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The conditions of primary and secondary fluid inclusion entrapment in clastic sedimentary rocks in the Scotian Basin, and the relationship between inclusion entrapment and reservoir charging

Play Fairway Analysis – Fluid inclusions laboratory analysis contract
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Primary investigator, author: Prof. Jacob Hanley
Research associate: Dr. Atika Karim
Mineral Exploration and Ore Fluids Laboratory
Saint Mary's University
923 Robie Street, Halifax, NS, B3H3C3

Summary

Fluid inclusions were studied in samples of clastic sedimentary rocks from seven wells in the Scotian Basin in attempt to constrain the temperature, pressure and chemical composition of fluid migration during diagenesis and later fracturing of the rocks. The intention of the study was to provide possible thermochemical criteria that can be used to ascertain the likelihood of oil/gas preservation in specific areas of the basin.

Microthermometry was performed on fluid inclusions using conventional heating-freezing microscopy techniques, with the advantage of being able study small (< 5 um) inclusions in clastic overgrowths and cements. Inclusions observed were low-intermediate salinity aqueous inclusions with salinities generally higher than Cretaceous seawater indicating that the sample areas contained pore fluids associated with lithostatic confining pressures. Based on microthermometry, the general thermal evolution of fluids was that of an increase in temperature progressively from quartz overgrowths on detrital quartz grains, to carbonate cements to secondary inclusions crosscutting detrital quartz and cements. Current well temperatures fall considerably below fluid trapping conditions, indicating that a peak thermal event had passed. Fluid salinity does not show a systematic change with time. Minor CO_2 was detected in some inclusions, based on the observation of clathrate melting rather than ice melting. Importantly, with the exception of only a few inclusions, hydrocarbons were not detected and where present, represent the localized heterogeneous entrapment of hydrocarbons (detrital ?) and aqueous fluid and not a primary regional fluid phase that migrated through the rocks. Generally, through the application of a graphic technique that utilizes fluid inclusion microthermometric data to find the actual trapping conditions for inclusions, primary and secondary fluids in dry wells (aqueous charge only) were hotter than in wells with oil/gas showings. In addition to trapping conditions, estimates of the change in sample depth since overgrowth/cementation were made. The graphic technique may provide a reliable means to predict whether a given clastic sequence experienced thermal conditions related to pore fluid migration/entrapment and later fluid fracturing that was appropriate for oil/gas migration and preservation.

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1. Introduction

1.1 Motivation

The formation of a gas/oil reservoir requires that P-T-X conditions within the host formation remain suitable for hydrocarbon stability. Fluid inclusions in clastic rocks associated with hydrocarbon deposits may provide valuable information about the conditions of diagenesis leading up to deposit formation, the likelihood of oil or gas preservation during reservoir charging, and the origin and nature of hydrocarbon-bearing fluids. Whereas bulk rock samples provide information about the cumulative effects of hydrothermal activity, fluid inclusion analysis, when conducted according to current research protocol, can provide a snapshot of conditions associated with single geochemical/hydrothermal events, providing valuable constraints on the origin of deposits by placing stages in the deposit evolution into context with one another.

Unlike in hydrothermal ore deposits hosted in crystalline (metamorphic and igneous rocks), fluid inclusions in clastic sedimentary rocks are rarely studied, due in part to the lack of suitable host phases, ambiguity of diagenetic evolution, and very small size of inclusions that prevent adequate observations in transmitted light for most laboratories. In the offshore Scotia Basin, fine to medium grained clastic sediments provide suitable host phases for fluid inclusion study but limited inclusion data has been collected in this environment and data collected to date appears ambiguous with respect to fluid inclusion origin (see discussion below).

1.2 Objective

The objective of the study was to determine whether fluid inclusion studies will yield any unconventional geochemical criteria that may be used in conjunction with geophysical, biostratigraphic, lithostratigraphic and borehole P-T-X data to delineate new and additional hydrocarbon targets in the offshore environment of Nova Scotia.

2. Methodology

2.1 Sample selection and fluid inclusion petrography

Samples were selected for detailed fluid inclusion study after a comprehensive petrographic evaluation was performed by optical microscopy on dozens of core samples from clastic rocks of the the Logan Canyon, Missisauga and Mic Mac Formations at different depths in the following wells: Dauntless D-35 (n=4 samples), Tantallon M-41 (n=8), Peskowesk A-99 (n=38), Louisbourg J-47 (n=31), Panuke B-90 (n=59), Cohasset A-52 (n=54), Sable Island C-67 (n=9), Kegeshook G-67 (n=1). Examination focused on the following: (i) determination if suitable host phases (quartz, calcite) for fluid inclusions are present, (ii) identification of fluid inclusions, and if present, assigning the inclusions to assemblages. Assemblages are particularly important and were lacking in other studies in the past. An assemblage is a group of inclusions that formed simultaneously within ong a texturally-constrained growth feature, i.e. a growth zone in a quartz crystal (a primary assemblage) or a healed fracture in a calcite crystal (a secondary assemblage). Inclusions and inclusion assemblages were classified by their textural origin, host mineral phase, and visible phase relations at room temperature. Samples deemed suitable for study were prepared into double polished thin sections at Vancouver Petrographics Ltd. (~100-150 μm, two sides with high polish), photographed, and cut into small chips for microthermometric analysis. The chips had to be released from the epoxy and glass supporting base using acetone as a solvent. This does not influence the final data in any way. Fluid inclusions were extremely uncommon in all samples studied, despite an abundance of suitable host phases. Part of this statement is justified by the likely small size (rather than absence) of inclusions. Of all samples examined in the preliminary screening, only 12 were studied in detail. However, it is critical to point out that a few well constrained measurements provide far more than a large volume of data from ambiguous samples in any fluid inclusion study.

2.2 Microthermometry

Microthermometric measurements on fluid inclusions were performed using an FTIR 600 heating-freezing stage (from Linkam Scientific Instruments) mounted on an Olympus BX51 microscope (Saint Mary's University, Halifax, Nova Scotia). The stage was calibrated using synthetic fluid inclusion standards containing pure CO_2 (melting at -56.6°C) and pure, critical density H_2O (melting at 0°C and homogenizing at 374.1°C). All phase changes were observed at heating rates of 1-2°C/minute using a TMS94 stage controller (Linkam). Based on analyses of these standards, uncertainties on measured temperatures are ± 0.2° C for phase changes observed at a heating rate of 1°C/min. The only phase changes that could be observed adequately given the very small size of inclusions were final ice melting temperature (T_m) and homogenization temperature (T_h). Ice melting temperatures were used to calculate NaCl wt% equivalency values for the inclusions (i.e., bulk salinity) based on the salinity-freezing point depression relationship of Bodnar and Vityk (1994). Salinities for some inclusions with ice melting temperatures lower than -21.2°C were calculated in the $CaCl_2$-H_2O system using a salinity-freezing point depression relationship from Zhang and Frantz (1987). Isochores for all fluid inclusions, modeled in the chemical system NaCl-H_2O, were calculated using the formulation of Brown and Lamb (1992).

2.3 Fluid conditions modeling technique developed in this study

The general approach in any fluid inclusion study is to use the phase changes observed under the microscope as inclusion contents are cooled and heated to determine information about the physical and chemical conditions at the time the fluid was trapped. Primary inclusions form when fluid is trapped in growing crystals and the fluid contained in the inclusions represents the fluid from which the minerals grew, thereby constraining the conditions of mineral growth. Secondary and pseudosecondary inclusions occur along healed fractures and are all too often ambiguous since the timing of their formation can only be accurately constrained to be later than primary inclusions, unless cross-cutting relationships between different inclusion trails can be used to determine the relative age of events, and therefore provide some constraints on how fluids evolved in a complex hydrothermal system. In this study, the focus of measurements was on primary inclusions, although some data for secondary inclusions is also reported.

Generally, when an aqueous inclusion is heated (such as those studied here), the inclusion contents move along a boundary in P-T space known as a liquid-vapour curve. As this occurs, the vapour bubble in the inclusions decreases in size until it disappears at a point known as the vapour-out temperature. If this phase change is the last phase change occur on heating (as in this study), it is also called the homogenization temperature (T_h). With continued heating, the inclusion would follow a defined P-T path known as an isochore (line of constant density). The inclusion was trapped at some P and T along this isochore but with microthermometry alone, T_h is only a <u>minimum</u> and will be less than the true trapping temperature (T_t). Also measured during heating of the inclusion from a frozen state is the final ice melting temperature (T_m), which will be lower than 0°C if salts such as NaCl are present. We assume, unless otherwise indicated, that NaCl is the dominant (but not the only) salt present and report the salinity of the inclusion (based on the T_m) as a wt% equivalent NaCl value (i.e., a value that would be the equivalent amount of pure NaCl required to lower the final melting T of water as much as observed during heating the frozen inclusion). The T_h value defines the starting point in P-T space for the isochore, and the slope of the isochore is defined by the inclusion salinity. More saline inclusions have steeper isochores. The described general behavior of inclusions is illustrated below in Figure 1.

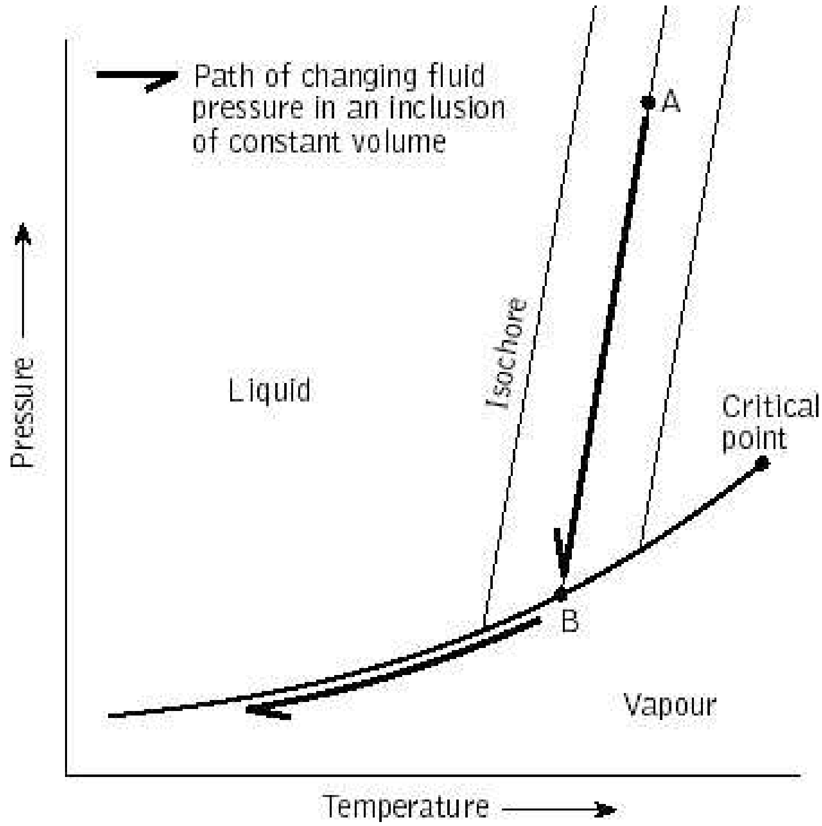


Figure 1. Schematic showing the expected heating-cooling behavior of inclusion contents in P-T space for an aqueous inclusion similar to those described in this study. At the moment of entrapment when the inclusion is isolated from migrating fluid passing through the host rock, the bulk inclusion lies on an isochore (bold line extending below point ‘A’, the trapping P-T for the inclusion). Upon cooling, the inclusion follows an isochoric path to the liquid + vapour curve at which point a vapour bubble appears in the inclusion (point ‘B’). Continued cooling causes the inclusion to pass along the L+V curve below point ‘B’. In the inclusion, the vapour bubble increases in size along this curve. This pathway is reversed during microthermometric measurements, the only difference being that the sample containing the inclusions is not exposed to the same confining pressure as was present at the time of inclusion formation. Heating much higher than ‘B’ can cause decrepitation and this would not provide any additional information because the last phase change in a two-phase L+V aqueous inclusion is the homogenization (T_h, point ‘B’). Shown in the diagram are a series of isochores for inclusions with different T_h values but constant salinities (~ density).

Figure 2 shows the graphical technique developed in this study by the P.I. Hanley incorporating fluid inclusion data and geothermal gradient data to provide constraints on reservoir charging. This technique was applied to each well studied here (see 'Results' below). In Figure 2, primary fluid inclusion isochores (constrained from microthermometric data) are shown and define a diagonal field ("fluid inclusion isochore range") corresponding to the possible P-T conditions at which inclusions in cement (or overgrowth rims on detrital grains) were trapped in the rock. Recall from the discussion above that T_h is only a minimum conditions of entrapment and do not actually represent the absolute P and T (P_t and T_t) associated with fluid migration through the host rock. This is commonly misinterpreted in the literature but it is completely incorrect to assume that higher T_h in one population of inclusions compared to another indicates that the inclusions formed at higher temperature.

Once the field of possible conditions of entrapment are known from microthermometry (i.e., we can draw the isochores for the inclusions), a second constraint (external) of either P or T is needed to constrain the absolute ("true") P and T of entrapment along the isochore. Normally in studies of igneous rocks, this is determined through microprobe analysis of minerals or mineral assemblages for which calibrated geothermometers or barometers exist. The intersection of a known P or T with the isochore constraints the unknown T or P for the inclusion. In the case of clastic sediments, there are no such mineral thermobarometers. The current depth of sample, well pressure and well temperature have nothing to do with the conditions at which the inclusions were trapped, another misconception that can be demonstrated in this study. Additionally, estimates of approximate formation temperature from diagenetic studies only loosely constraint the lowest temperature at which minerals such as quartz or calcite start to form overgrowth and cements (>90 ºC for quartz overgrowths: Worden and Morad, 2000; Schmid et al., 2004; >100 ºC for carbonate cement: Girard, 1998; El-ghali et al., 2006)., whereas true T of formation is likely to be much higher as this study will also show. The only viable method to finding an intersection between the fluid inclusion isochores and some external constraint on P or T is to use estimated geothermal gradients for specific periods of geological time. A geothermal gradient can be drawn as a line on a P-T diagram because depth can be correlated to pressure, and can be shown for two confining pressure scenarios, either lithostatic conditions (assuming overburden and no connectivity between the site of inclusion formation and the ocean floor) or hydrostatic conditions (assuming overburden is pore fluid and that this pore fluid can communicate with the seafloor). In this study, it is thought that lithostatic conditions are more likely to predominate during inclusion formation since the transmissivity (i.e., open permeability) of sandstones at an advanced stage of diagenesis cannot be very high, a point that is demonstrated in here (see 'Results' and Appendix 3). Again, current well pressures indicating hydrostatic or "overpressured" conditions (approaching lithostatic) have no relation to paleopressures within confined pore spaces and should not be related to conditions at the time of fluid migration or entrapment.

In Figure 2 (and for well sites studied, see 'Results' and Appendix 3), the intersection of a geothermal gradient at the time of inclusion formation (estimated ~ 55^{o}C/km; Karim et al., submitted, 2010) and the isochores for fluid inclusions must intersect at a P and T that represents the actual P and T of inclusion formation. In fact, it is best to show the range of isochores, defined by the lowest homogenizing T and highest homogenizing T inclusions. This defines a narrow range of possible P-T conditions. The bold black angled line (indicated with black arrow) in Figure 2 shows the P-T conditions defined by this intersection. Determination of this intersection then provides a meaningful set of P-T conditions for each well that provide valuable new constraints on the relationship between diagenesis and eventual (or possible) reservoir charging at each sample point.

a. The upper P-T conditions at the intersection must <u>represent the minimum conditions prior to fluid overpressuring</u> (required to cause fracturing in the rocks necessary to allow fluid transmission and reservoir charging) since, unless rocks are exhumed partly after cementation, post-diagenesis burial of the rocks should correspond to increasing confining P and increasing T as the samples drop deeper along the regional or local geothermal gradient.

b. The P of primary fluid inclusion entrapment when compared to the current lithostatic P at the sample site (not the well pressure) allows us to determine the amount of burial that has occurred since fluid inclusion entrapment, and specifically determine by how much potential reservoir rock depths changed after quartz overgrowth and carbonate cementation. Differences between inclusion entrapment P and current lithostatic P are associated with burial.

c. The T of primary fluid inclusion entrapment allows us to determine the temperature of the rocks prior to reservoir charging. Rock temperature will continue to increase after primary entrapment during burial, a statement confirmed by the microthermometric characteristics of secondary inclusions in this study. If the oil or gas thermal windows (oil: 70-170^{o}C; gas: 170-270^{o}C; Selley, 1998) are lower than the primary fluid inclusion temperature, oil and/or gas in the rocks or passing through the rocks would not be preserved, resulting in “dry” reservoir charging (i.e., fluid migration during fracturing, but with no hydrocarbons present). If the window is higher or at equivalent temperature to the calculated inclusion entrapment conditions, oil and/or gas passing through that rock at some post-diagenetic stage could have been preserved and therefore, the area may be prospective for exploration.

Note that the geothermal gradient used for the graphical interpretation is considered a maximum, while lower gradients, consistent with observed temperature profiles in primary inclusions are in the range of 20-35^{o}C/km. The intersections of lower gradient lines with isochores occur at higher P and T because the gradient lines are steeper. This would raise the window of inclusion entrapment farther outside (higher than) the thermal window for oil preservation, and into the thermal window for gas preservation for many of the studied wells.

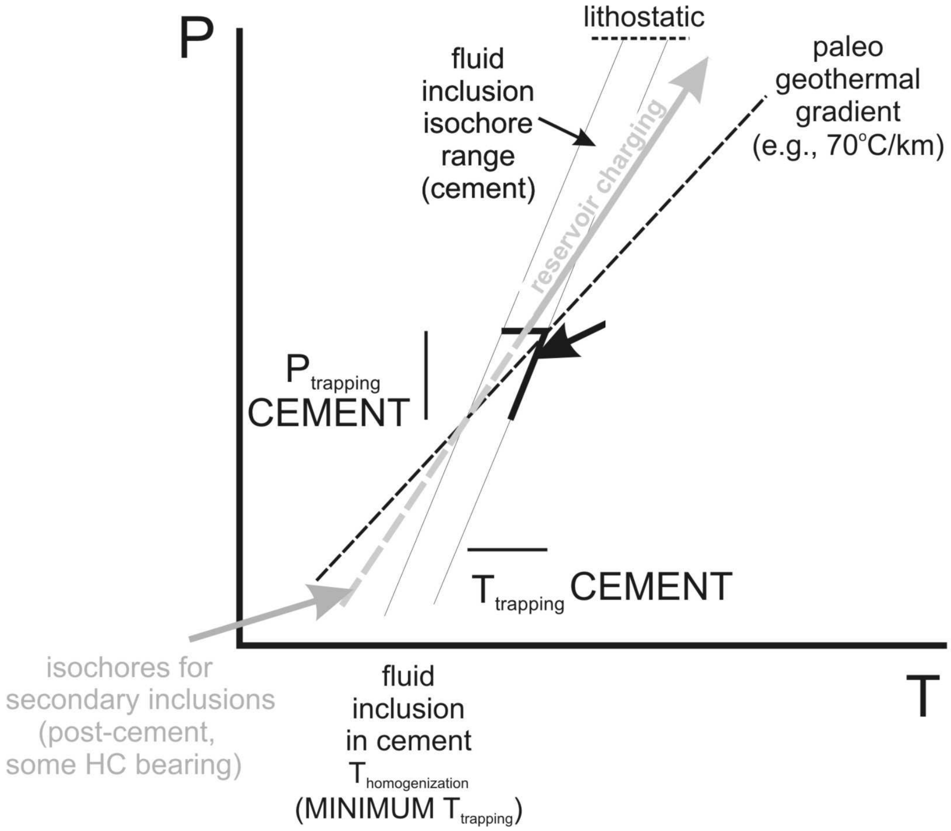


Figure 2. Schematic diagram showing graphic interpretation technique for primary and secondary fluid inclusion entrapment conditions in relation to reservoir charging (see text for description and graphical interpretations from each well studied here).

3. Results

3.1 Inclusion petrography

Two-phase fluid inclusions, containing an aqueous liquid phase and a small vapour bubble (5-8 vol%), were observed in quartz overgrowths (Figure 3) and calcite cement (matrix to detrital grains; Figure 4) and are designated Type I inclusions. The inclusions are considered to be primary in origin as they show morphologies in calcite that are consistent with negative rhombohedrons, and in both quartz and calcite, they never occur along planar structures (healed fracture planes). The inclusions are very small ranging in size from ~2-5 μm. Two-phase fluid inclusions, also containing a liquid phase and vapour bubble were observed aligned along planar features that commonly crosscut grain boundaries (Figure 5). These inclusions, designated Type II, are secondary in origin and were trapped either prior to overgrowth and cementation (where textures indicate that they do not cross-cut grain boundaries or grain-overgrowth interfaces), or after overgrowth and cementation, in cases where they crosscut these features. The type II inclusions are generally larger than type I inclusion, ranging in size from ~ 2-15 μm.

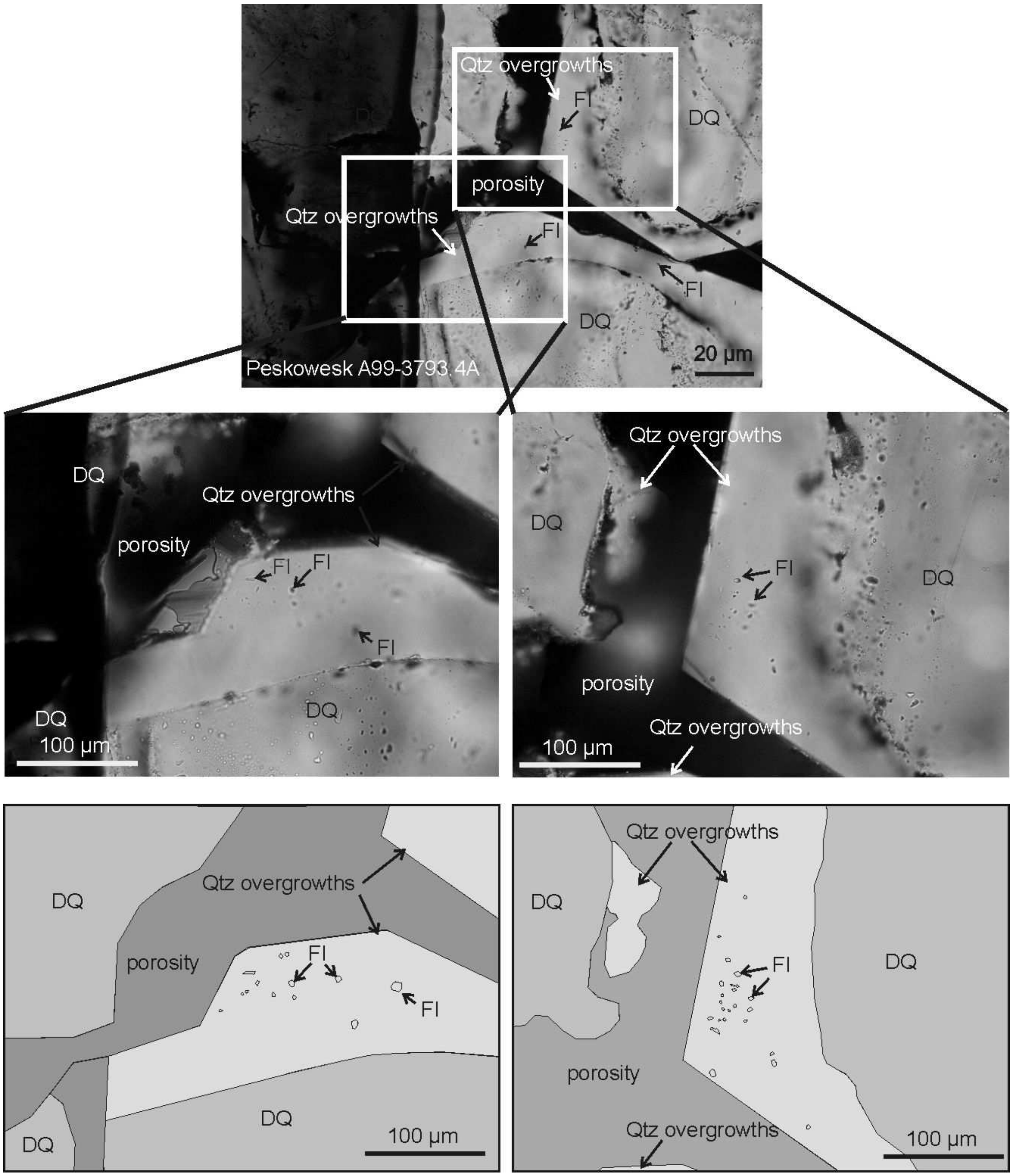


Figure 3. Petrographic characteristics of type I inclusions in quartz overgrowths on detrital quartz grains (DQ). The top frame shows a sandstone with two areas (in boxes) enlagedin the lower frames. The top, centre left and centre right frames show the quartz overgrowths clearly in transmitted, plane-polarized light. Primary fluid inclusions (type I) are visible (FI) in the quartz overgrowthswhich truncate commonly against the porosity in the form of euhedral to subhedral crystals. Fluid inclusions related to the onset of overgrowth are visible along the boundary between the overgrowths and DQ. The lower left and right frames show a cartoon depiction of the different phases present.

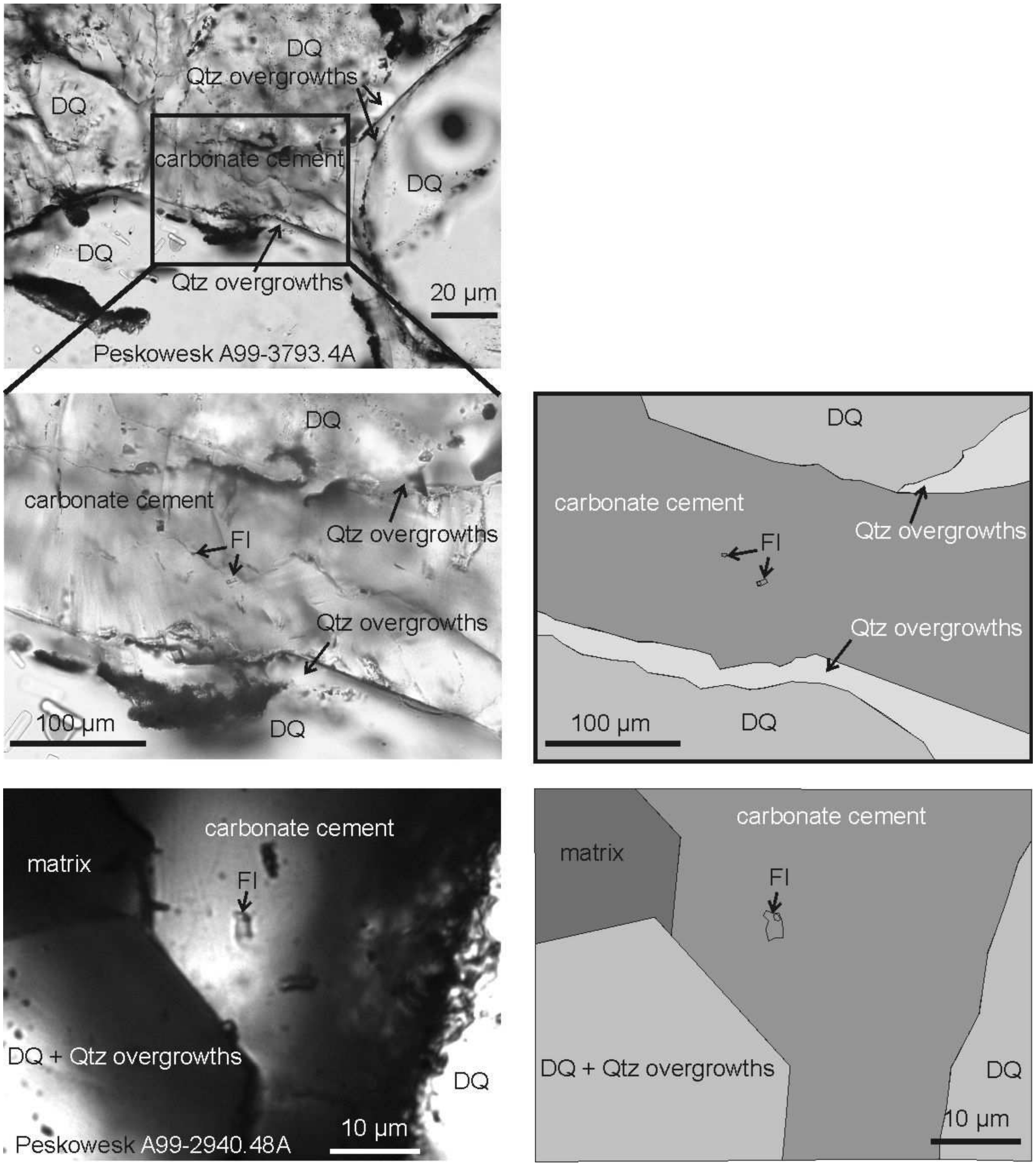


Figure 4. Petrographic characteristics of type I inclusions in carbonate ceement forming part of the matrix to detrital quartz grains (DQ). The top frame shows a sandstone with an area (in box) enlaged in the lower frames. The top, centre left and bottom left frames show the cements clearly, along with primary matrix material in transmitted, plane-polarized light. Primary fluid inclusions (type I) are visible (FI) in the cement. which truncate commonly against the porosity in the form of euhedral to subhedral crystals. The lower left and right frames show a cartoon depiction of the mineralogical relationships where cement is present. Timing is constrained by these images, such that quartz overgrowths predate cementation.

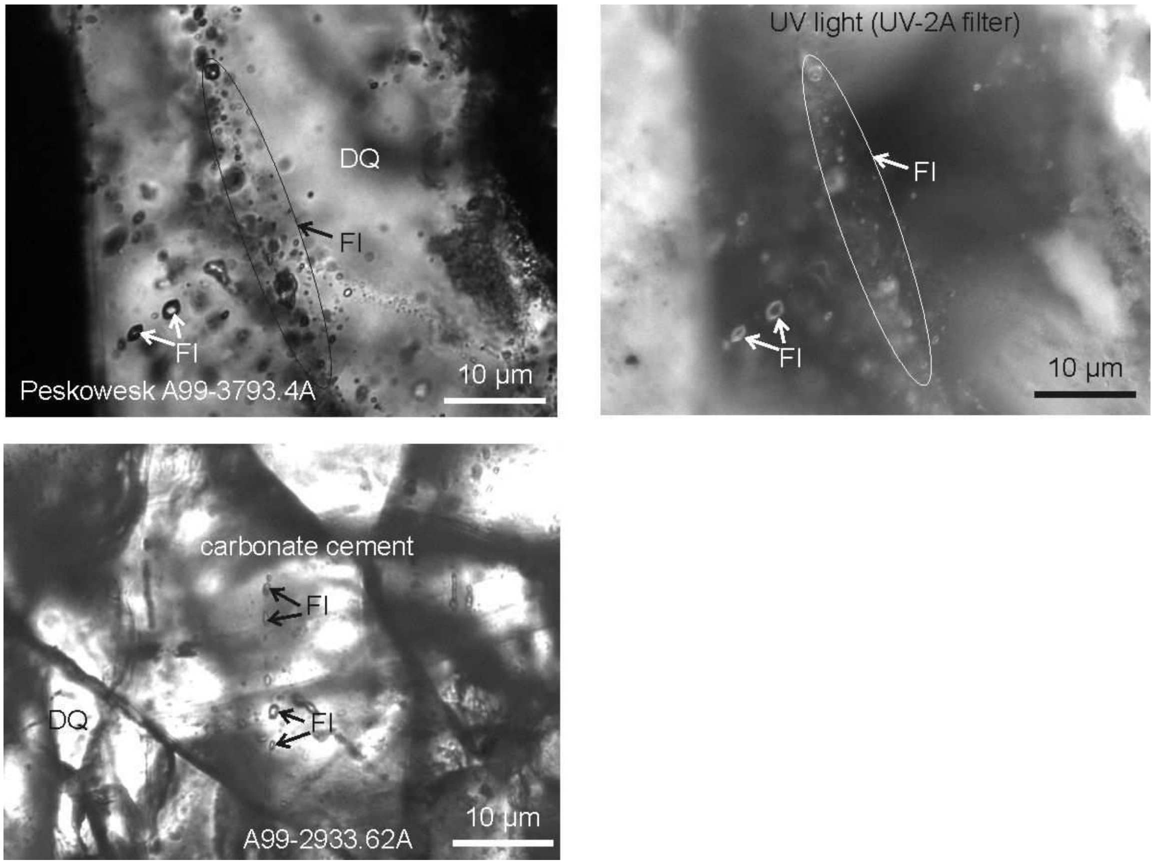


Figure 5. Petrographic characteristics of secondary (type II) inclusions (FI). All images taken in transmitted, plane-polarized light with the exception of the top right frame that was photographed using an ultraviolet excitation source rather than visible light source. The top two frames show a typical trail of type II inclusions hosted in detrital quartz (DQ) in visible light (top left) and UV light (top right). Very rarely (only reported in one sample and not in all inclusions), yellowish-brown fluorescence was observed in a thin film lining the walls of the inclusions, and is suggested to be a hydrocarbon phase (see text for description). The lower image shows a trail of type II inclusions within carbonate cement, constraining the origin of the inclusions as secondary but also postdating the cementation. This was only observed in a few samples unambiguously.

3.2 Fluorescence

Very few fluid inclusions showed fluorescence and the few assemblages or inclusions that did show this were always secondary (type II; Figure 5) and never type I. Where fluorescence was observed, it was not consistent from inclusion to inclusion, and most secondary trails showed now fluorescence at all using any of the filter cubes in the microscope set-up. Where it was observed, the fluorescence generally is present as a thin layer along the inner walls of the inclusions, and implies that a hydrocarbon phase may be present. However, owing to the lack of consistency of observations and overall lack of fluorescence, it is likely that the observations are consistent with an accidentally trapped phase rather than a primary fluid component, or that some trails trapped immiscible hydrocarbon and aqueous fluid.

3.3 Trapping conditions relative to current conditions, and significance

Table 1 summarizes the graphical determinations of trapping conditions for all inclusions in quartz overgrowths, carbonate cements and secondary inclusions (post-cement) by well and depth. Appendix 2 summarizes all fluid inclusion microthermometric data from which the graphic estimates of true trapping P and T were determined (see graphic estimates in Appendix 3). Also included in this Table are the actual current pressure and temperatures from each well, calculated P for each sample location (based on lithostatic and hydrostatic loads at a given sample depth), and the estimated change in depth of each sample location since entrapment of primary inclusions in the overgrowths and cements. It should be noted that the conditions of entrapment are based on the intersections of fluid inclusion isochores with lithostatic and hydrostatic thermal gradient lines (Appendix 3), and that the maximum conditions are most appropriate for comparison of well conditions because the pressures at the time of fluid inclusion entrapment were likely lithostatic-dominated. A more detailed description of the overall significance of the data can be found in the Conclusions to this report. The summary table shows the following key results with respect to fluid inclusion trapping conditions:

a. Maximum temperatures in dry wells are higher than in wells with documented oil and/or gas showings

b. Depths at which formation of quartz overgrowths and carbonate cements occurred are broadly consistent from well to well

c. All wells show temperatures lower currently than at the time of diagenesis and post-cementation fracturing, indicating that the regional thermal maximum has passed.

Table 1 - Summary of trapping conditions[1] of fluid inclusions in all wells and estimates of changes in conditions since inclusion entrapment

Well		[2]Charge	Depth (m)	P_l	P_h	P_a	T_a	$T_{tr\ qtz}$	$P_{tr\ qtz}$	$T_{tr\ carb}$	$P_{tr\ carb}$	$T_{tr\ sec}$	$P_{tr\ sec}$	ΔP	ΔD (km)
Louisbourg	J47	gas	4528	1199	444	596	117	108-119	190-450			118-135	200-500	254-749	2.6-2.8
Louisbourg	J47	gas	5451	1444	535	981	132					148-151	250-610		
Tantallon	M41	oil/gas	5298	1403	520	603	117	104-115	195-445					325-958	3.3-3.6
Dauntless	D35	dry	3163	838	310	358	85	110-146	200-575					110-263	1.0-1.1
Sable Island	C67	dry	3378	895	331	383	93			134-155	250-630				
Panuke	B90	oil/gas	2321	615	228	244	n.a.			98-135	180-520				
Peskowesk	A99	dry	2934	777	288	304	n.a.	74-94	150-305	98-180	180-750			138-472	1.4-1.8
Peskowesk	A99	dry	3793	1005	372	393	110	101-120	195-460					177-545	1.8-2.0
Peskowesk	A99	dry	2940	779	288	306	n.a.	108-120	195-450	101-160	270-660			93-329	0.9-1.2
Peskowesk	A99	dry	2239	593	220	214	71	122-135	220-540					<53	<0.5
Peskowesk	A99	dry	2225	589	218	227	71	100-130	190-520			163-192	300-800	28-69	0.3
Cohasset	A52	oil/gas	2130	564	209	187	74			99-106	290-400				

[1]All pressures in bars; all temperatures in ^{o}C
[2]Presence of oil, gas, oil/gas or now showing based on actual well results rather than Basin atlas

Abbreviation codes: Pl = lithostatic P at current sample depth; Ph = hydrostatic P at current sample depth; Pa = measured P at current sample depth
Ta = measured T at current sample depth, or comparable; Ttr qtz = min/max range of fluid trapping T in quartz overgrowths
Ptr qtz = min/max range of fluid trapping P in quartz overgrowths; Ttr carb = min/max range of fluid trapping T in carbonate cement;
Ptr carb = min/max range of fluid trapping P in carbonate cement; Ttr sec = min/max range of fluid trapping T for secondary (post-cement) inclusions
Ptr sec = min/max range of fluid trapping P for secondary (post-cement) inclusions; ΔP = change in sample P since primary inclusion formation

3.4 Deviation from the original objectives and methodology

The final number of fluid inclusion measurements is ~20% less than agreed upon but it was impossible to gauge this until a very late stage in the study since the last 2 wells studied in July yielded far fewer inclusion measurements than anticipated. A disproportionate large amount of data, for example, was obtained from Peskowesk A-99. The very small size of inclusions and general lack of inclusions of primary origin in the samples are the two problematic issues. There appears to be no discernable controls on these two issues. The equipment used for the study is state-of-the-art and the expertise advanced, allowing observations on inclusions as small as ~3 um. Average inclusions in this study were less than 5 um Typical inclusions hydrothermal ore deposits and magmatic rocks are in the 10-100 um range, so in principle, the limits of the technique have been pushed in this study as far as possible without further development of the analytical equipment, which was beyond the scope of the study.

4. Dissemination and Technology Transfer

As part of a larger study being conducted by Dr. Georgia Pe-Piper at Saint Mary's University, the results of this study have been communicated to her group and will aid in an overall model for diagenesis and its relation to oil and gas deposition in the Scotian Basin. Upon submission of this report, potential end users will be identified and a seminar at Saint Mary's University will be planned in September-October/2010 to enable knowledge transfer and clarify key elements of the study for other researchers directly involved in the OETR Play Fairway Analysis program, subject to confidentiality review by OETR. It is too early to document the potential benefits to Nova Scotia's petroleum industry, aside from aiding in identification of new target areas where thermochemical histories were suitable for oil/gas preservation. Success will rely on careful integration of the results of this study with other related studies being conducted presently.

A peer-reviewed article documenting the graphic technique for determining reservoir conditions prior to and during charging is in preparation for publication, subject to confidentiality review by OETR (see 'Publications').

5. Conclusions, Recommendations and Future Work

5.1 Summary of key conclusions

The study has shown that fluid inclusions trapped in inclusions in diagenetic cements can provide important constraints on the formation of clastic reservoir rocks. The main conclusions of the study are as follows:

a. Estimates of T trapping for different fluid inclusion types in overgrowths, cements and post-cementation migration of (possibly) hydrocarbon fluid indicate that the rocks reached a thermal maximum in the past and that temperatures today are generally lower than at the time of diagenesis and reservoir charging. However, it is uncertain when this thermal maximum occurred. Trapping T for inclusions in the Scotian Basin are notably much higher than in the majority of other oil/gas fields worldwide (e.g., Abu Dhabi: Morad et al., 2010) and while some producing fields show comparatively high temperatures in early cements and overgrowths, these fields always show late stage fluids having much lower temperatures associated with reduced heat flow common to aborted rift basins (e.g., Sirt Basin, Libya: Cerani et al., 2002). Direct fluid inclusion evidence for a gradual reduction in heat flow is lacking in the Scotian Basin and better constraints on the timing of thermal retrogression relative to hydrocarbon charging are needed.

b. Wells with oil and gas showings based on field evidence have overall lower temperatures associated with overgrowth, cementation and fracturing, whereas wells without oil and gas contain warmer fluid inclusions with absolute trapping temperatures that lie near the upper limit of or above the oil window. The T of trapping for inclusions in calcite cement provide the most reliable indicator of hydrocarbon potential because reservoir charging occurred after calcite cementation, and secondary inclusions can often have an ambiguous origin.

c. Changes in depth after cementation can be estimated by comparing paleolithostatic (from trapping conditions, estimated using intersection of geothermal gradients and isochores) and current lithostatic pressures (current sample depth). Changes in P with depth is recorded by the inclusions, but changes in T with depth are not consistent with expected rock temperatures from simple burial, indicating that other factors must have influenced pore fluid temperature. The migration of salt bodies (known to modify local geothermal gradients) and hydrothermal activity due to deep-seated volcanic processes may be possible reasons for this.

d. Changes in P due to fracturing (to create secondary inclusions) would have been sufficiently high to cause unmixing of any hydrocarbon + water mixture; therefore at the time of reservoir charging, oil/gas and water would have been transported as separate phases that had different properties and abilities to migrate through fractures and pore connectivity. While rare, the occurrence of hydrocarbons in secondary inclusions is consistent with heterogeneous entrapment, suggesting that unmixing had already taken place at the time of entrapment.

e. Microthermometry shows that salinities of pore fluids were 2-3 times higher than Cretaceous seawater salinity but lower than typical basinal brine salinity, and only slight changes in salinity were associated with transition from quartz overgrowth-hosted to carbonate cement-hosted to secondary inclusions. This suggests that pore fluids and migrating secondary fluids were not in communication with the seafloor, and that lithostatic modelling of isochore-geothermal gradient intersections is most appropriate for predicting the actual trapping conditions of fluid inclusions in this study region.

f. Importantly, inclusions containing hydrocarbons of primary origin (cements, overgrowths) are non-existent, indicating that either hydrocarbons did not pass through the pore spaces (syn-overgrowth and cementation) or fractures (post-diagenesis) in the area of the sampled wells, or that fluids that passed through the area were too hot to preserve liquid hydrocarbons. The latter case is more likely based on graphical modeling of the fluid inclusion microthermometric data. The only sample that appeared to contain some hydrocarbons was not convincing, and certainly not representative of a single phase fluid. This raises serious questions about the nature of oil/gas reservoir charging in the sample area.

5.2 Recommendations and future work related to this study

Using the graphic technique discussed here and the knowledge obtained by its application, continued systematic fluid inclusion study of prospective areas through the analysis of more samples is necessary. Fluid inclusion study is very labour intensive but inexpensive to do, and given the extended costs of drilling a well, a small investment into unconventional research of this type is worthwhile. A disproportionate amount of time and funding is placed on structural investigations, for example, with disregard to the importance of thermochemical conditions having been suitable for oil to be transported and preserved chemically and fluid inclusion studies may provide the only unambiguous means to determine this. Studies of fluid inclusions in other world-class oil and gas fields (e.g., Ceriani et al., 2002) have been very instructive and have yielded useful tools for exploration.

Future work should focus on combining these results with recently published data from Venture, Glenelg and Chebucto (Karim et al., 2009; Karim et al., 2010, submitted) and to begin to spatially model inclusion temperatures and pressures in attempt to define and map out areas of the basin that were too hot for hydrocarbon migration and areas that were ideal for its concentration. While more difficult to work with due to their small size, inclusions in clastic and carbonate rocks (primary and secondary) provide the only record of fluid migration that is likely to be isochoric/isoplethic in nature. Considerable effort has been placed on characterizing halite-hosted inclusions that commonly contain hydrocarbons. Such inclusions are a complete red-herring with respect to oil migration and have ambiguous meaning, as has been demonstrated through peer-reviewed fluid inclusion literature. They receive considerable attention because of the common presence of hydrocarbons within the inclusions. Among the problems that plague halite-hosted inclusions:

a. The mineral stretches on reheating at surface pressure. Therefore, any measurements of homogenization temperature will be inaccurate as the container the fluid is hosted in changes shape, deviating from isochoric behavior.

b. The mineral is soluble, therefore, during heating, the walls of the inclusions will dissolve, causing irreversible changes in the inclusion volume, yielding erroneous homogenization behavior. Dissolution is not a reversible process because the rate at which halite dissolves is not the same as the rate at which it precipitates. Halite reprecipitation is a disequilibrium processn at the time scale of laboratory measurements.

c. The origin of halite inclusions is difficult to constrain. While primary inclusions may form when the halite is being precipitated in near-surface (or surficial) evaporate basins, they may also form during plastic-state migration of salt bodies, a process that occurs in the Scotian Basin. Secondary inclusions have an unknown origin and can be related to fracturing at any time post-formation and most likely during dissolution-reprecipitation, an phenomenon that can also generate apparently primary inclusions. Primary inclusions containing hydrocarbons may also have an uncertain origin and a variety of scenarios may trap hydrocarbons in halite during halite precipitation (e.g., where bitumen seeps occur in evaporating basins).

d. Deviations in the local regional geotherm as a consequence of the high heat conductivity of salt results in interpreted inclusion temperatures both in salt and outside of salt bodies to be erroneously high and misrepresentative of regional thermal stratigraphy.

e. Hydrocarbons and the high salinity fluid associated halite-hosted inclusions are nearly completely immiscible and therefore, inclusions do not preserve a regional fluid composition. Rather, they likely show the local effect of initially low salinity, hydrocarbon-bearing aqueous fluid (as dissolved oil or gas, not free oil or gas) reacting with evaporate sequences. This will cause an increase in fluid salinity, locally, and unmixing of hydrocarbon and aqueous fluid locally.

5.3 Possible directions for other future research

While fluid compositions in halite are not representative of regional fluid flow fields, the process of oil-water unmixing in proximity to salt deposits may have significant impact on the concentration of hydrocarbons, in particular oil, in the Scotia Basin. It is the opinion of the author of this report that this should be a direction of future research. Correlation of high fluid inclusion salinities and oil traps may be testable. Specifically, salt domes, tongues and diapirs are known to be associated with prospective trapping environments from a structural standpoint, but there may be an important 'chemical trap' associated with the salt as well. As initially low salinity fluid carrying trace hydrocarbons comes into contact with salt, increases in salinity in the aqueous component will cause unmixing of the oil phase from the aqueous phase.

Such oil separation from water by this process may have two important implications for reservoir formation: (i) it may enable large scale reservoirs to be charged with economically viable deposits oil even though source fluids may be apparently oil poor (i.e., not pure hydrocarbon fluids, but rather aqueous fluids with small amounts of dissolved hydrocarbon), and (ii) it may impact the ability (negatively) for hydrocarbons to be transmitted through permeable sedimentary horizons, since two-phase fluids (i.e., droplets of oil in water) will experience pore-clogging effects and wetting contrasts against detrital grains that will impede migration.

An additional tool yet to be realized in the offshore industry is the application of gas chromatography in analyzing volatiles trapped in inclusions (rather than analyses of bulk oil, for which results can be ambiguous). Remnant pathways for hydrocarbon migration may be determined by analyzing trace amounts of hydrocarbon present within sedimentary horizons using a microcrushing system attached to a gas chromatograph. Saint Mary's University will soon have the capability to search for the hydrocarbon finger print left behind by migrating fluids, beginning in 2011.

6. Publications

Hanley, J.J. and Karim, A. (2010) The application of fluid inclusions in constraining thermochemical properties of hydrocarbon reservoir rocks prior to charging: examples from the Scotian Basin, Canada. *in preparation for CIM Bulletin.*

7. Expenditures of OETR Funds

Eligible Costs	Budgeted Amounts	Actual Expenditures
Salaries and Benefits	13,746	13,746
Equipment and Facilities	5,000	5,000
Overhead	5,623	5,623
Totals	**$24,369**	**$24,369**

8. Employment Summary

Name	Position	Student (Yes/No)	PhD., MSc., Undergrad.	Full or Part Time	Scientific contributions made to the research	Work-months associated with the Research Project
Erin Adlakha	Research Assistant	Yes	Undergraduate	Part time	Sample preparation	1 month (40 hours)
Dr. Atika Karim	Research Associate	No	Postdoctoral Fellow	Full time	Conducted measurements and fluid inclusion petrography	4 months (240 hours)

9. References

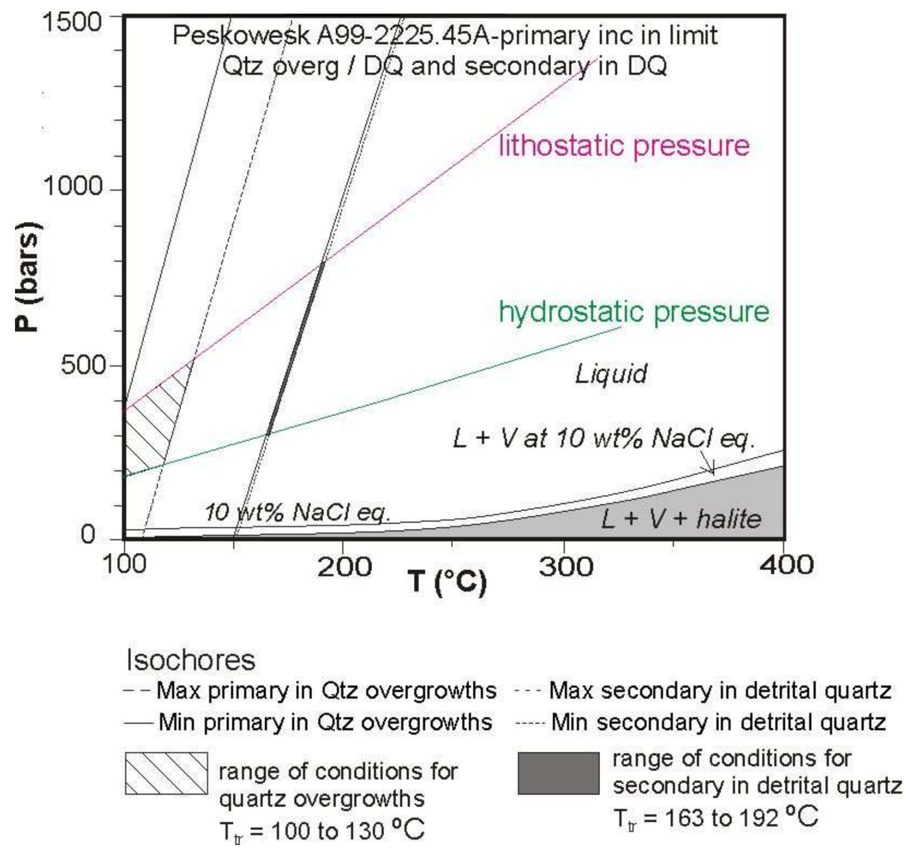
Under compilation, to be forwarded as a separated document

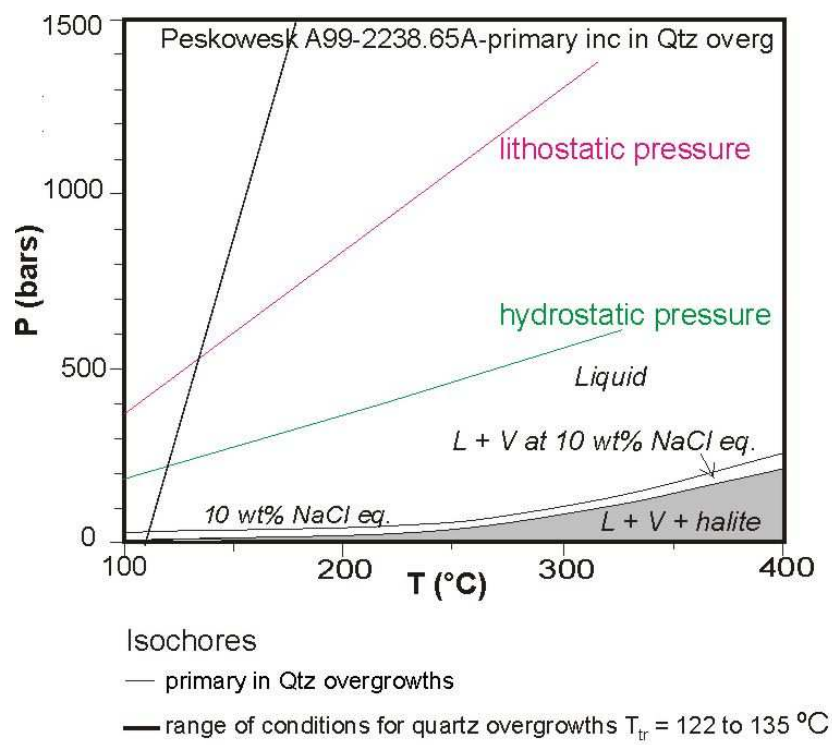
10. Appendices

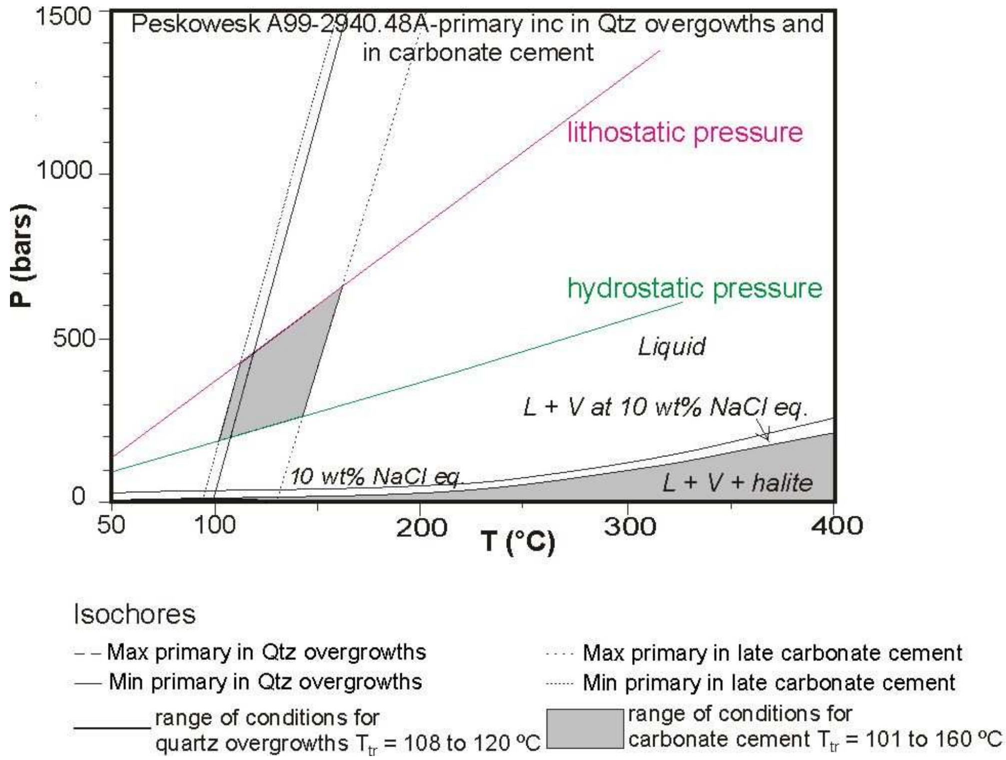
Appendix 1 - Sample list from final assessment of all thin sections (attachment)

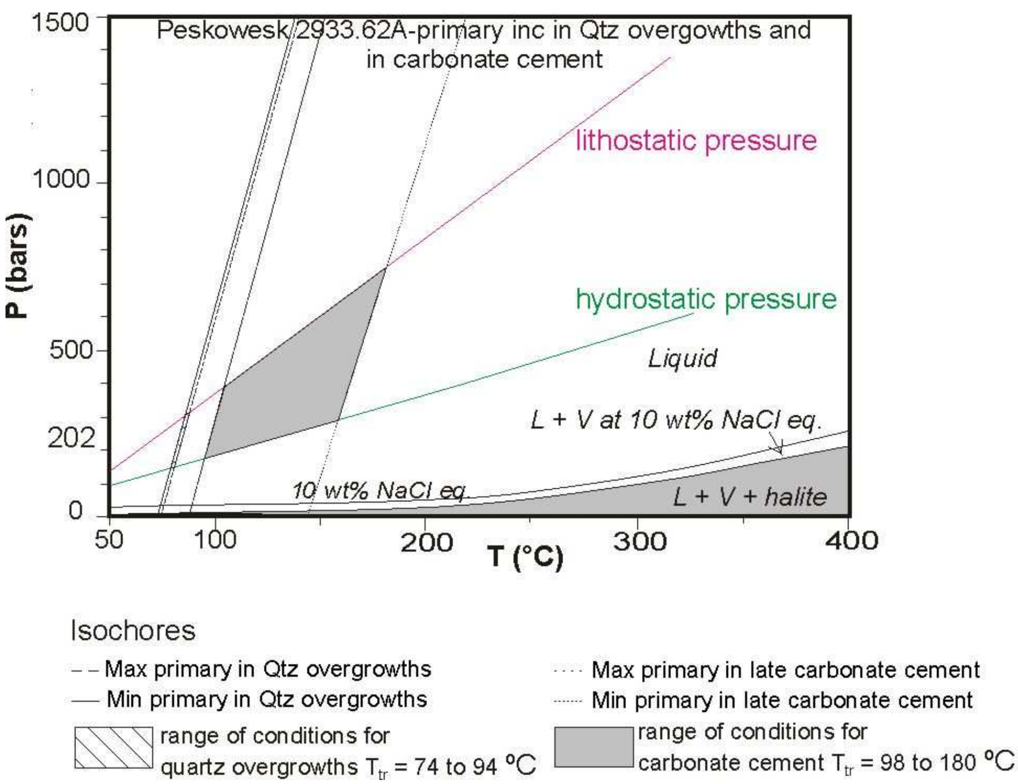
Appendix 2 - Fluid inclusion data table (attachment)

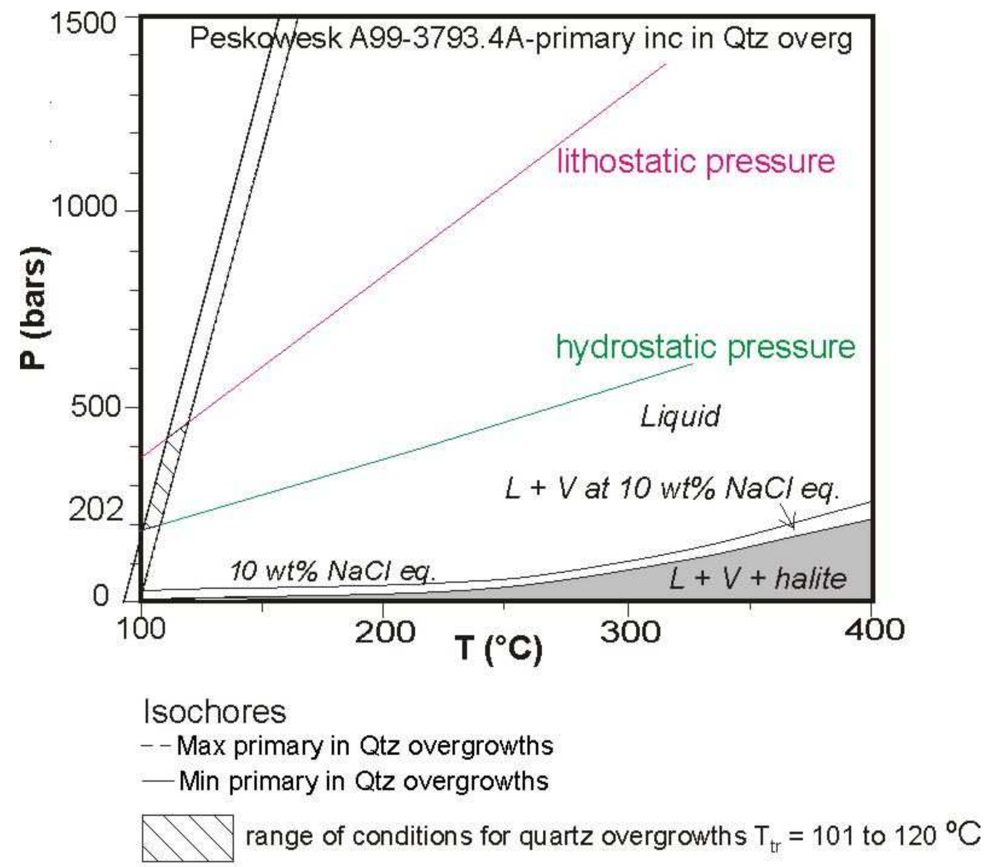
Appendix 3 – Pressure-temperature diagrams constraining inclusion trapping conditions

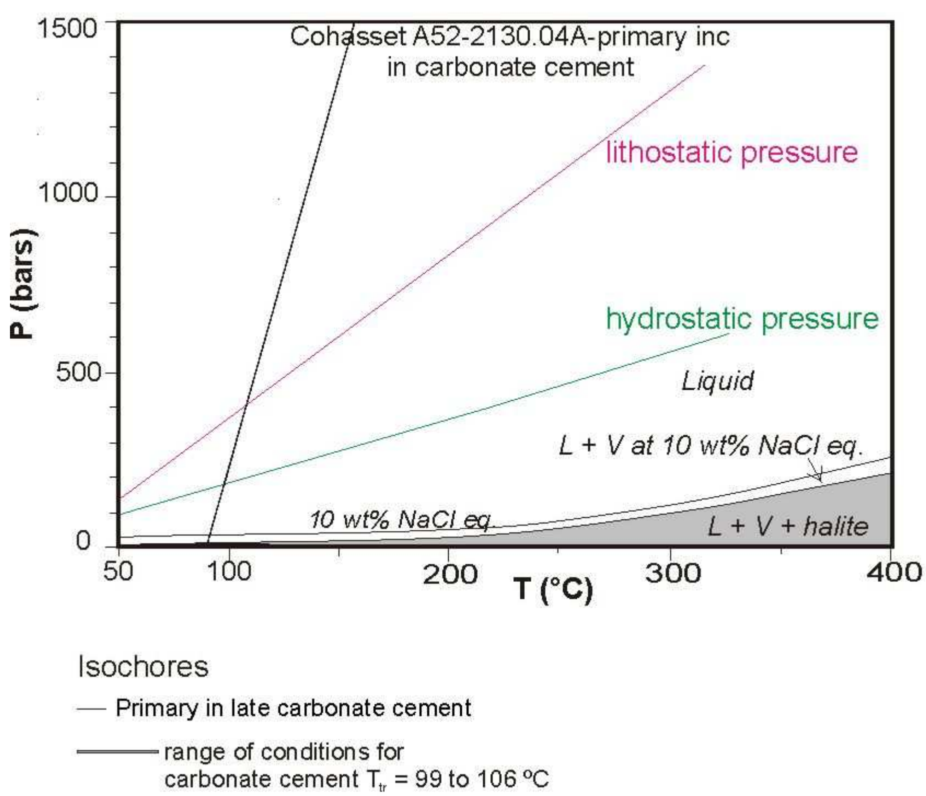


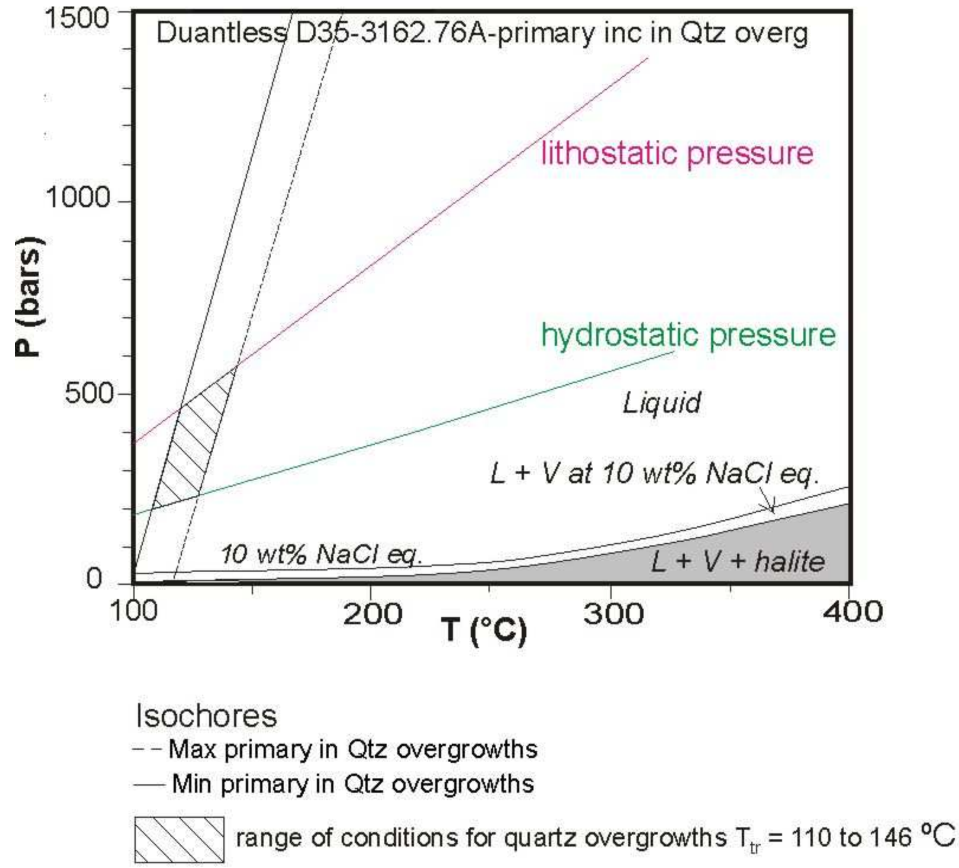


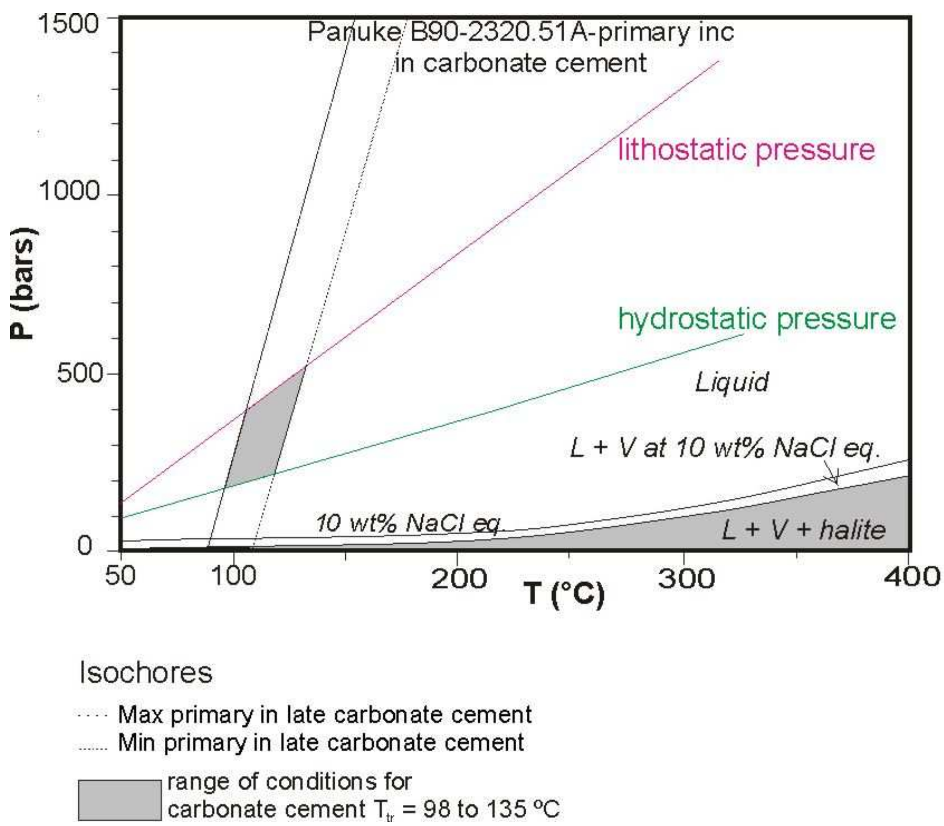

Peskowesk A99-2940.48A-primary inc in Qtz overgrowths and in carbonate cement
lithostatic pressure
hydrostatic pressure
Liquid
L + V at 10 wt% NaCl eq.
10 wt% NaCl eq.
L + V + halite
P (bars)
T (°C)
1500
1000
500
0
50
100
200
300
400
Isochores
Max primary in Qtz overgrowths
Min primary in Qtz overgrowths
range of conditions for quartz overgrowths Ttr = 108 to 120 ºC
Max primary in late carbonate cement
Min primary in late carbonate cement
range of conditions for carbonate cement Ttr = 101 to 160 ºC

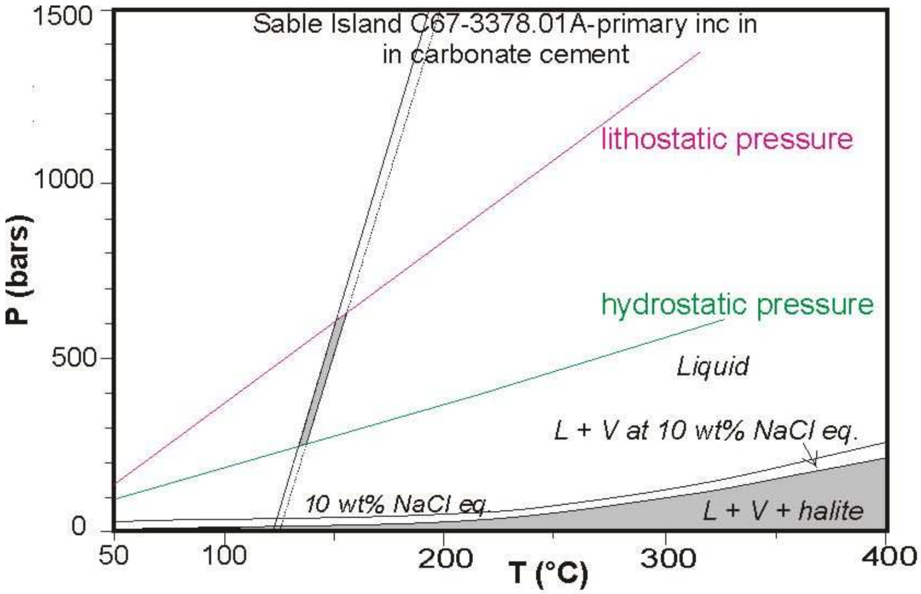

Peskowesk 2933.62A-primary inc in Qtz overgrowths and in carbonate cement
lithostatic pressure
hydrostatic pressure
Liquid
L + V at 10 wt% NaCl eq.
10 wt% NaCl eq.
L + V + halite
P (bars)
T (°C)
1500
1000
500
202
0
50
100
200
300
400
Isochores
Max primary in Qtz overgrowths
Min primary in Qtz overgrowths
range of conditions for quartz overgrowths Ttr = 74 to 94 ºC
Max primary in late carbonate cement
Min primary in late carbonate cement
range of conditions for carbonate cement Ttr = 98 to 180 ºC


Peskowesk A99-3793.4A-primary inc in Qtz overg
lithostatic pressure
hydrostatic pressure
Liquid
L + V at 10 wt% NaCl eq.
10 wt% NaCl eq.
L + V + halite
P (bars)
1500
1000
500
202
0
100
200
300
400
T (°C)
Isochores
Max primary in Qtz overgrowths
Min primary in Qtz overgrowths
range of conditions for quartz overgrowths T_{tr} = 101 to 120 °C


Cohasset A52-2130.04A-primary inc
in carbonate cement
lithostatic pressure
hydrostatic pressure
Liquid
L + V at 10 wt% NaCl eq.
10 wt% NaCl eq.
L + V + halite
P (bars)
1500
1000
500
0
50
100
200
300
400
T (°C)
Isochores
Primary in late carbonate cement
range of conditions for
carbonate cement Ttr = 99 to 106 °C


Duantless D35-3162.76A-primary inc in Qtz overg
lithostatic pressure
hydrostatic pressure
Liquid
L + V at 10 wt% NaCl eq.
10 wt% NaCl eq.
L + V + halite
P (bars)
1500
1000
500
0
100
200
300
400
T (°C)
Isochores
Max primary in Qtz overgrowths
Min primary in Qtz overgrowths
range of conditions for quartz overgrowths T_tr = 110 to 146 °C


Panuke B90-2320.51A-primary inc
in carbonate cement
lithostatic pressure
hydrostatic pressure
Liquid
L + V at 10 wt% NaCl eq.
10 wt% NaCl eq.
L + V + halite
P (bars)
1500
1000
500
0
50
100
200
300
400
T (°C)
Isochores
Max primary in late carbonate cement
Min primary in late carbonate cement
range of conditions for
carbonate cement T_tr = 98 to 135 °C

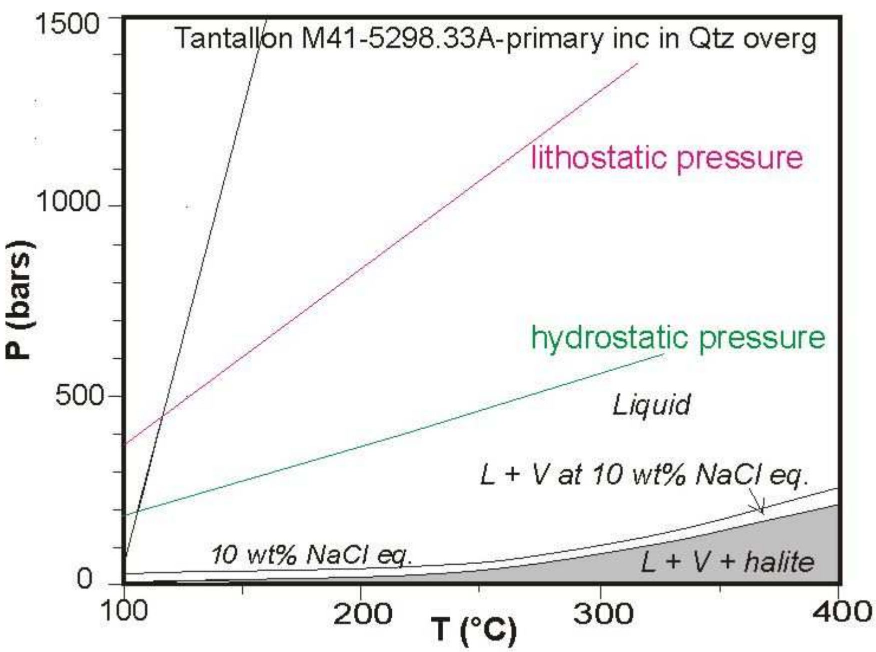


Isochores

···· Max primary in late carbonate cement

······· Min primary in late carbonate cement

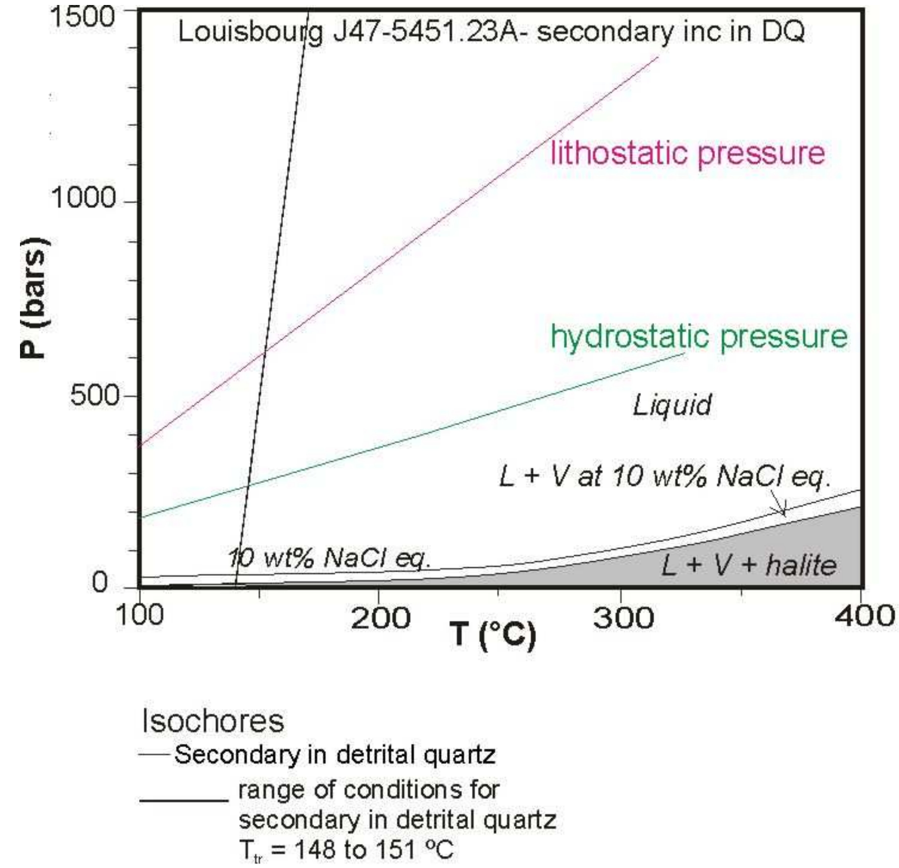
range of conditions for carbonate cement T_{tr} = 134 to 155 °C

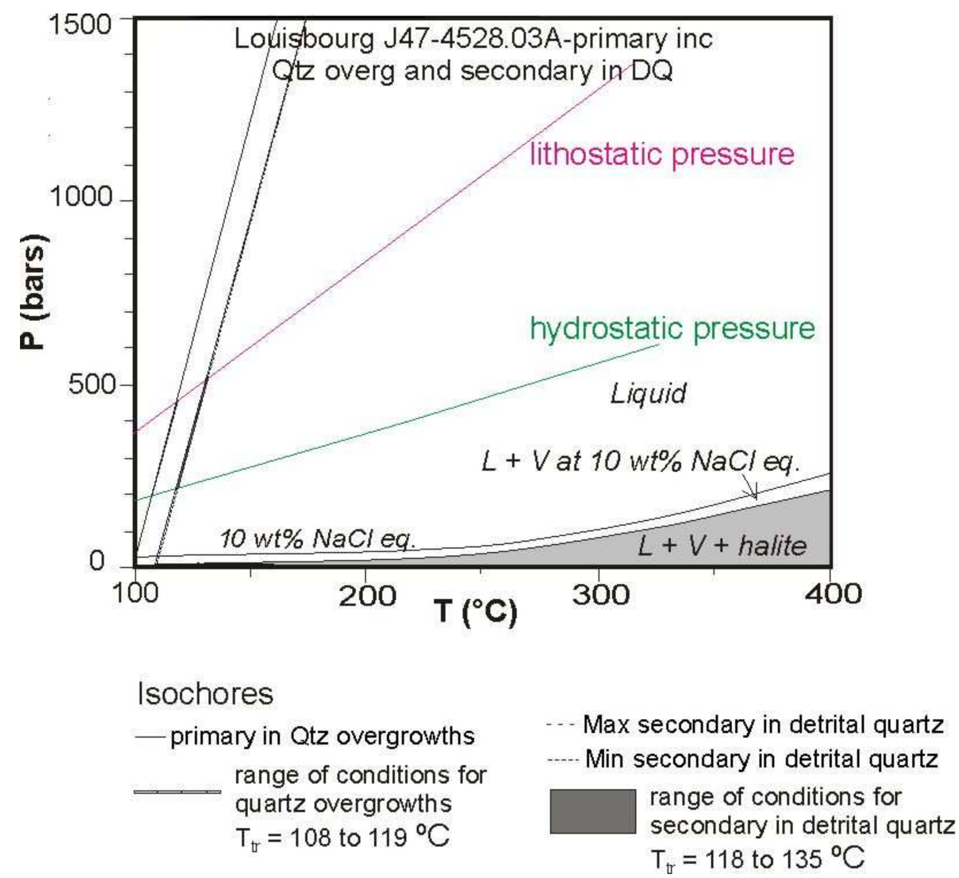


Isochores

— primary in Qtz overgrowths

▬ range of conditions for quartz overgrowths T_{tr} = 104 to 115 °C


Louisbourg J47-5451.23A- secondary inc in DQ
1500
1000
500
0
P (bars)
lithostatic pressure
hydrostatic pressure
Liquid
L + V at 10 wt% NaCl eq.
10 wt% NaCl eq.
L + V + halite
100
200
300
400
T (°C)
Isochores
Secondary in detrital quartz
range of conditions for secondary in detrital quartz
T_{tr} = 148 to 151 °C


Louisbourg J47-4528.03A-primary inc
Qtz overg and secondary in DQ
1500
1000
500
0
P (bars)
lithostatic pressure
hydrostatic pressure
Liquid
L + V at 10 wt% NaCl eq.
10 wt% NaCl eq.
L + V + halite
100
200
300
400
T (°C)
Isochores
primary in Qtz overgrowths
range of conditions for quartz overgrowths
T_{tr} = 108 to 119 °C
Max secondary in detrital quartz
Min secondary in detrital quartz
range of conditions for secondary in detrital quartz
T_{tr} = 118 to 135 °C