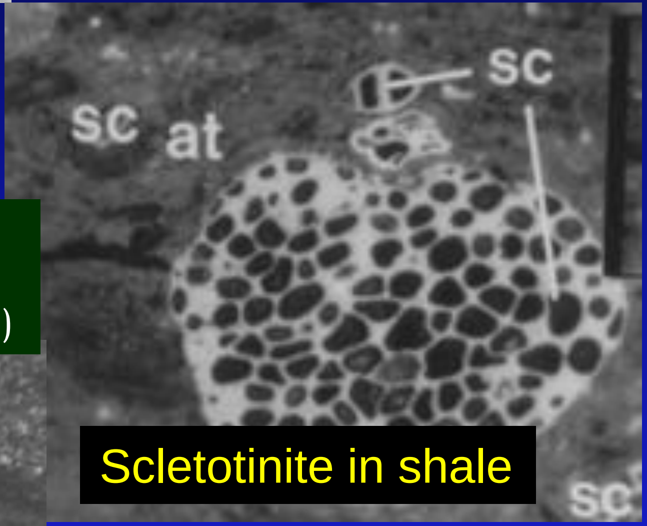
Primary Maceral Pores within Shale Network

Pores present within Primary Macerals inside shale kerogen network



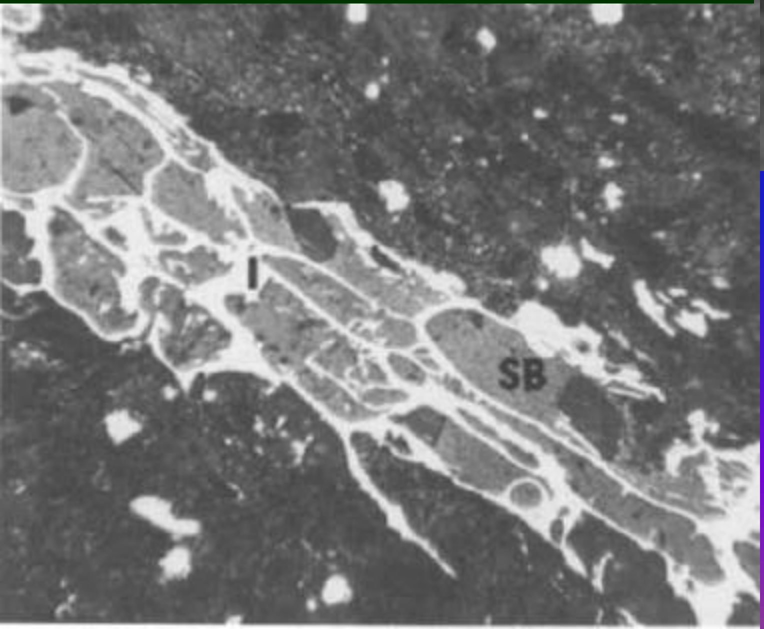
Semifusinite in shale

Ro between 0.2 to 2.5%



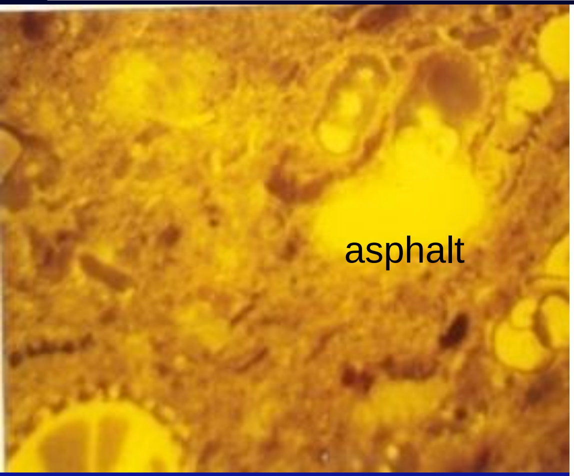
Scletotinite in shale

Solid bitumen within Inertinite
Cell Lumens from Nordegg Formation
(Courtesy:Riedeger 1993; IJCG vol. 22)

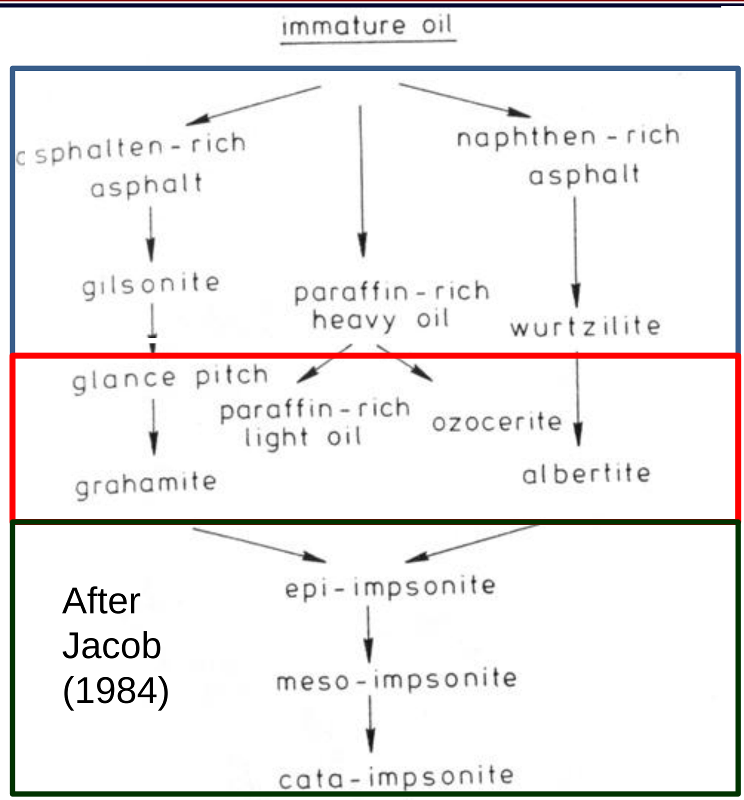


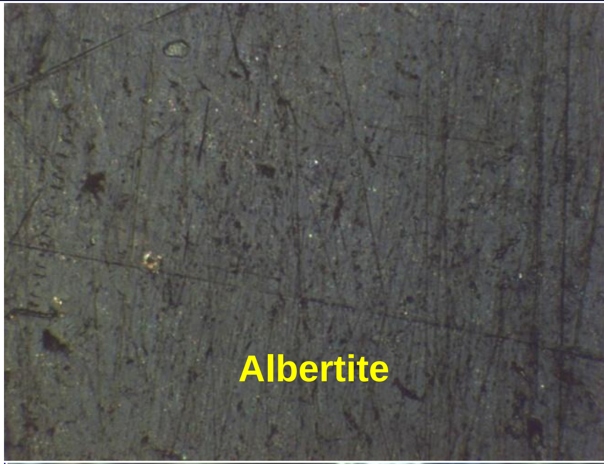
Zooclasts in shale
(bitumen impregnated)

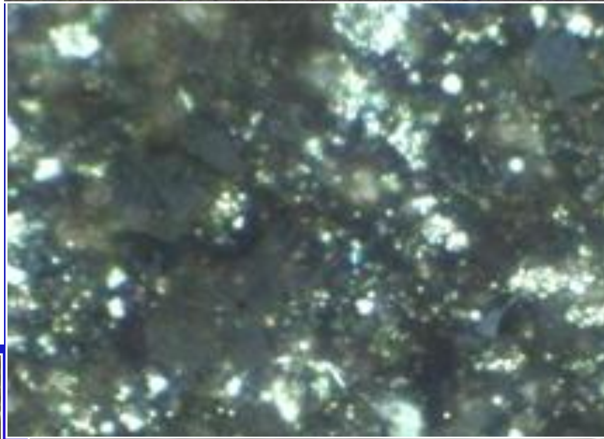
Early generated bitumen, maturation trend, Mobility of HCs, and pores (Ro: 0.3 to 0.6%)

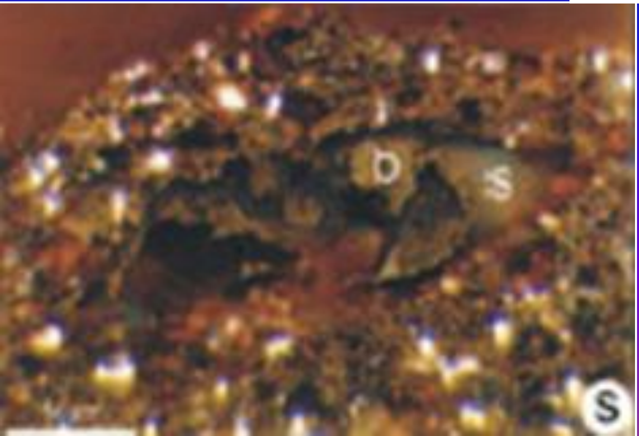


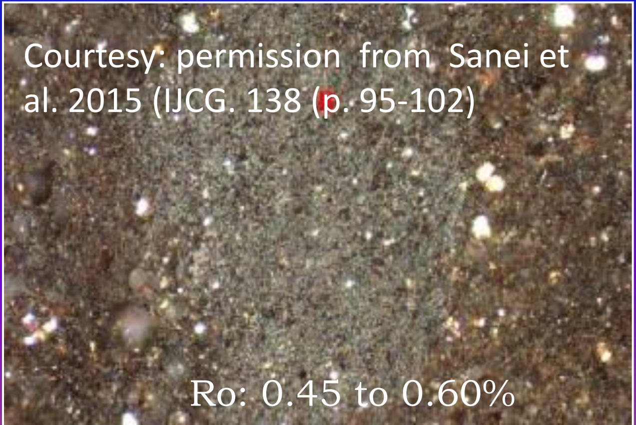
1, Liquid Bitumen: oil
2. Solid Bitumen: pore filling and granular

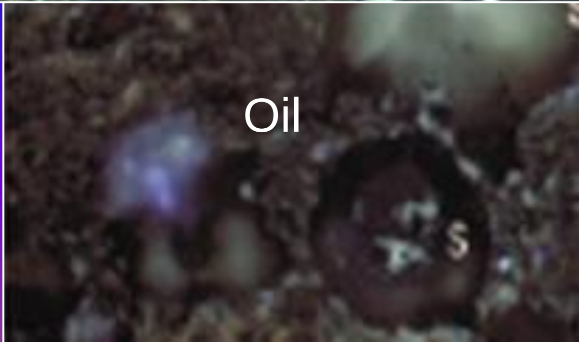






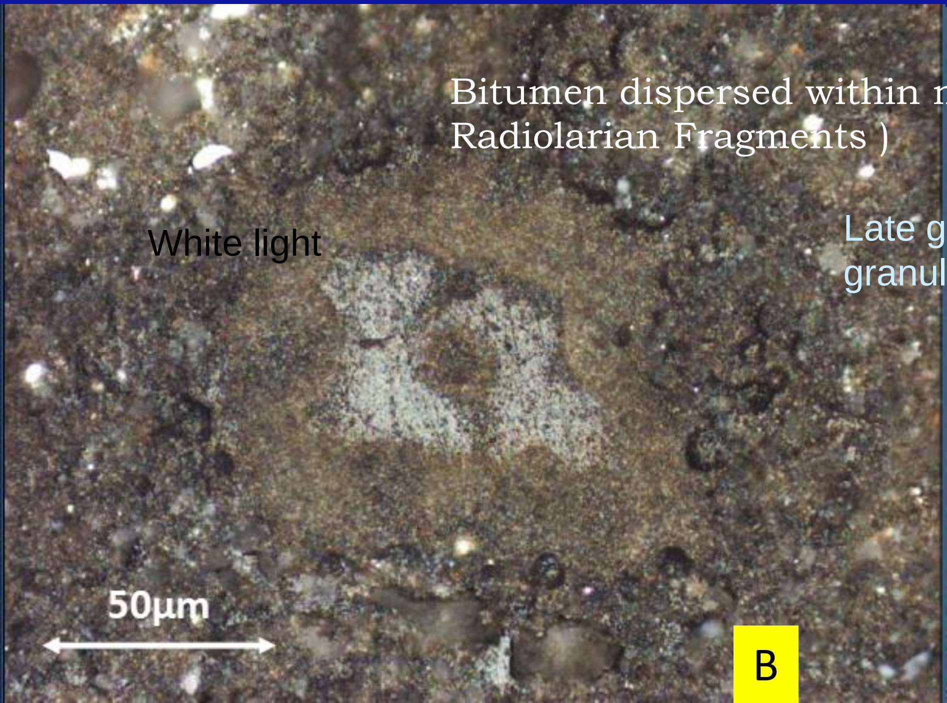




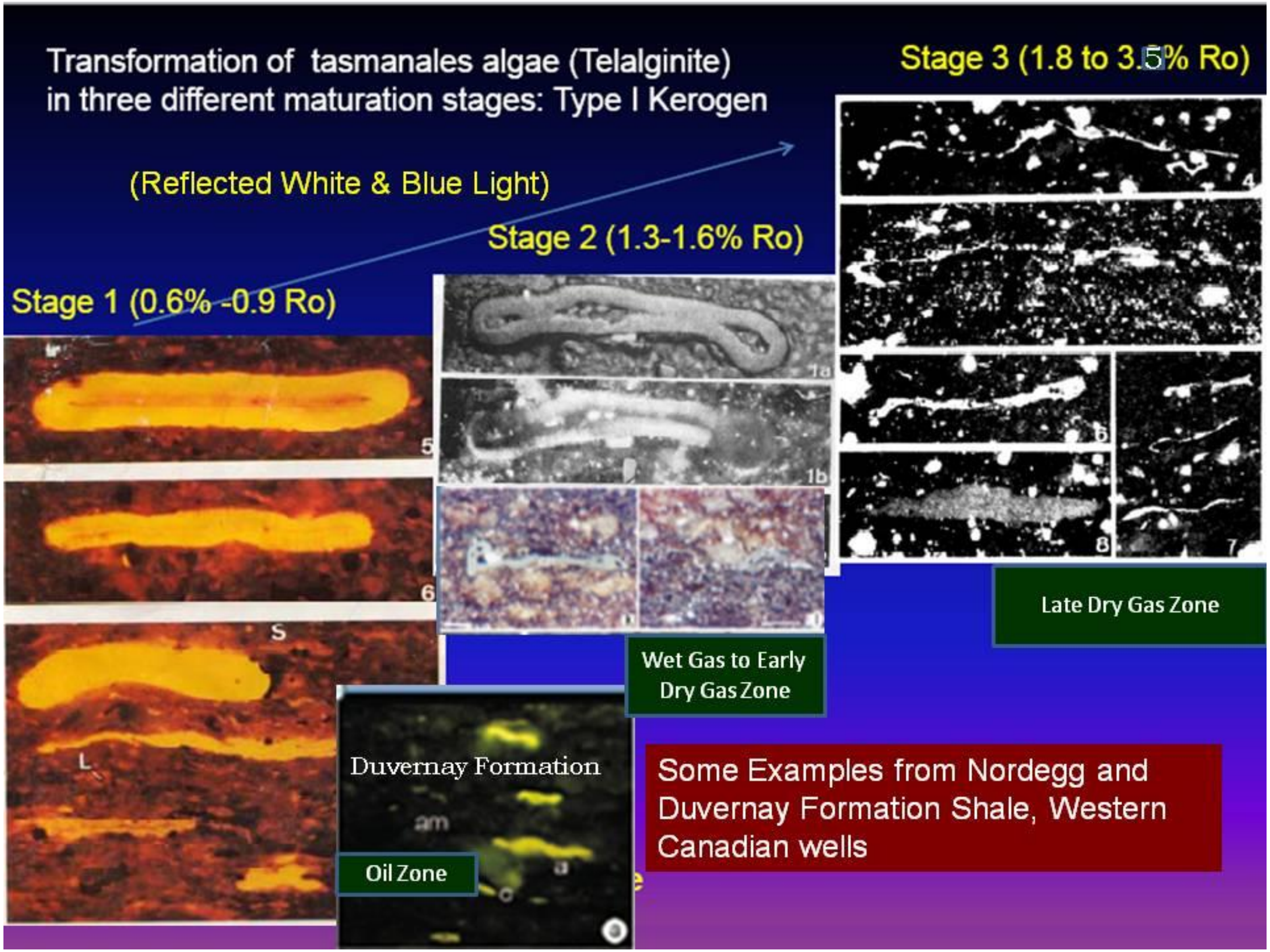


Types of selected solid bitumen within Jurassic Nordegg Formation, Western Canada

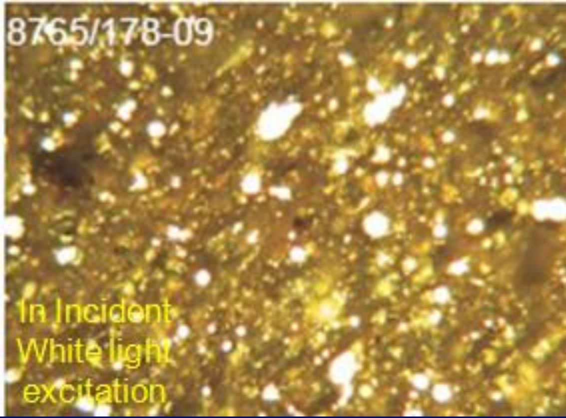
Courtesy: kind permission from Nnenna Isinguzo, University of Calgary, AB, Canada and Dr. Hamed Sanei, Geological Survey of Canada, Calgary, AB, Canada (slide courtesy of Dr. Mark Tobey, EnCana Corporation

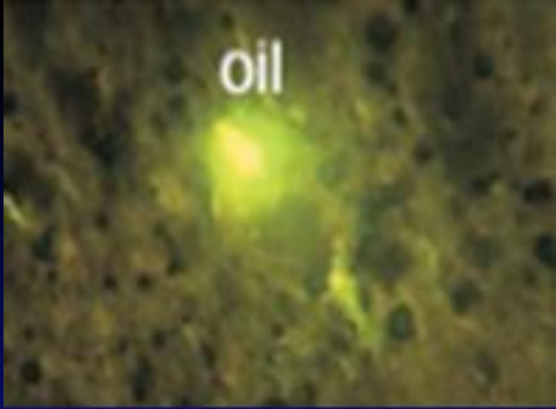


Effect of Advanced Maturity Formation of Pores in in Type I and Type II Shale



Presenter's Notes: Identification of macro-fracture within layers organic rich shale or carbonate using a new technique (acetone drying features).



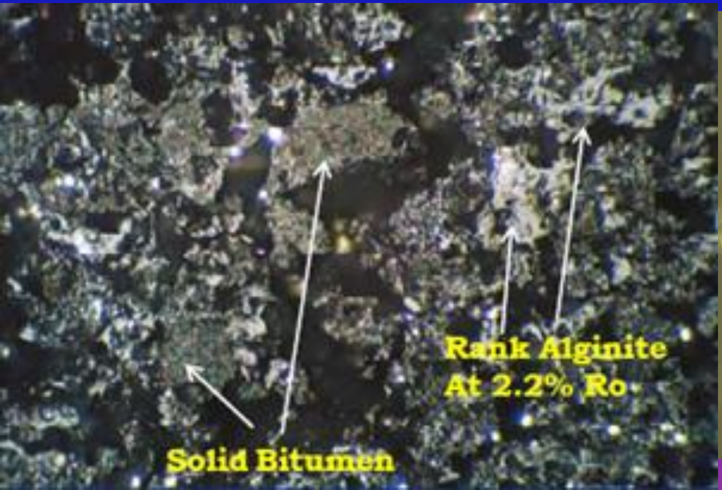


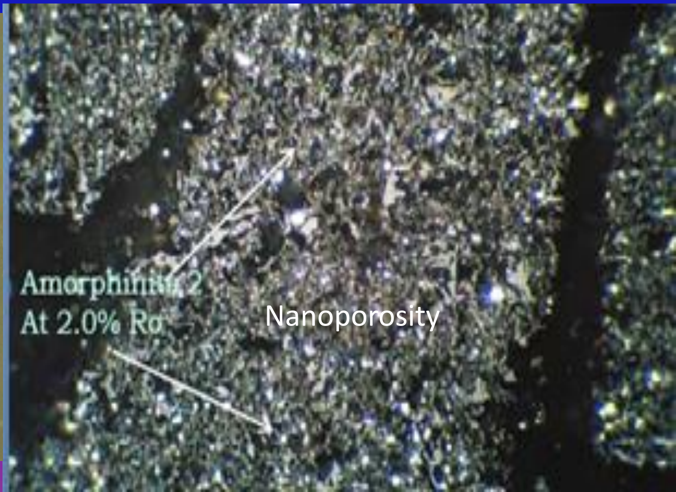
Early to main Oil Zone

Transformation of Type II Shale

Example from the Type II Triassic Montney Formation Shale, Alberta and BC, Western Canada

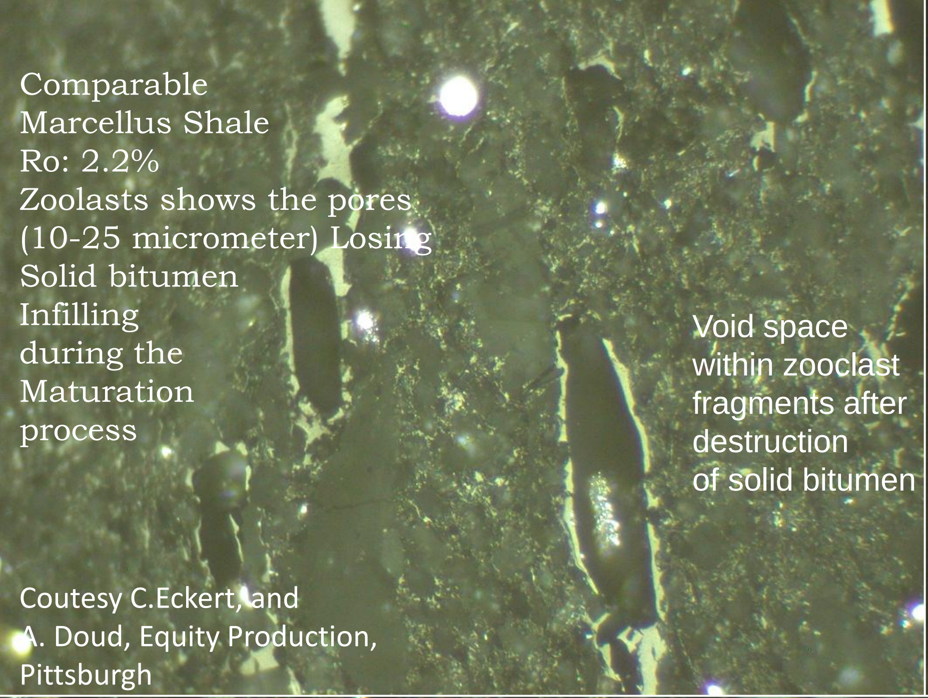
Main Phase of Gas Formation and the Pore formation within algae and amorphous liptinite

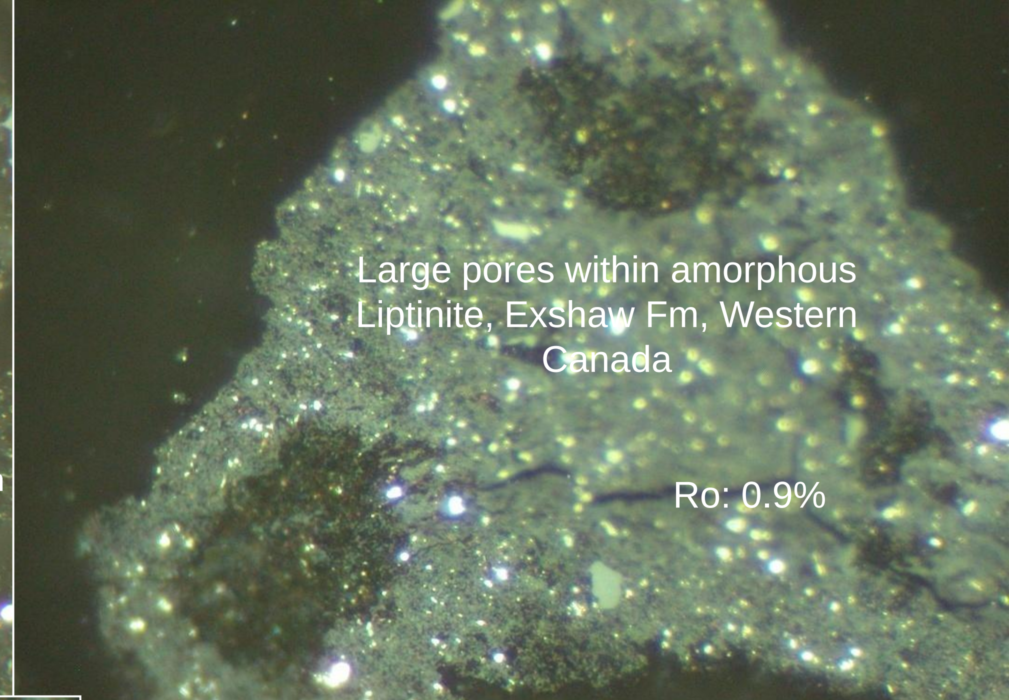


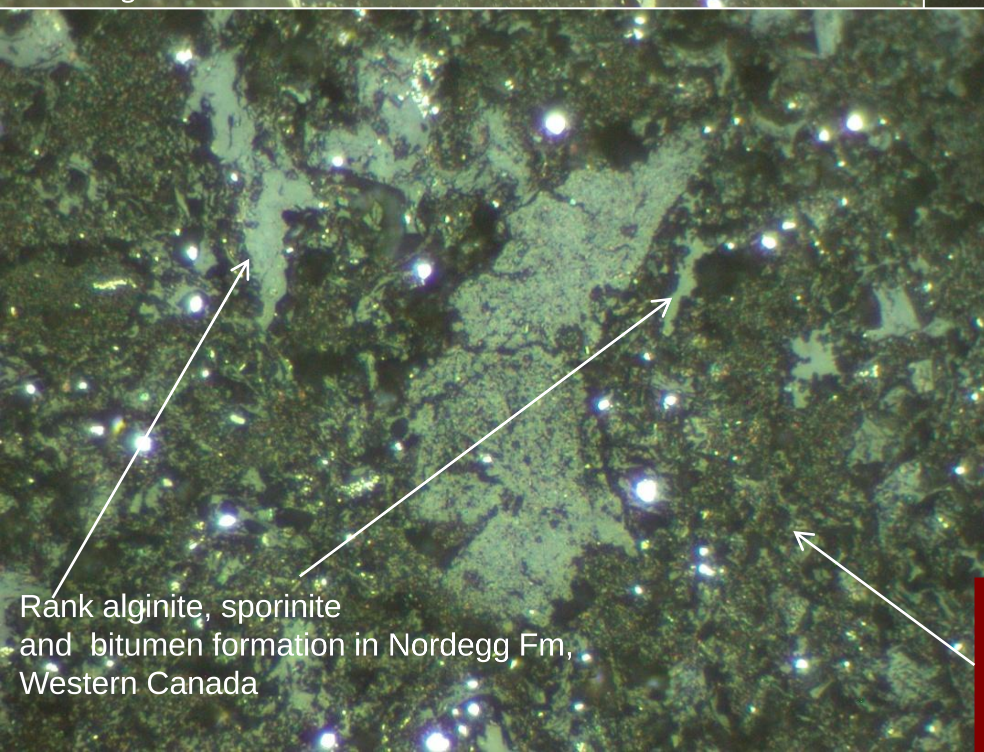


Gas Phase Secondary Porosity within AOM 2 and rank alginite

Maturation Pores







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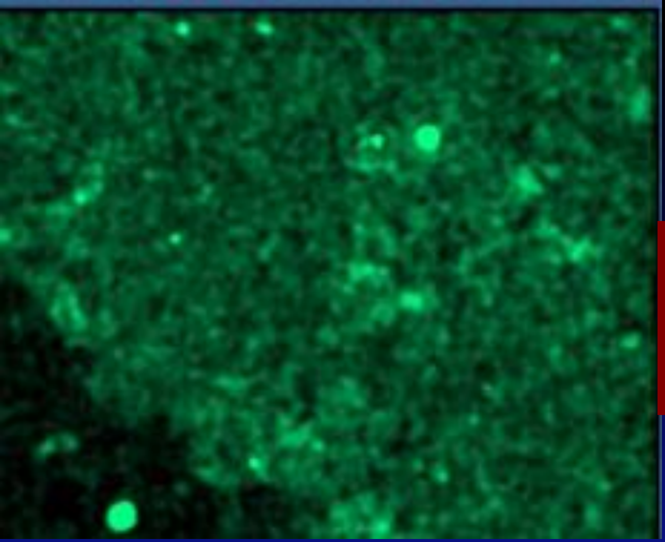
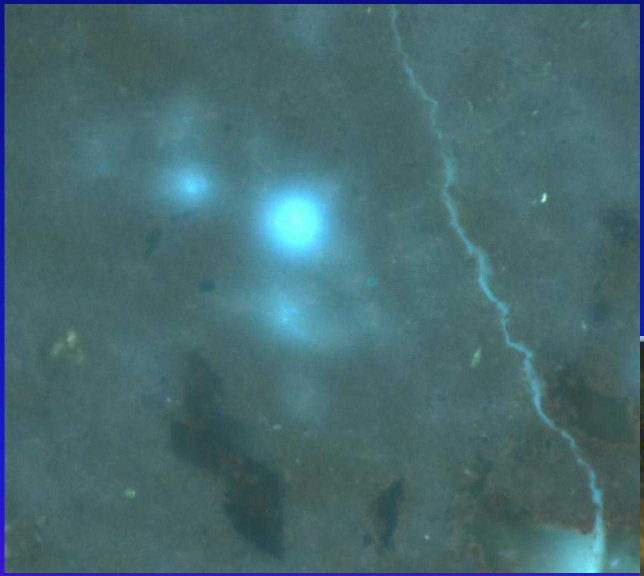
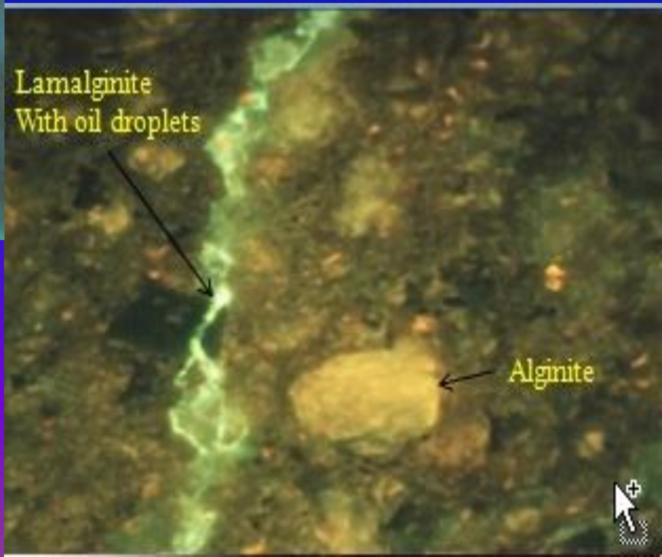


Oil phase bitumen and migration of oil as bubbles and frcture planes within shale in Nordegg and other Shale source rocks from Western Canada





Concept of Organic Porosity in Shale based on Organic Petrological Criteria (Mukhopadhyay 2010 and 2015)

- Fracture due to stress regime and relaxation of stress (mm to micrometer or nanometer sizes (1)
- Organic Porosity developed within Primary Maceral Bodies mostly micrometer to sometimes nanometer sizes (2)
- Development of pores due to differences in density or adsorption capacity (Ro: 0.4% to 0.9%) (3) density variabilities:

  (a)within various maceral grain boundaries (maceral densities: AOM2 – 1.05 to 1.1 g/cc^3; alginite: 1.10 to 1.20 g/cc^3; vitrinite: 1.20 to 1.25 g/cc^3; inertinite: 1.25 to 1.40 g/cc^3; minerals >1.9 g/cc^3
- (b) various maceral and mineral grain boundaries (e.g., clays, pyrite or quartz or carbonate minerals)
- Porosity developed due to maturation effects within both Primary and Secondary (Liquid and Solid Bitumen) Maceral Surfaces (4)
- Migration of Liquid hydrocarbons (as bubble and fracture phases) (5)


Thank You
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National Geographic Magazine
(Web Photo)