Technical Report

Title: ***Two-Phase Flow Parameters Determined from DGR-2, DGR-3 and DGR-4 Laboratory Petrophysical Data***

Document ID: **TR-08-33**

Author: **Nicola Calder**

Revision: **0**

Date: **March 31, 2011**

DGR Site Characterization Document
Geofirma Engineering Project 08-200

Geofirma
Engineering Ltd

Intera Engineering DGR Site Characterization Document		
Title:	Two-Phase Flow Parameters Determined from DGR-2, DGR-3 and DGR-4 Laboratory Petrophysical Data	
Document ID:	TR-08-33	
Revision Number:	0	Date: March 31, 2011
Author:	Nicola Calder	
Technical Review:	John Avis, Kenneth Raven, Dick Jackson; Andy Parmenter, Eric Sykes (NWMO)	
QA Review:	John Avis	
Approved by:	Kenneth Raven	

Document Revision History		
Revision	Effective Date	Description of Changes
0	March 31, 2011	Initial Release

TABLE OF CONTENTS

LIST OF APPENDICES

1 Introduction

Geofirma Engineering Ltd. (formerly Intera Engineering Ltd.) has been contracted by Nuclear Waste Management Organization (NWMO), on behalf of Ontario Power Generation, to implement the Geoscientific Site Characterization Plan (GSCP) (Intera Engineering Ltd., 2006, 2008) for the Bruce nuclear site located near Tiverton, Ontario. The purpose of this site characterization work is to assess the suitability of the Bruce nuclear site to construct a Deep Geologic Repository (DGR) to store low-level and intermediate-level radioactive waste.

In a Deep Geologic Repository for low and intermediate level nuclear waste, it is typical that the waste generates gas, arising from the interaction of water with the waste materials under anaerobic conditions, as the closed repository oxidizes available oxygen and undergoes slow invasion by water. Both corrosion of metallic wastes and biodegradation of organic wastes can be expected (Walker et al., 2009). Additionally, analyses of pore fluid saturations on core samples collected from deep boreholes DGR-2, DGR-3 and DGR-4 at Ontario Power Generation's (OPG) proposed DGR project at the Bruce nuclear site in the Municipality of Kincardine, Ontario indicate the presence of a gas phase within the pore space of the Ordovician shale and limestone formations. Consequently, it is anticipated that numeric modelling of flow undertaken for the Bruce nuclear site will need to consider both the gas and liquid phases. Two-phase flow modelling requires parameters to describe two-phase flow behaviour, such as van Genuchten's two-phase flow characteristic curves (capillary pressure and relative permeability as a function of water saturation). Two-phase flow parameters and equations are described in detail in Section 2. Two-phase flow parameters were determined from laboratory petrophysics data for DGR-2, DGR-3 and DGR-4 according to Intera Test Plan TP-08-19 (Intera Engineering Ltd., 2009a). These parameters describe van Genuchten two-phase flow characteristic curves for the Bruce nuclear site. van Genuchten two-phase flow characteristic curves include capillary pressure and relative permeability as a function of saturation , i.e., typically a wetting-phase fluid such as brine (water) in this case. Note that two-phase flow of gas and brine is assumed; oil is assumed to be at an irreducible saturation and at sufficiently low saturation that it can be ignored.

This technical report develops two-phase flow parameters for DGR-3 and DGR-4 data, as well as provides summary parameters on a formation basis that considers the data and parameters for DGR-2, DGR-3 and DGR-4 data. Two-phase flow parameters for DGR-2 data were previously developed and reported in the Intera Technical Report TR-08-05 (Intera Engineering Ltd., 2009b). As the methodology changed slightly since development of the DGR-2 data, parameters for DGR-2 data were determined with the new methodology for inclusion in the formation average parameters, and are reported in Appendix A.

2 Methodology

Two-phase flow parameters will be determined by fitting the van Genuchten characteristic curves (capillary pressure and relative permeability as a function of saturation) to laboratory petrophysics data (capillary pressure versus saturation data, as well as relative gas permeability measurements). This will be accomplished within paCalc, a framework application with optimization and sampling tools. The optimizers within paCalc use the same code and libraries as the optimizers within nSIGHTS, a numerical well-test analysis code (Nuclear Waste Management Program, 2006).

The following van Genuchten equations (van Genuchten, 1980) were implemented in paCalc:

$$P_c = -\frac{1}{\alpha}\left[S_{ec}^{-1/m} - 1\right]^{1/n} \quad [1]$$

$$S_{ec} = \frac{S_l - S_{lr}}{1 - S_{lr}} \quad [2]$$

$$k_{rl} = S_{ek}^{1/2}\left[1-(1-S_{ek}^{1/m})^{m}\right]^{2} \quad [3]$$

$$k_{rg} = (1-S_{ek})^{1/3}\left[1-S_{ek}^{1/m}\right]^{2m} \quad [4]$$

$$S_{ek} = \frac{S_l - S_{lr}}{1-S_{lr}-S_{gr}} \quad [5]$$

where: k_{rl} is the liquid (brine) phase relative permeability [ratio];

k_{rg} is the gas phase relative permeability [ratio];

P_c is the capillary pressure [Pa];

S_e is the effective brine saturation for the capillary pressure curve (S_{ec}) and the relative permeability curve (S_{ek})

S_l is the liquid saturation [volume ratio];

S_{lr} is the residual liquid saturation [volume ratio];

S_{gr} is the residual gas saturation [volume ratio];

m is a van Genuchten fitting parameter [-];

n is a van Genuchten fitting parameter [-]; and

α is a van Genuchten fitting parameter [Pa^{-1}].

For the capillary pressure relationship (equation 1), n and m are separate fitting parameters. The relative permeability relationships (equations 3 and 4), which only contain the m fitting parameter, assume that m is equal to 1 – 1/n. Consequently, contrary to the form of equations 1, 3 and 4, the n parameter in the capillary pressure relationship (equation 1) is equivalent to the n parameter in the relative permeability relationships (equations 3 and 4), and m parameter may have a different value(if m is not equal to 1 - 1/n in the capillary pressure equations) in the capillary pressure relationship (equation 1) from the m parameter in the permeability relationships (equations 3 and 4).

Within paCalc and for each core sample with available data, Equation 1 for capillary pressure was fit to high-pressure mercury porosimetry (HPMI) data, optimizing for parameters α, m, n and S_{lr}. HPMI data, converted to a brine/gas system from a mercury/air system, was obtained from the laboratory petrophysics data, documented in Appendix A and B of TR-08-28 (Intera Engineering Ltd., 2010) for DGR-3 and DGR-4, respectively. A log fit was used (i.e. the log of HPMI data and the van Genuchten capillary pressure curves were taken before a fit was calculated) with the downhill Simplex method, and the S_{ls} parameter was limited to values between 0 and 1. The fit value is equivalent to the sum of squares, with a perfect fit equal to zero.

Two fits were calculated: one fit for the full set of data (referred to as the full fit), and the second fit restricted to the data with a liquid saturation (S_l) greater than 0.7 (referred to as the limited fit). The limited fit was generated to provide a relationship with an improved fit to high liquid saturation data, as modelling of two-phase flow in the host rock will likely remain highly saturated with liquid. Once the capillary pressure curve was determined, a value for S_{gr} between 0 and 1 was estimated in attempt to match the relative gas permeability curve (Equation 4) to the ‘as received’ measurement of relative gas permeability. The “as received” relative gas permeability was calculated by dividing the “as received” gas permeability by the “clean and dry” gas permeability. For samples with permeability below that detectable by the methodology, the methodology limit was used to determine the relative permeability, and the sample value was marked as “maximum sample relative permeability” on the relative permeability plots. Use of the maximum sample relative permeability provides an improved estimate of the S_{gr} parameter (i.e. the parameter will be between 0 and the actual value of the parameter, rather than zero, as would be if the sample was simply discarded). Values for m and S_{lr} determined for the capillary pressure curve were used. Note that fitting the relative gas permeability value to the van Genuchten relative gas permeability curve was not always possible by simply adjusting the S_{gr} parameter. In these cases, a S_{gr} value of zero was selected.

3 Results

Results for DGR-3 and DGR-4 are presented in the next two sections. The last section presents a summary of parameters for each formation, based on the data and parameters for DGR-2, DGR-3 and DGR-4. Samples are identified by both the Intera Sample Identifiers and sample numbers identical to those reported in the petrophysics data, with a prefix indicating the associated core of the sample (e.g. sample 1V-B from DGR-3 is referred to as 3-1VB). Since the methodology has been modified slightly since generation of the DGR-2 parameters (Both n and m are now fitting parameters for the capillary pressure curves; previously, only m was considered a fitting parameter, assuming that m = 1 – 1/n as in the relative permeability curves. Also, limited fits are calculated), the fits for DGR-2 data were recalculated and are presented in Appendix A.

The van Genuchten capillary pressure curves provide a reasonable representation of the data. For some core samples, the van Genuchten capillary pressure curve provides an excellent representation of the data, whereas for other core samples, it is evident that the shape of the HPMI data does not match the general shape of the van Genuchten curve (e.g. Salina-E Formation, Appendix B). Note that the shape of the van Genuchten curve is mainly governed by m and n. While α mainly affects the displacement of the curve on the y axis, and S_{lr} mainly impacts the location of the low liquid saturation asymptote, these parameters can have some impact on the resulting curve shape. In particular, α affects the shape of the curve at high values of m (high values of α are associated with high values of m, and in these cases α reflects a shape parameter rather than curve displacement along the y axis). However, despite differences in curve shape, the van Genuchten capillary pressure curve is not an unreasonable approximation for these samples.

As previously mentioned, it was not always possible to have the van Genuchten relative gas permeability curve pass through the measured relative gas permeability data point by simply adjusting the value of S_{gr}. Generally, for these cases, the measured relative gas permeability was greater than provided by the van Genuchten curve with an S_{gr} of 0 (i.e. in order for the fitted relative gas permeability curve to pass through the measured point, S_{gr} would be less than zero). Given the minimal data available and the uncertainty in the data (some relative permeability values did not seem reasonable, e.g. sample 2-12 has very large differences in relative permeability for the horizontal and vertical core samples), no further adjustments were made in the relative permeability curves. Data uncertainty is discussed in Section 4.

3.1 DGR-3 Results

The resulting two-phase flow parameters for each DGR-3 sample are summarized in Table 1 for the full fit and Table 2 for the limited fit. Each table provides a fit value, which is the sum of squares of the residuals. The table for the full fit provides both a full fit value as well as a limited fit value; the limited fit value provides the sum of squares of residuals for the limited data set, using the parameters optimized for the full data set, and provides an indication of the quality of the full fit to data at high liquid saturations.

The resulting capillary pressure and relative permeability curves, compared to the laboratory petrophysics data, are provided in Appendix B.

Table 1: Two-Phase Flow Parameters for DGR-3 Samples

Formation	Intera Sample Identifier	Sample No.	α [Pa^{-1}]	m	N	S_{lr}	S_{gr}	Fit	Limited Fit
Salina-F	DGR3-200.50	3-1VB	4.53E-08	1.567	1.62	0.000	0.020	0.087	0.062
	DGR3-204.24	3-2VB	3.55E-08	0.356	5.52	0.000	0.000^{+}	0.007	0.004
	DGR3-230.47	3-3VB	4.31E-08	0.527	4.48	0.000	0.100	0.003	0.003
Salina-E	DGR3-251.68	3-4VB	1.50E-07	0.843	1.24	0.000	0.180	0.469	0.313
Salina-C	DGR3-270.49	3-5VA	1.43E-06	0.580	1.73	0.020	0.000*	0.430	0.132
Salina-B	DGR3-291.57	3-6VB	1.21E-07	0.931	2.17	0.000	0.035	0.048	0.029
Salina-A2	DGR3-308.53	3-7VA	5.76E-06	0.248	3.70	0.000	0.000	0.292	0.019
Salina-A2 Evaporite	DGR3-334.81	3-8VB	4.86E-07	0.990	2.28	0.010	0.100	0.185	0.096
Salina-A1	DGR3-345.38	3-9H	2.57E-08	0.990	2.41	0.000	0.000^{+}	0.099	0.080
Salina-A0	DGR3-385.82	3-11VB	2.41E-07	0.990	2.71	0.004	0.265	0.030	0.015
Goat Island	DGR3-398.05	3-12VA	3.42E-08	0.840	5.67	0.030	0.000	0.002	0.001
	DGR3-408.41	3-13VB	3.77E-08	0.527	6.54	0.020	0.000^{+}	0.004	0.003
Cabot Head	DGR3-432.57	3-14VB	6.83E-08	0.243	6.82	0.000	0.000*	0.011	0.005
Manitoulin	DGR3-452.76	3-15VB	3.00E-08	0.682	3.87	0.000	0.100	0.009	0.005
Queenston	DGR3-477.90	3-16VB	3.81E-08	0.429	8.84	0.080	0.000	0.001	0.000
	DGR3-496.54	3-17VB	2.83E-08	0.880	2.88	0.000	0.070	0.122	0.110
	DGR3-513.72	3-17.5VA	6.22E-09	3.696	1.17	0.000	0.000	0.392	0.343
	DGR3-521.05	3-18VB	3.59E-08	0.523	6.82	0.100	0.060	0.002	0.001
Georgian Bay	DGR3-547.79	3-19VA	1.34E-08	3.195	2.66	0.022	0.000	0.023	0.020
	DGR3-565.40	3-20VA	3.84E-08	0.546	4.46	0.102	0.000	0.003	0.002
	DGR3-565.92	3-22.5VB	5.68E-08	1.378	1.24	0.000	0.050	0.561	0.449
	DGR3-585.89	3-21VB	4.78E-08	0.457	4.51	0.000	0.120	0.004	0.002
Blue Mountain	DGR3-629.11	3-22VA	2.95E-08	1.104	3.76	0.155	0.000^{+}	0.011	0.008
Blue Mountain Lower	DGR3-661.03	3-23H	2.26E-08	0.830	3.05	0.000	0.000	0.034	0.029
Sherman Fall	DGR3-715.85	3-26H	2.89E-08	0.791	2.51	0.210	0.000	0.068	0.030
Kirkfield	DGR3-755.38	3-27H	5.78E-09	7.216	2.17	0.000	0.150	0.037	0.027
Coboconk	DGR3-776.82	3-28VB	1.14E-08	2.726	1.70	0.000	0.050	0.043	0.028
Gull River	DGR3-814.66	3-29VB	2.50E-08	0.775	4.06	0.210	0.110	0.006	0.002

*No samples to provide fitted data.

$^{+}$Unable to fit to measured relative permeability data, set to zero. See text for discussion.

Table 2: Two-Phase Flow Parameters for High Liquid Saturation Data from DGR-3 Samples (Limited Fit)

Formation	Intera Sample Identifier	Sample No.	α [Pa^{-1}]	M	n	S_{lr}	S_{gr}	Fit
Salina-F	DGR3-200.50	3-1VB	1.86E-07	0.257	1.92	0.000	0.185	0.027
	DGR3-204.24	3-2VB	4.92E-08	0.119	7.69	0.093	0.000^{+}	0.000
	DGR3-230.47	3-3VB	6.98E-08	0.100	5.97	0.000	0.090	0.001
Salina-E	DGR3-251.68	3-4VB	1.70E-06	0.046	4.31	0.010	0.150	0.003
Salina-C	DGR3-270.49	3-5VA	5.18E-06	0.065	5.56	0.028	0.000*	0.001
Salina-B	DGR3-291.57	3-6VB	4.51E-07	0.090	3.94	0.029	0.001	0.004
Salina-A2	DGR3-308.53	3-7VA	7.91E-06	0.128	5.65	0.027	0.000	0.000
Salina-A2 Evaporite	DGR3-334.81	3-8VB	1.85E-06	0.099	4.13	0.006	0.050	0.005
Salina-A1	DGR3-345.38	3-9H	3.06E-08	0.418	1.99	0.011	0.000^{+}	0.025
Salina-A0	DGR3-385.82	3-11VB	6.16E-07	0.147	3.32	0.144	0.270	0.006
Goat Island	DGR3-398.05	3-12VA	4.81E-08	0.296	7.82	0.335	0.010	0.000
	DGR3-408.41	3-13VB	5.68E-08	0.070	12.3	0.065	0.000^{+}	0.000
Cabot Head	DGR3-432.57	3-14VB	5.95E-08	0.727	8.84	0.000	0.000*	0.000
Manitoulin	DGR3-452.76	3-15VB	6.16E-08	0.067	7.28	0.000	0.060	0.000
Queenston	DGR3-477.90	3-16VB	3.80E-08	0.741	9.08	0.400	0.000	0.000
	DGR3-496.54	3-17VB	1.75E-08	0.880	2.04	0.000	0.090	0.045
	DGR3-513.72	3-17.5VA	2.72E-07	0.083	1.77	0.030	0.000	0.099
	DGR3-521.05	3-18VB	2.48E-08	3.062	6.09	0.000	0.050	0.000
Georgian Bay	DGR3-547.79	3-19VA	3.19E-08	0.460	2.73	0.226	0.000	0.017
	DGR3-565.40	3-20VA	3.14E-08	0.855	3.99	0.064	0.000	0.001
	DGR3-565.92	3-22.5VB	6.34E-07	0.115	1.47	0.000	0.050	0.248
	DGR3-585.89	3-21VB	3.87E-08	0.854	4.16	0.000	0.120	0.001
Blue Mountain	DGR3-629.11	3-22VA	2.82E-08	0.822	3.43	0.052	0.000^{+}	0.006
Blue Mountain Lower	DGR3-661.03	3-23H	2.29E-08	0.690	2.62	0.248	0.000	0.013
Sherman Fall	DGR3-715.85	3-26H	7.85E-08	0.084	3.18	0.000	0.000	0.004
Kirkfield	DGR3-755.38	3-27H	1.78E-08	0.868	2.02	0.321	0.155	0.014
Coboconk	DGR3-776.82	3-28VB	3.18E-08	0.658	1.91	0.000	0.030	0.018
Gull River	DGR3-814.66	3-29VB	4.08E-08	0.166	5.00	0.222	0.100	0.001

*No samples to provide fitted data.

$^{+}$Unable to fit to measured relative permeability data, set to zero. See text for discussion.

3.2 DGR-4 Results

The resulting two-phase flow parameters for each DGR-4 sample are summarized in Table 3 for the full fit and Table 4 for the limited fit. As with the DGR-3 data, the table for the full fit provides both a full fit value as well as a limited fit value; the limited fit value provides the sum of squares of residuals for the limited data set, using the parameters optimized for the full data set, and provides an indication of the quality of the full fit to data at high liquid saturations.

The resulting capillary pressure and relative permeability curves, compared to the laboratory petrophysics data, are provided in Appendix B.

Table 3: Two-Phase Flow Parameters for DGR-4 Samples									
Formation	**Intera Sample Identifier**	**Sample No.**	**α [Pa^{-1}]**	**m**	**n**	**S_{lr}**	**S_{gr}**	**Fit**	**Limited Fit**
Salina-C	DGR4-255.08	4-2VB	4.85E-07	0.728	1.53	0.080	0.000	0.888	0.479
Salina-A2	DGR4-296.97	4-3VB	3.04E-07	1.046	2.42	0.000	0.000	0.081	0.065
Salina-A0	DGR4-373.63	4-5VB	1.20E-07	1.272	1.79	0.000	0.020	0.114	0.102
	DGR4-375.40	4-5.5VB	7.42E-06	0.948	1.96	0.054	0.000+	0.252	0.161
Goat Island	DGR4-398.63	4-6VB	9.47E-09	15.244	2.17	0.020	0.000+	0.054	0.047
Manitoulin	DGR4-441.78	4-7VB	2.00E-08	1.927	3.43	0.211	0.000+	0.002	0.001
Queenston	DGR4-468.92	4-8VB	2.64E-08	0.883	3.39	0.003	0.000+	0.037	0.025
Georgian Bay	DGR4-538.65	4-10VB	4.15E-09	10.708	1.84	0.000	0.000+	0.060	0.055
Cobourg-Lower	DGR4-668.89	4-18VB	2.69E-08	0.109	7.56	0.171	0.000	0.001	0.001
Coboconk	DGR4-767.65	4-21VB	1.99E-08	0.738	1.94	0.000	0.000	0.021	0.015

+Unable to fit to measured relative permeability data, set to zero. See text for discussion.

Table 4: Two-Phase Flow Parameters for High Liquid Saturation Data from DGR-4 Samples (Limited Fit)								
Formation	**Intera Sample Identifier**	**Sample No.**	**α [Pa^{-1}]**	**m**	**n**	**S_{lr}**	**S_{gr}**	**Fit**
Salina-C	DGR4-255.08	4-2VB	2.01E-06	0.634	2.87	0.665	0.000	0.030
Salina-A2	DGR4-296.97	4-3VB	1.27E-06	0.051	5.76	0.000	0.000	0.005
Salina-A0	DGR4-373.63	4-5VB	5.07E-07	0.160	2.19	0.015	0.000	0.052
	DGR4-375.40	4-5.5VB	2.73E-05	0.145	4.89	0.248	0.000+	0.000
Goat Island	DGR4-398.63	4-6VB	3.22E-08	0.842	1.98	0.017	0.000+	0.033
Manitoulin	DGR4-441.78	4-7VB	1.95E-08	1.415	3.31	0.001	0.000+	0.001
Queenston	DGR4-468.92	4-8VB	8.54E-09	14.53	2.97	0.000	0.000+	0.018
Georgian Bay	DGR4-538.65	4-10VB	1.68E-08	0.822	1.79	0.060	0.000+	0.045
Cobourg-Lower	DGR4-668.89	4-18VB	2.76E-08	0.136	7.99	0.385	0.000	0.000
Coboconk	DGR4-767.65	4-21VB	5.89E-08	0.135	2.48	0.000	0.000	0.006

+Unable to fit to measured relative permeability data, set to zero. See text for discussion.

3.3 Formation Results

For geologic units with more than one sample, from DGR-2, DGR-3, or DGR-4, average parameters for the geologic unit are calculated and provided in Table 5 for the full fit, and Table 6 for the limited fit. These tables include values for formations with a single sample, and consequently no parameter averaging, for completeness. Appendix B provides the capillary pressure and relative permeability curves resulting from formation average parameters.

For the full fit of the Salina-A2 formation, the limited fit of the Salina-C formation, and the limited fit of the Blue Mountain Lower Formation, the average parameters did not provide the expected average capillary pressure curve (i.e. the average curve is expected to be visually similar to the curves upon which the average is based). This was due to large differences in the shape parameters for the samples contributing to the Formation average. Consequently, the parameters affecting the shape were adjusted, still within the value range provided by the two samples, to provide an improved visual formation average. Adjusted values are marked within Table 5 and 6. The limited fit for the Manitoulin Formation and limited and full fits for the Cobourg Formation also do not provide the expected average capillary pressure curves; however, simple adjustment of shape parameters was insufficient to improve the fit. Consequently, the average fit was kept as is, since the average capillary pressure curves were considered visually reasonable. Similarly, the full fit for the Georgian Bay formation using all samples does not provide a good visual average fit, due to the large differences in the shape parameters for all samples. As there are a large number of samples for the Georgian Bay formation, the full fit average was obtained by removing samples 2-4 (DGR2-540.00), 3-22.5VB (DGR3-565.92) and 4-10VB (DGR4-538.65).

Table 5: Formation-Average Two-Phase Flow Parameters

Formation	Sample No.	α [Pa^{-1}]	m	n	S_{lr}	S_{gr}
Salina-F	3-1VB, 3-2VB, 3-3VB	4.11E-08	0.818	3.87	0.000	0.100
Salina-E	3-4VB	1.50E-07	0.843	1.24	0.000	0.180
Salina-C	3-5VA, 4-2VB	8.33E-07	0.654	1.63	0.050	0.000
Salina-B	3-6VB	1.21E-07	0.931	2.17	0.000	0.035
Salina-A2	3-7V-A, 4-3VB	1.32E-06	0.500*	3.06	0.000	0.000
Salina-A2 Evaporite	3-8VB	4.86E-07	0.990	2.28	0.010	0.100
Salina-A1	3-9H	2.57E-08	0.990	2.41	0.000	0.000
Salina-A0	3-11VB, 4-5VB	1.70E-07	1.130	2.25	0.002	0.143
Goat Island	3-12VA, 3-13VB, 4-6VB	2.30E-08	5.522	4.79	0.023	0.000
Goat Island	3-12VA, 3-13VB	3.59E-08	0.684	6.11	0.025	0.000
Cabot Head	3-14VB	6.83E-08	0.243	6.82	0.000	0.000**
Manitoulin	3-15VB , 4-7VB	2.45E-08	1.306	3.65	0.106	0.050
Queenston	2-1, 2-2, 2-3, 3-16VB, 3-17VA, 3-18VB, 4-6VB	2.81E-08	1.133	4.45	0.086	0.056
Georgian Bay	2-5, 2-6, 2-7, 2-8, 3-19VA, 3-20VA, 3-21VB	3.32E-08	1.096	3.82	0.166	0.037
Blue Mountain	2-8, 2-9, 3-22VA	3.08E-08	0.747	3.50	0.108	0.017
Blue Mountain Lower	2-10, 3-23H	1.53E-08	1.601	2.72	0.000	0.000
Cobourg-Collingwood	2-11	1.06E-08	2.570	2.14	0.000	0.120
Cobourg-Lower	2-12, 2-13, 2-14, 4-18VB	1.62E-08	1.689	3.13	0.060	0.025
Sherman Fall	2-15, 3-26H	3.54E-08	0.999	2.33	0.170	0.110
Kirkfield	3-27H	5.78E-09	7.22	2.17	0.000	0.150
Coboconk	3-28VB, 4-21VB	1.51E-08	1.734	1.82	0.000	0.025
Gull River	3-29VB	2.50E-08	0.775	4.06	0.210	0.110
Cambrian	2-20	4.41E-06	0.583	1.20	0.040	0.000

* Adjusted to provide improved visual average
**No samples to provide fitted data

The Salina-A0 formation average, both full and limited fit, does not include sample 4-5.5VB (DGR4-375.40) as alpha values are considerably greater for this sample (i.e. analogous air-entry pressure, 1/alpha, is an order of magnitude less than for the other samples). Examining the location of sample 4-5.5VB, a metre of the bottom of the Salina-A0 Unit, suggests that this sample may be more representative of the Guelph formation than the Salina-A0 formation.

Goat Island provides two formation averages: one considering all samples, including the sample from DGR-4; the other considering only samples from DGR-3. This was done given the similarity of the capillary pressure curves for the DGR-3 samples, and the large difference in these curves compared to the DGR-4 sample. As sample 4-6VB (DGR4-398.63) is very close to the bottom of the formation, approximately half a meter above the bottom of the formation, it may be more representative of the Gasport formation.

Table 6: Formation-Average Two-Phase Flow Parameters for High Liquid Saturation Data (Limited Fit)

Formation	Sample No.	α [Pa^{-1}]	m	n	S_{lr}	S_{gr}
Salina-F	3-1VB, 3-2VB, 3-3VB	8.61E-08	0.159	5.19	0.031	0.092
Salina-E	3-4VB	1.70E-06	0.046	4.31	0.010	0.150
Salina-C	3-5VA, 4-2VB	3.23E-06	0.350	4.22	0.55*	0.000
Salina-B	3-6VB	4.51E-07	0.090	3.94	0.029	0.010
Salina-A2	3-7V-A, 4-3VB	3.17E-06	0.090	5.71	0.014	0.000
Salina-A2 Evaporite	3-8VB	1.85E-06	0.099	4.13	0.006	0.050
Salina-A1	3-9H	3.06E-08	0.418	1.99	0.011	0.000
Salina-A0	3-11VB, 4-5VB	5.59E-07	0.154	2.76	0.080	0.135
Goat Island	3-12VA, 3-13VB, 4-6VB	4.45E-08	0.403	7.37	0.139	0.003
Goat Island	3-12VA, 3-13VB	5.23E-08	0.183	10.1	0.200	0.005
Cabot Head	3-14VB	5.95E-08	0.727	8.84	0.000	0.000**
Manitoulin	3-15VB , 4-7VB	3.47E-08	0.739	5.30	0.001	0.030
Queenston	2-1, 2-2, 2-3, 3-16VB, 3-17VA, 3-18VB, 4-6VB	1.43E-08	6.949	4.01	0.071	0.057
Georgian Bay	2-5, 2-6, 2-7, 2-8, 3-19VA, 3-20VA, 3-21VB	3.21E-08	1.815	3.32	0.094	0.028
Blue Mountain	2-8, 2-9, 3-22VA	1.98E-08	1.973	3.08	0.144	0.050
Blue Mountain Lower	2-10, 3-23H	1.11E-08	2.500*	2.44	0.124	0.000
Cobourg-Collingwood	2-11	3.39E-08	0.307	2.18	0.170	0.165
Cobourg-Lower	2-12, 2-13, 2-14, 4-18VB	3.87E-08	0.619	3.94	0.252	0.021
Sherman Fall	2-15, 3-26H	9.89E-08	0.142	3.09	0.084	0.105
Kirkfield	3-27H	1.78E-08	0.868	2.02	0.321	0.155
Coboconk	3-28VB, 4-21VB	4.33E-08	0.397	2.20	0.000	0.015
Gull River	3-29VB	4.08E-08	0.166	5.00	0.222	0.100
Cambrian	2-20	2.22E-05	0.158	2.12	0.034	0.000

* Adjusted to provide improved visual average, see discussion in text
**No samples to provide fitted data

The Queenston formation average fit, both the full and limited fit, does not include sample 3-17.5A (DGR3-513.72), as the capillary pressure curves differ considerably from all seven other samples.

The Gull River formation has substantially different capillary pressure curves between the DGR-2 and DGR-3 samples. The DGR-2 sample provides capillary pressure curves comparable to the Cambrian, whereas as the DGR-3 provides a capillary pressure curve comparable to the Ordovician sediments. Since Gull River is within the Ordovician, only the DGR-3 sample (sample 3-29VB, DGR3-814.66) was considered to represent the Gull River formation.

4 Data Quality and Use

Parameters were estimated for each formation based on both full and limited fits (Table 5 and 6, respectively). It is up to the user of the data to determine which parameters, based on the limited or full fits, is best suited for their particular task. If the parameters are being used to describe flow only under high water saturations (e.g. water saturation greater than 0.7), the limited fit is preferred.

The two-phase flow parameters rely on the laboratory petrophysics data, as the petrophysical data provides the best estimate available for obtaining these two-phase flow parameters. Uncertainties in the laboratory petrophysics data that will impact the uncertainty of the two-phase flow parameters include:

- Relative permeability curves typically rely on a single relative gas permeability point to determine the value of the S_{gr} parameter. These relative gas permeability points are often quite variable within a single formation, and can have considerable impact on the shape of the relative permeability curves.

- Core samples have undergone stress relaxation, causing possible increases in measured permeabilities and development of micro-fractures that will strongly affect mercury intrusion. As well, the process of cleaning the core samples may dissolve some grain surfaces, resulting in an overestimation of the permeability.

- HPMI is reported as uncertain due to the difficulties injecting mercury, sample compressibility and the very small pore volumes of the samples.

- The “clean and dry” samples may not be fully de-saturated of brine and/or oil, due to the very low permeabilities of the samples. Presence of water in the samples affects:

    - HPMI results. HPMI results may therefore reflect a three-phase system of mercury-air-water or perhaps residual oil that has wet pore throats.

    - Relative and absolute permeabilities. The absolute permeability as determined from the “clean and dry” sample will be underestimated, resulting in an underestimation of the relative gas permeability. In conjunction with underestimated water saturation, the S_{gr} parameter will be overestimated.

5 Summary and Conclusions

Two-phase flow parameters were developed for the formations of the Bruce nuclear site with HPMI data and relative gas permeability measurements obtained from laboratory petrophysics. The resulting van Genuchten curves provide a reasonable approximation to the HPMI data, and for the majority of the formations, the relative gas permeability measurements.

6 References

Intera Engineering Ltd., 2010. Technical Report: Laboratory Petrophysical Testing of DGR-3 and DGR-4 Core, TR-08-28, Revision 0, February 23, Ottawa.

Intera Engineering Ltd., 2009a. Test Plan: Determination of Two-Phase Flow Parameters from Laboratory Petrophysics, TP-08-19, Revision 1, July 21, Ottawa.

Intera Engineering Ltd., 2009b. Technical Report: Two-Phase Flow Parameters Determined from DGR-2 Laboratory Petrophysical Data, TR-08-05, Revision 0, April 16, Ottawa.

Intera Engineering Ltd., 2008. Phase 2 Geoscientific Site Characterization Plan, OPG's Deep Geologic Repository for Low and Intermediate Level Waste, Report INTERA 06-219.50-Phase 2 GSCP-R0, OPG 00216-REP-03902-00006-R00, April, Ottawa.

Intera Engineering Ltd., 2006. Geoscientific Site Characterization Plan, OPG's Deep Geologic Repository for Low and Intermediate Level Waste, Report INTERA 05-220-1, OPG 00216-REP-03902-00002-R00, April, Ottawa.

Nuclear Waste Management Program. April 12, 2006. nSIGHTS 2.40 User Manual Version 2.1. ERMS #530161. Carlsbad, NM: Sandia National Laboratories.

Van Genuchten , M.Th.,1980, A closed-form equation for predicting the hydraulic conductivity of unsaturated soils. Soil Science Society of America Journal, Vol. 44, pp. 892-898.

Walker, R., L. Limer, R. Little and G. Towler. 2009. Postclosure Safety Assessment (V1): Analysis of the Normal Evolution Scenario. Nuclear Waste Management Organization (NWMO) Report DGR-TR-2009-02-R0. Toronto, Canada.

APPENDIX A

TWO-PHASE FLOW PARAMETERS FOR DGR-2

This section provides the two-phase flow parameters for the DGR-2 sample fits, using the methodology described in Section 2 of this report.

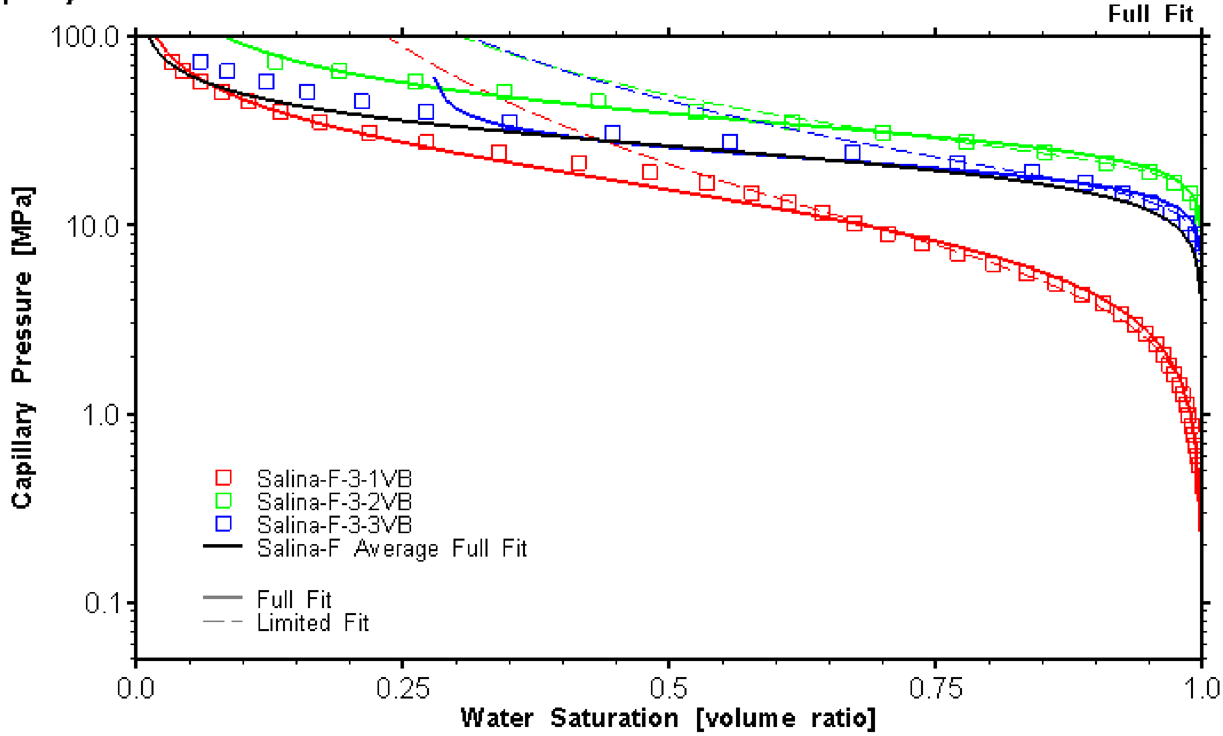
Table A-1: Two-Phase Flow Parameters for DGR-2 Samples									
Formation	**Intera Sample Identifier**	**Sample No.**	**α [Pa^{-1}]**	**m**	**n**	**S_{lr}**	**S_{gr}**	**Fit**	**Limited Fit**
Queenston	DGR2-457.66	2-1	3.41E-08	1.214	3.81	0.190	0.070	0.051	0.046
	DGR2-488.51	2-2	1.58E-08	1.537	2.97	0.030	0.000*	0.029	0.020
	DGR2-515.01	2-3	2.54E-08	2.466	2.47	0.197	0.195	0.100	0.075
Georgian Bay	DGR2-540.00	2-4	6.99E-08	0.300	2.79	0.000	0.000*	0.055	0.035
	DGR2-556.33	2-5	4.22E-08	0.674	2.93	0.377	0.100	0.023	0.020
	DGR2-576.09	2-6	3.95E-08	0.551	4.58	0.223	0.000*	0.014	0.011
	DGR2-596.09	2-7	3.25E-08	1.160	3.74	0.270	0.000	0.018	0.013
Blue Mountain	DGR2-613.93	2-8	3.80E-08	0.505	3.62	0.126	0.050	0.045	0.032
	DGR2-633.41	2-9	2.61E-08	0.636	3.11	0.043	0.000*	0.033	0.022
Blue Mountain Lower	DGR2-650.12	2-10	1.04E-08	2.372	2.38	0.000	0.000*	0.026	0.022
Cobourg-Collingwood	DGR2-658.88	2-11	1.06E-08	2.570	2.14	0.000	0.120	0.043	0.036
Cobourg-Lower	DGR2-669.10	2-12	7.11E-09	3.454	1.52	0.015	0.000	0.145	0.137
	DGR2-678.63	2-13	1.43E-08	2.038	2.32	0.090	0.000*	0.010	0.010
	DGR2-687.10	2-14	2.51E-08	1.481	2.97	0.160	0.085	0.002	0.001
Sherman Fall	DGR2-696.05	2-15	4.33E-08	1.206	2.16	0.130	0.220	0.020	0.011
Gull River	DGR2-818.61	2-19	3.42E-06	0.437	2.47	0.014	0.150	0.188	0.066
Cambrian	DGR2-845.96	2-20	4.41E-06	0.583	1.20	0.040	0.000*	1.747	0.787

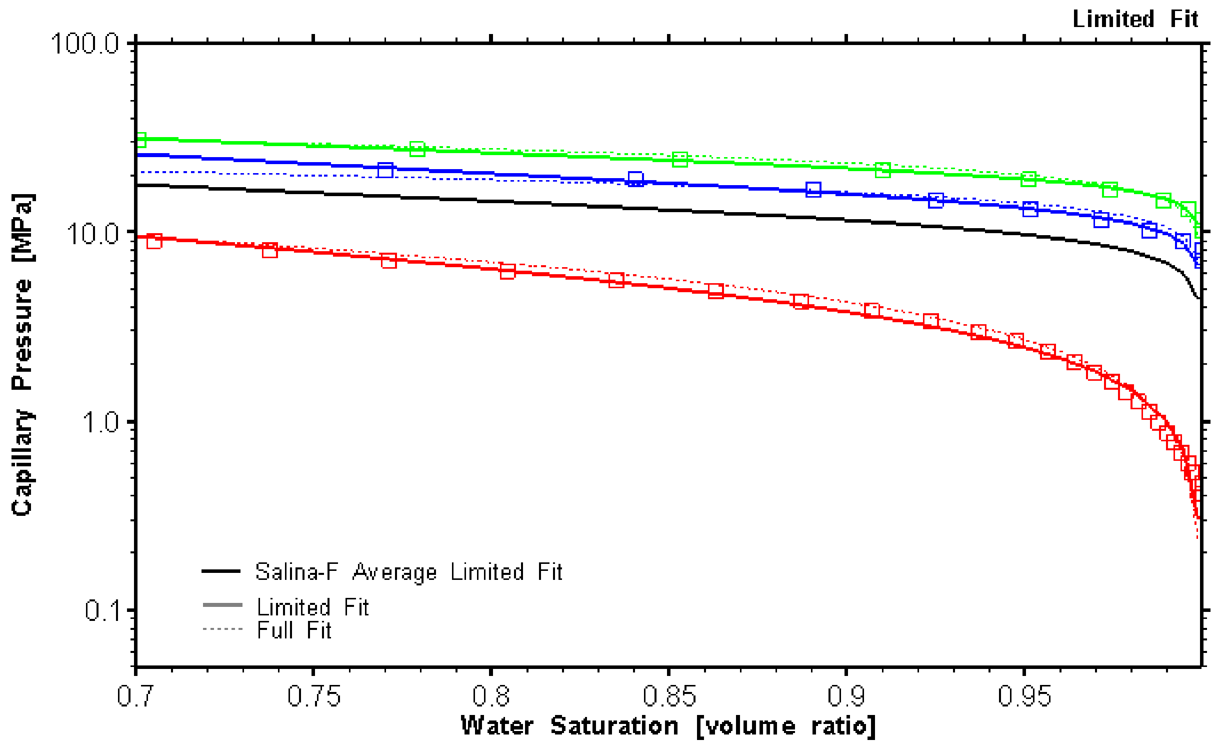
Table A-2: Two-Phase Flow Parameters for High Liquid Saturation Data from DGR-2 Samples (Limited Fit)								
Formation	**Intera Sample Identifier**	**Sample No.**	**α [Pa^{-1}]**	**m**	**n**	**S_{lr}**	**S_{gr}**	**Fit**
Queenston	DGR2-457.66	2-1	1.17E-08	13.29	3.15	0.016	0.060	0.031
	DGR2-488.51	2-2	1.13E-08	2.354	2.69	0.000	0.000*	0.016
	DGR2-515.01	2-3	6.71E-09	13.81	2.04	0.079	0.200	0.046
Georgian Bay	DGR2-540.00	2-4	9.11E-08	0.230	3.43	0.129	0.000*	0.006
	DGR2-556.33	2-5	3.42E-08	0.778	2.73	0.249	0.160	0.017
	DGR2-576.09	2-6	4.05E-08	0.333	4.35	0.024	0.000*	0.010
	DGR2-596.09	2-7	1.37E-08	10.19	3.36	0.000	0.000	0.009
Blue Mountain	DGR2-613.93	2-8	1.87E-08	2.763	2.98	0.293	0.150	0.020
	DGR2-633.41	2-9	1.48E-08	2.334	2.84	0.086	0.000*	0.019
Blue Mountain Lower	DGR2-650.12	2-10	5.36E-09	8.257	2.26	0.000	0.000*	0.020
Cobourg-Collingwood	DGR2-658.88	2-11	3.39E-08	0.307	2.18	0.165	0.170	0.021
Cobourg-Lower	DGR2-669.10	2-12	1.14E-07	0.112	2.29	0.228	0.000*	0.055
	DGR2-678.63	2-13	2.90E-08	0.561	2.47	0.213	0.000*	0.009
	DGR2-687.10	2-14	2.45E-08	1.668	2.99	0.182	0.085	0.001
Sherman Fall	DGR2-696.05	2-15	1.25E-07	0.200	3.01	0.168	0.210	0.004
Gull River	DGR2-818.61	2-19	5.31E-06	0.380	3.89	0.288	0.135	0.006
Cambrian	DGR2-845.96	2-20	2.22E-05	0.158	2.12	0.034	0.000*	0.083

APPENDIX B

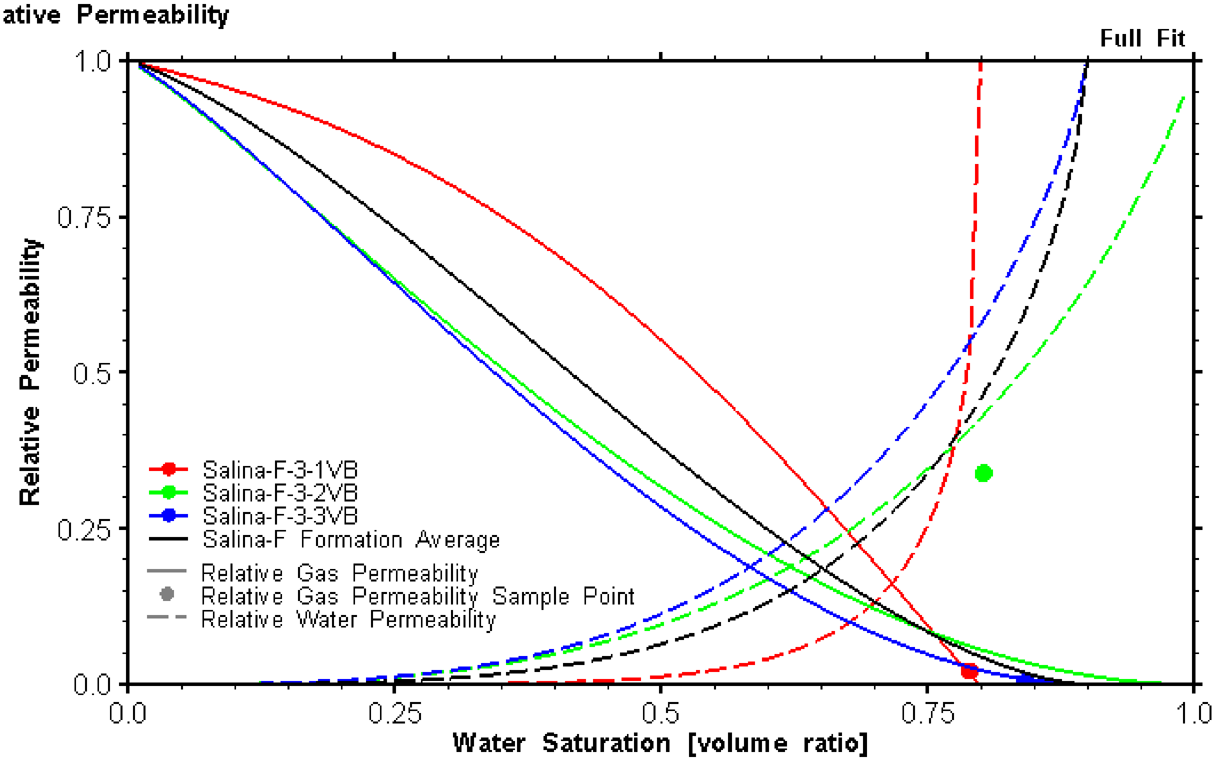
CAPILLARY PRESSURE AND RELATIVE PERMEABILTY CURVES

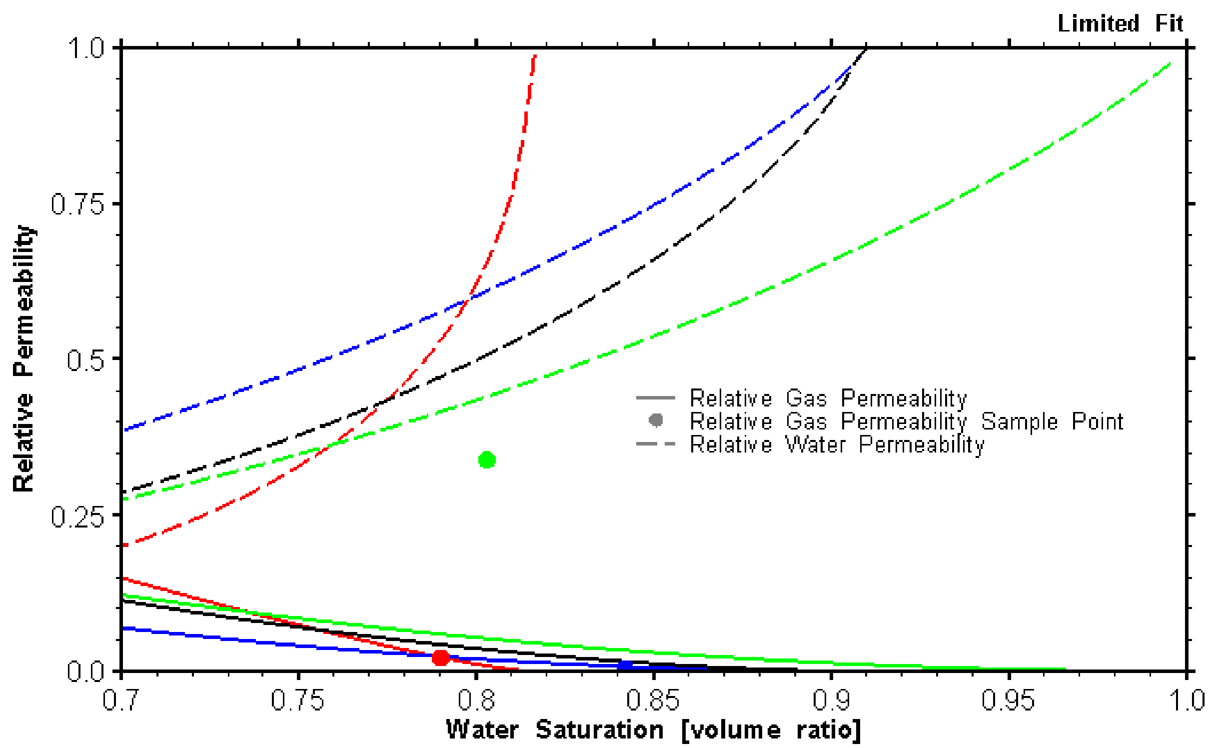
Salina-F Formation
Capillary Pressure



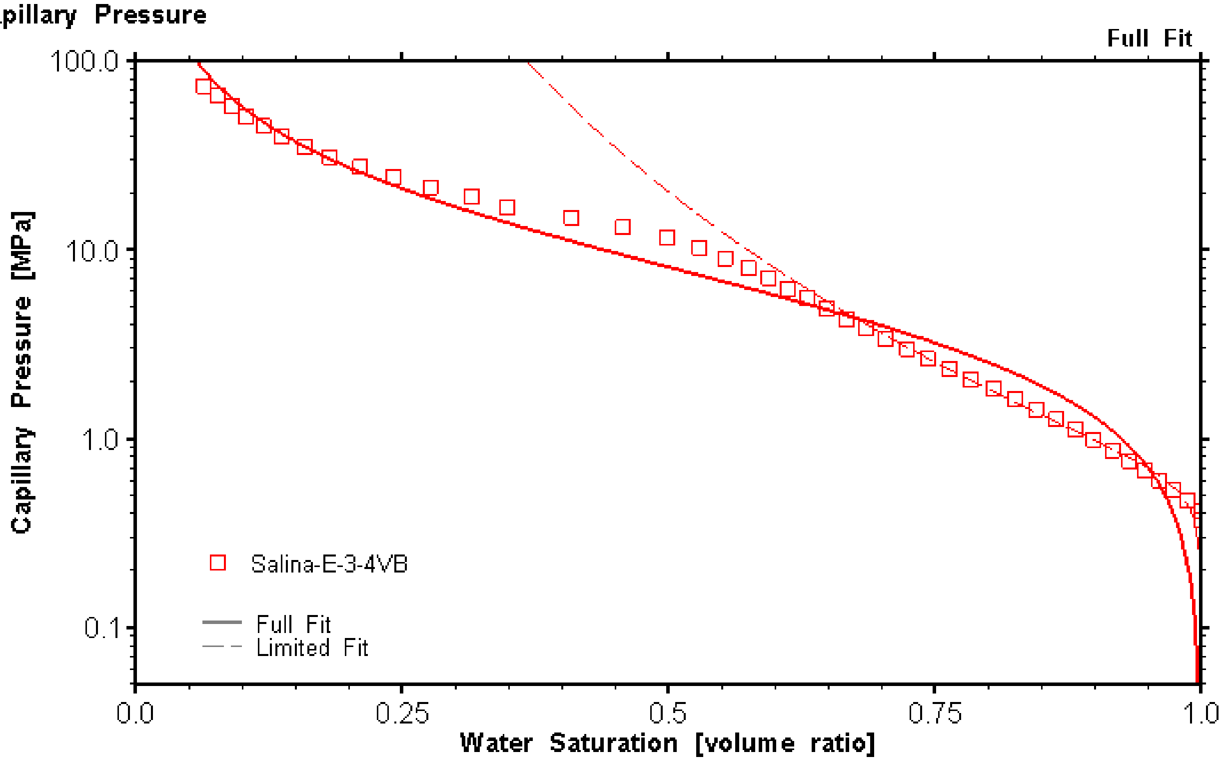


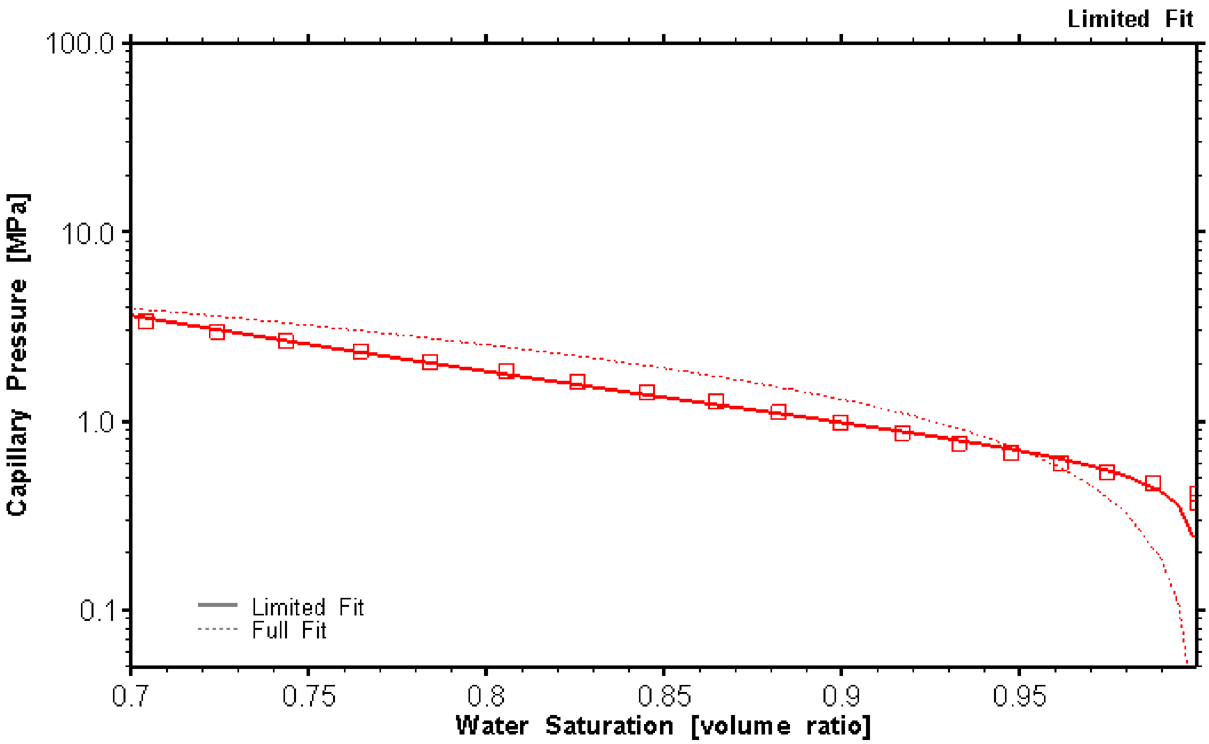
Salina-F Formation
Relative Permeability



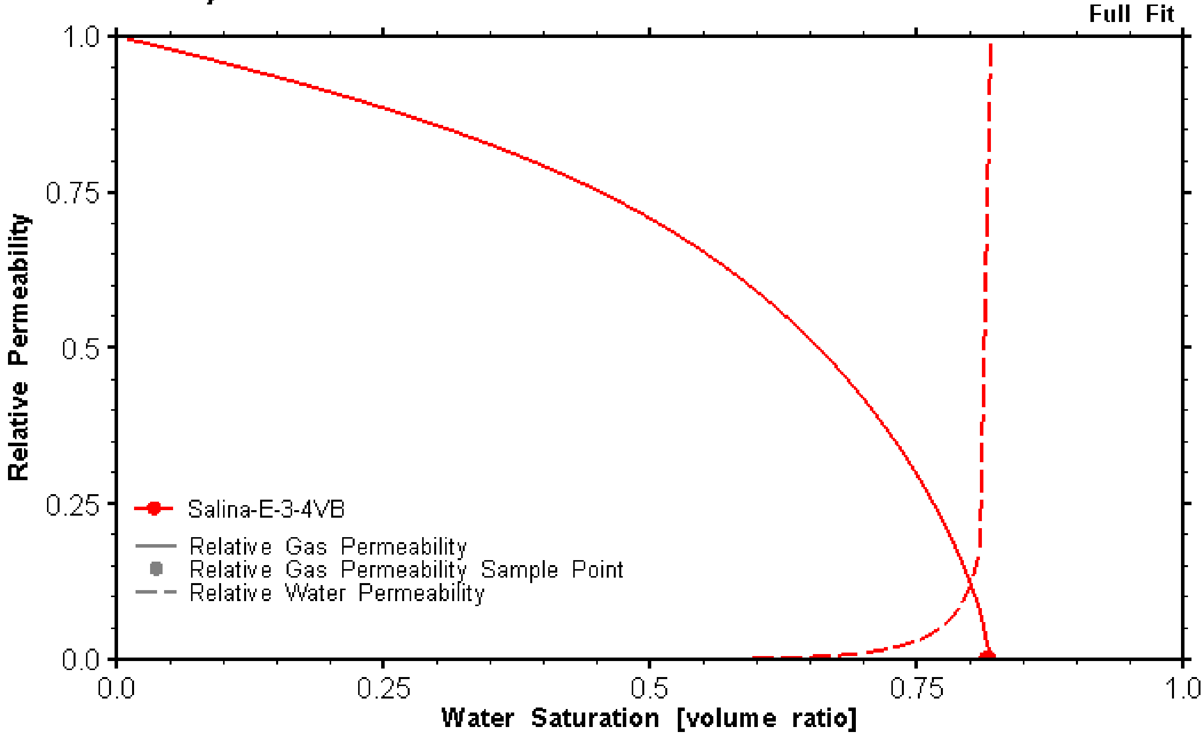


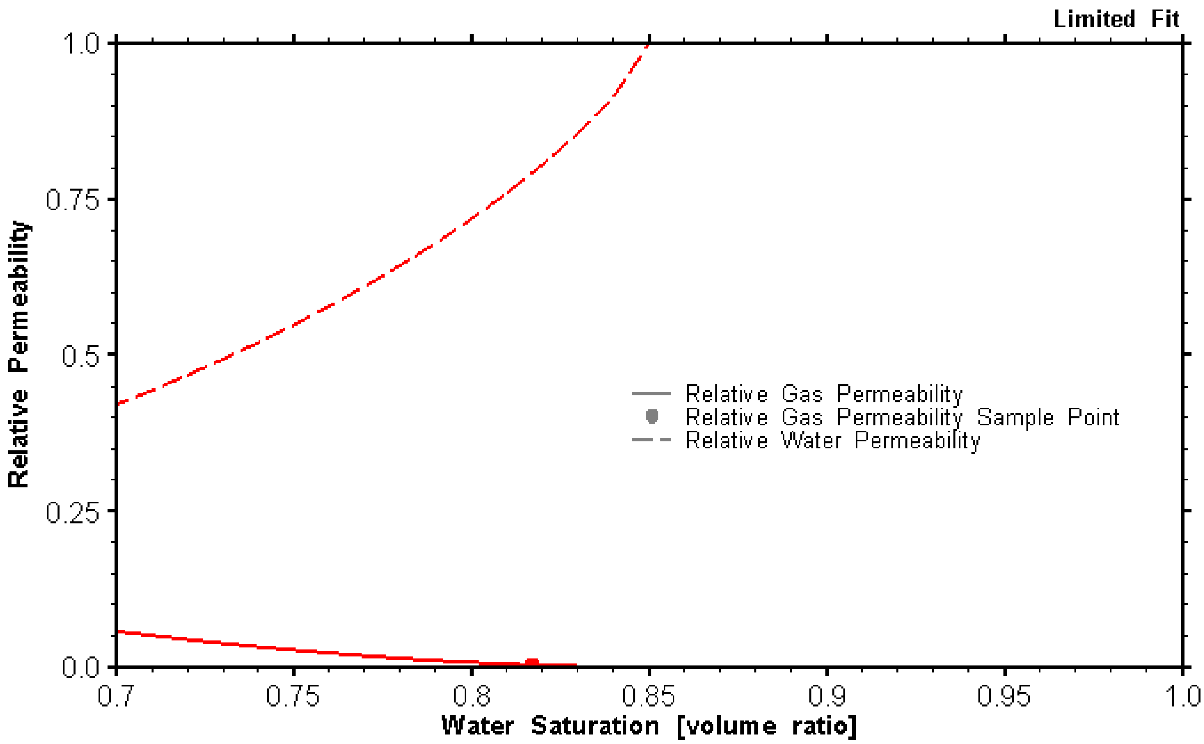
Salina-E Formation
Capillary Pressure



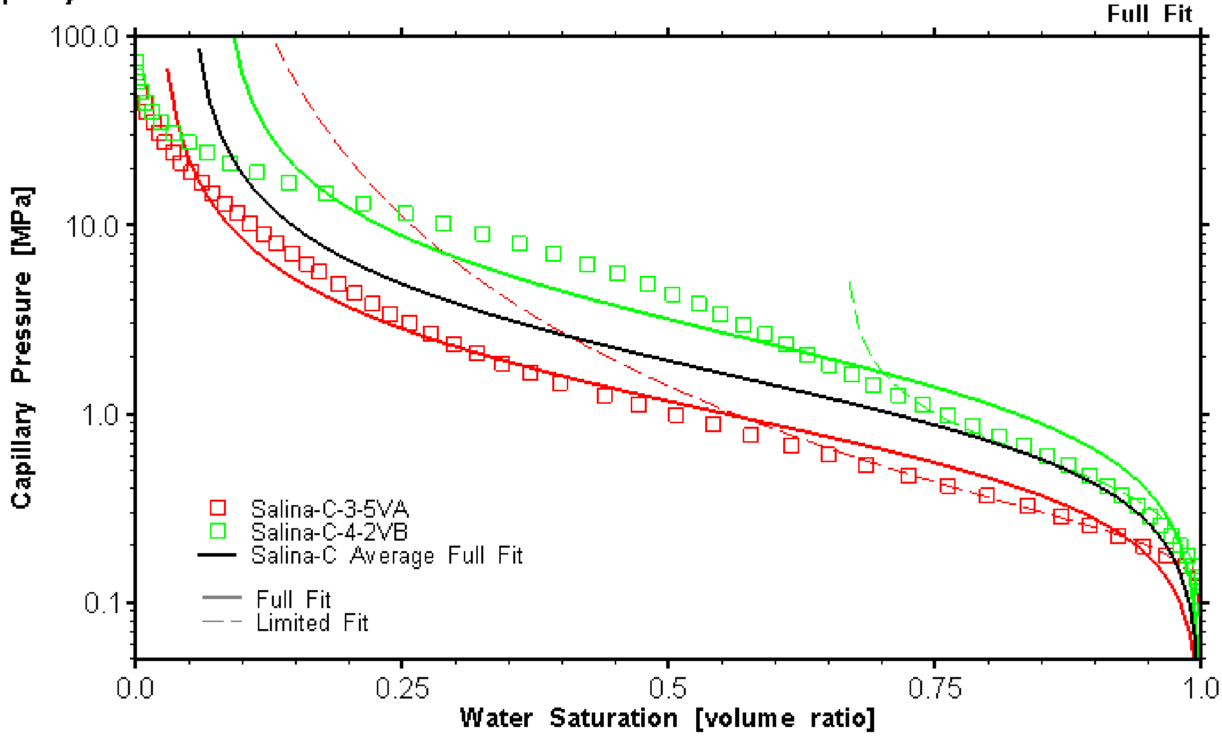


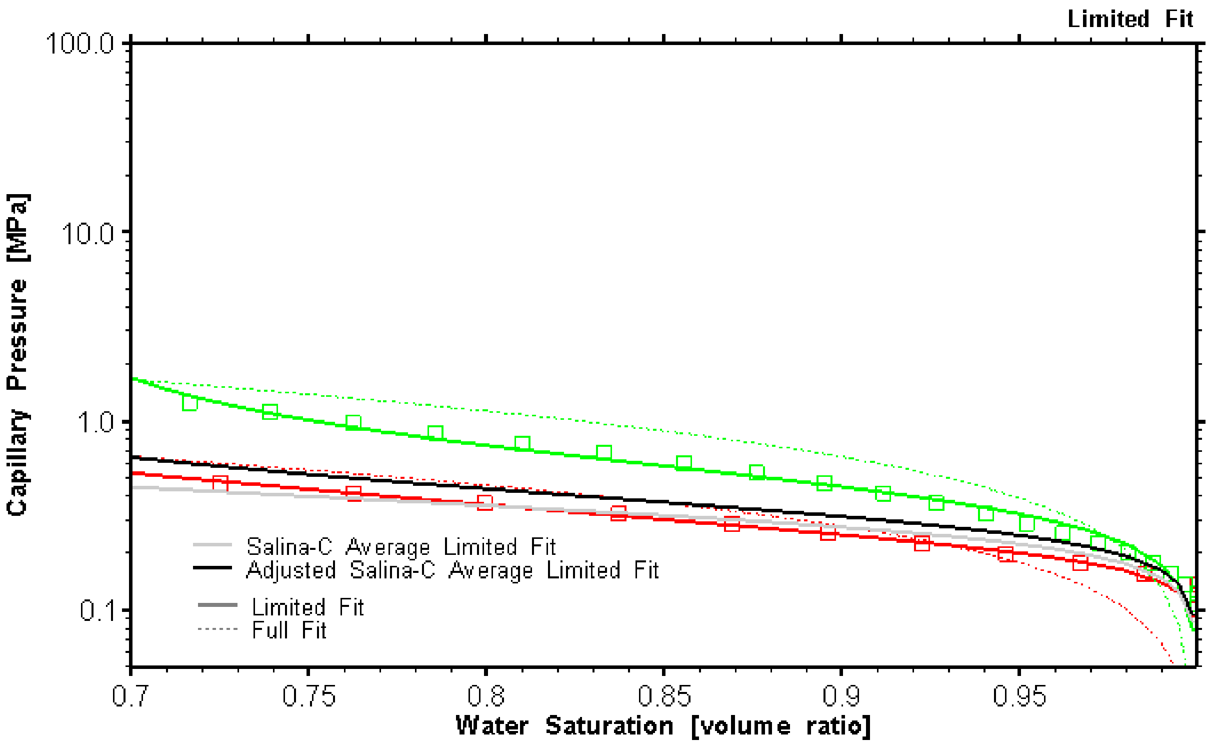
Salina-E Formation
Relative Permeability



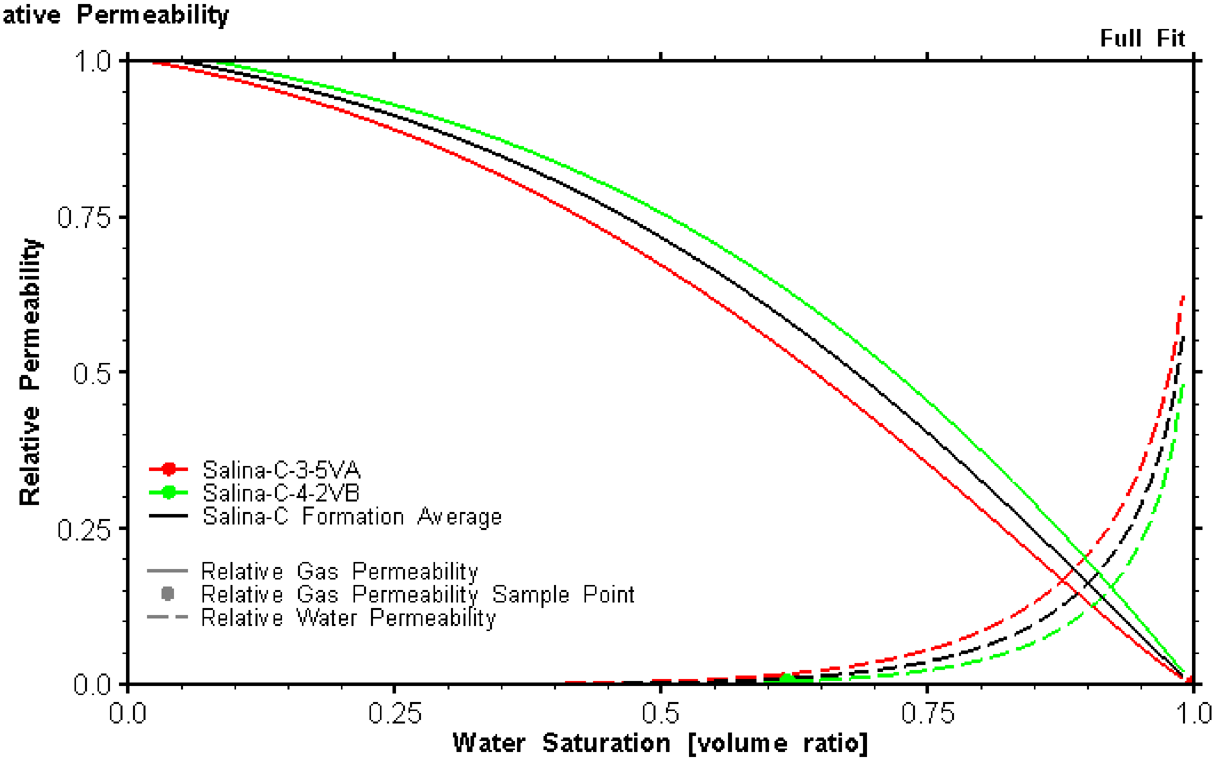


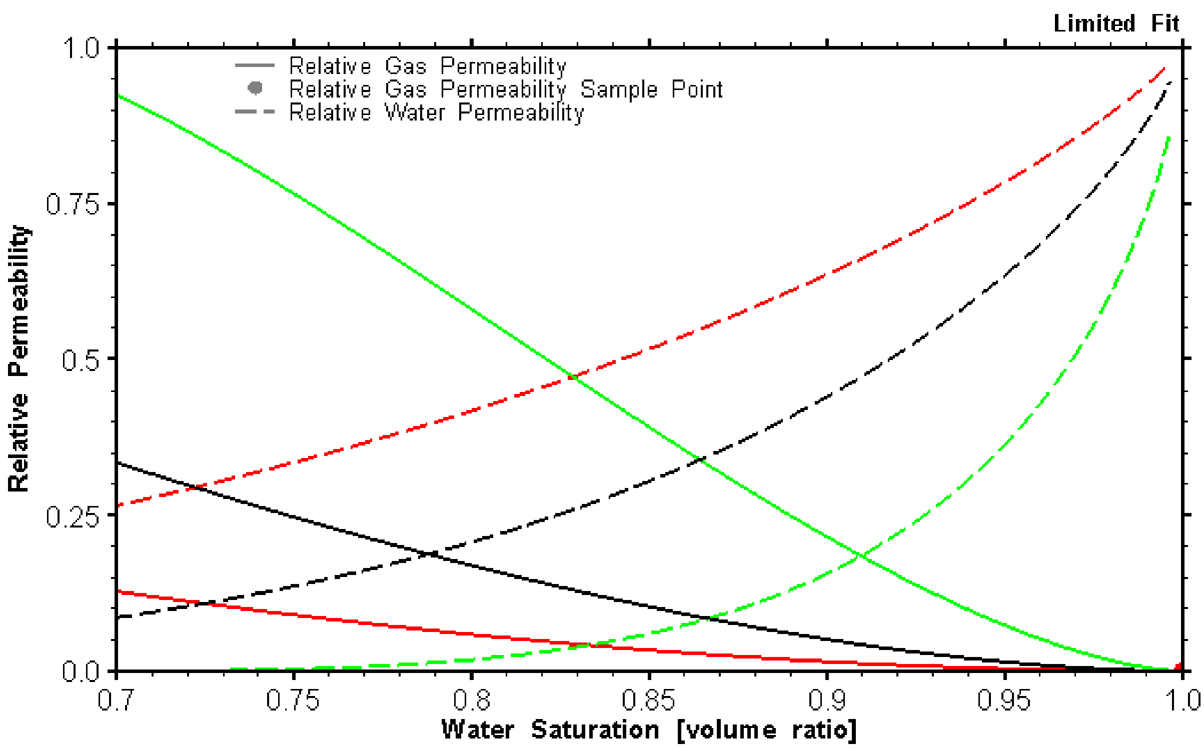
Salina-C Formation
Capillary Pressure



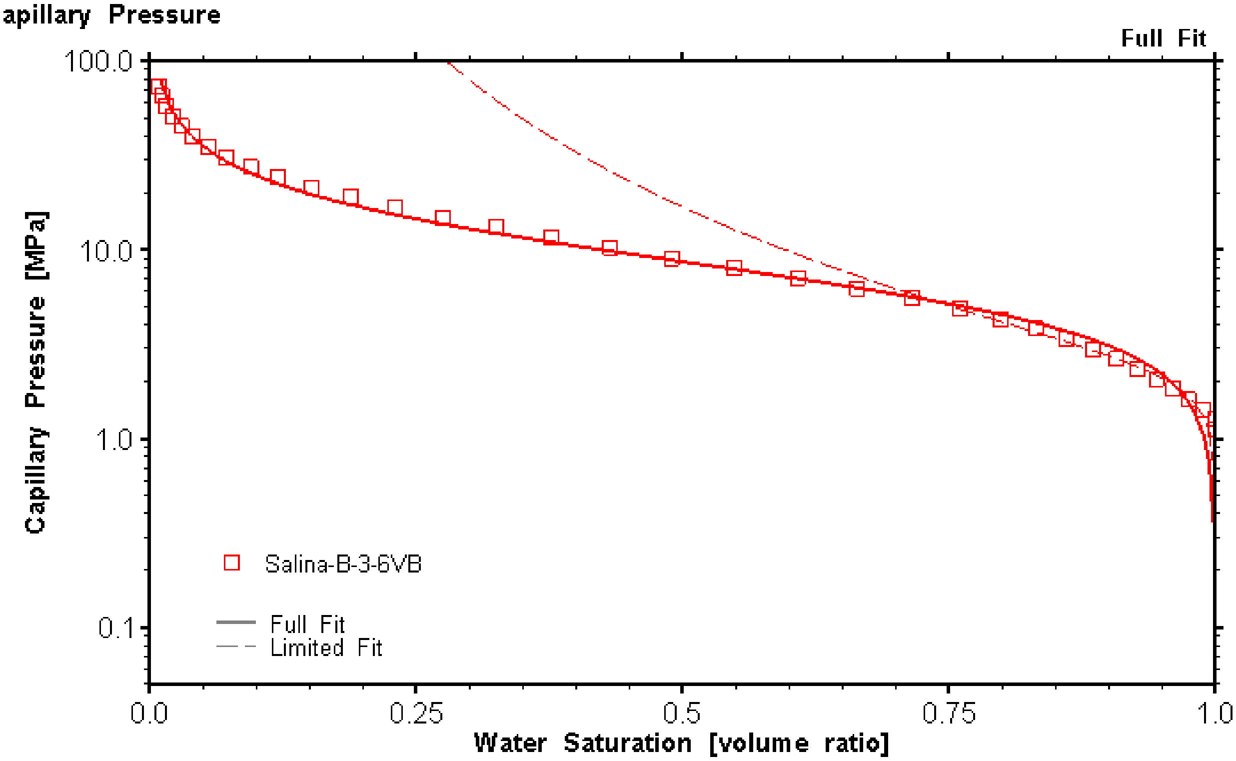


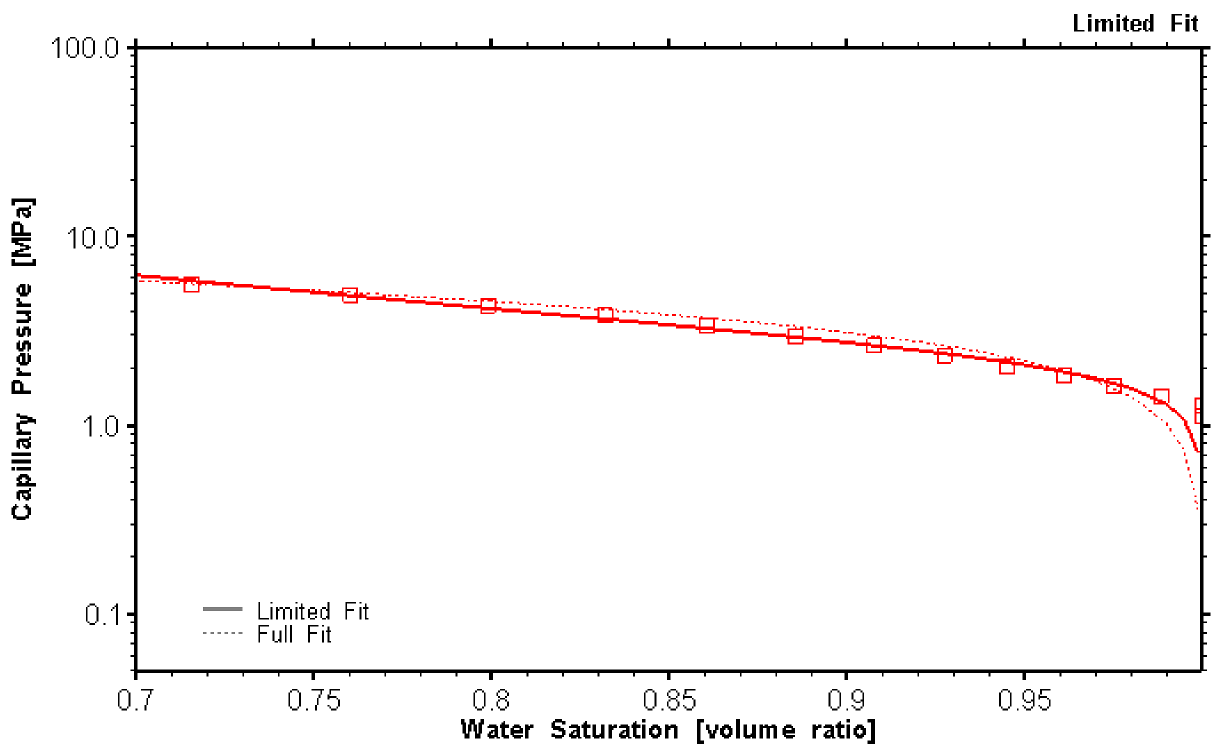
Salina-C Formation
Relative Permeability

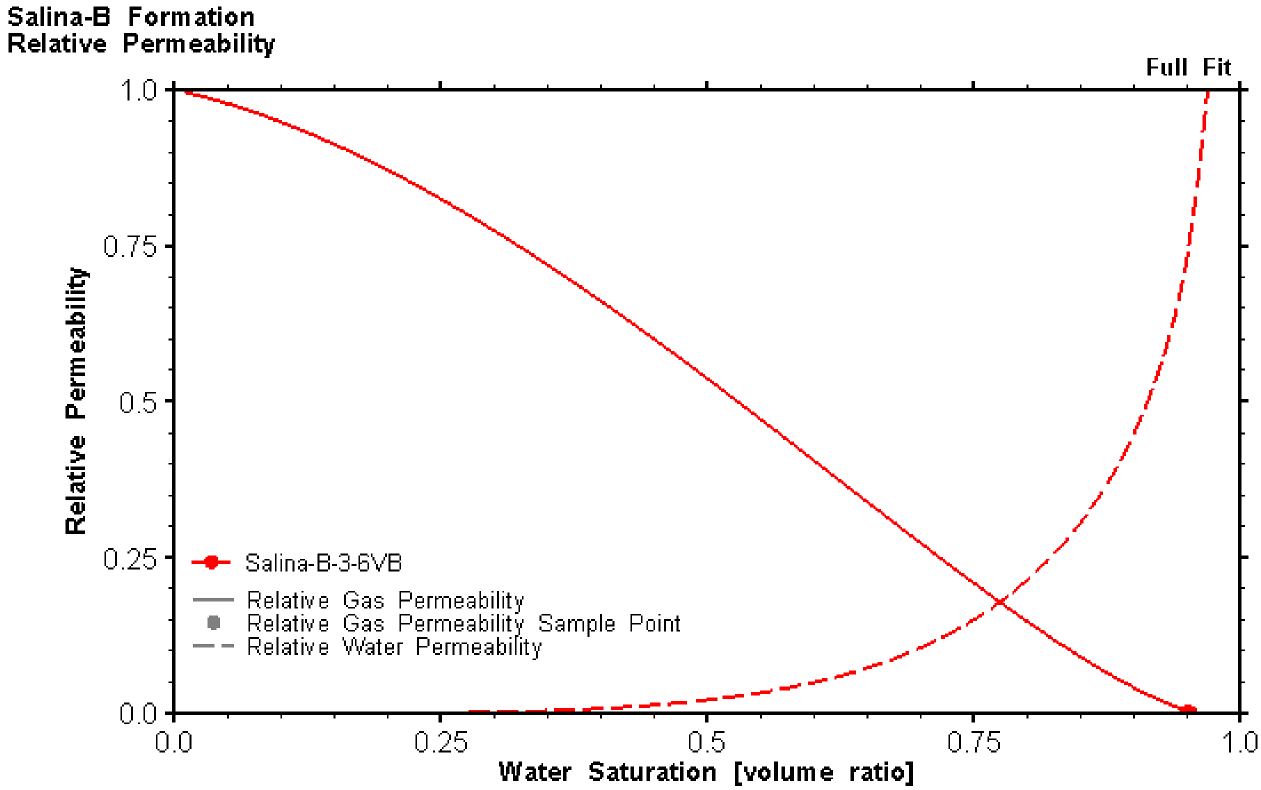


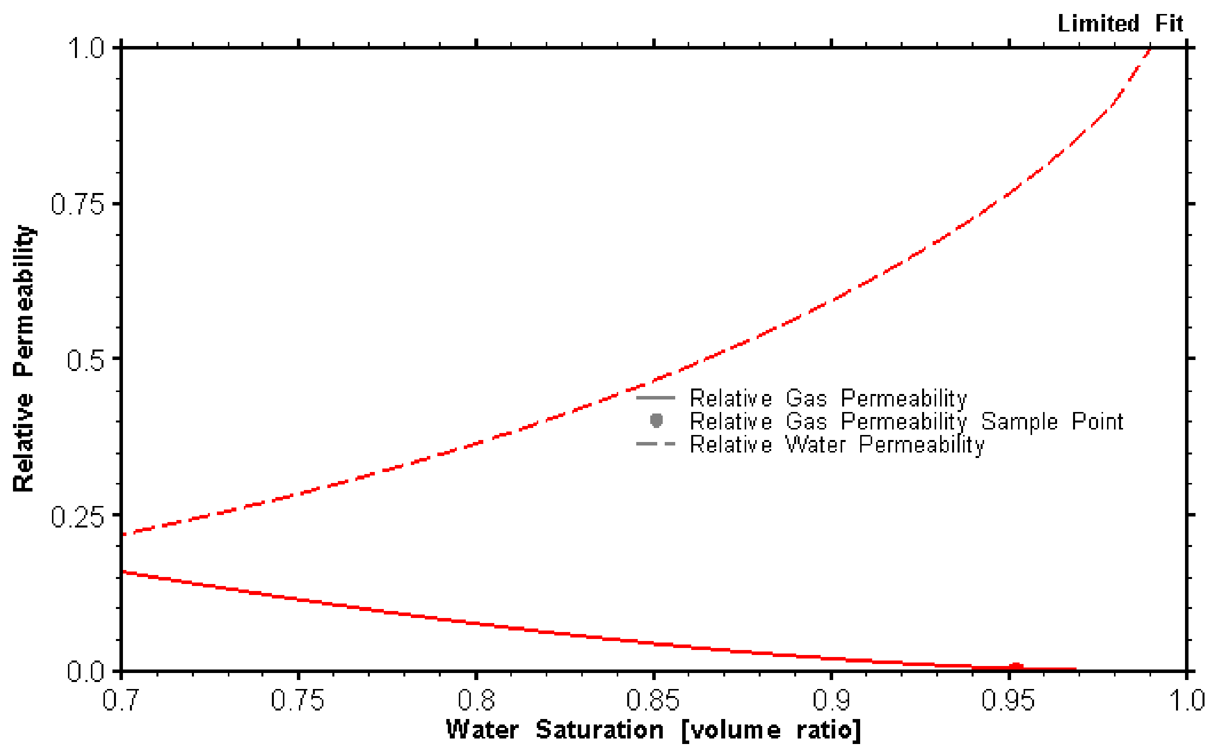


Salina-B Formation
Capillary Pressure

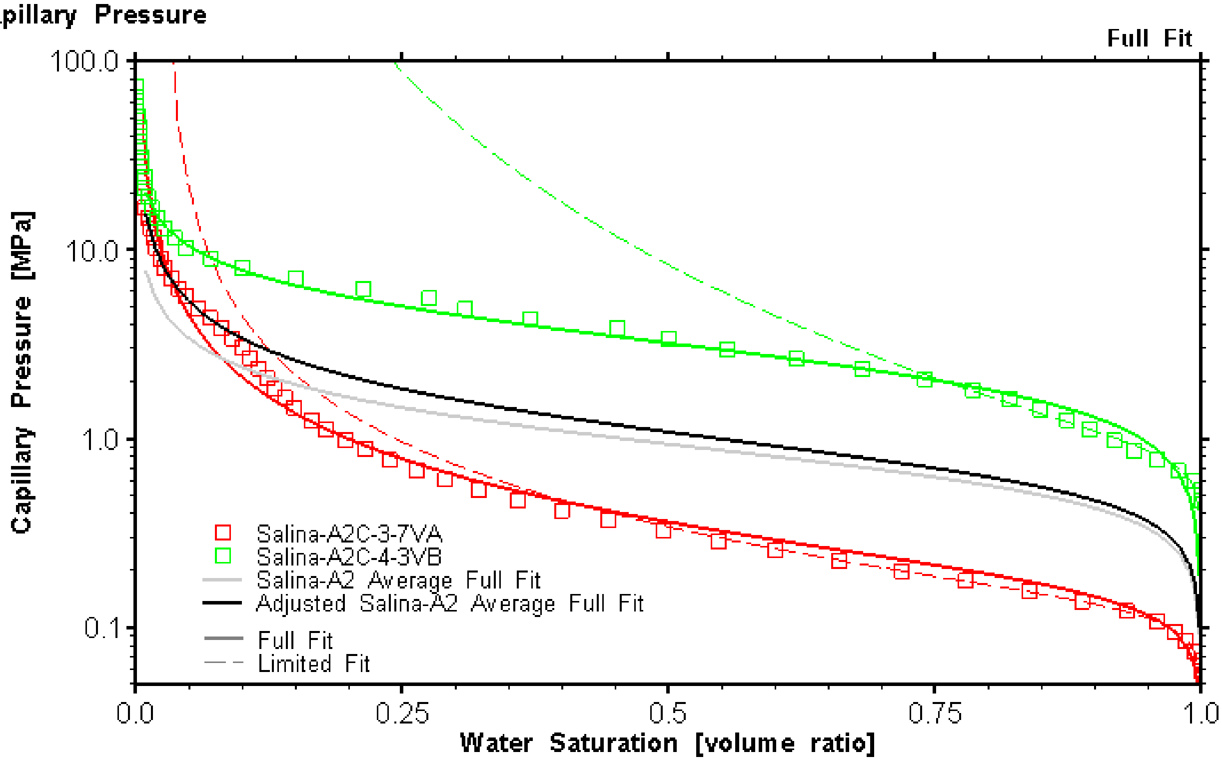


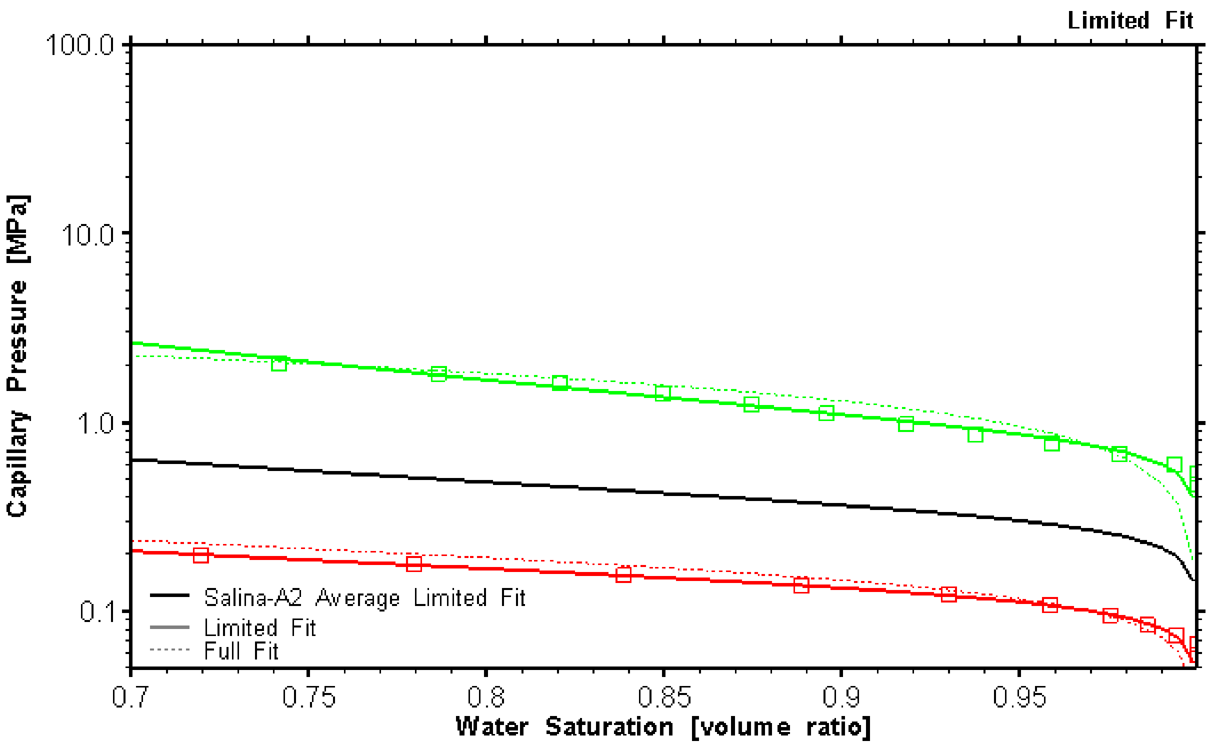



Salina-B Formation
Relative Permeability
Full Fit
1.0
0.75
0.5
0.25
0.0
Relative Permeability
Salina-B-3-6VB
Relative Gas Permeability
Relative Gas Permeability Sample Point
Relative Water Permeability
0.0
0.25
0.5
0.75
1.0
Water Saturation [volume ratio]

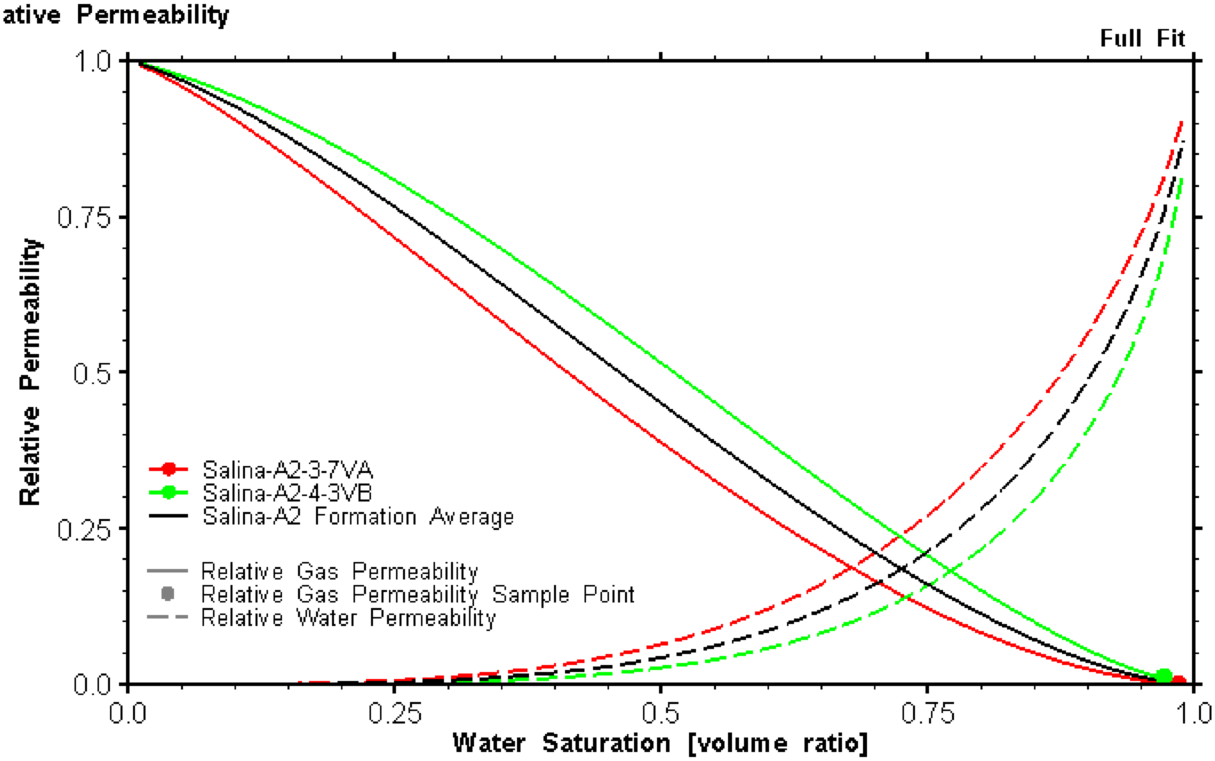

Limited Fit
1.0
0.75
0.5
0.25
0.0
Relative Permeability
Relative Gas Permeability
Relative Gas Permeability Sample Point
Relative Water Permeability
0.7
0.75
0.8
0.85
0.9
0.95
1.0
Water Saturation [volume ratio]

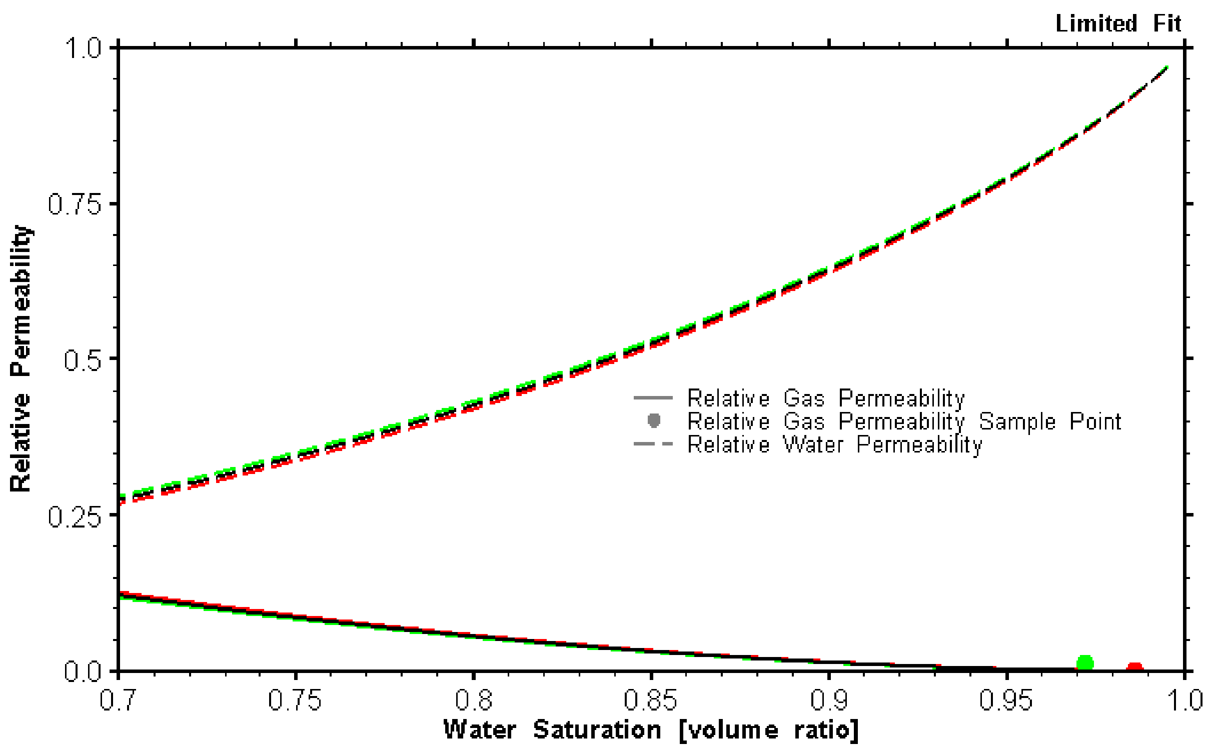
Salina-A2 Formation
Capillary Pressure



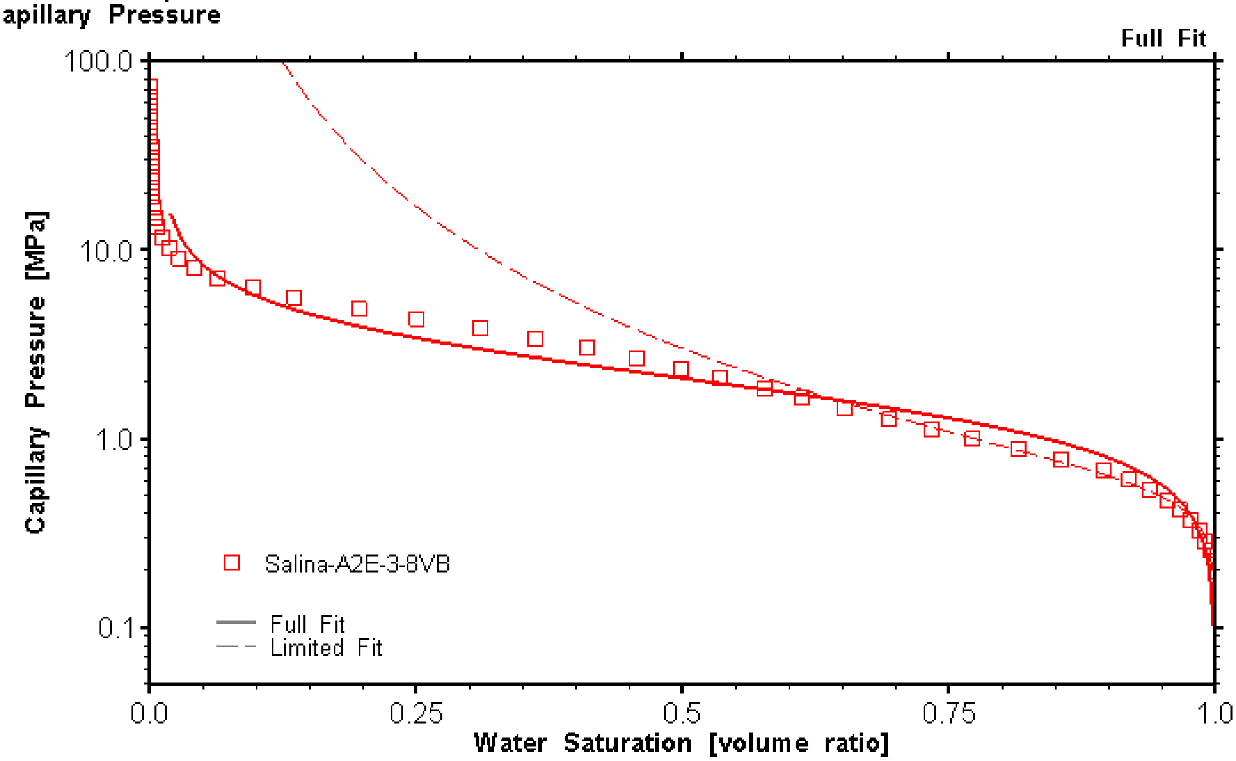


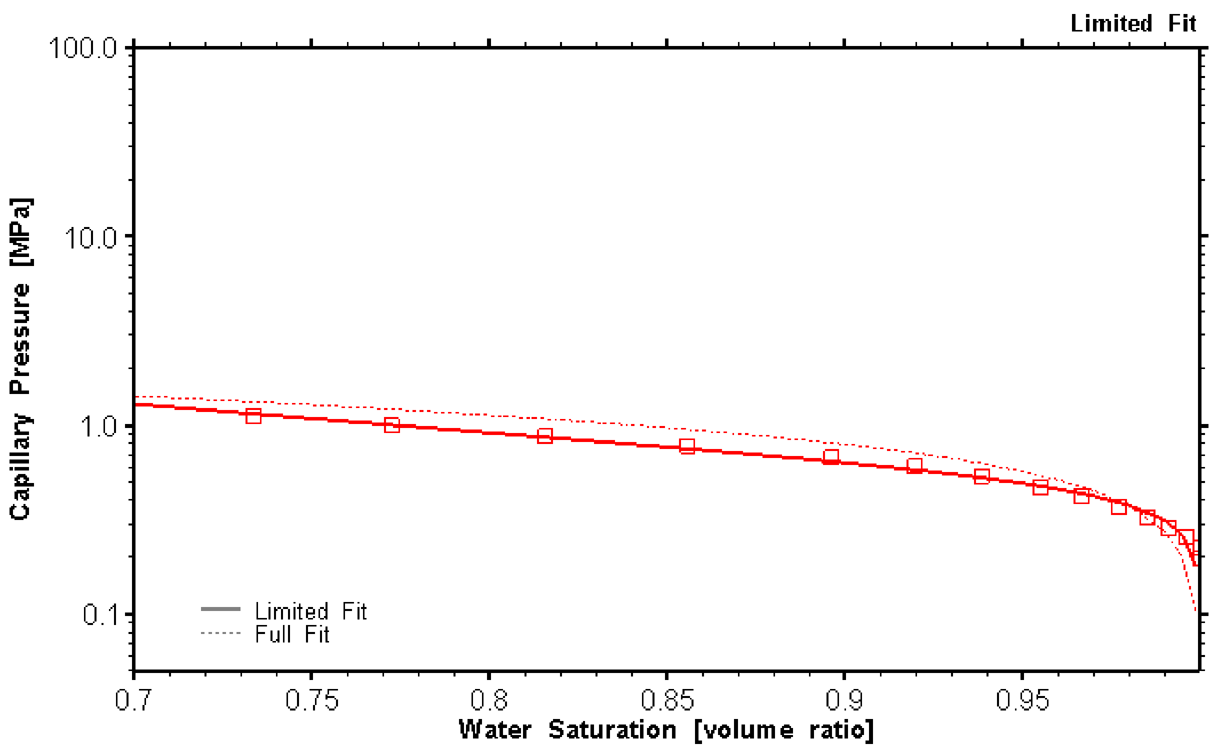
Salina-A2 Formation
Relative Permeability



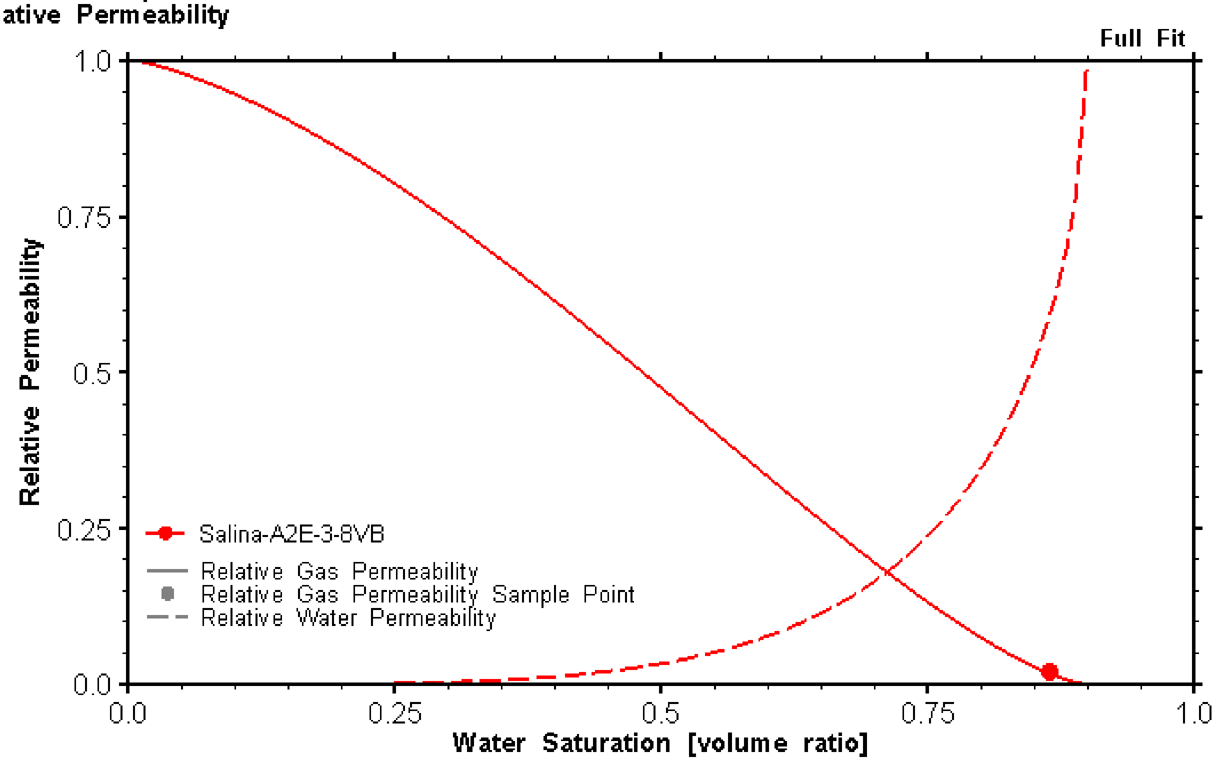


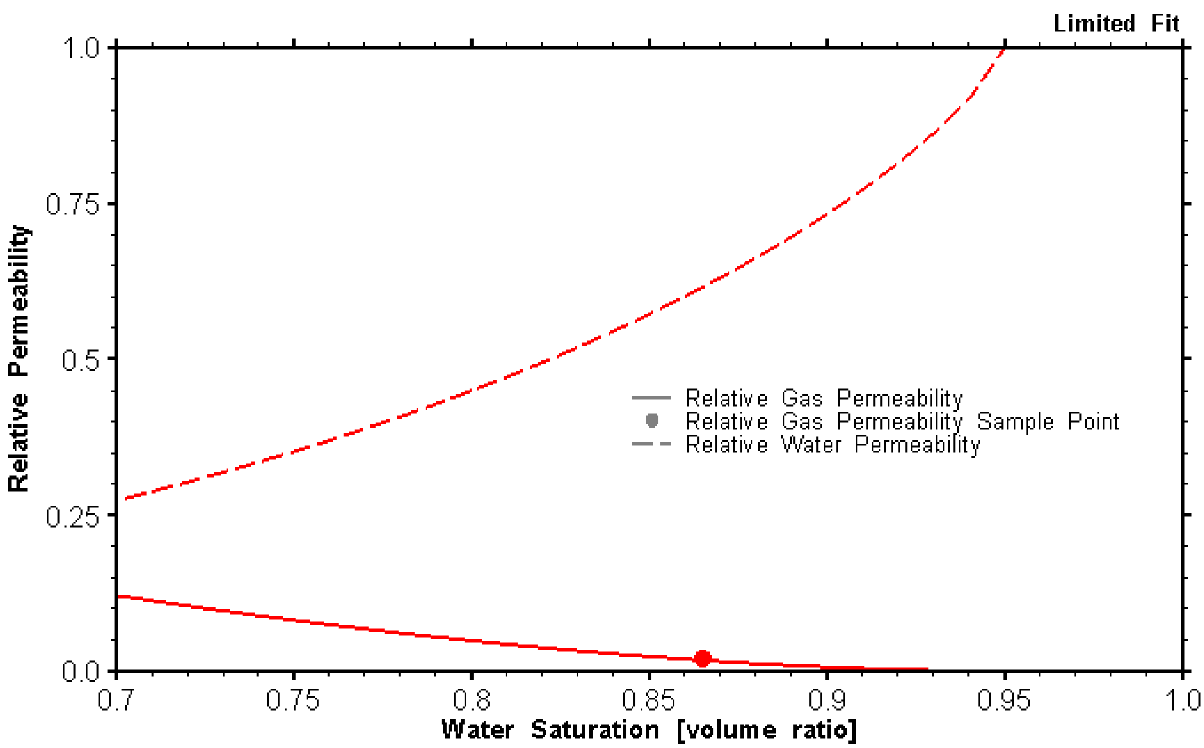
Salina-A2 Evaporite Formation
Capillary Pressure



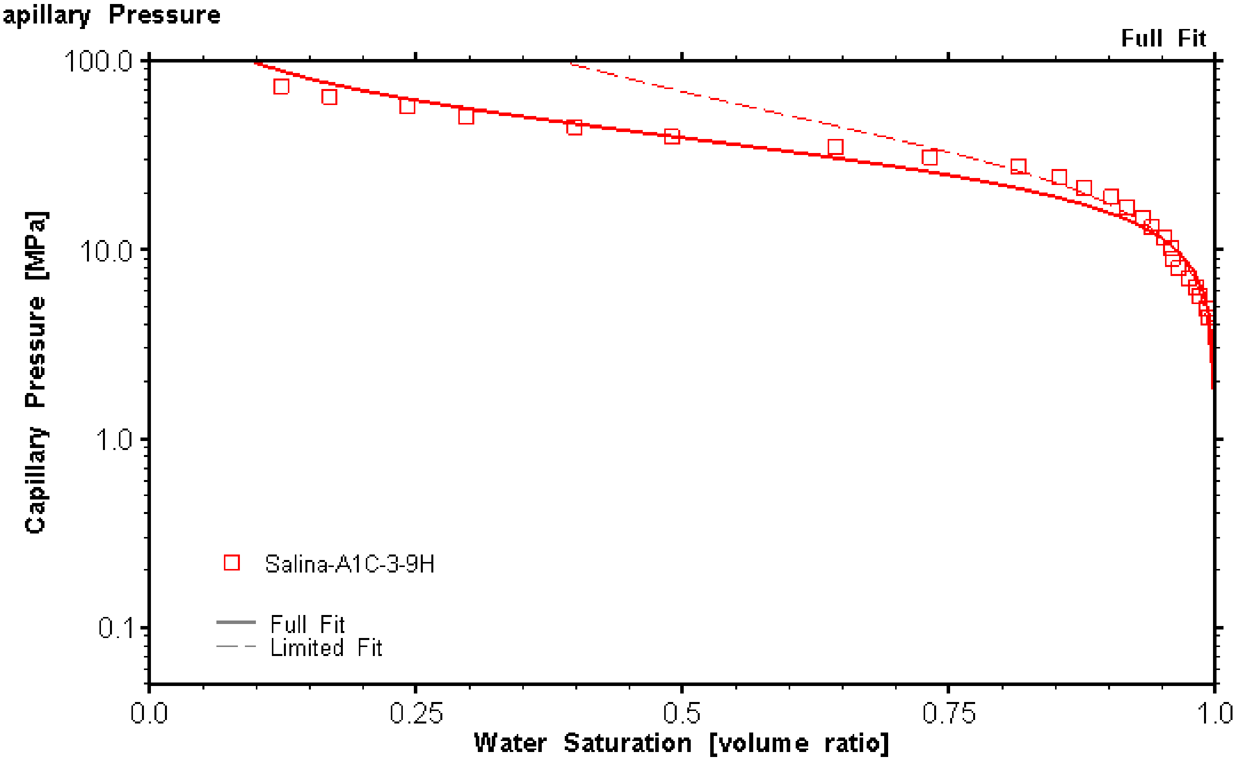


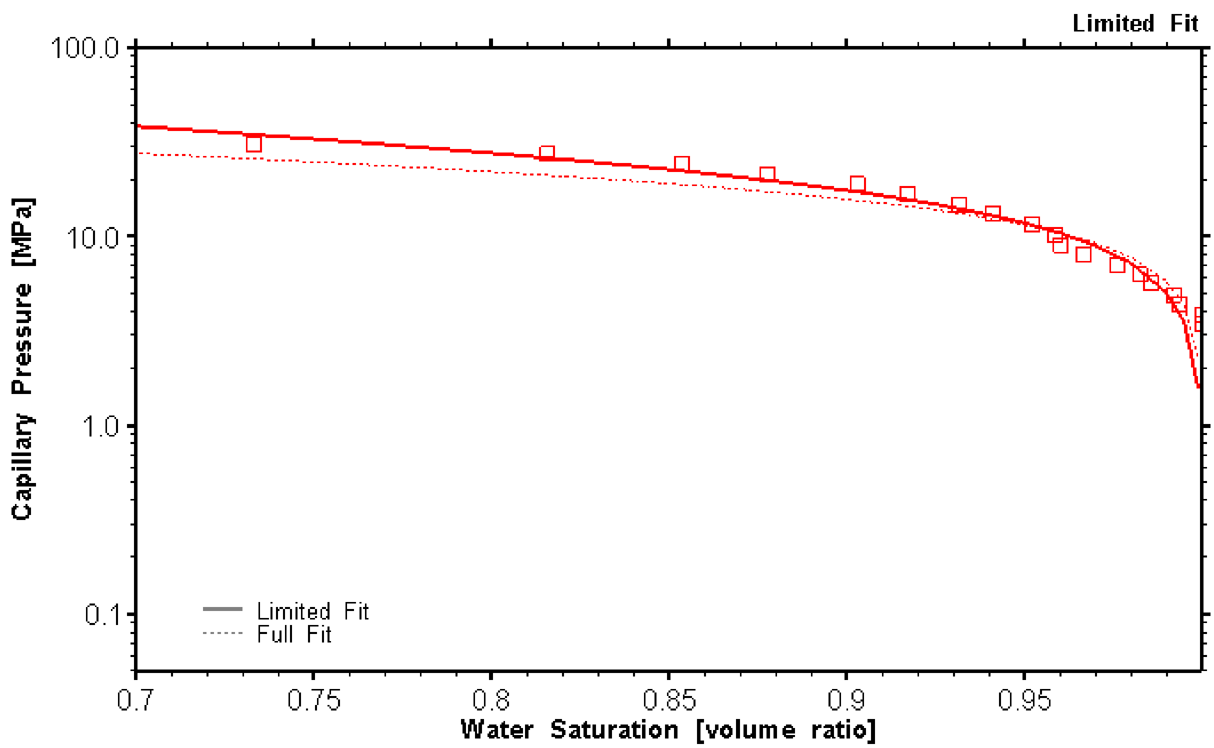
Salina-A2 Evaporite Formation
Relative Permeability



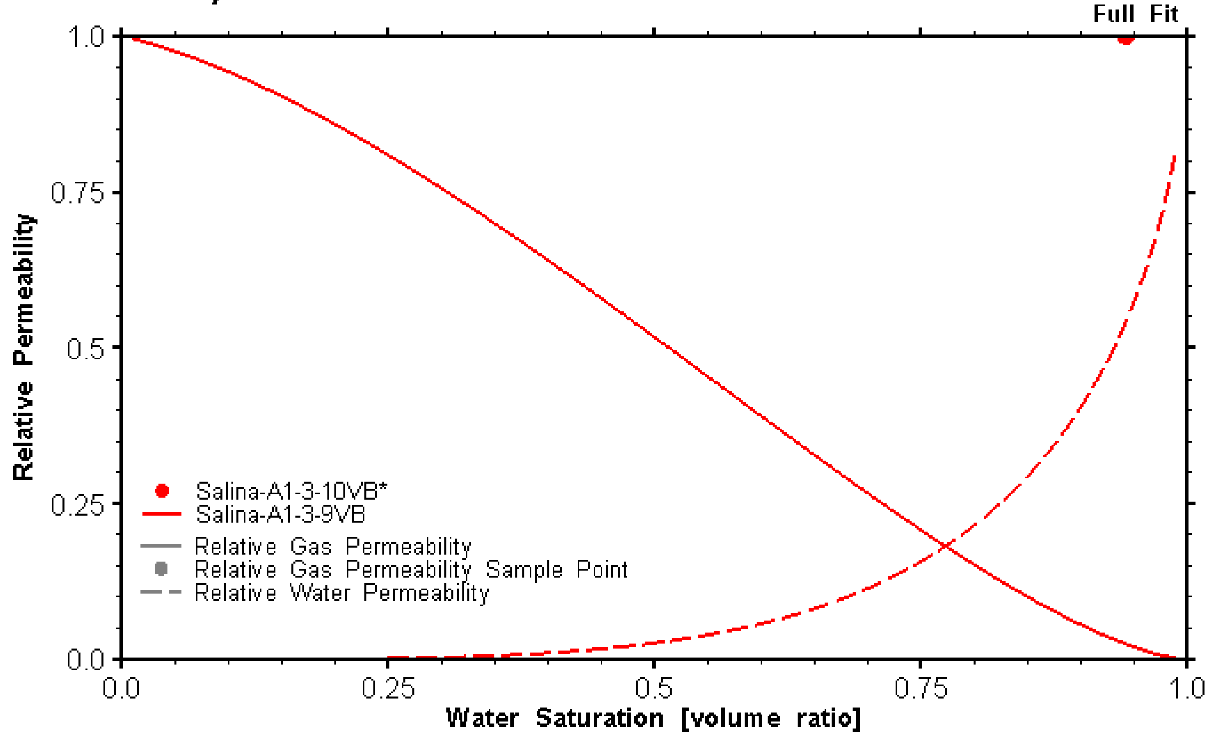


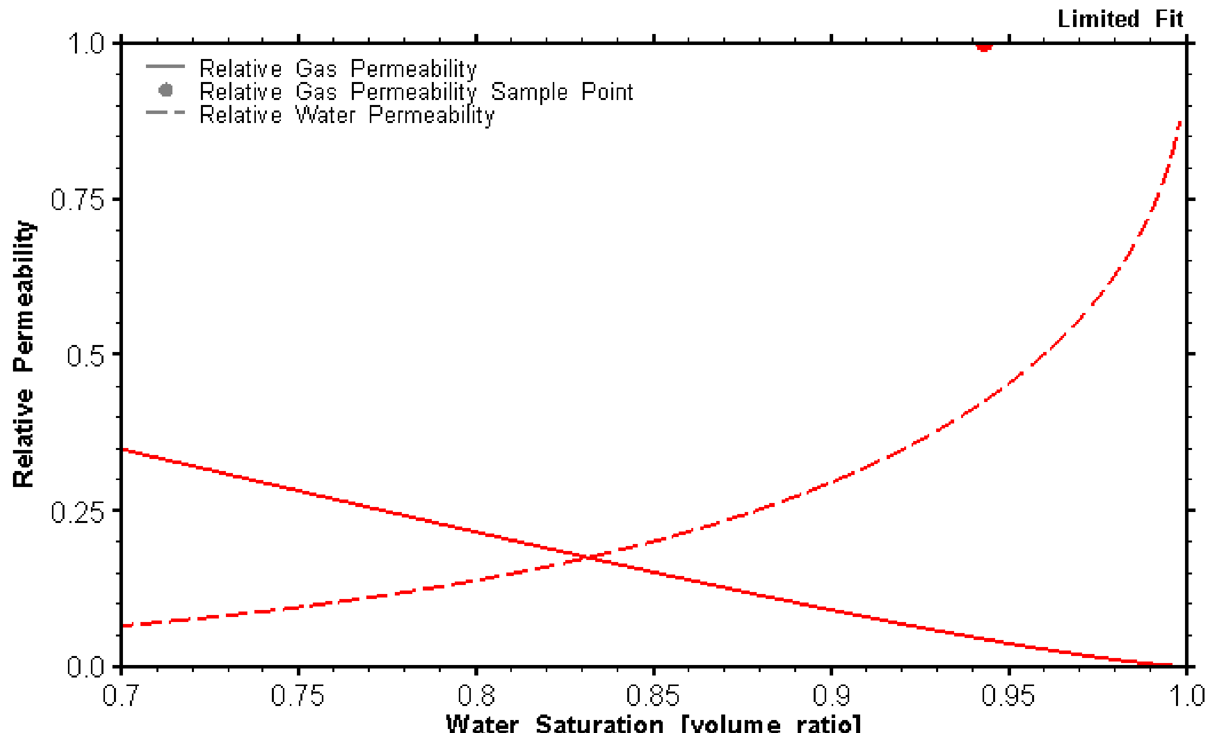
Salina-A1 Formation
Capillary Pressure





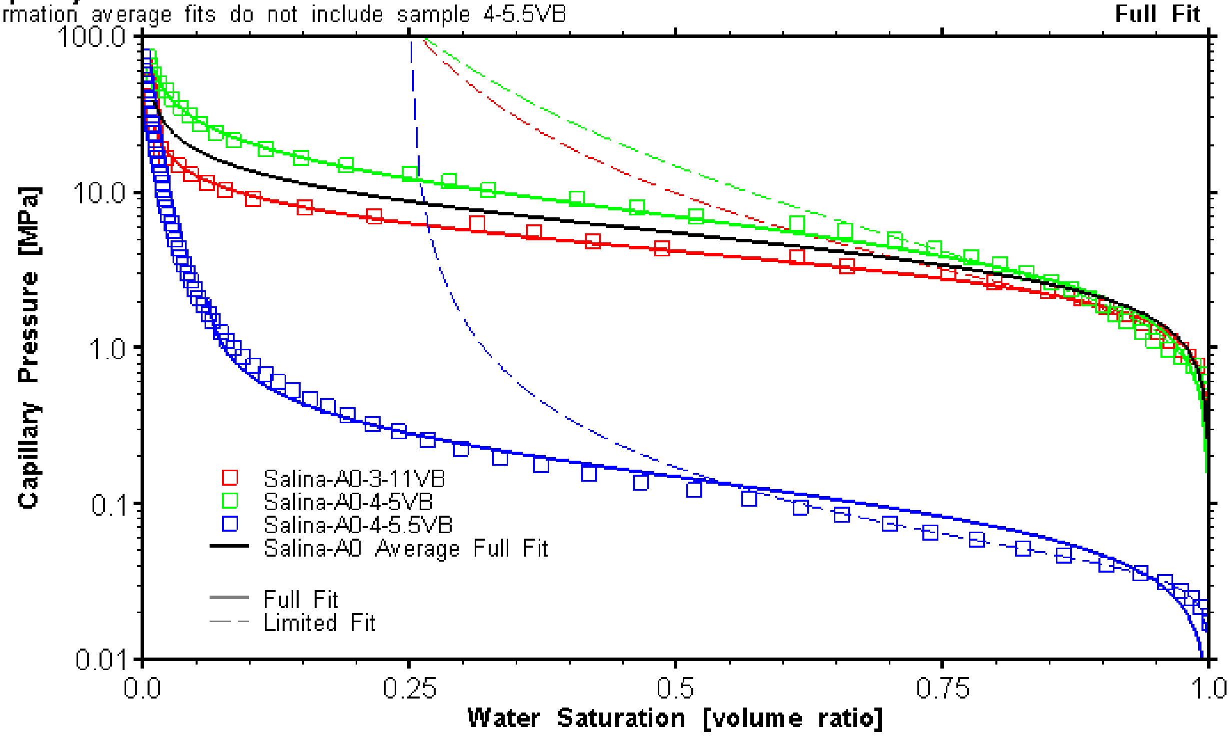
Salina-A1 Formation
Relative Permeability

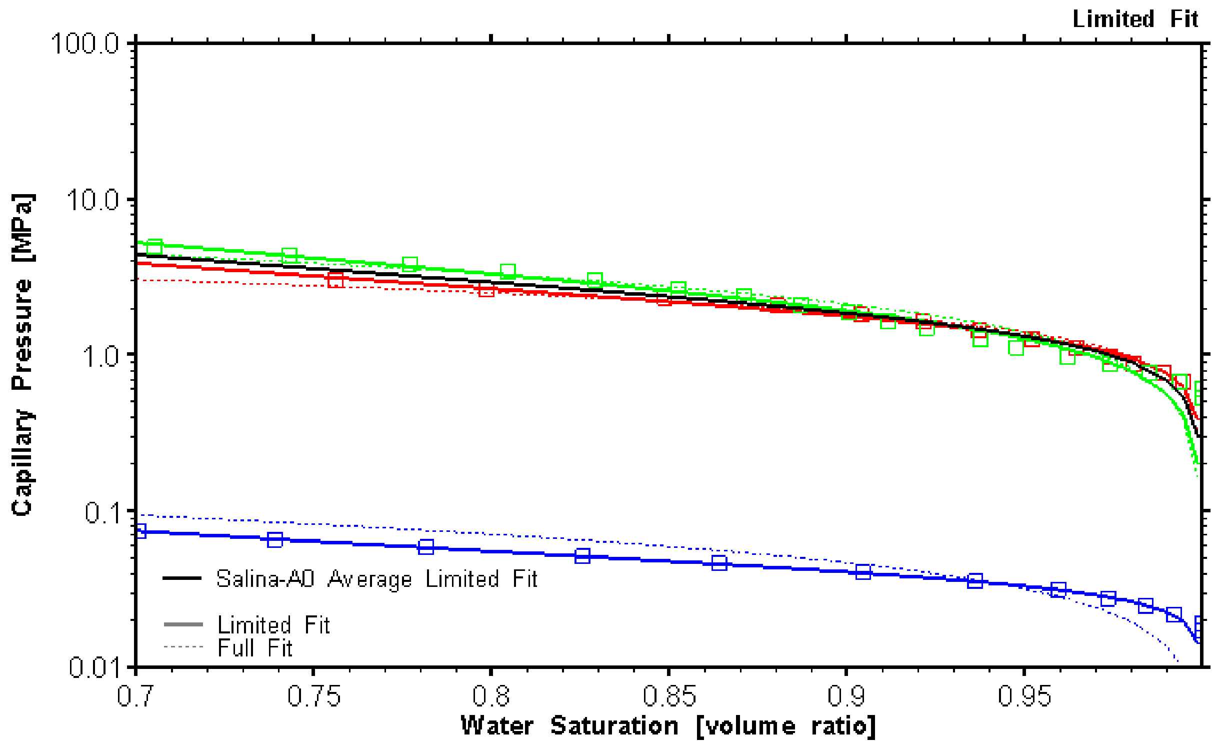


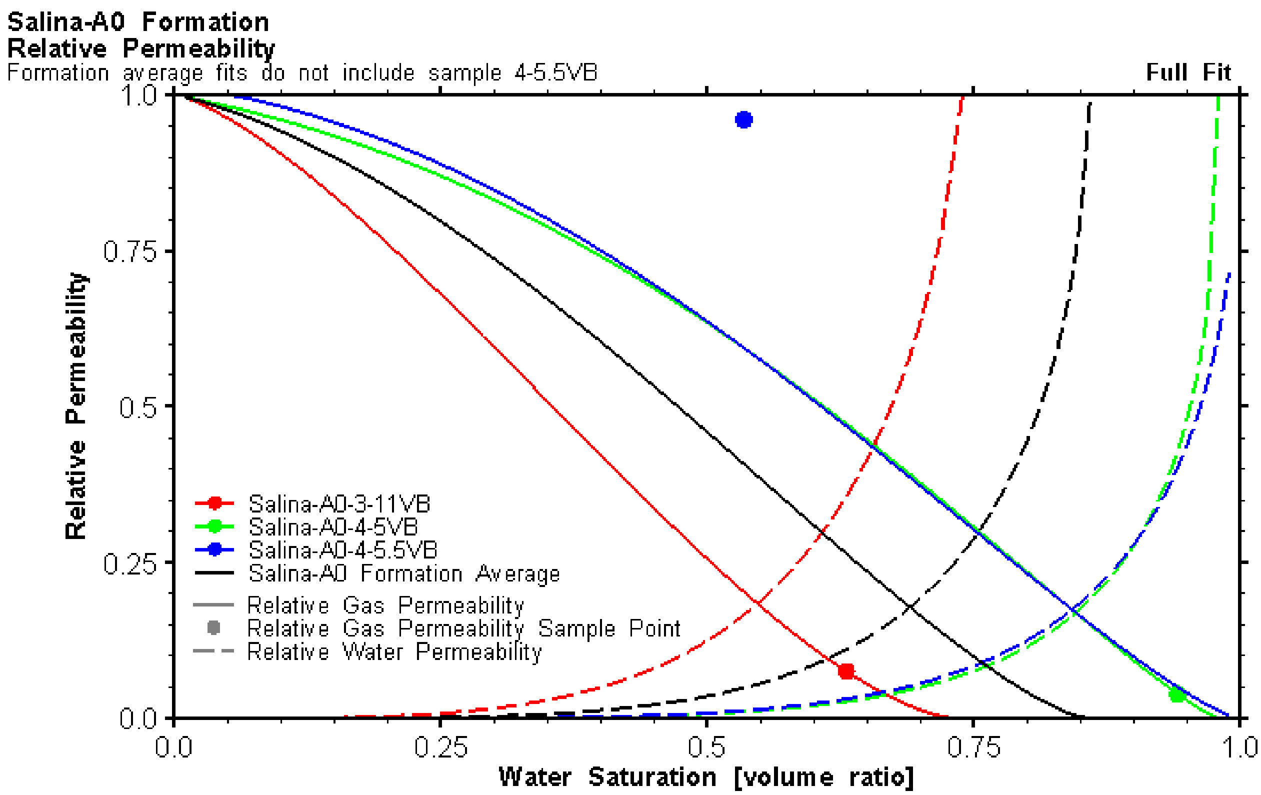


* Maximum sample relative permeability

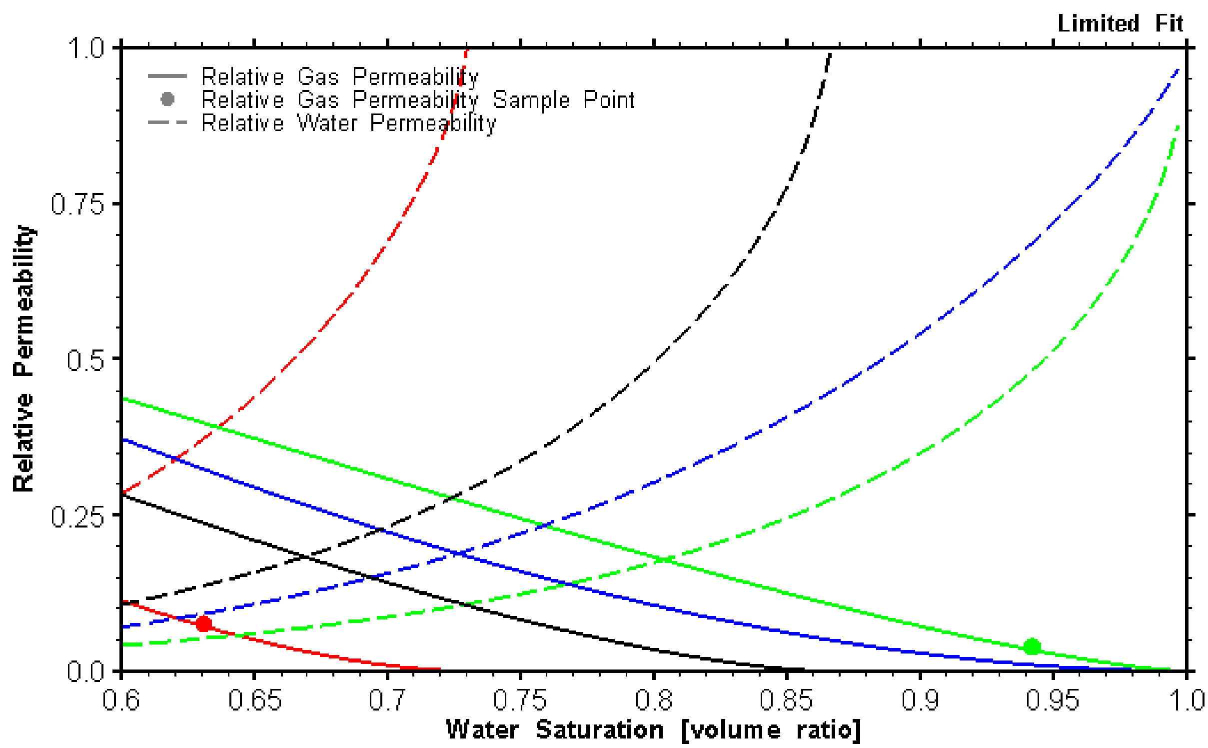
Salina-A0 Formation
Capillary Pressure
Formation average fits do not include sample 4-5.5VB





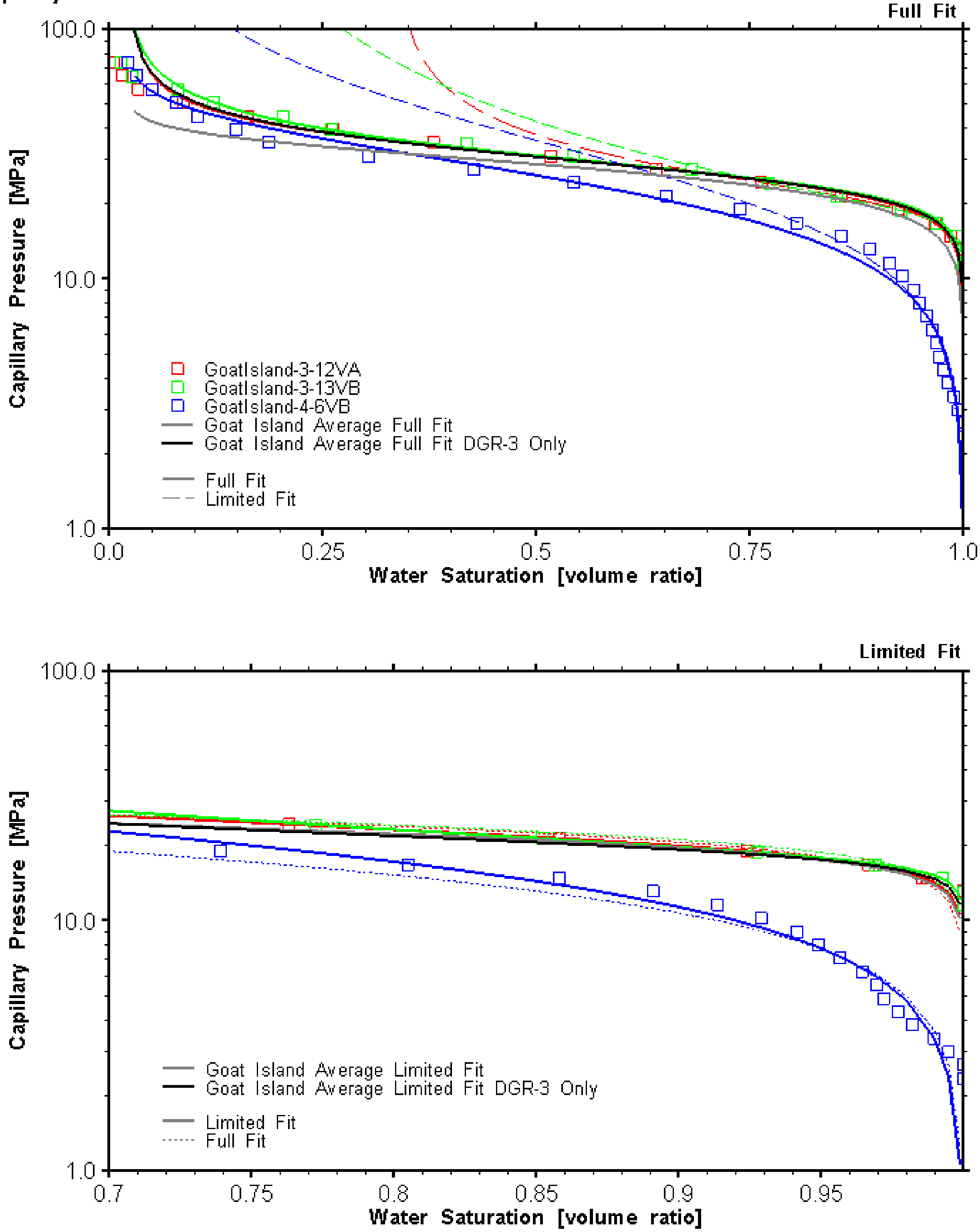


Salina-A0 Formation
Relative Permeability
Formation average fits do not include sample 4-5.5VB
Full Fit
Relative Permeability
Water Saturation [volume ratio]
Salina-A0-3-11VB
Salina-A0-4-5VB
Salina-A0-4-5.5VB
Salina-A0 Formation Average
Relative Gas Permeability
Relative Gas Permeability Sample Point
Relative Water Permeability
0.0
0.25
0.5
0.75
1.0

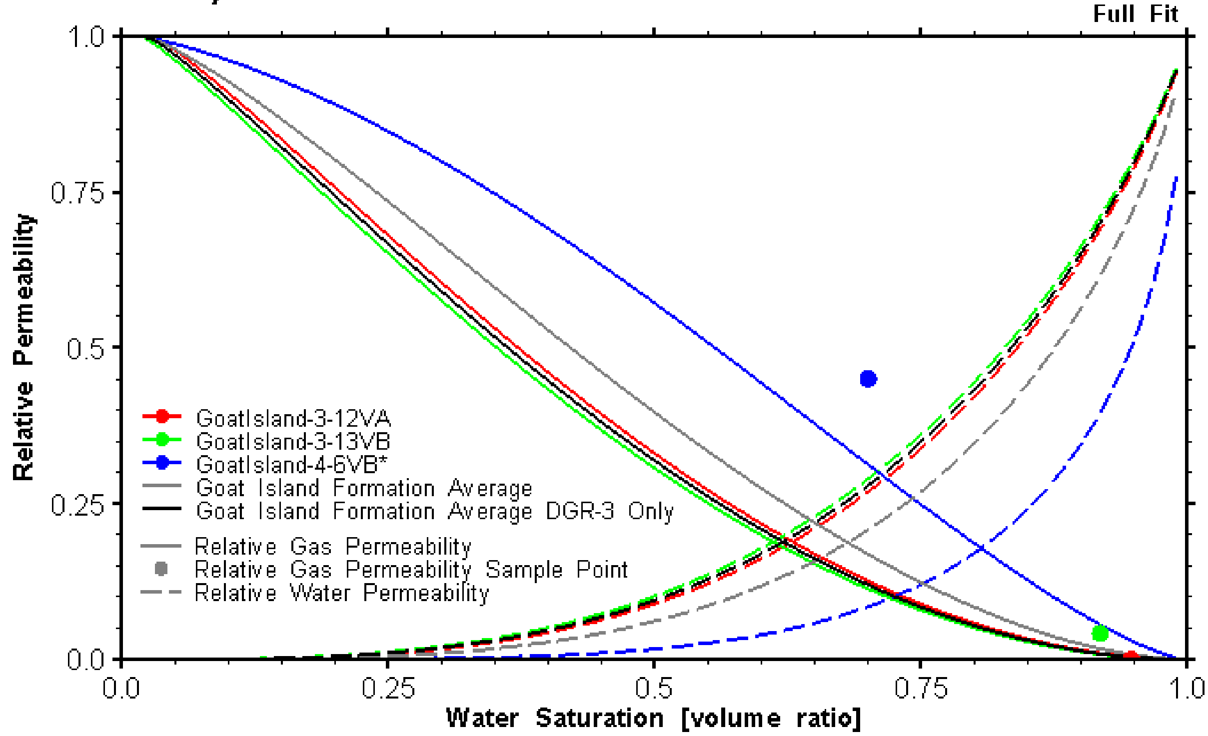


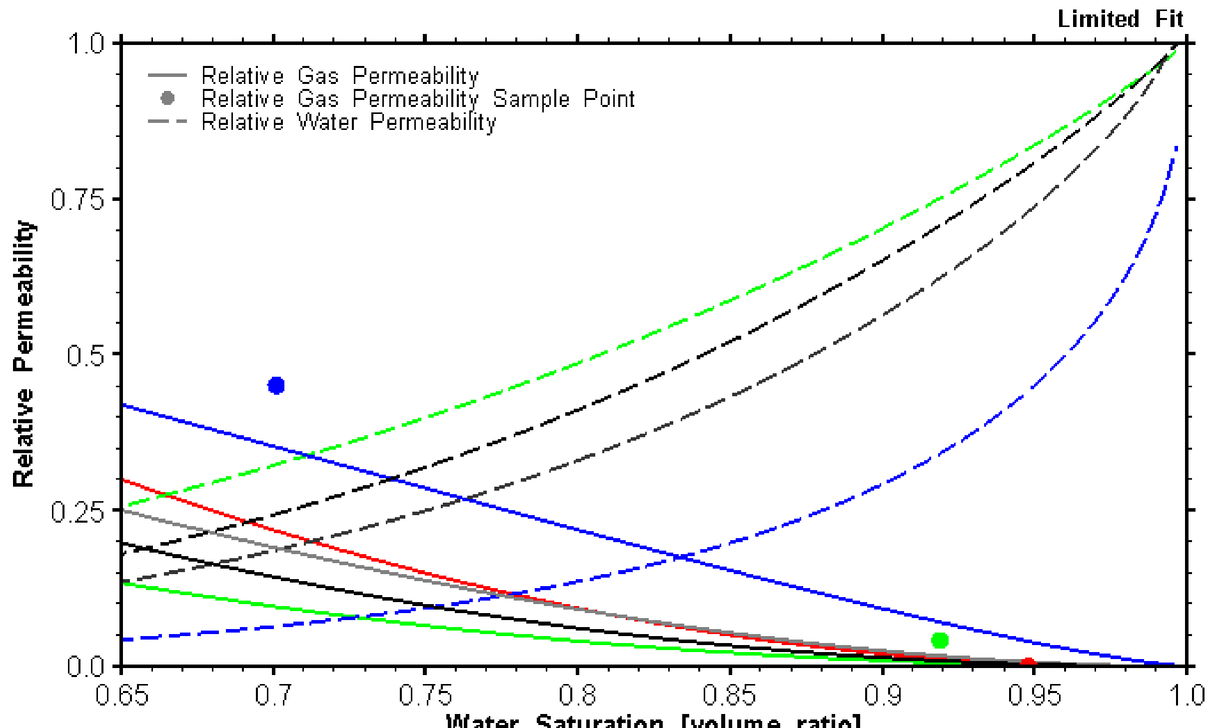
Limited Fit
Relative Gas Permeability
Relative Gas Permeability Sample Point
Relative Water Permeability
Relative Permeability
Water Saturation [volume ratio]
0.6
0.65
0.7
0.75
0.8
0.85
0.9
0.95
1.0
0.0
0.25
0.5
0.75
1.0

Goat Island Formation
Capillary Pressure



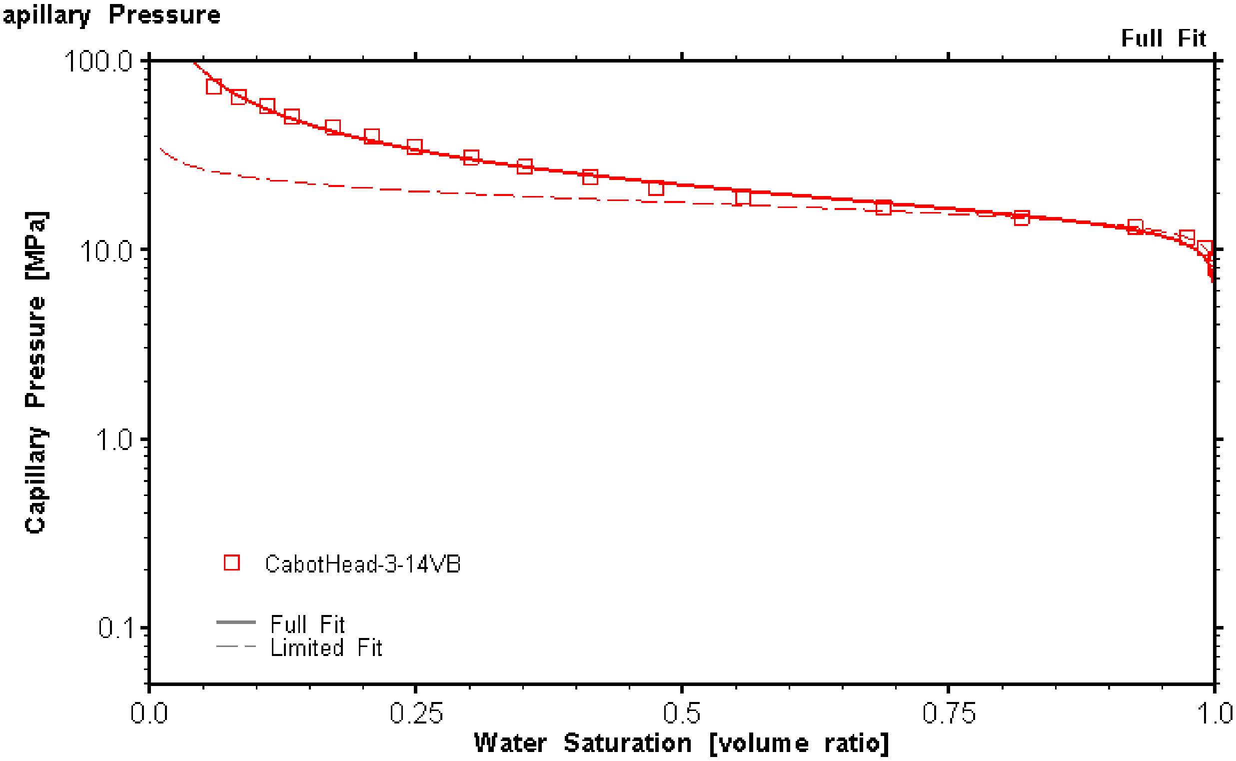
Goat Island Formation
Relative Permeability

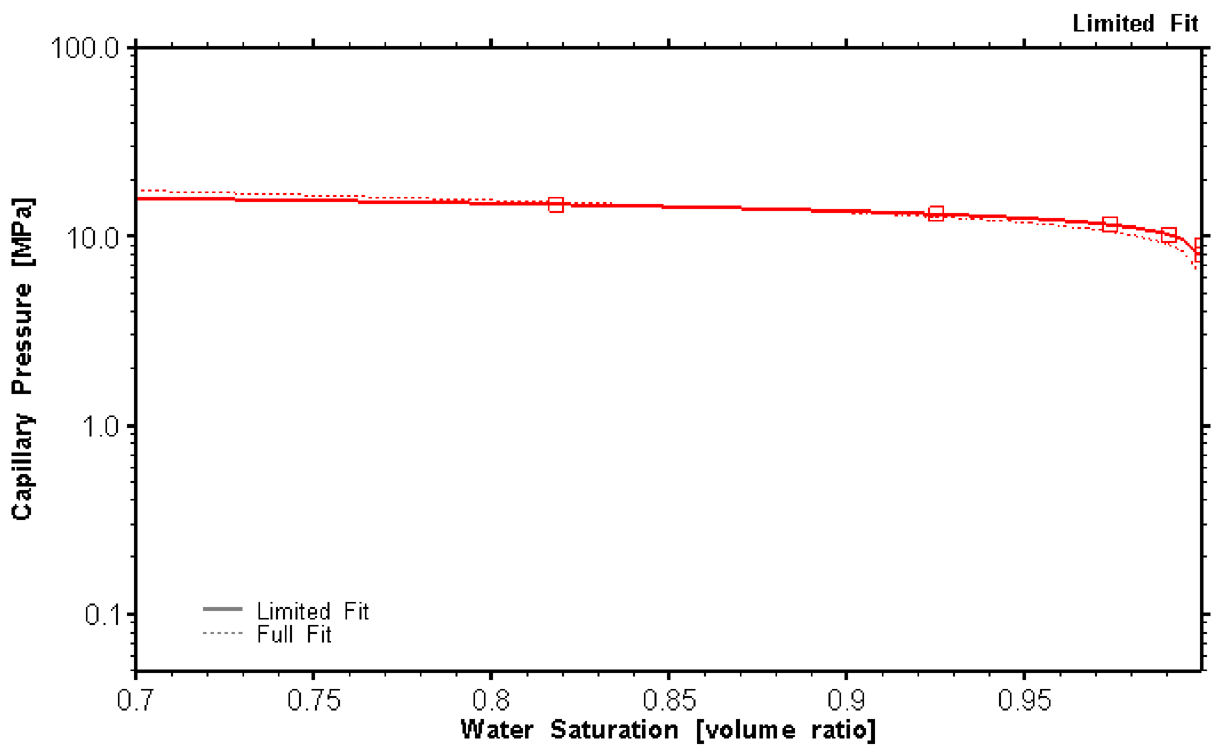




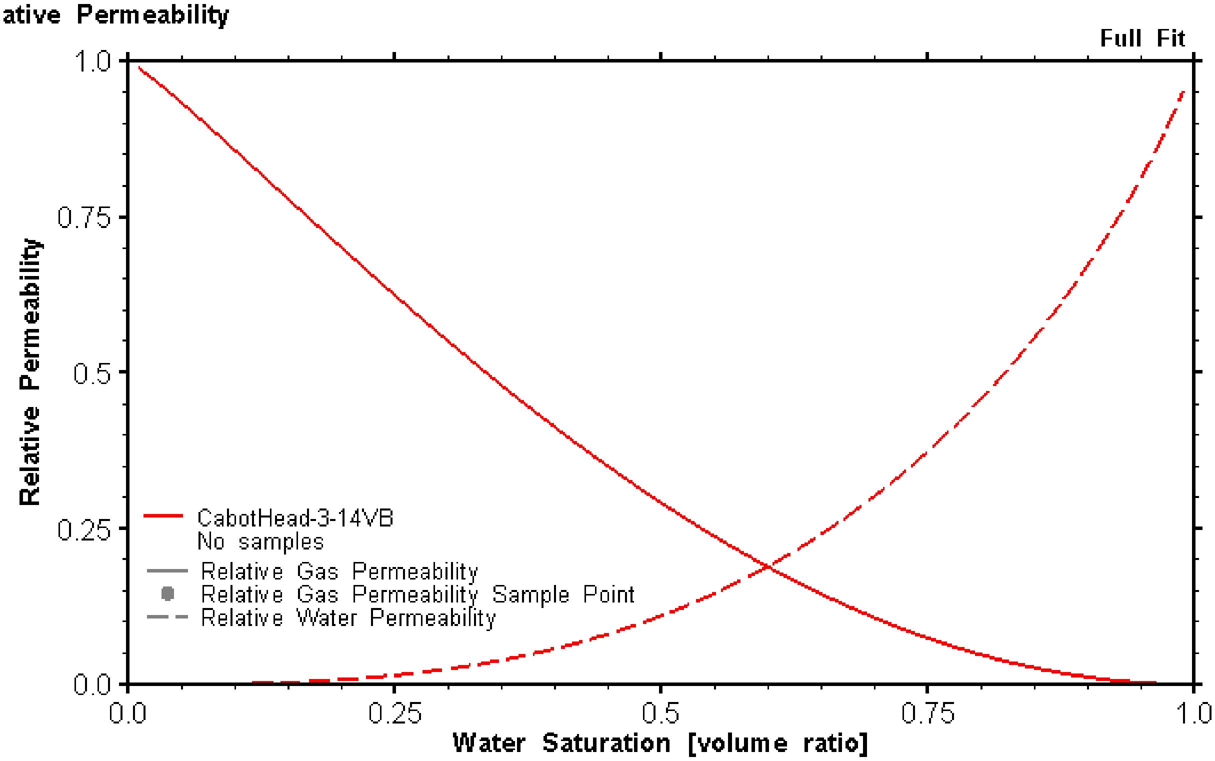
* Maximum sample relative permeability

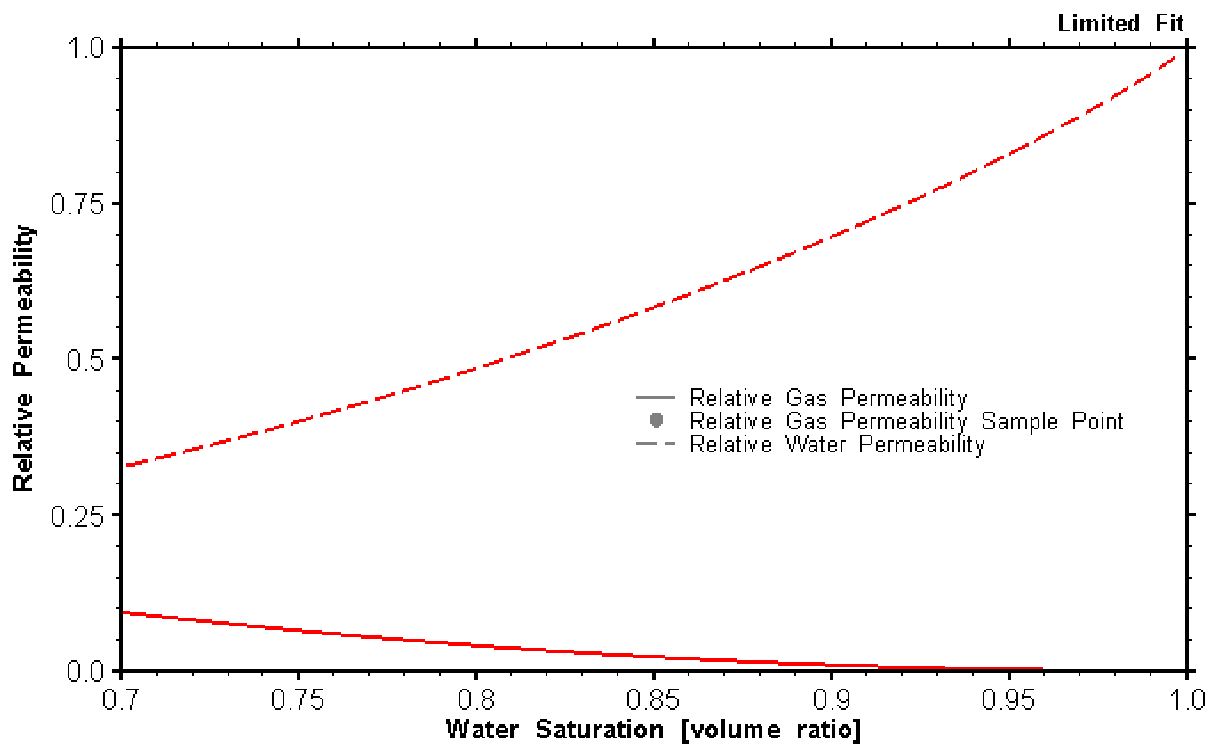
Cabot Head Formation
Capillary Pressure

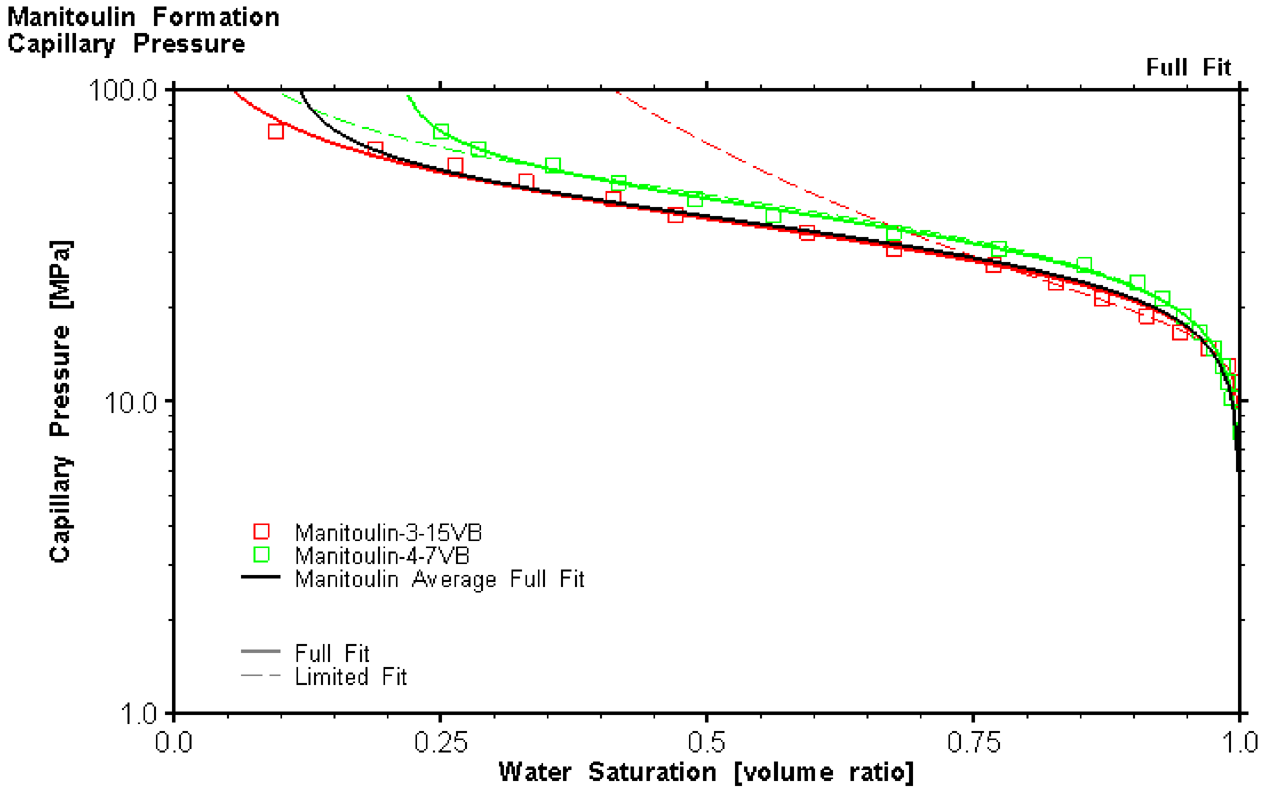


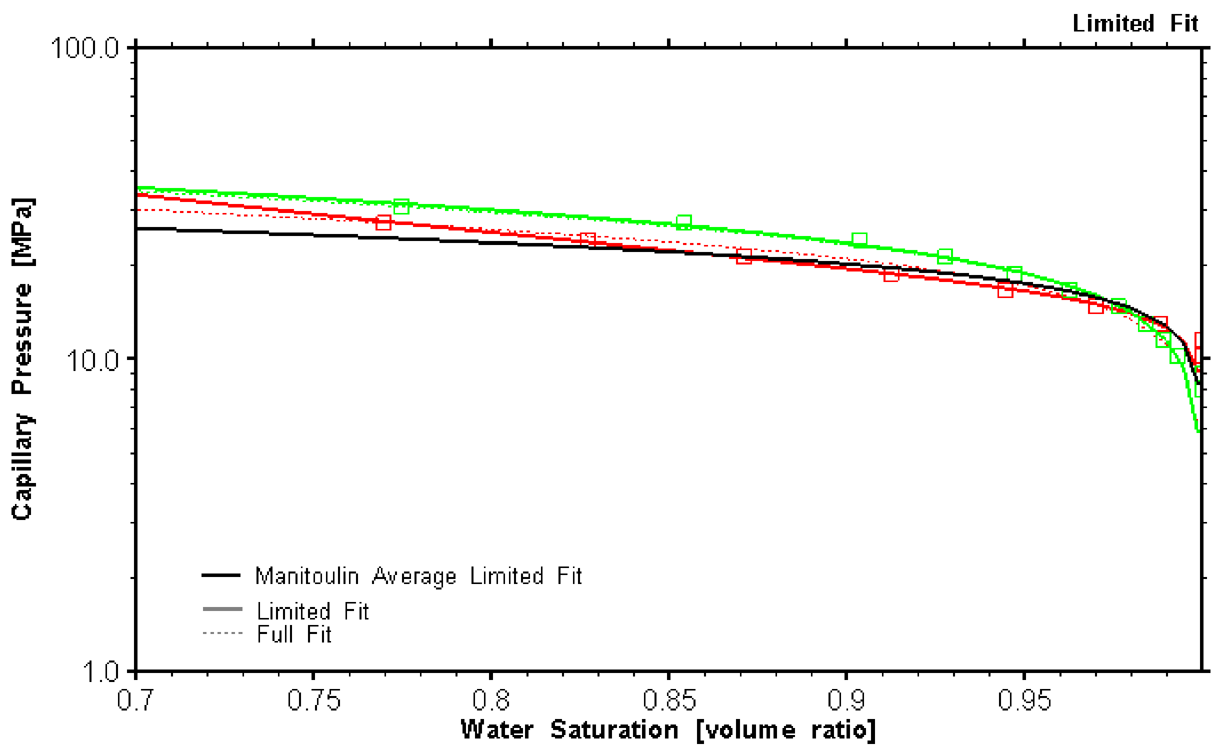


Cabot Head Formation
Relative Permeability

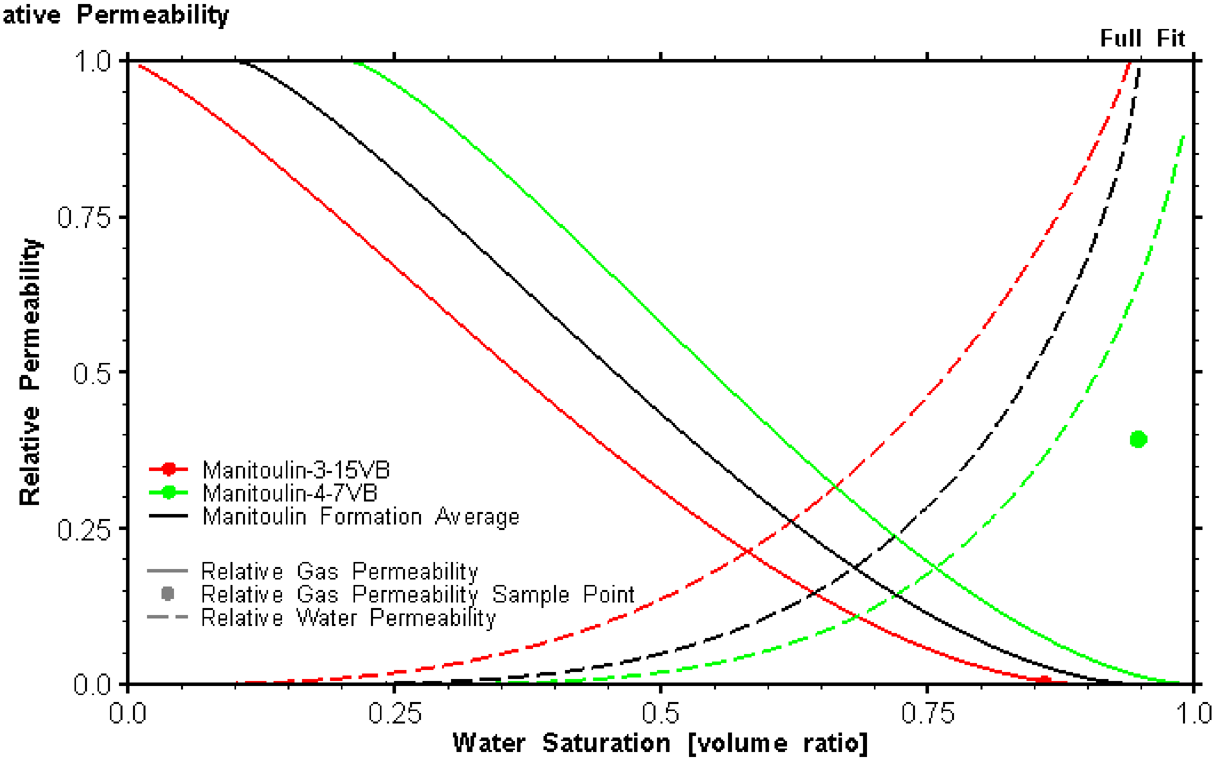


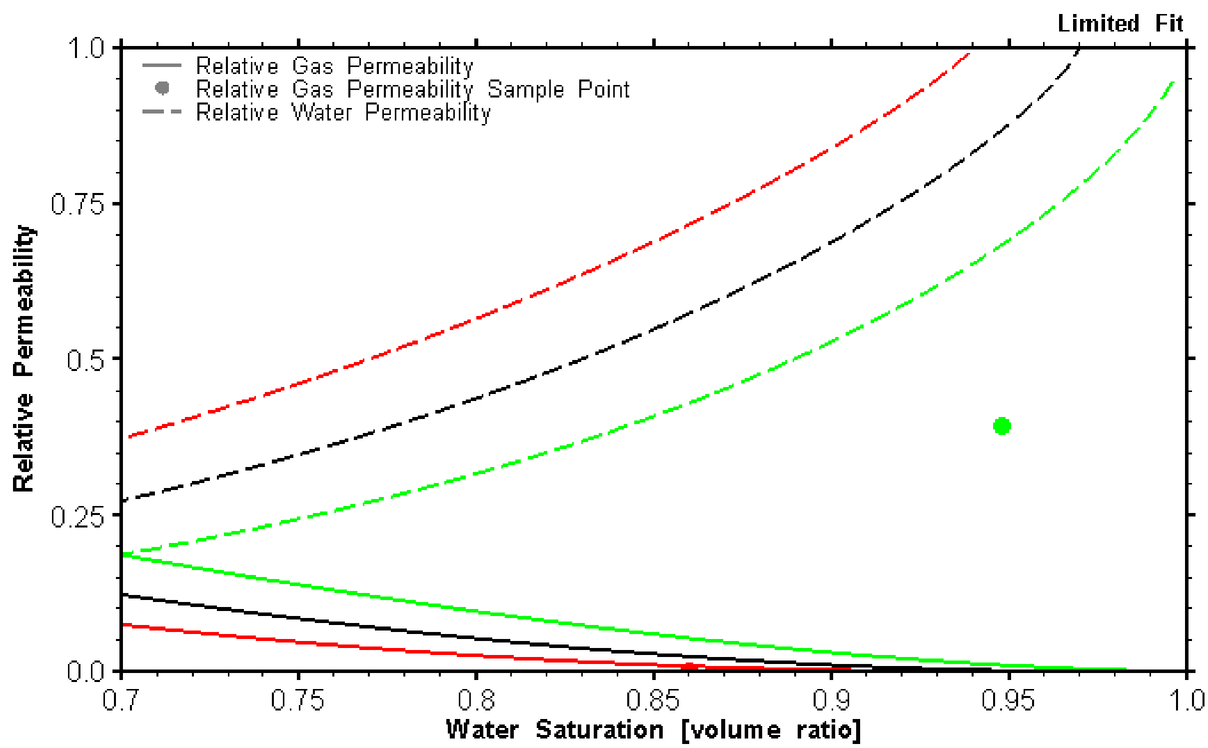


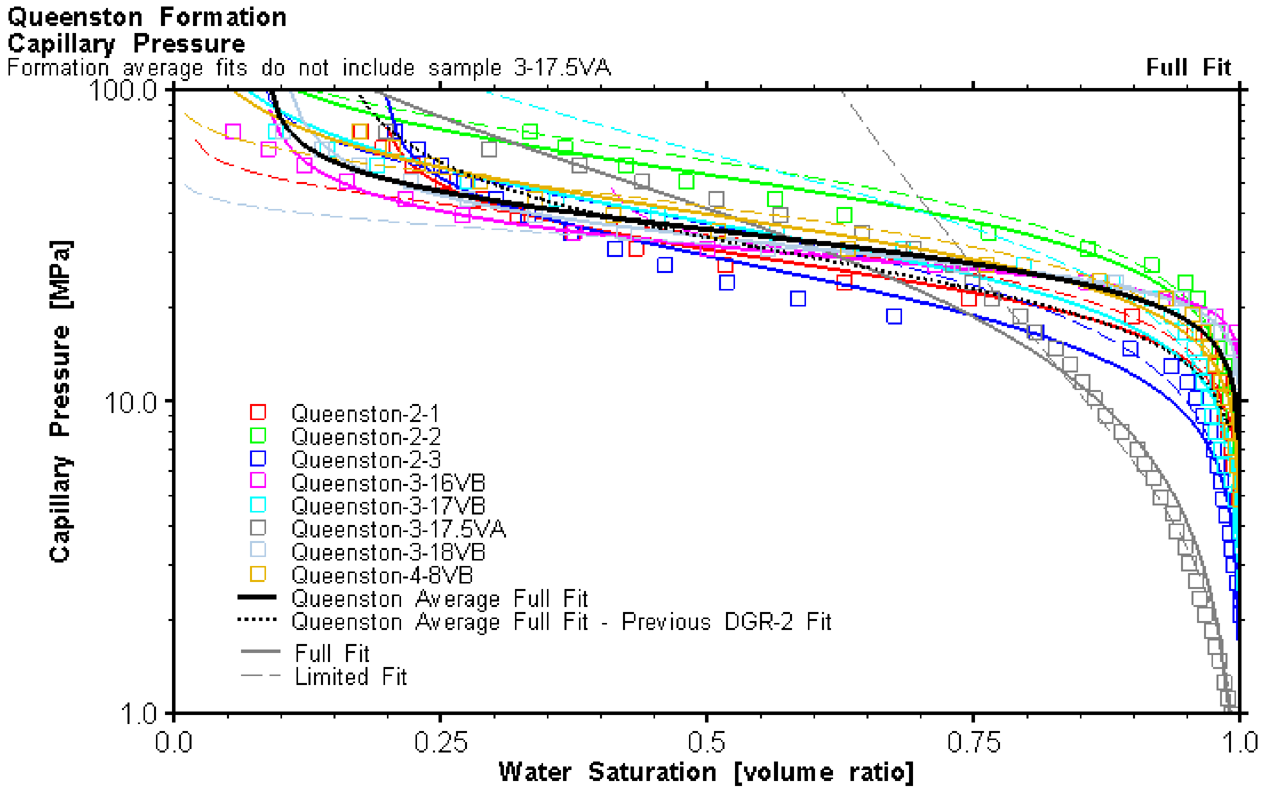

Manitoulin Formation
Capillary Pressure
Full Fit
100.0
10.0
1.0
Capillary Pressure [MPa]
Manitoulin-3-15VB
Manitoulin-4-7VB
Manitoulin Average Full Fit
Full Fit
Limited Fit
0.0
0.25
0.5
0.75
1.0
Water Saturation [volume ratio]

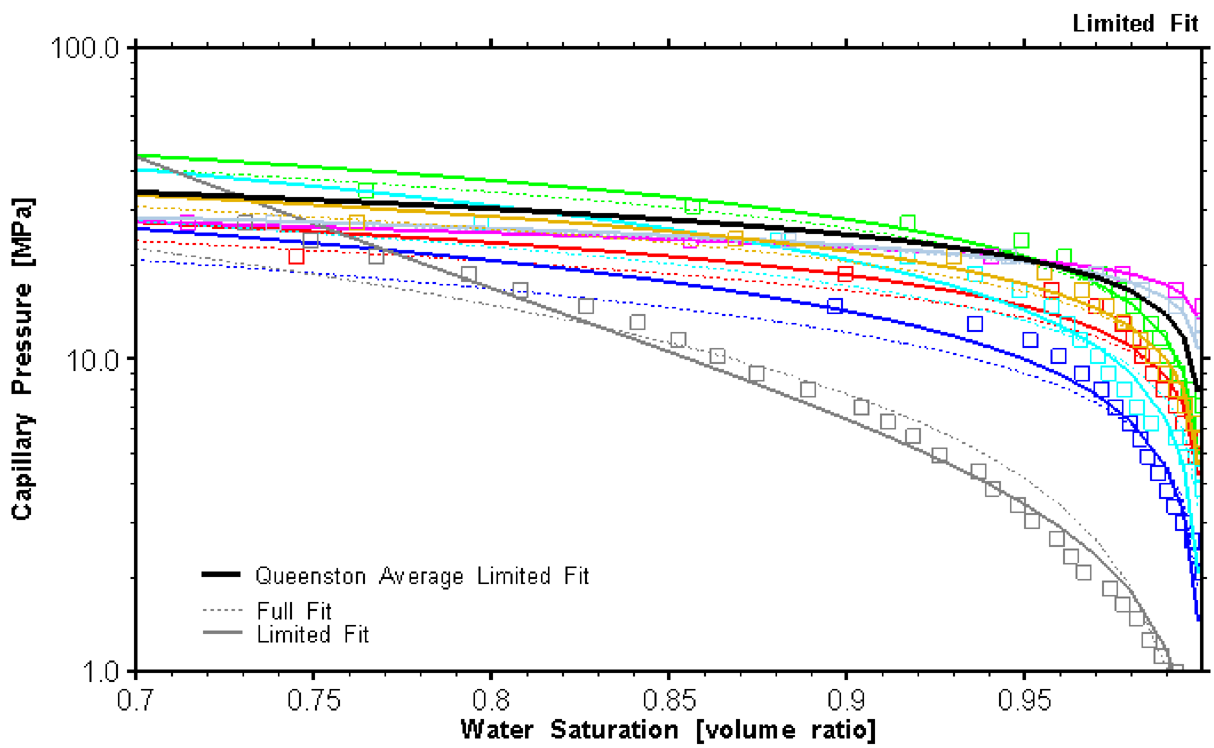

Limited Fit
100.0
10.0
1.0
Capillary Pressure [MPa]
Manitoulin Average Limited Fit
Limited Fit
Full Fit
0.7
0.75
0.8
0.85
0.9
0.95
Water Saturation [volume ratio]

Manitoulin Formation
Relative Permeability

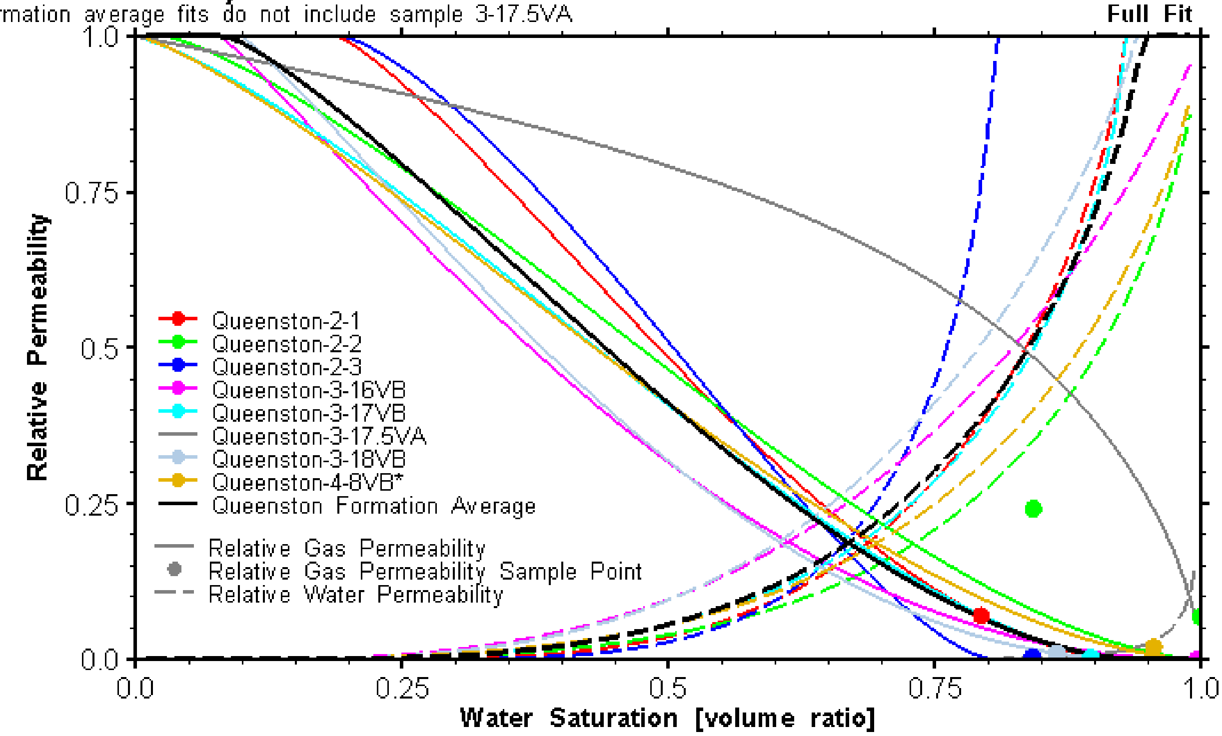


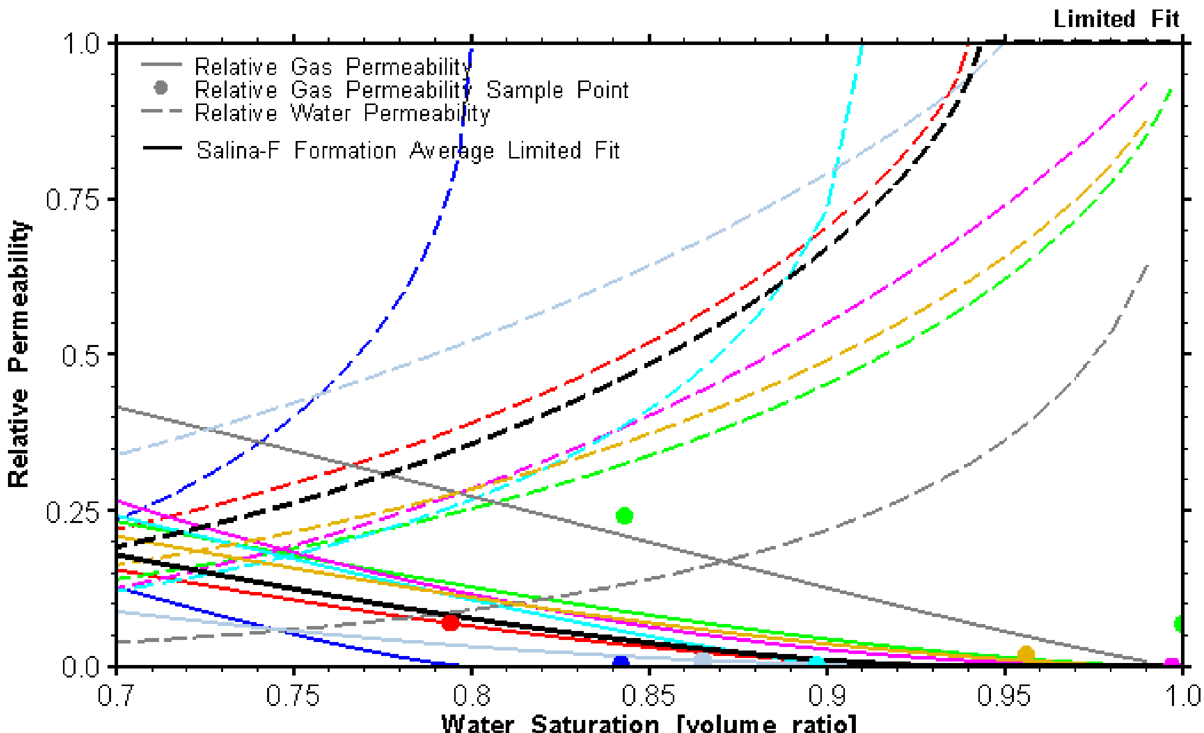



Queenston Formation
Capillary Pressure
Formation average fits do not include sample 3-17.5VA
Full Fit
Capillary Pressure [MPa]
100.0
10.0
1.0
0.0
0.25
0.5
0.75
1.0
Water Saturation [volume ratio]
Queenston-2-1
Queenston-2-2
Queenston-2-3
Queenston-3-16VB
Queenston-3-17VB
Queenston-3-17.5VA
Queenston-3-18VB
Queenston-4-8VB
Queenston Average Full Fit
Queenston Average Full Fit - Previous DGR-2 Fit
Full Fit
Limited Fit


Limited Fit
Capillary Pressure [MPa]
100.0
10.0
1.0
0.7
0.75
0.8
0.85
0.9
0.95
Water Saturation [volume ratio]
Queenston Average Limited Fit
Full Fit
Limited Fit

Queenston Formation
Relative Permeability
Formation average fits do not include sample 3-17.5VA

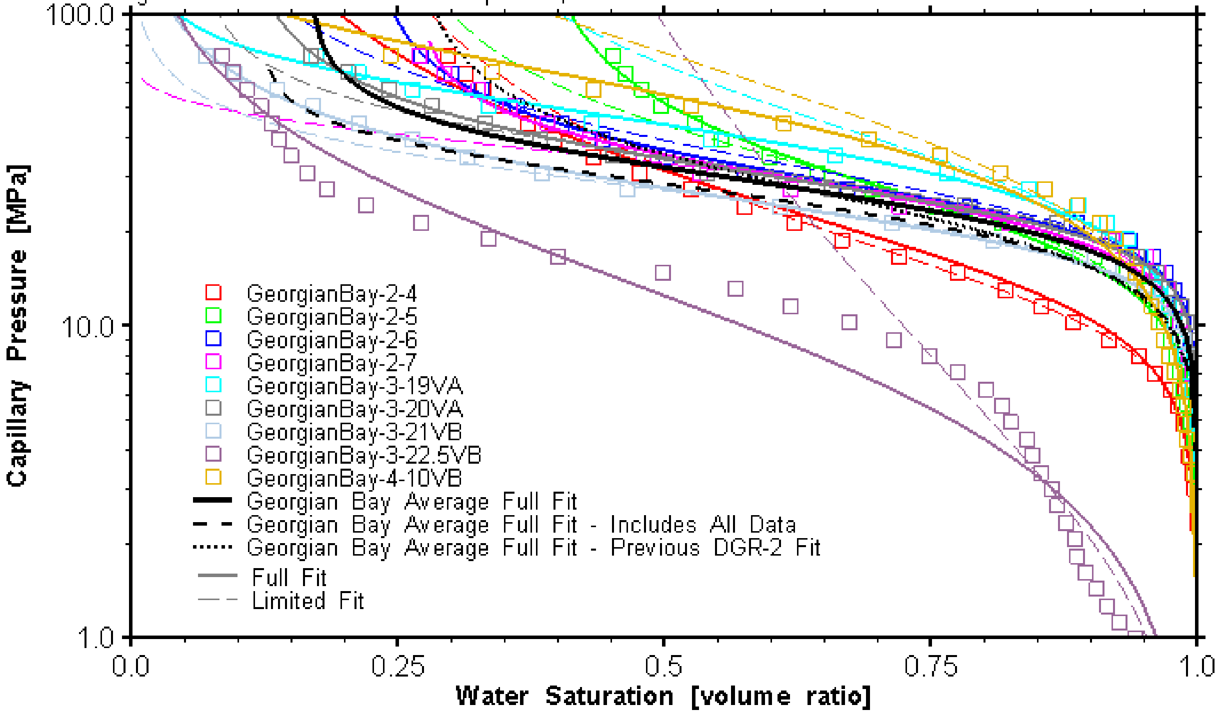




* Maximum sample relative permeability

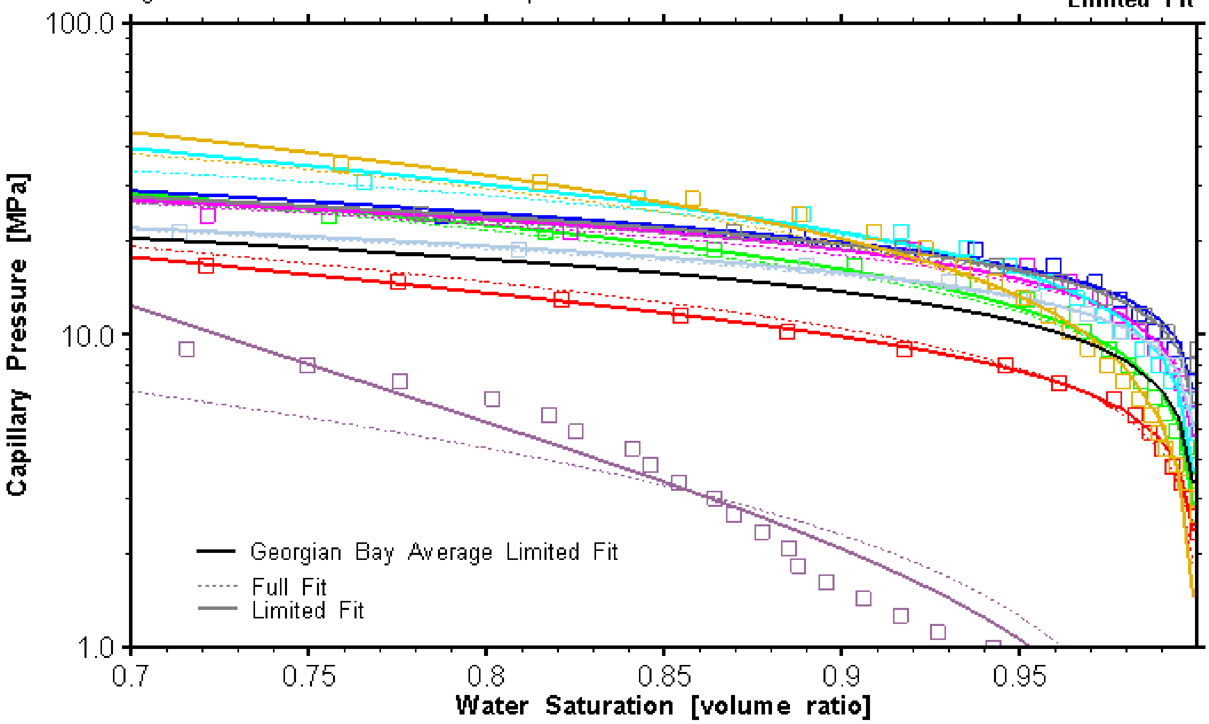
Georgian Bay Formation
Capillary Pressure
Formation average full fit does not include sample 2-4, 3-22.5VB and 4-10VB

Full Fit

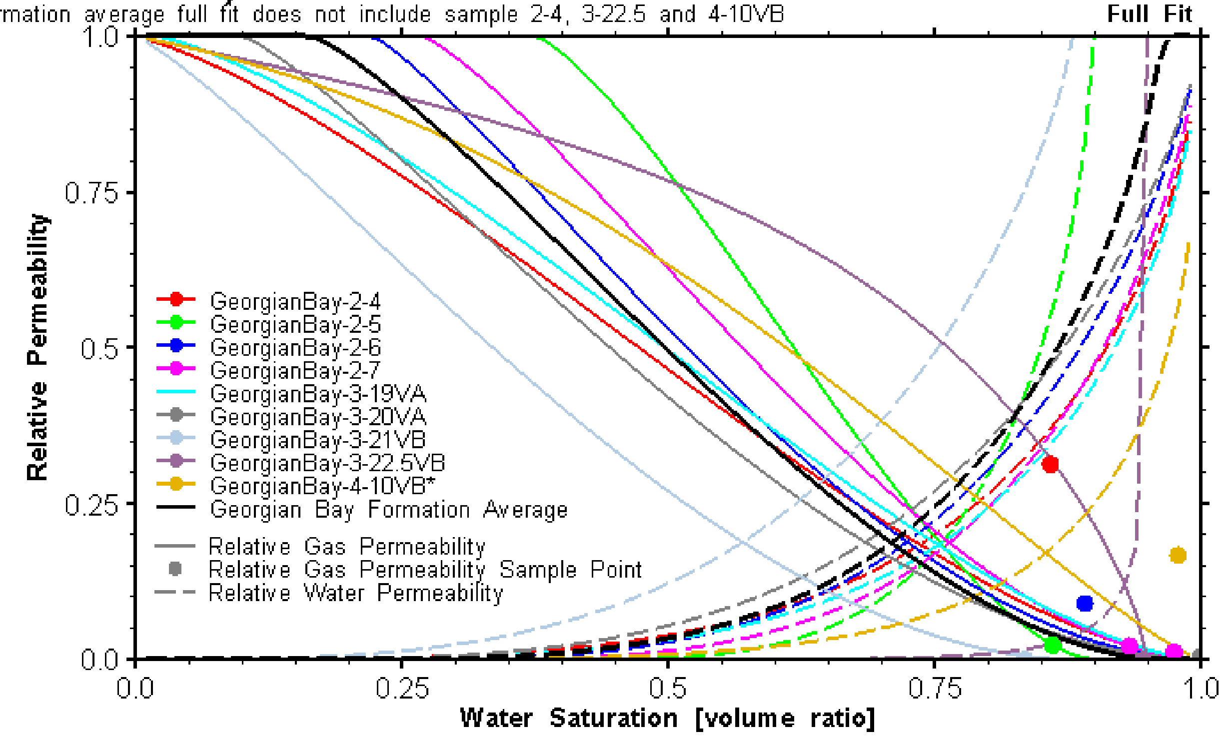


Formation average limited fit does not include sample 3-22.5VB

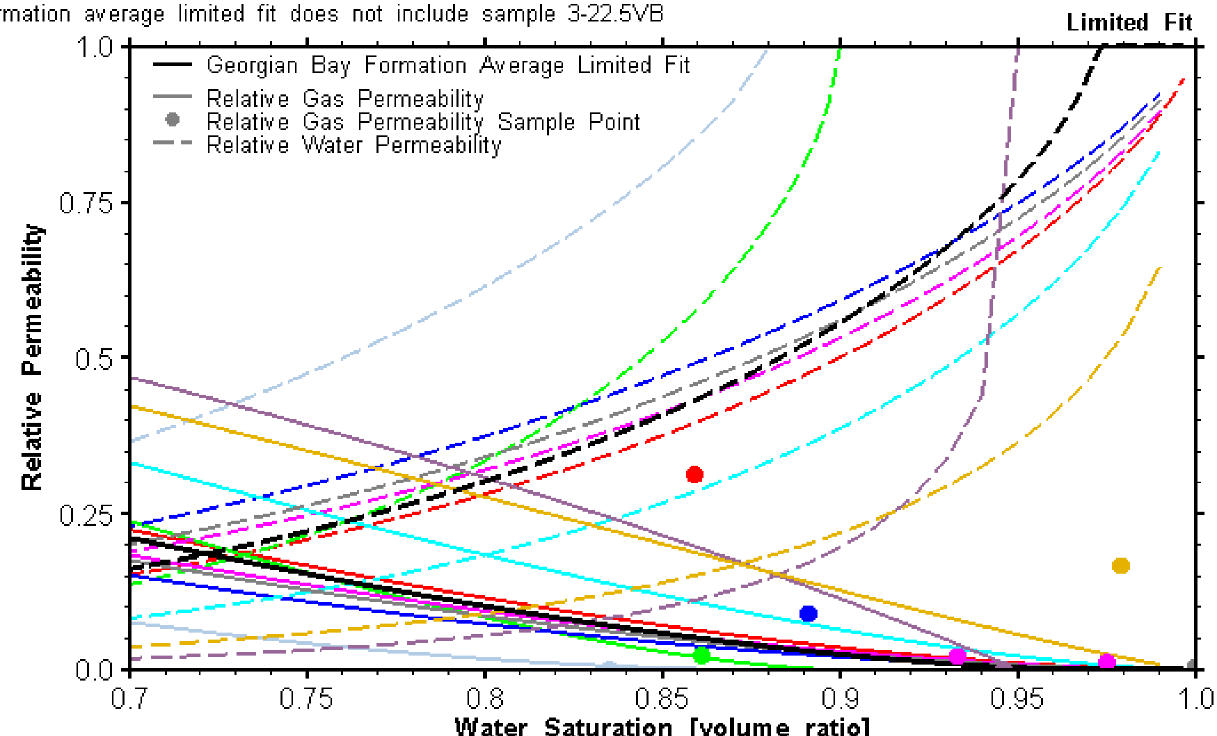
Limited Fit



Georgian Bay Formation
Relative Permeability
Formation average full fit does not include sample 2-4, 3-22.5 and 4-10VB

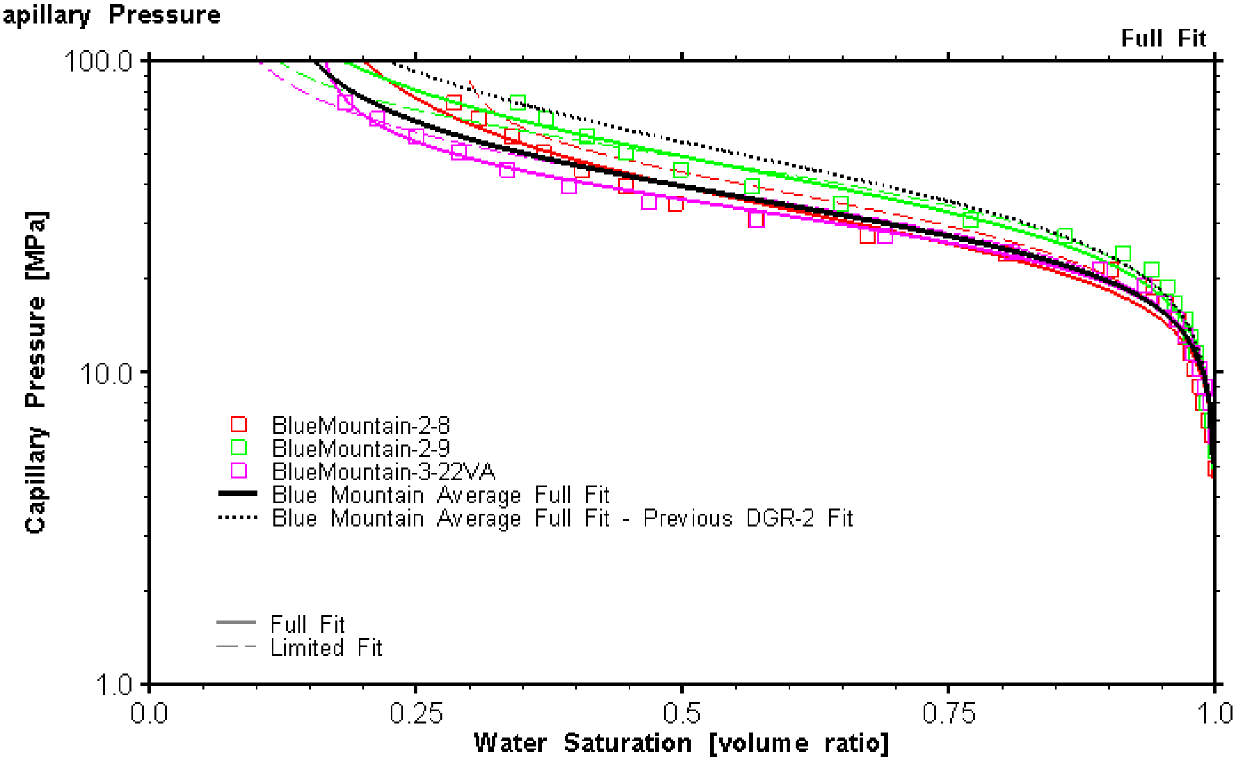


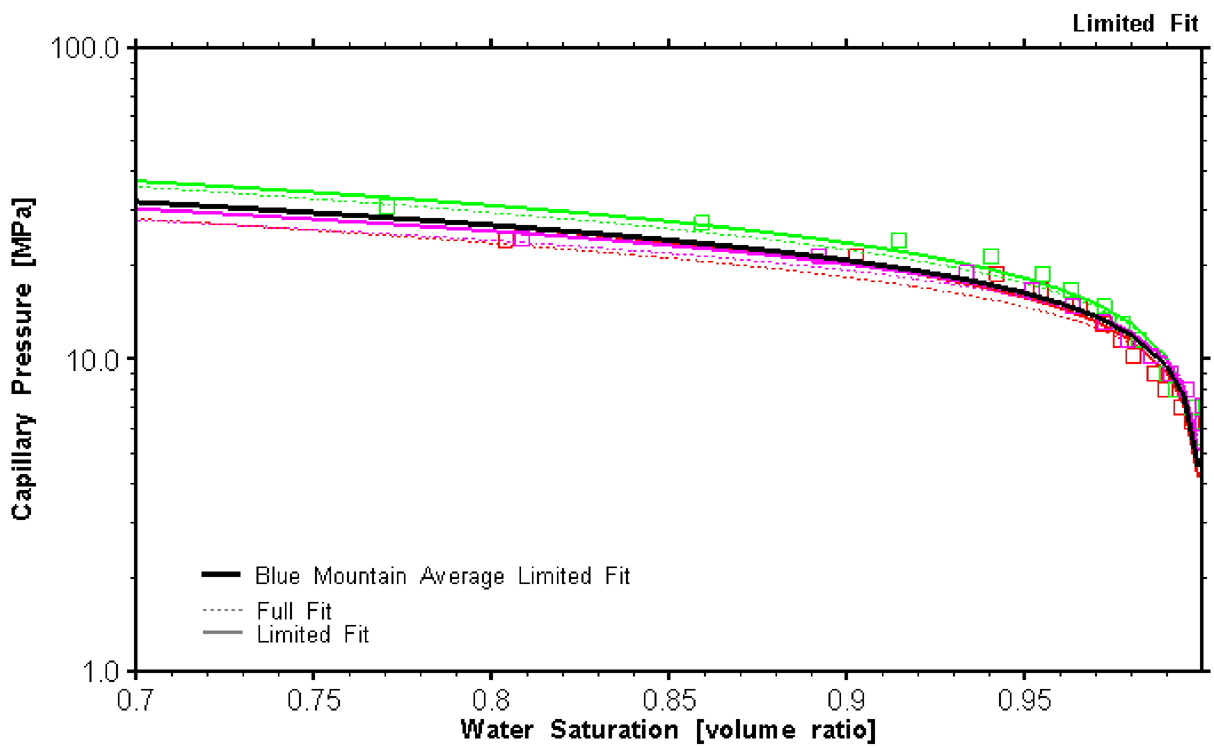
Formation average limited fit does not include sample 3-22.5VB



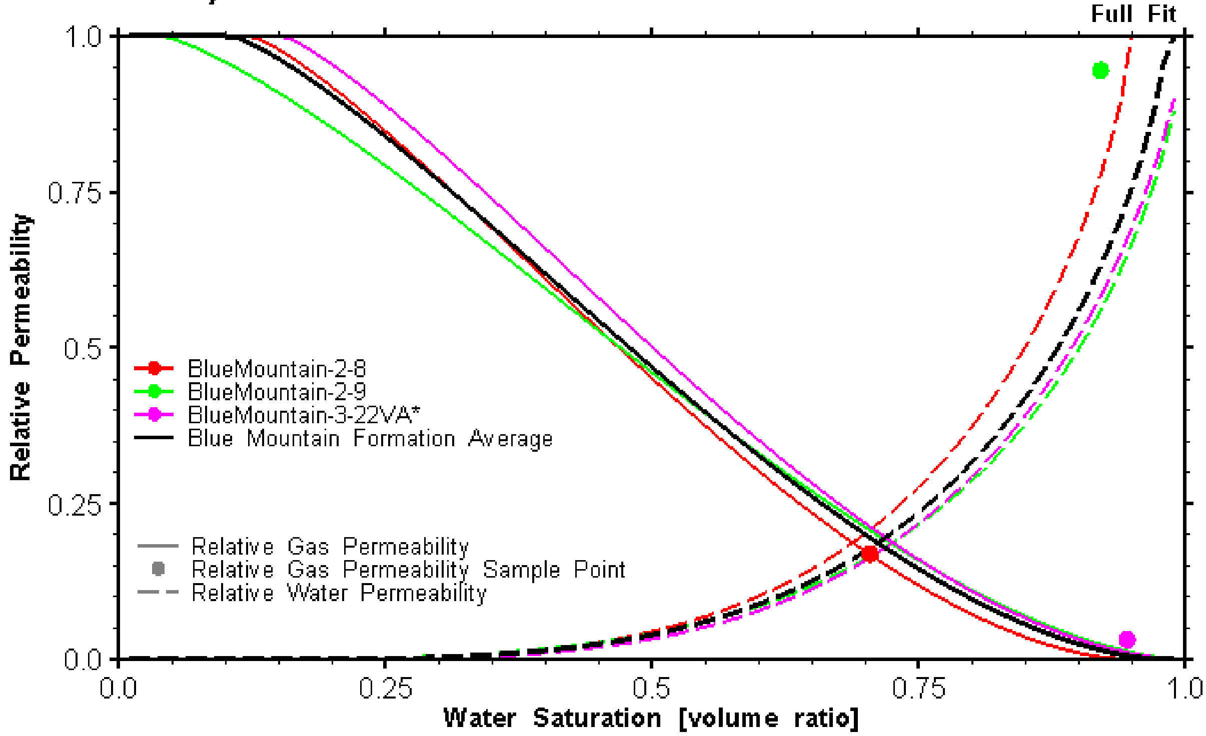
* Maximum sample relative permeability

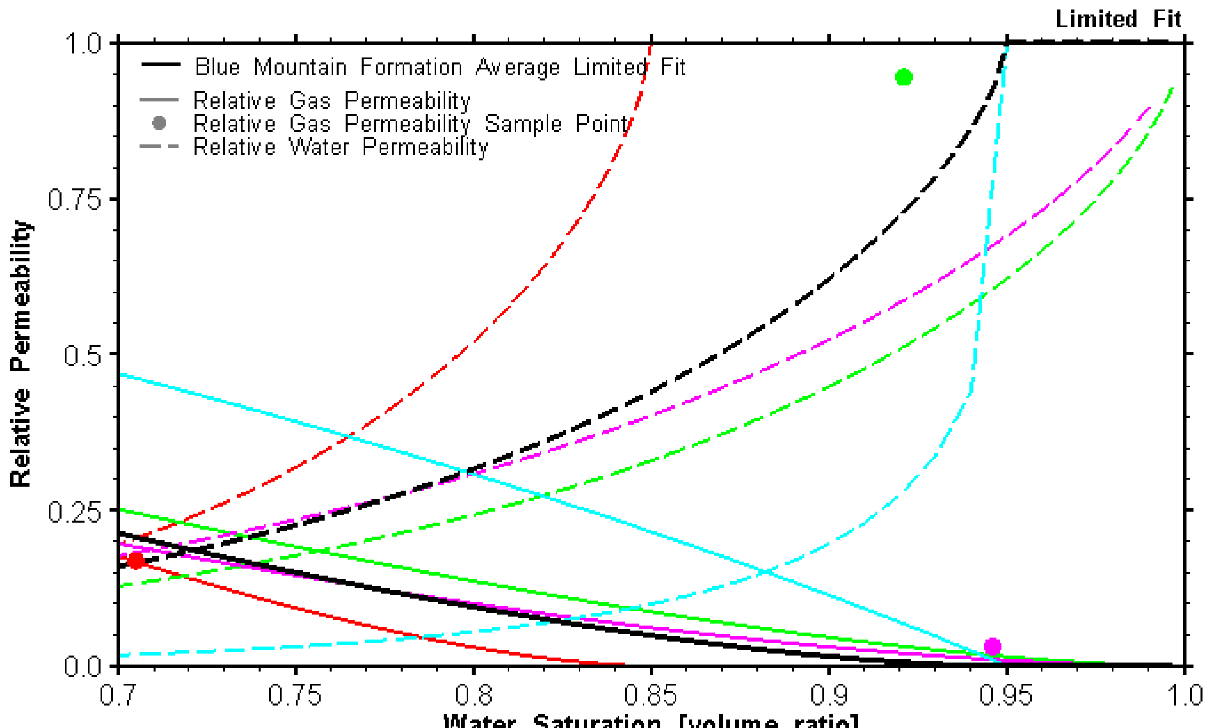
Blue Mountain Formation
Capillary Pressure





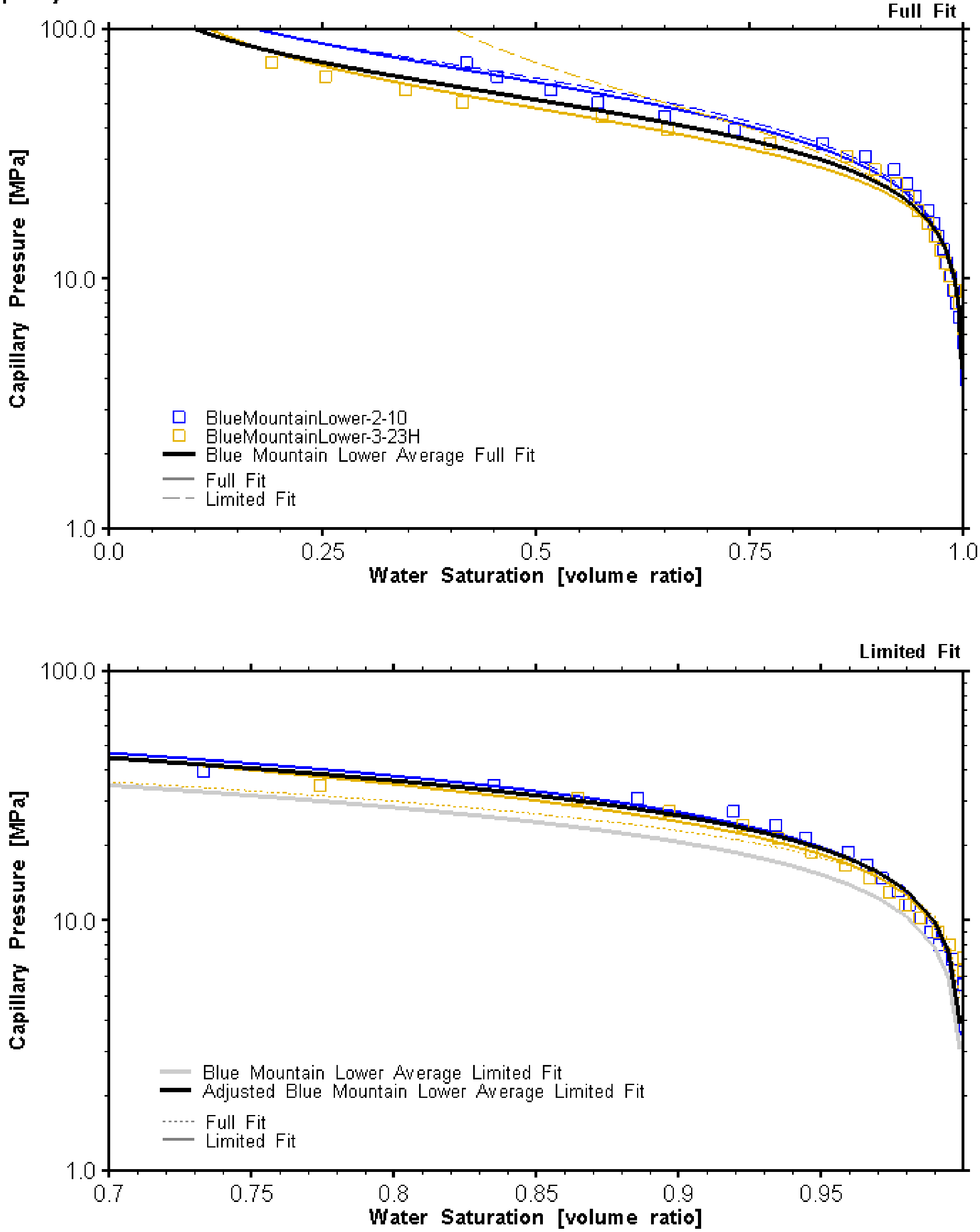
Blue Mountain Formation
Relative Permeability



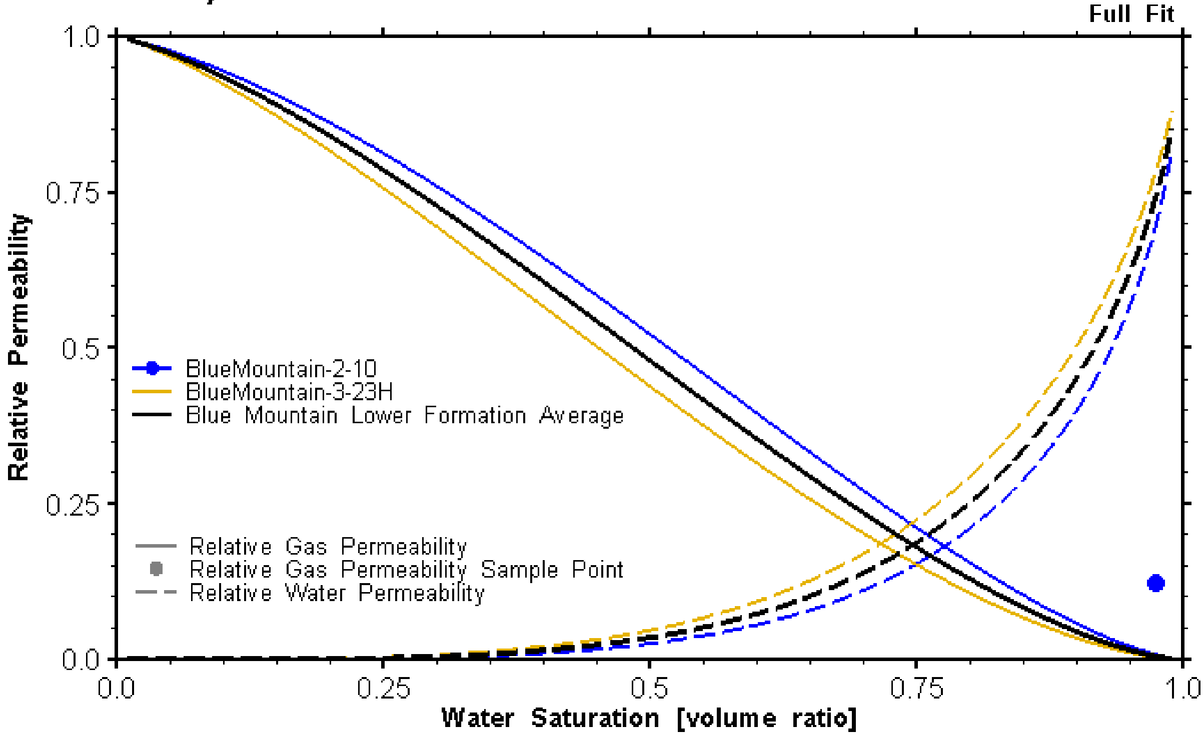


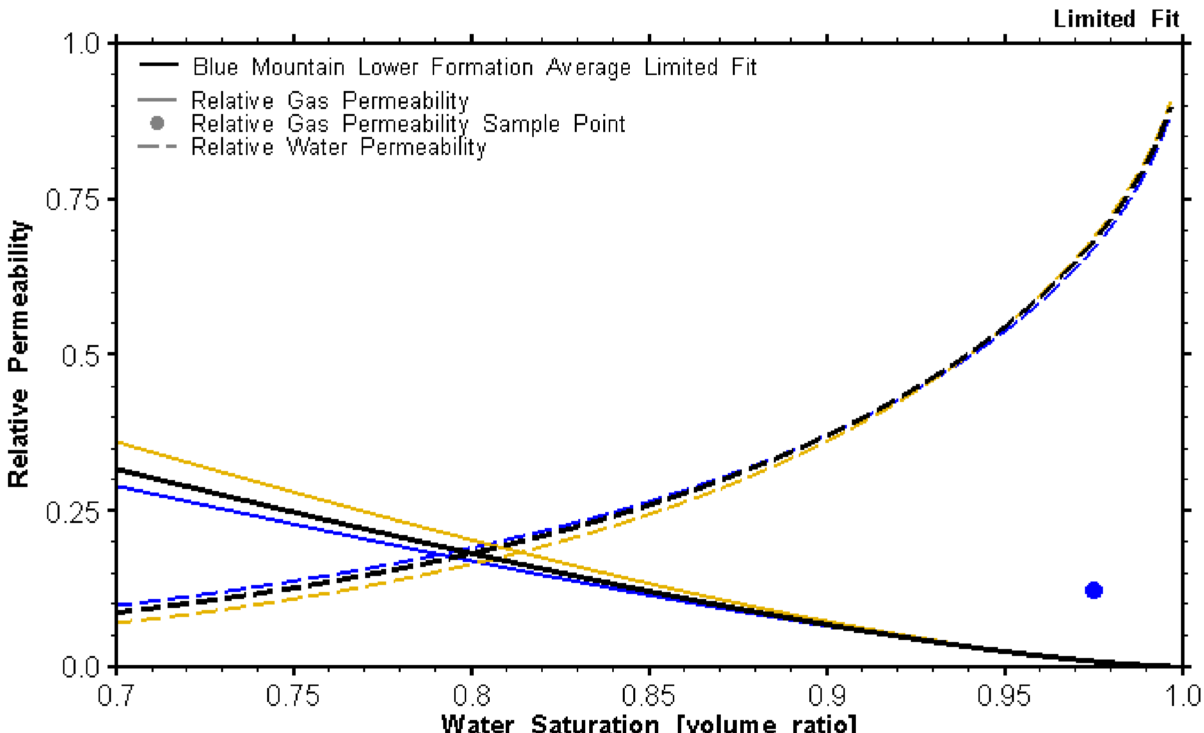
* Maximum sample relative permeability

Blue Mountain Lower Formation
Capillary Pressure



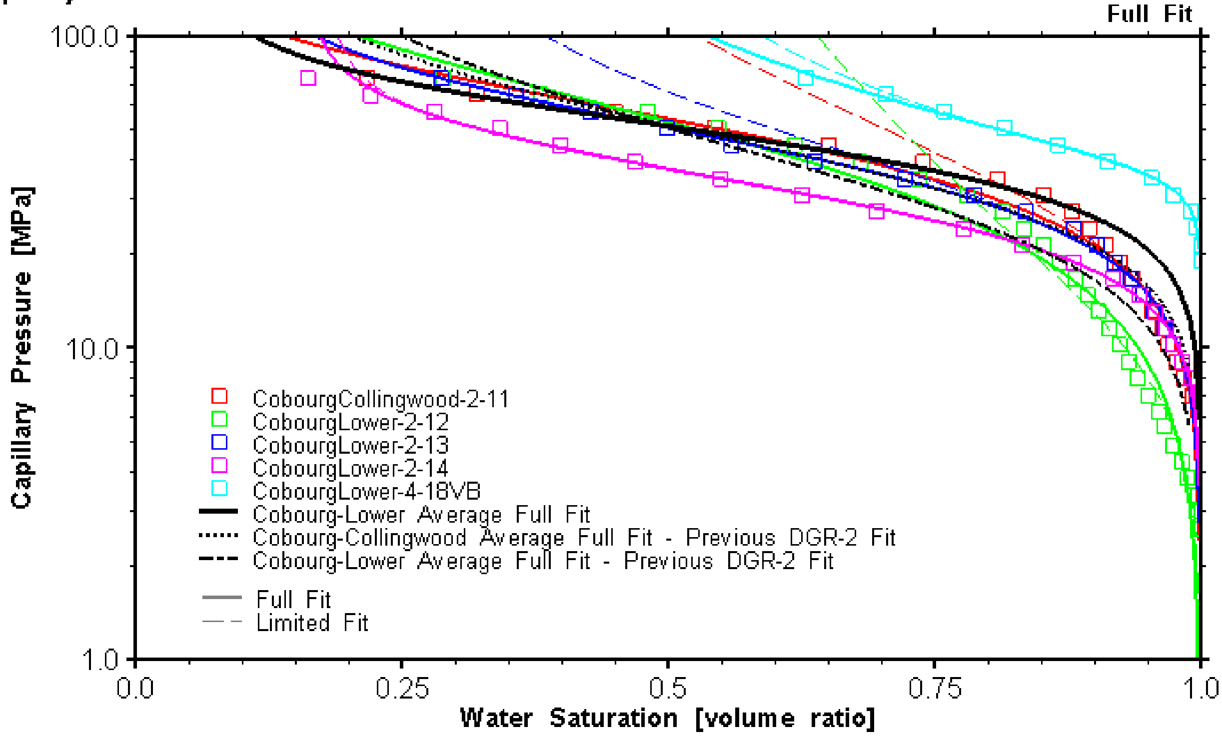
Blue Mountain Lower Formation
Relative Permeability

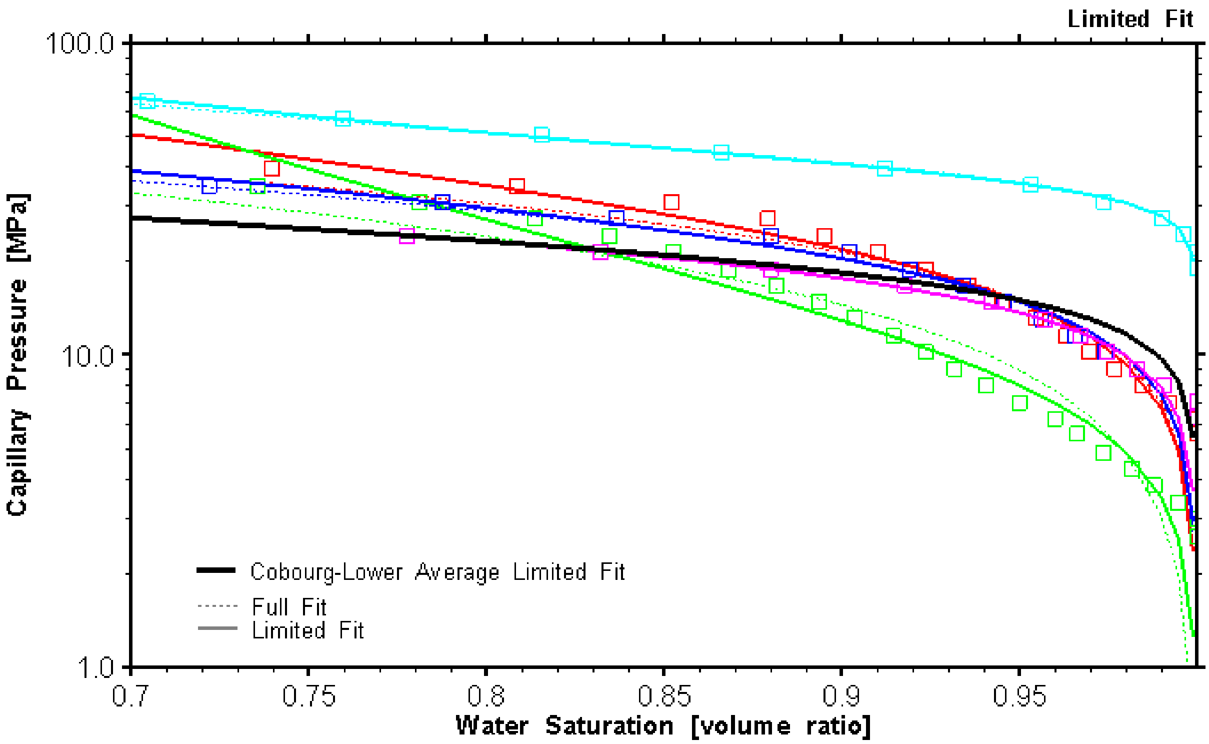




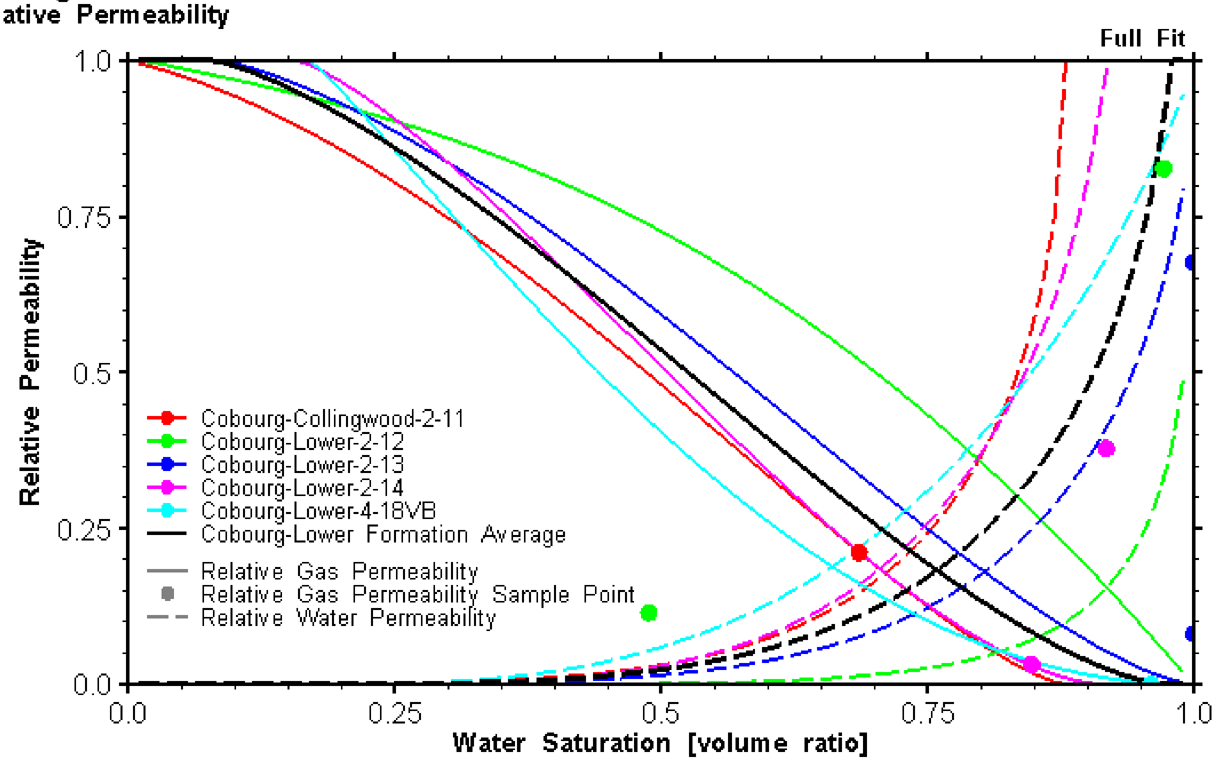
* Maximum sample relative permeability

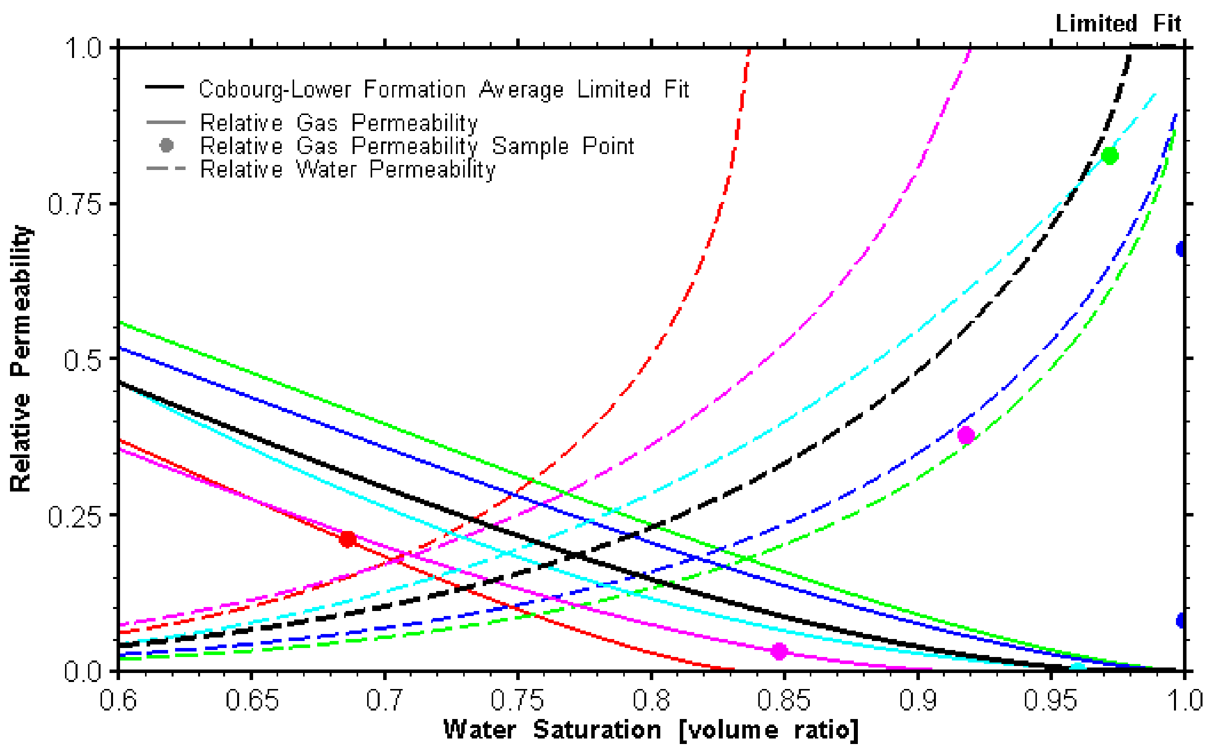
Cobourg Formation
Capillary Pressure



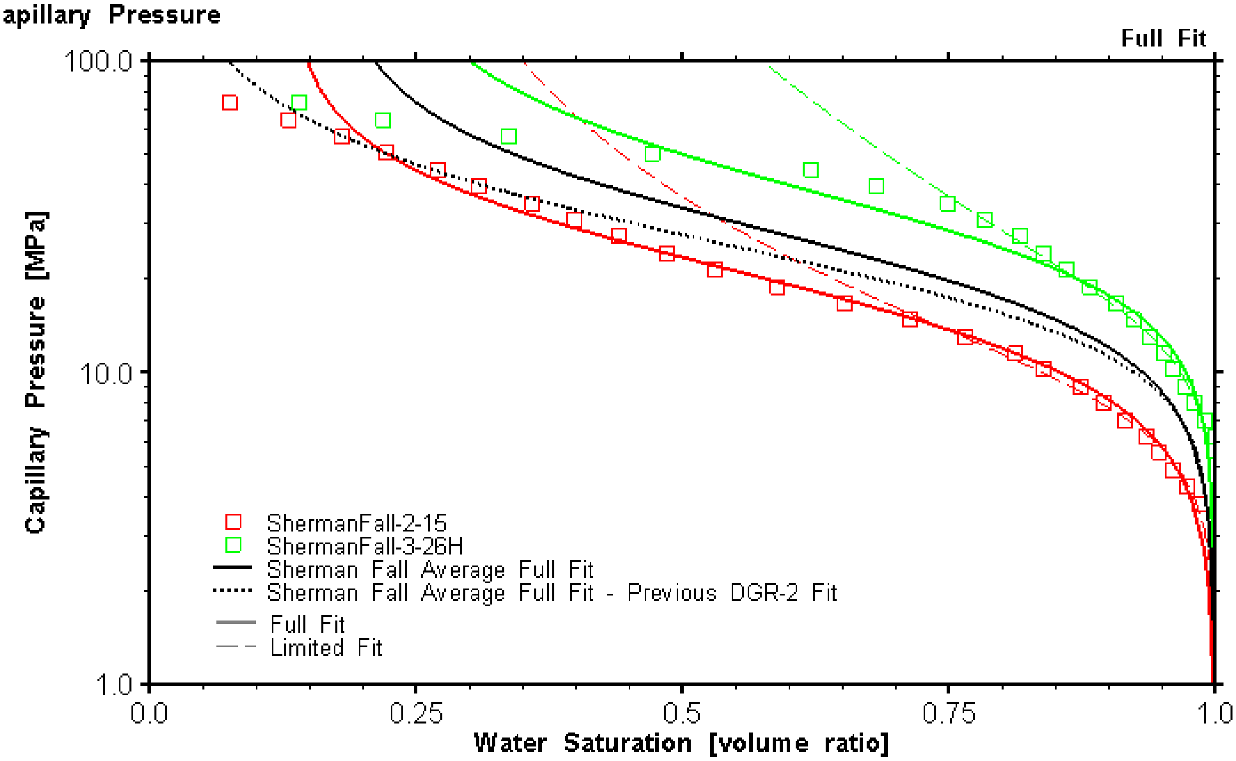


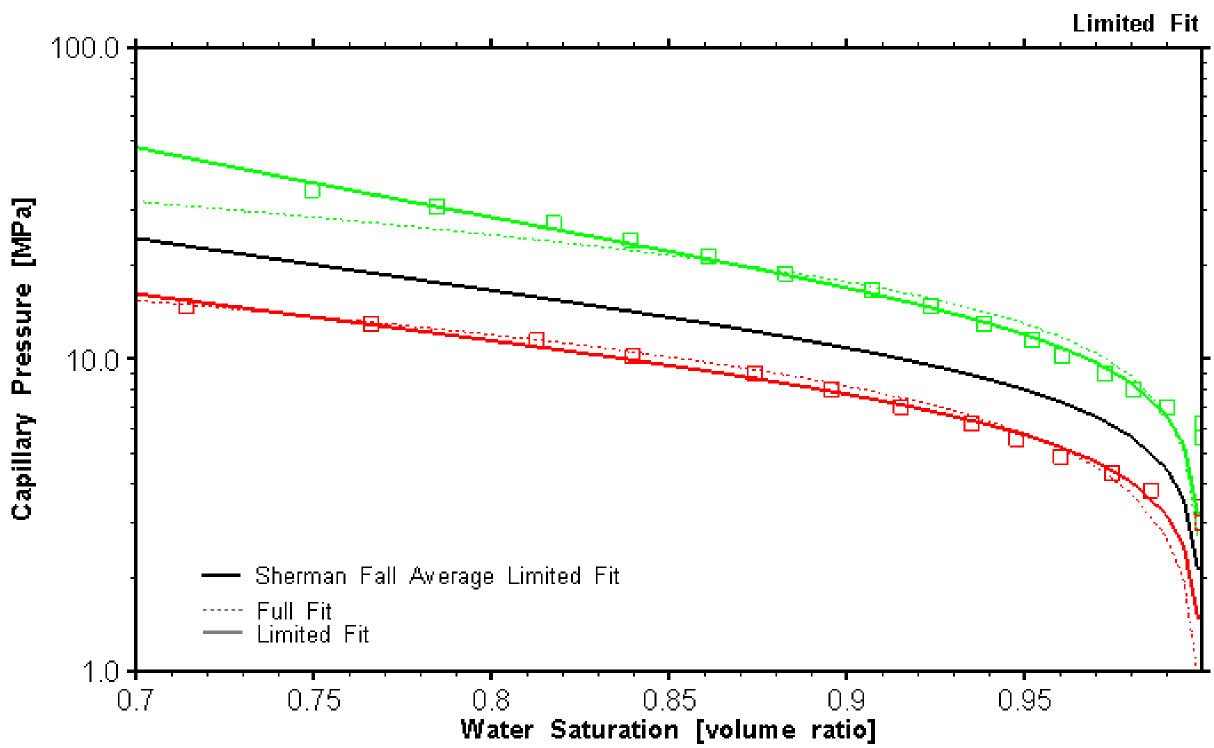
Cobourg Formation
Relative Permeability



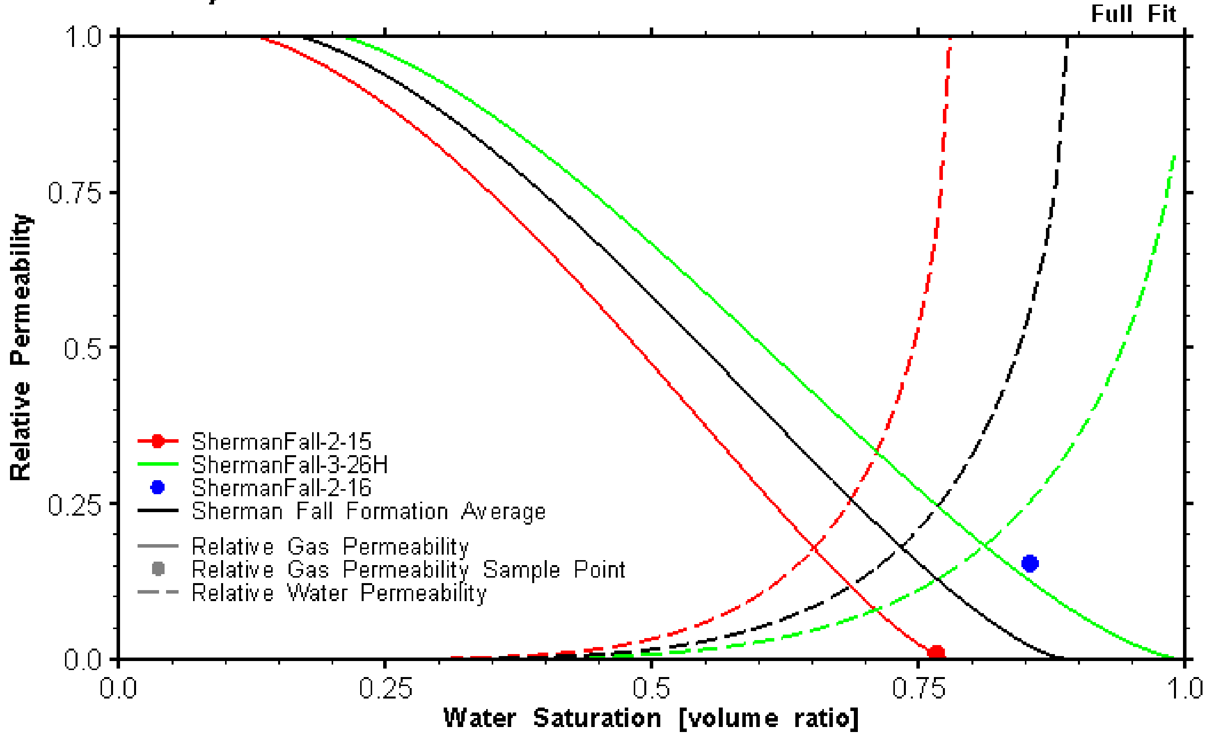


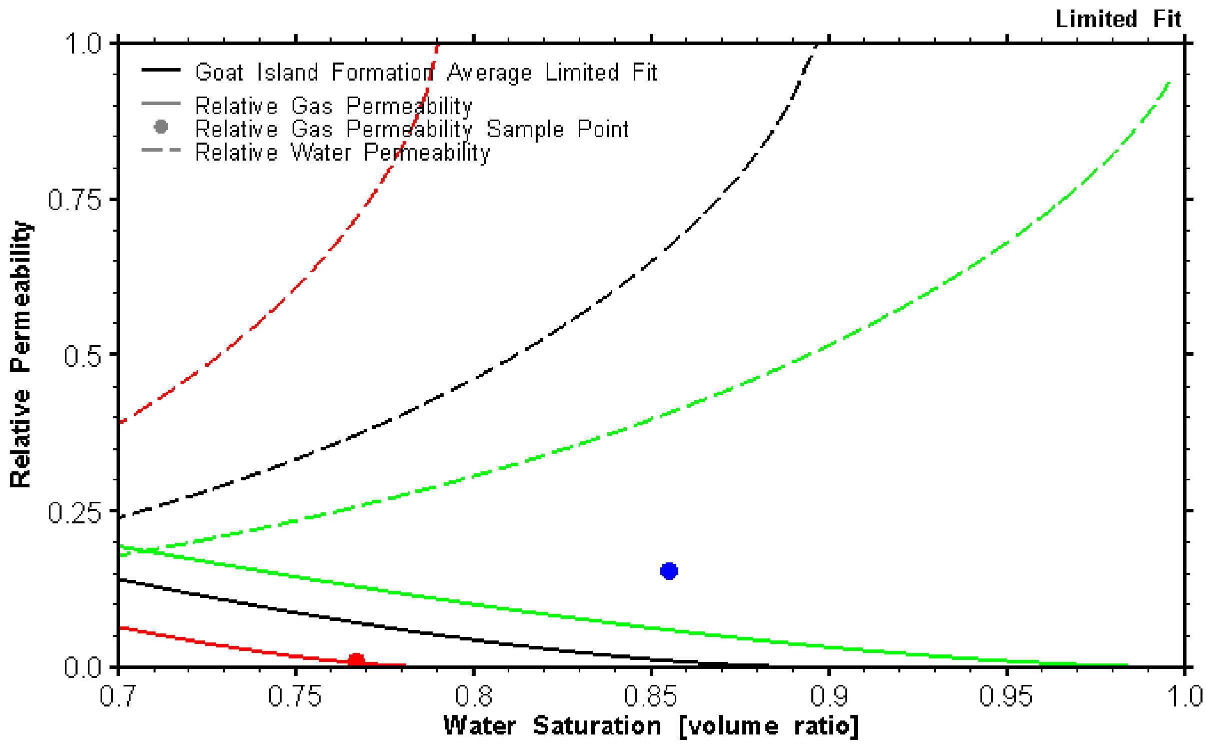
Sherman Fall Formation
Capillary Pressure



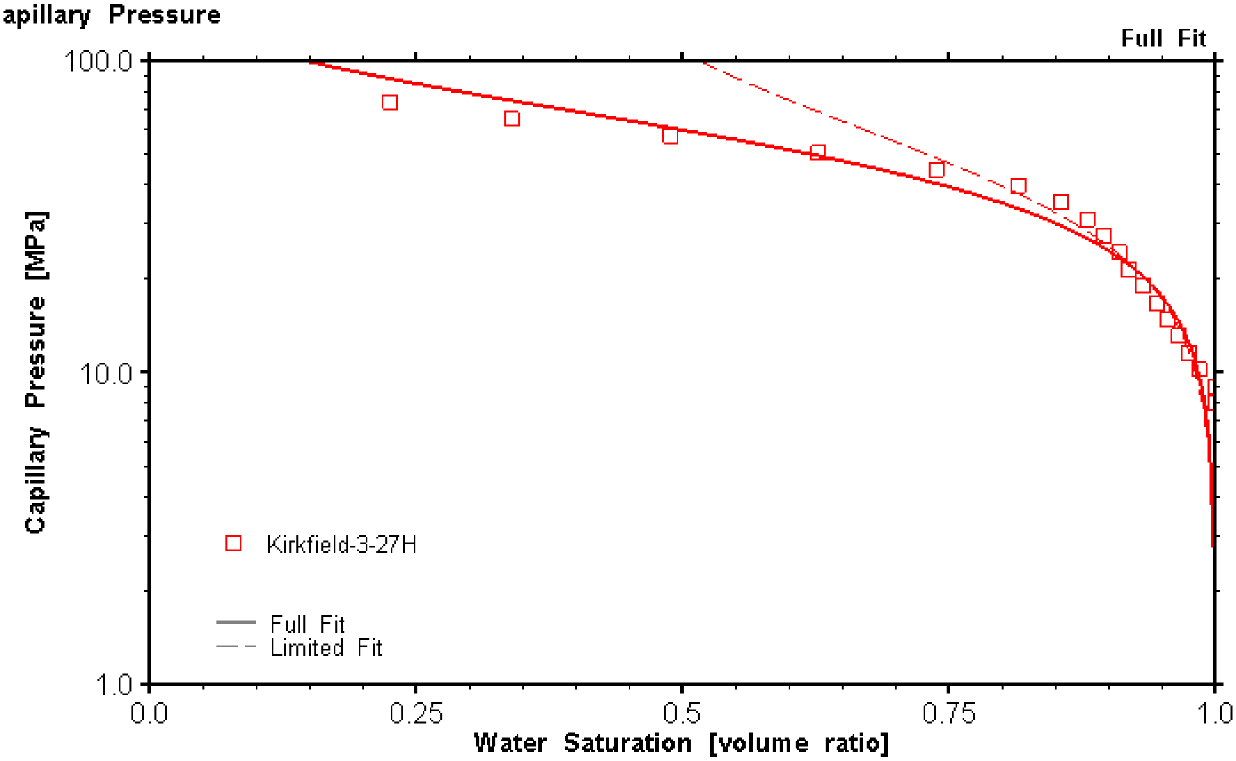


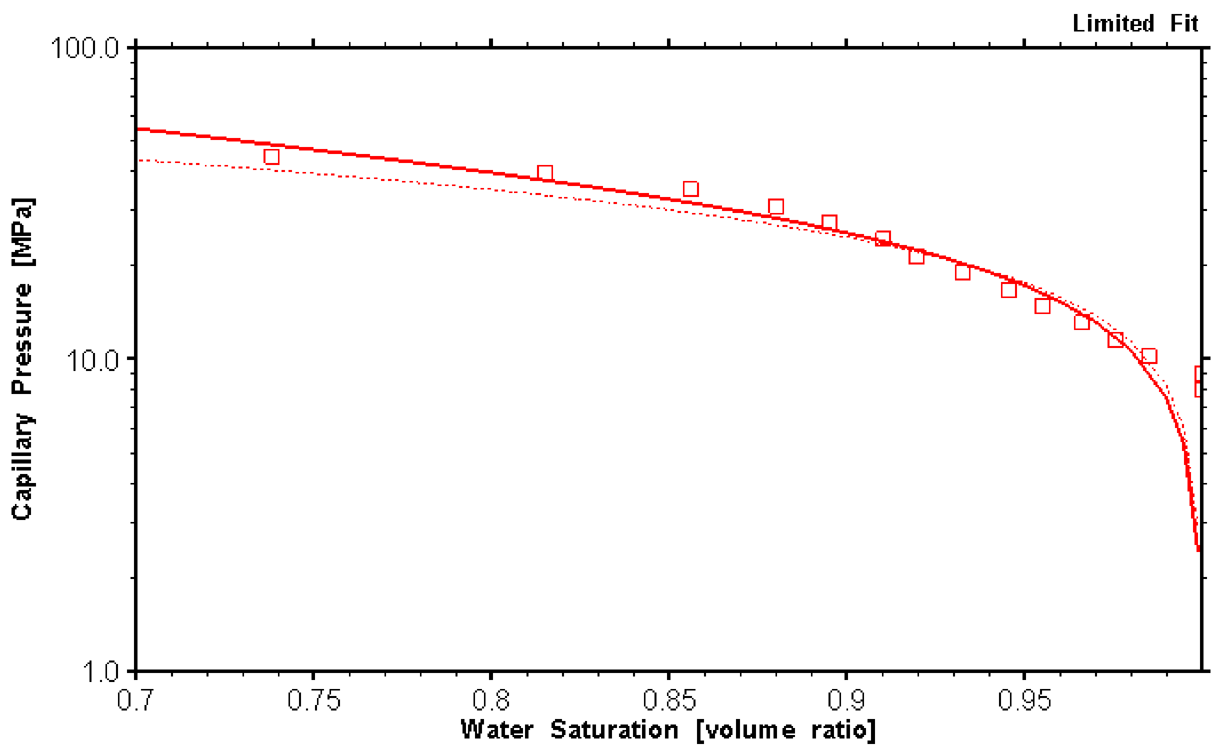
Sherman Fall Formation
Relative Permeability



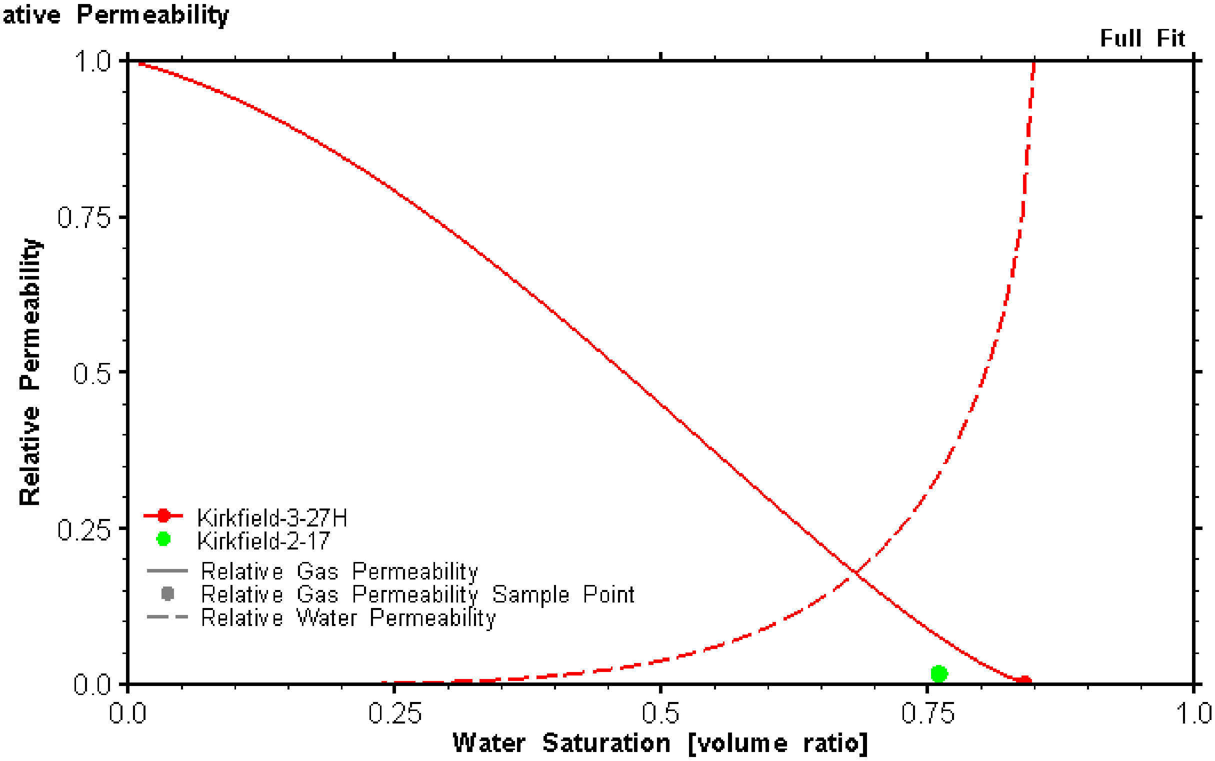


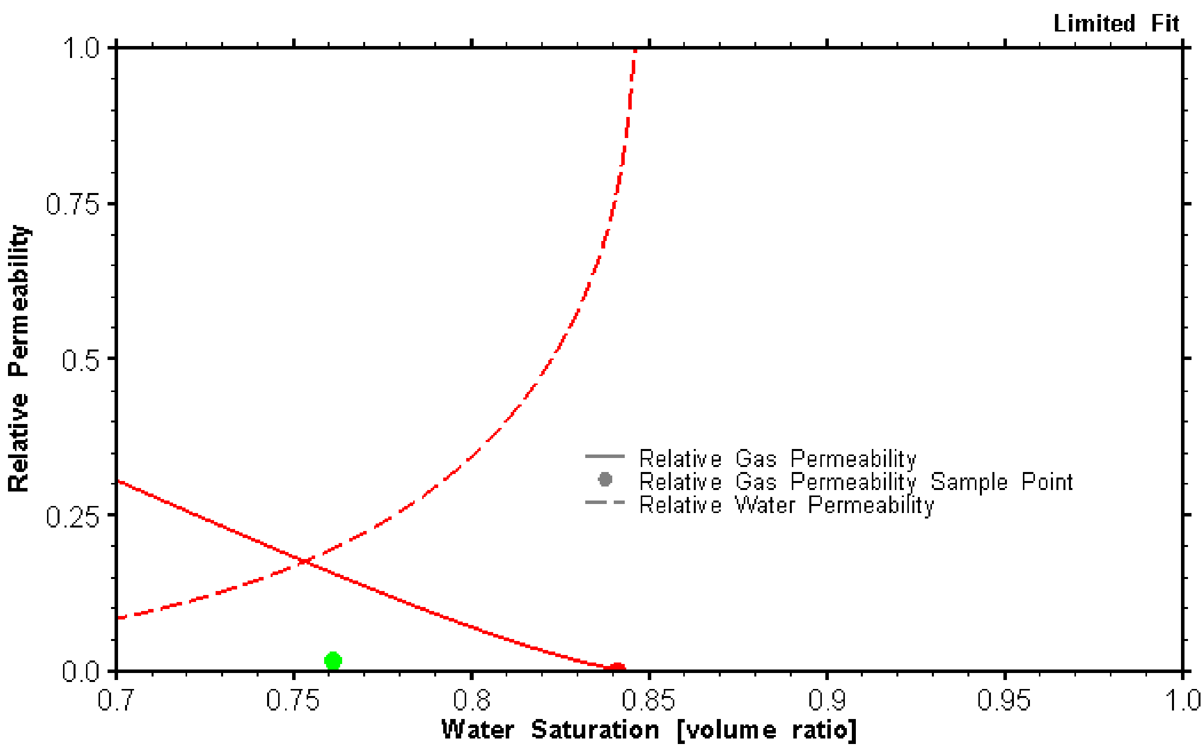
Kirkfield Formation
Capillary Pressure

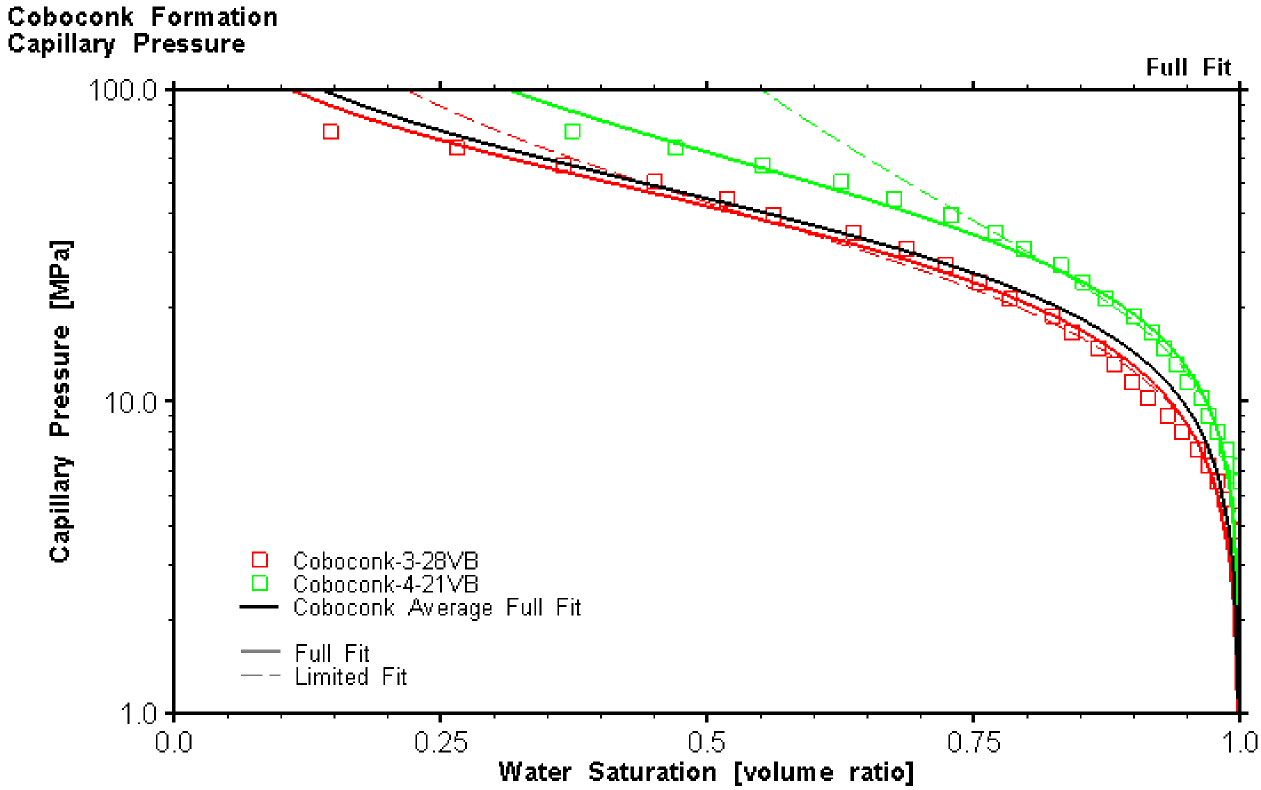




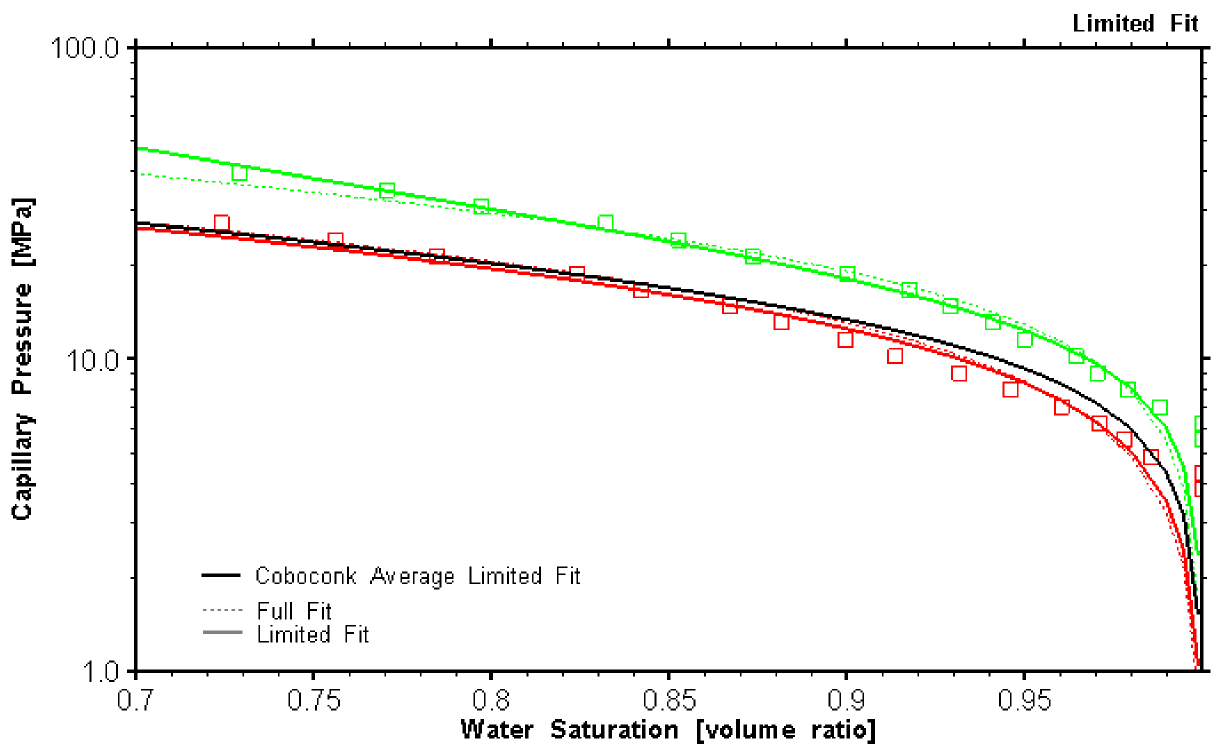
Kirkfield Formation
Relative Permeability



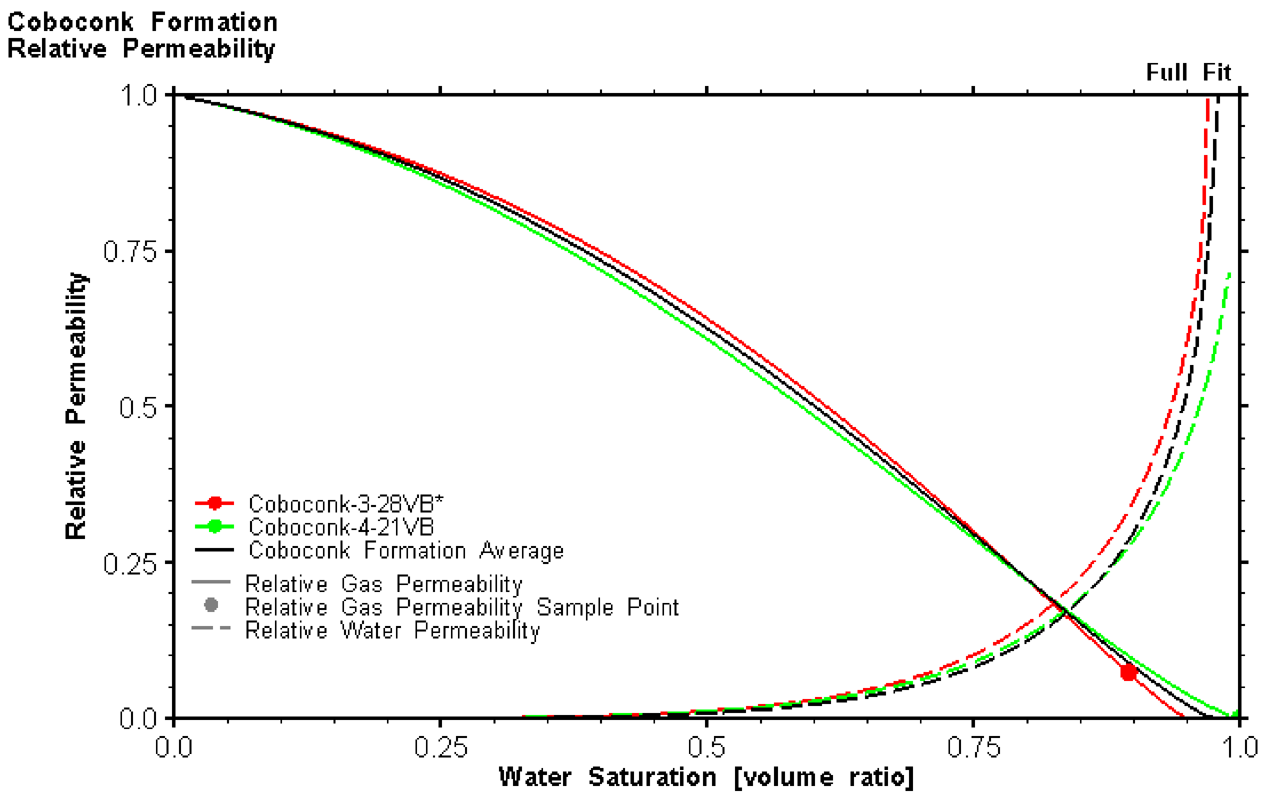


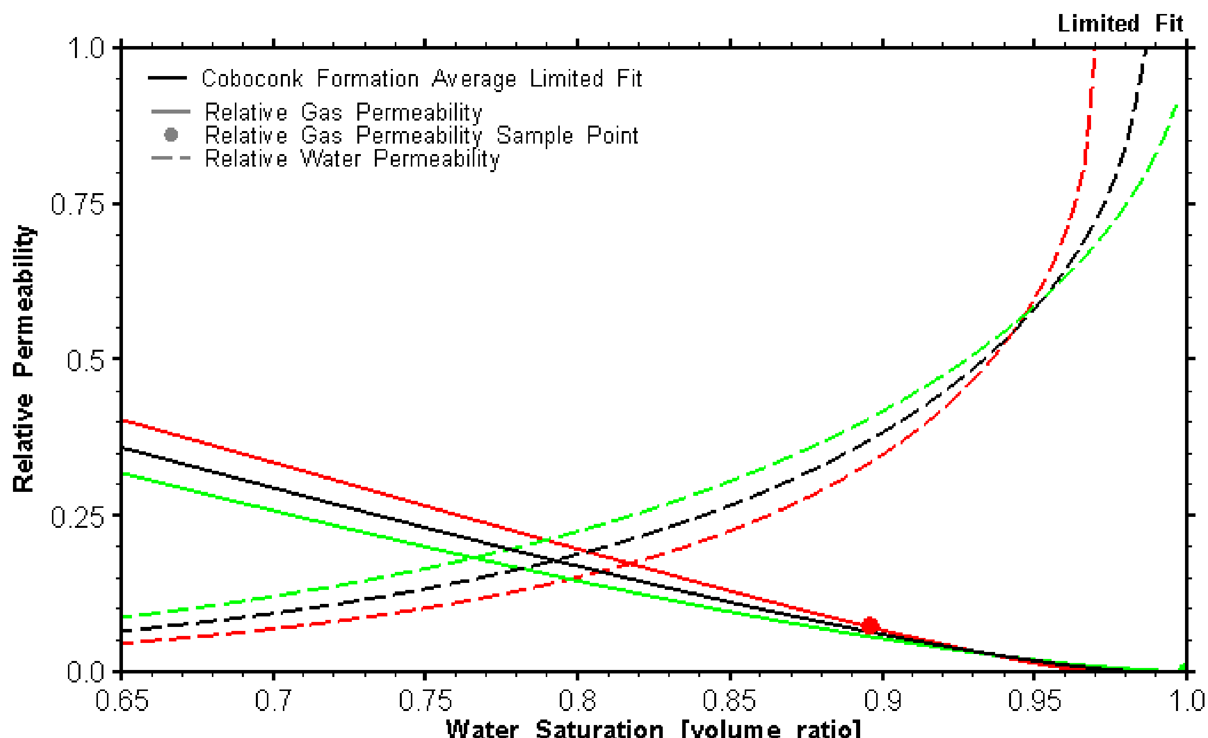


Coboconk Formation
Capillary Pressure
Full Fit
100.0
10.0
1.0
Capillary Pressure [MPa]
0.0
0.25
0.5
0.75
1.0
Water Saturation [volume ratio]
Coboconk-3-28VB
Coboconk-4-21VB
Coboconk Average Full Fit
Full Fit
Limited Fit



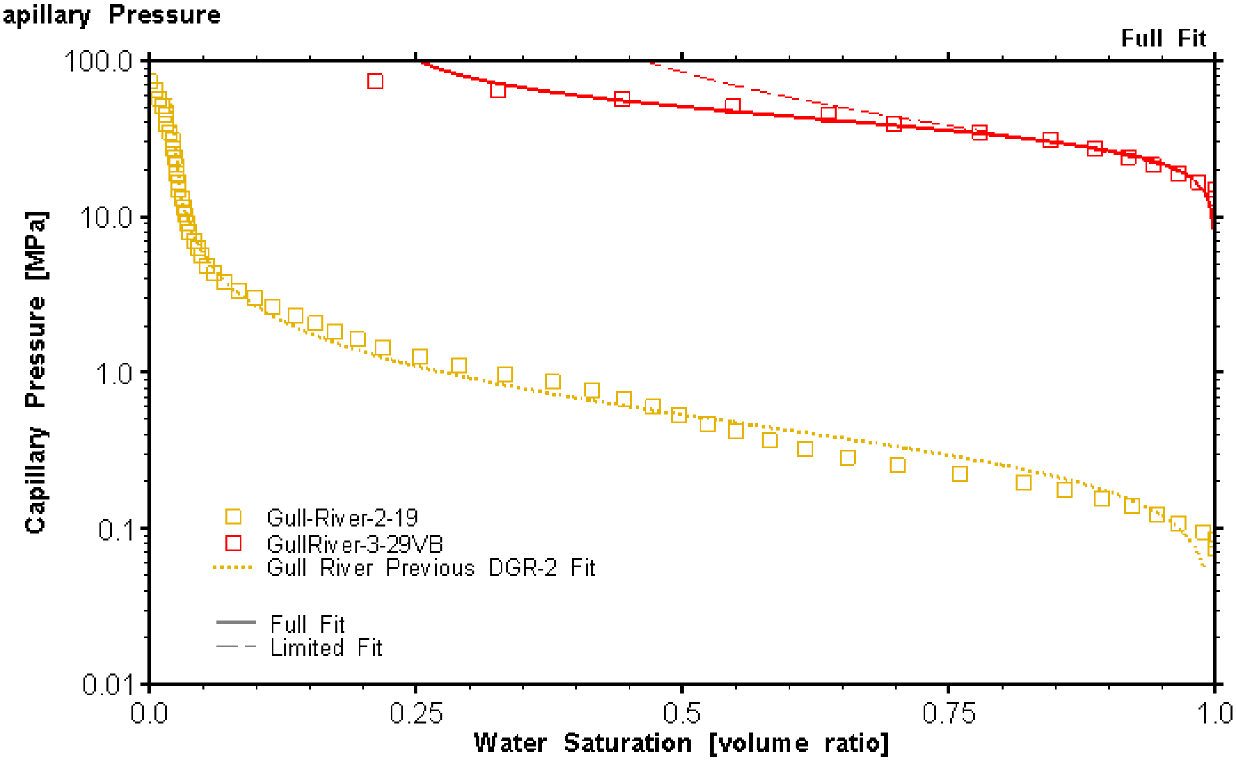
Limited Fit
100.0
10.0
1.0
Capillary Pressure [MPa]
0.7
0.75
0.8
0.85
0.9
0.95
Water Saturation [volume ratio]
Coboconk Average Limited Fit
Full Fit
Limited Fit

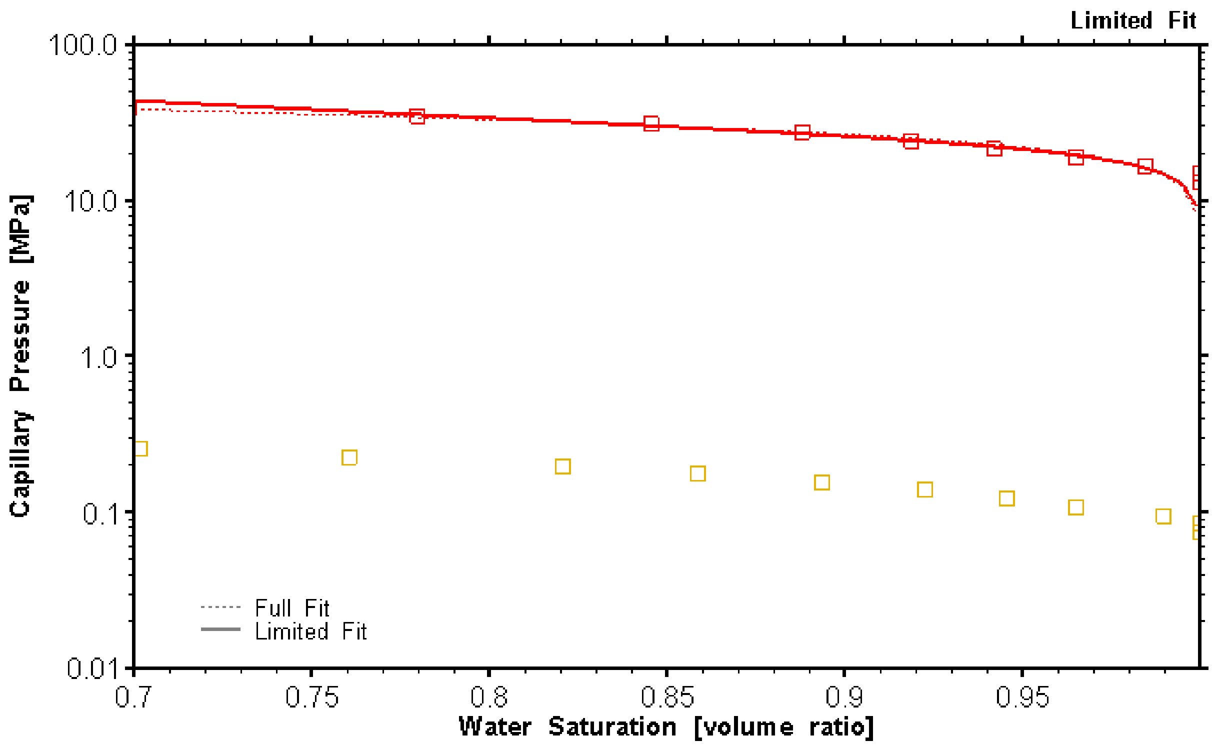




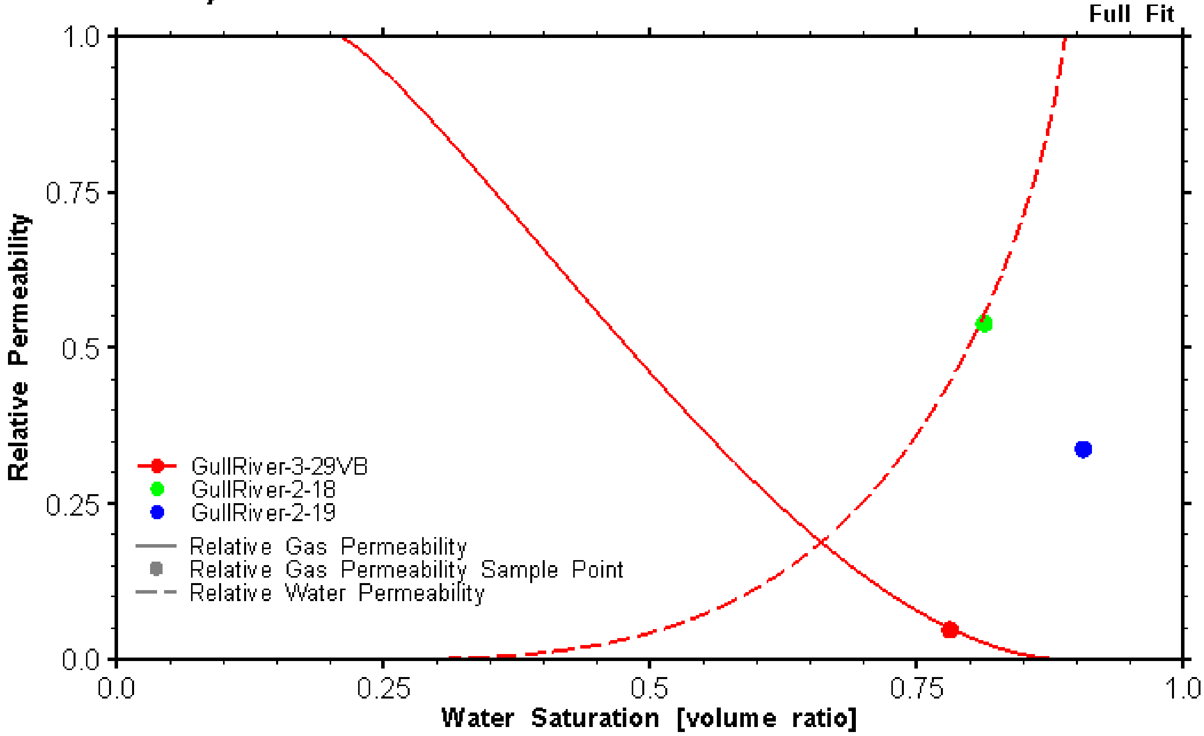
* Maximum sample relative permeability

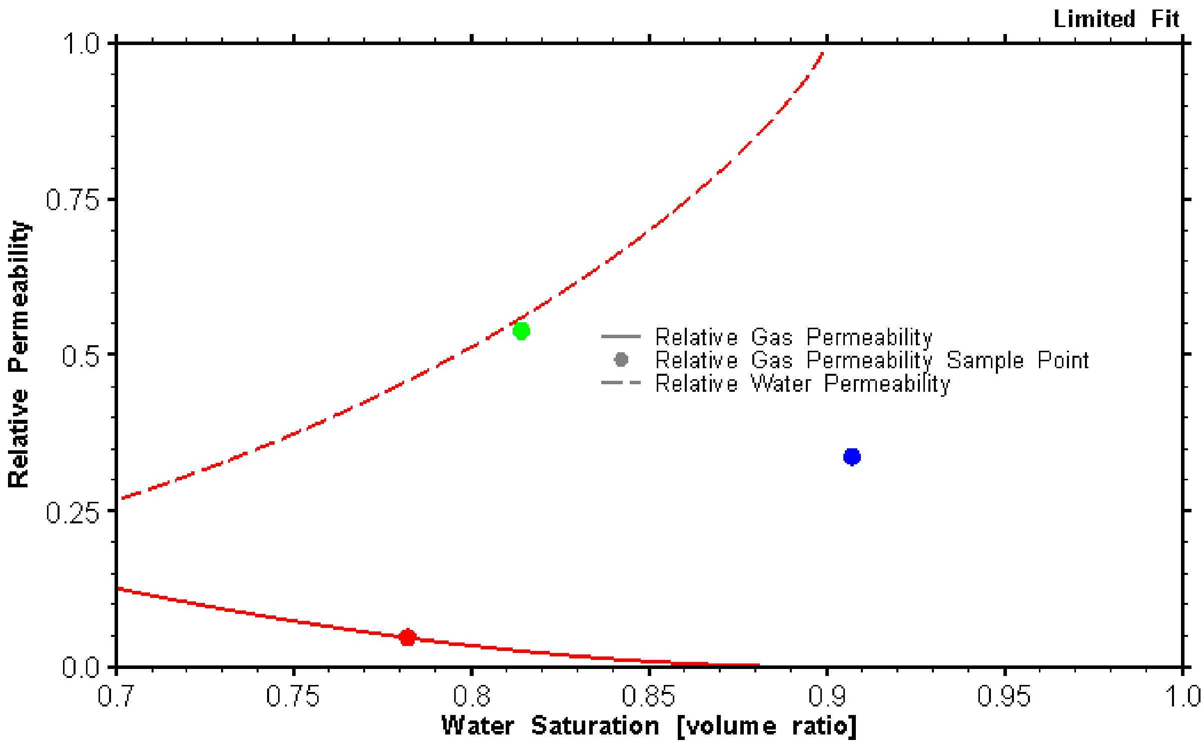
Gull River Formation
Capillary Pressure



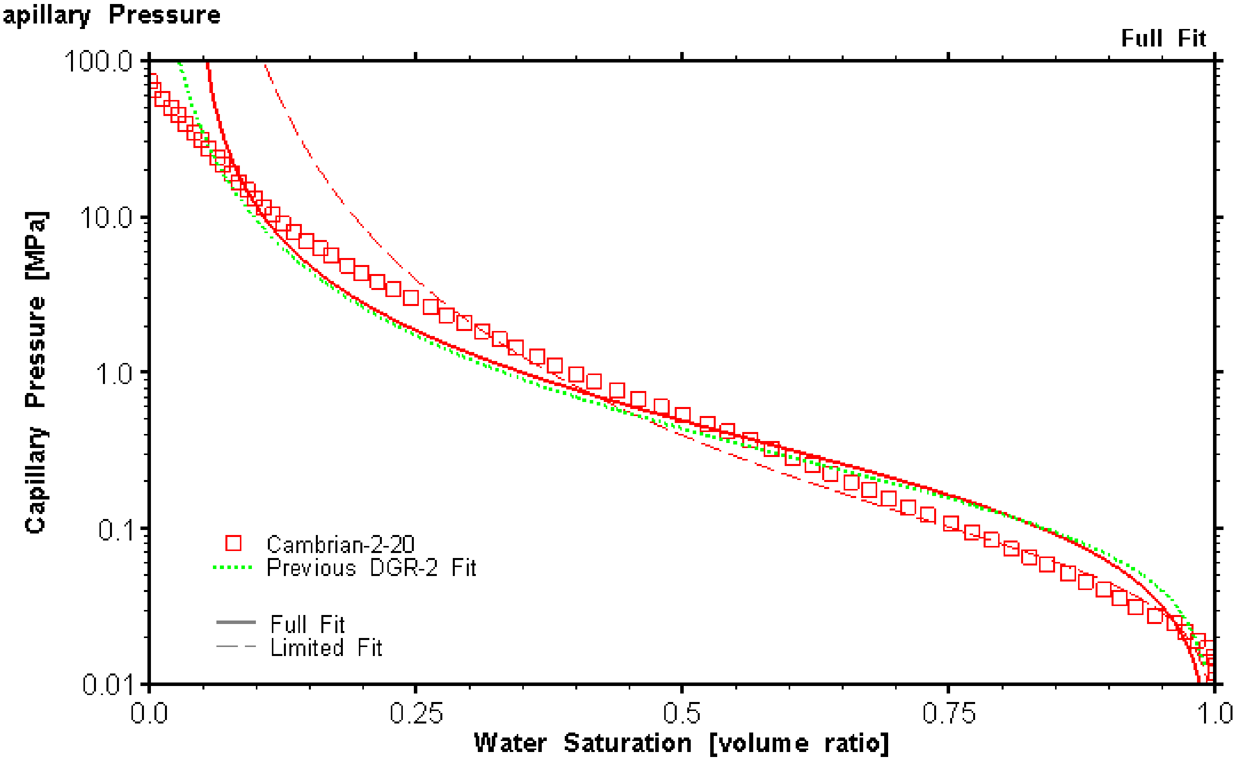


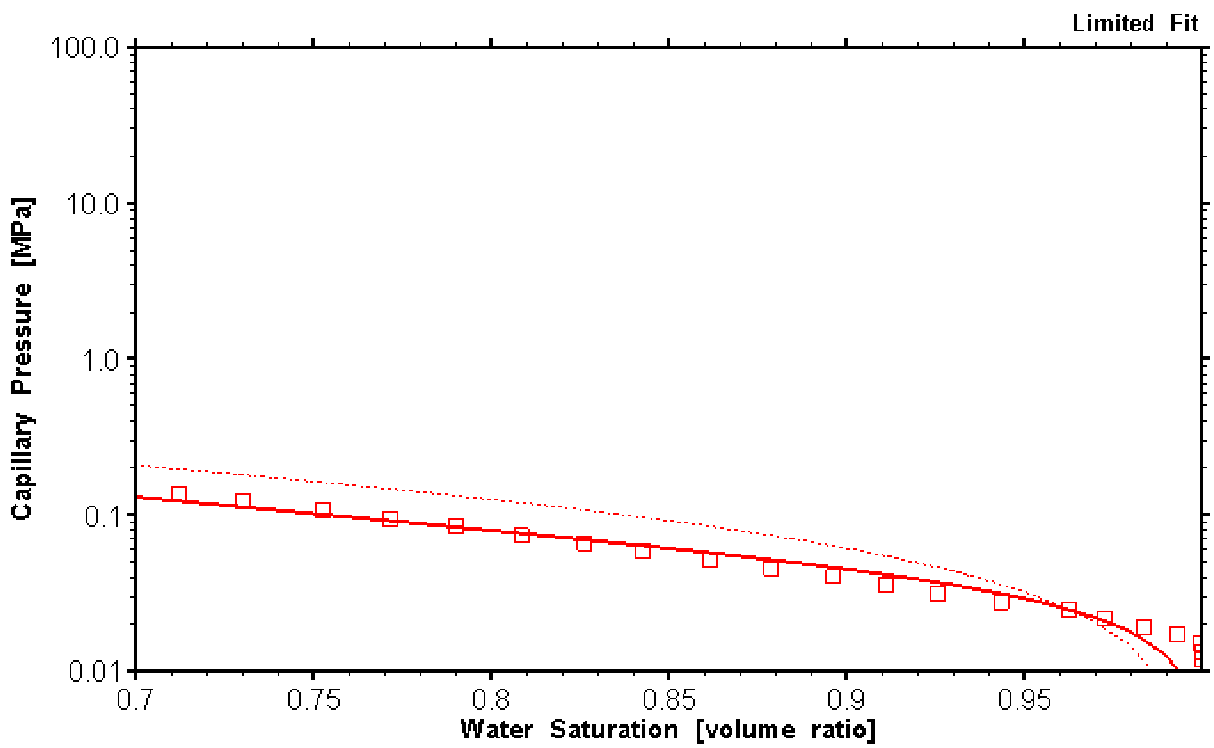
Gull River Formation
Relative Permeability





Cambrian Formation
Capillary Pressure





Cambrian Formation
Relative Permeability