PS A Conventional Look at an Unconventional Reservoir: Coalbed Methane Production Potential in Deep Environments*

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Search and Discovery Article #80122 (2010)
Posted November 22, 2010

*Adapted from poster presentation at AAPG Annual Convention and Exhibition, New Orleans, Louisiana, April 11-14, 2010

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Abstract

As technology evolves and the exploitation of unconventional resources becomes conventional practice, new applications and knowledge will lead engineers and geologists to explore marginal hydrocarbon saturations in unique geologic horizons. One of these horizons of interest is deep (greater than ~5000 ft.) coalbed methane (CBM).

It has been shown in numerous studies that coalbed permeability is highly sensitive to in-situ stress conditions and subsequent changes in stress that accompany both water and gas production. However, most studies have focused on shallow CBM, and there has been little research into coals at depth. This paper shows how simulation of CBM production is highly dependent on the assumption that pore volume compressibility remains constant as the coal experiences changes in effective stress. While this assumption may be acceptable for modeling shallow CBM production where stress changes are relatively small, the assumption likely does not hold true for deeper environments where necessary changes in stress would be more significant.

When this assumption is relaxed and adjusted so that pore volume compressibility is allowed to vary with changing stress conditions, a new vision of CMB emerges where permeability may be present and maintained during production from deeply buried coals. This conjecture comes with a caveat: deep coals that contain water as the dominant phase in the cleat system will likely never produce commercial rates of natural gas.

Nevertheless, the potential exists that CBM could produce at economic rates if the coal is present within a conventional trap with structural or stratigraphic closure and a seal that has led to the development of a gas-saturated cleat system. If a coal is considered a “conventional” reservoir where gas generation, timing, migration, and storage are optimal for creating an accumulation, economic gas production rates could be possible.

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Fracturing, **A**cidizing, &
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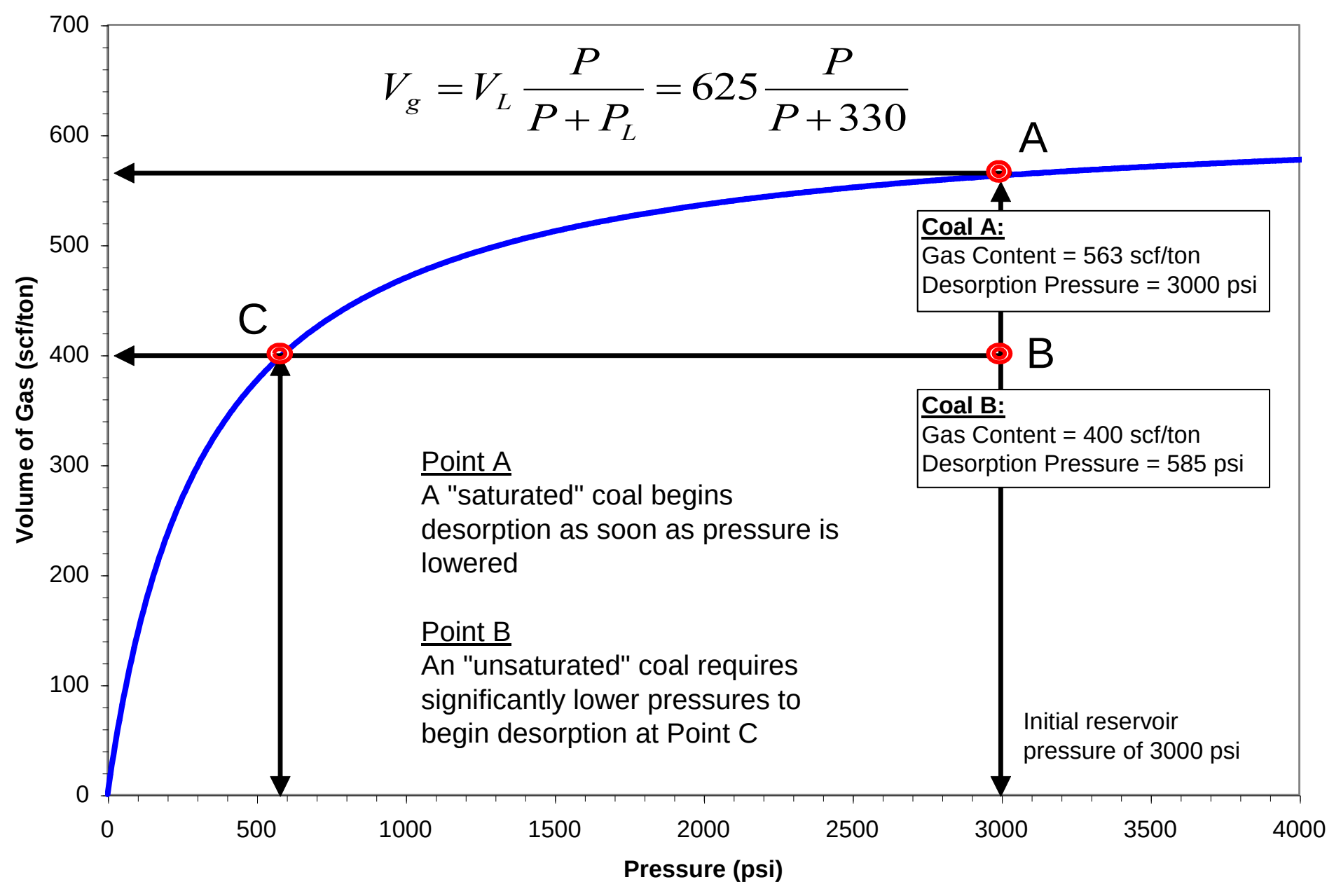
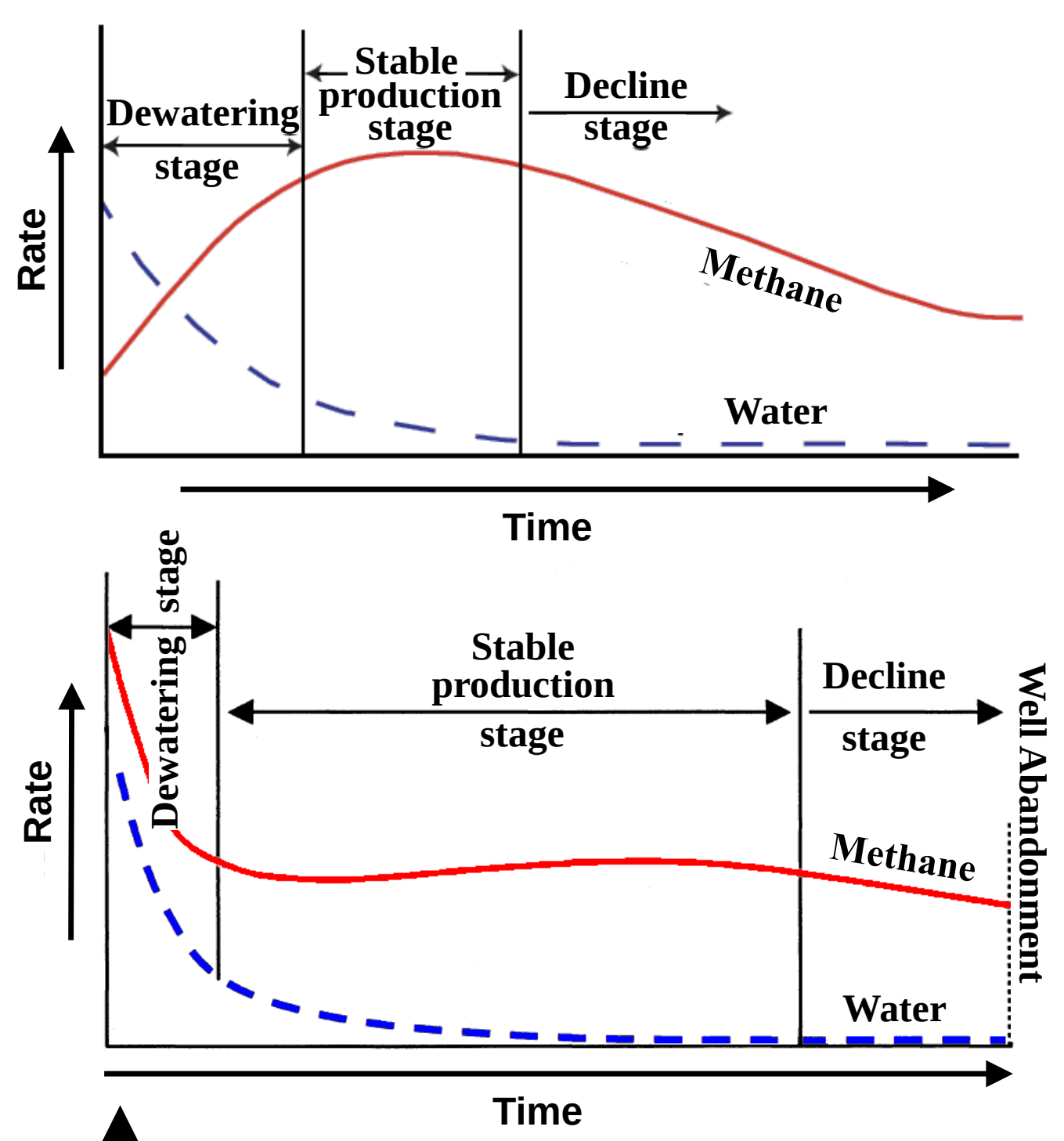
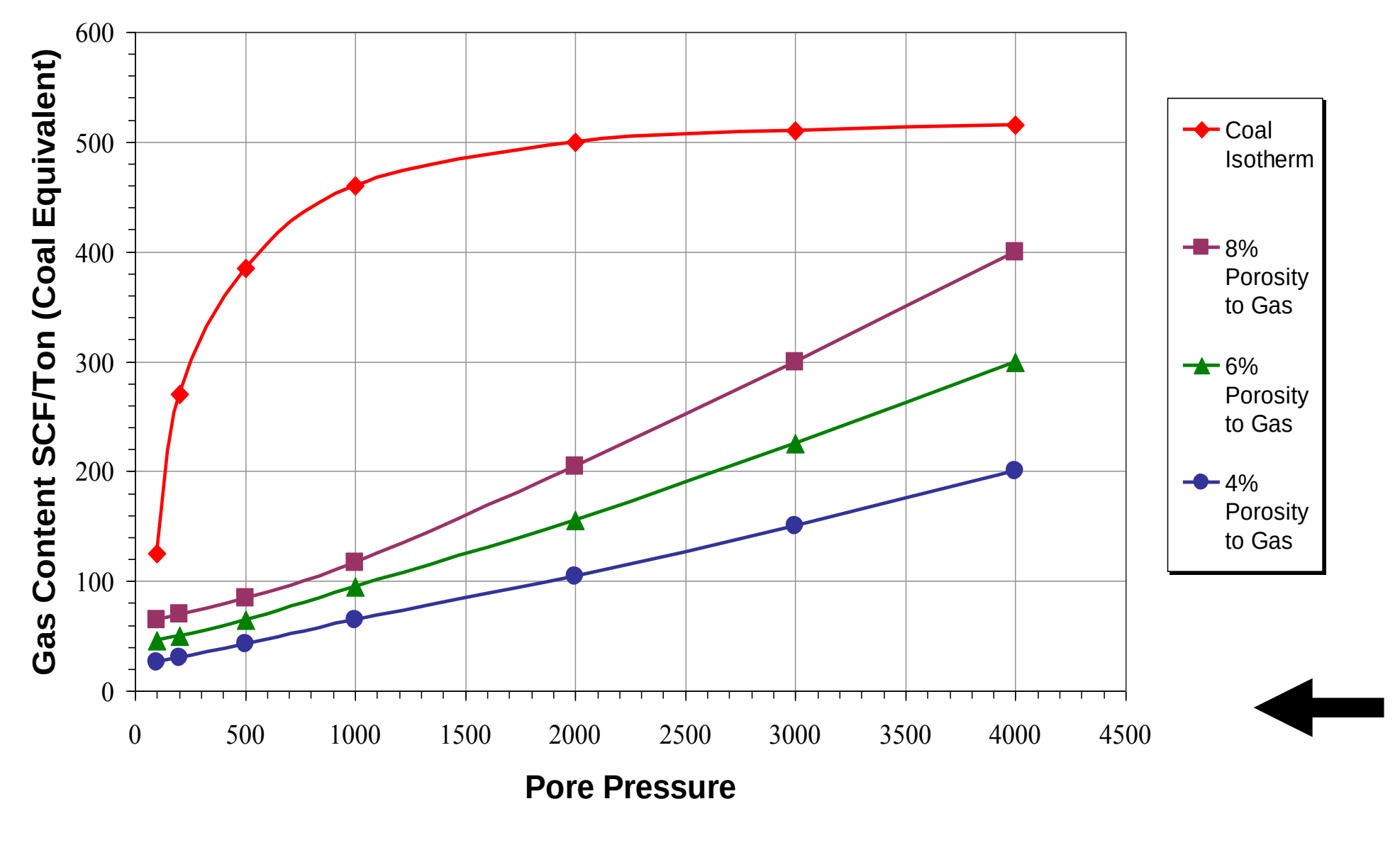
Langmuir Isotherms and Production Profiles



Example Langmuir isotherm. If a coal is unsaturated (in gas), a considerable drop in pressure is required before production initiates.



Hypothetical production profiles for shallow (top chart) and deep CBM well (bottom chart). The production profile for a deep CBM well resembles a typical resource play production profile with high initial gas rates followed by a long period of relatively stable production. From Ayers.[56]



Gas Content comparison between coal and sandstone. At 4,000 psi (~9,200 ft. in a normally pressured reservoir), the gas content of coal may contain significantly more gas than a low porosity tight gas sandstone.

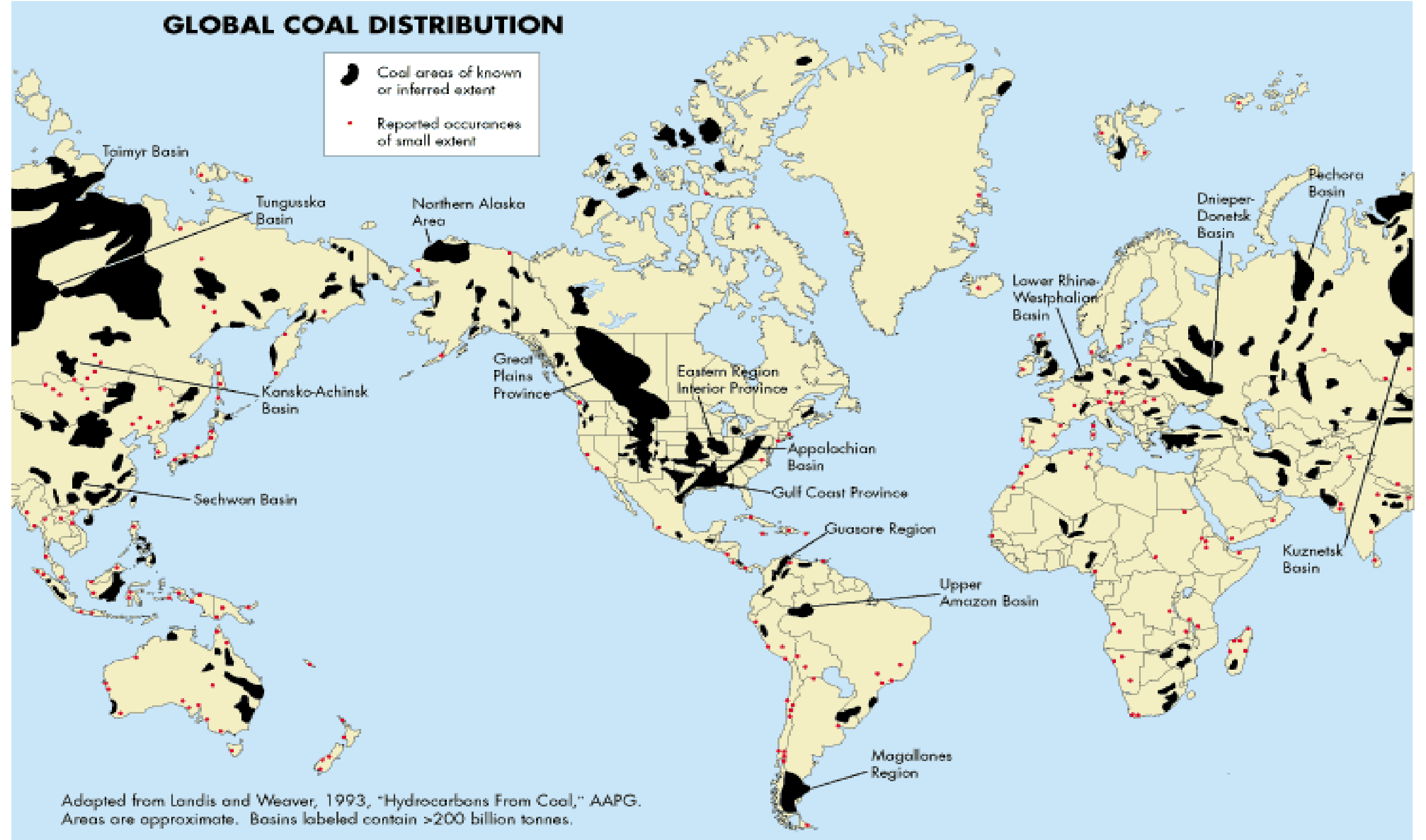
Worldwide CBM Resource

County	Basin	Formation or Coal	Size Estimates
United States	Piceance	Cameo	60 Tcf
	San Juan	Menefee coal	22-34 Tcf
	Green River	Fort Union, Almond (Meseverde)	
	Uinta	Castlegate (Meseverde)	
	Western Washington	Puget Group Coals	
Canada	Deep Alberta	Lower Cretaceous Spirit River to Nikanassin	150+ Tcf
Australia	Cooper	Permian Toolachee and Patchawarra coal	500 Tcf; 50,000 mi.^{2}
	sub-Surat	Rieds Dome, Tinowon Formation, and Blackwater Group	
	Bowen	Permian	
	Galilee	Permian	
China	Ordos	Carboniferous Taiyuan and Permian Shanxi	
	Junggar	Jurassic Badaowan, Sangonghe, Xishanyo	60,000 mi.^{2}
	Tarim	Carboniferous and Permian	220,000 mi.^{2}
Kazakastan	Karaganda	Karagandinskaya coal	30 Tcf, 1,000 mi.^{2}
Russia	Kuznetsk	Permian-Carboniferous Yerunakovskaya	1200 Tcf (>4,000 ft.)
Others: Spain, Germany, Switzerland and the United Kingdom			

Country	CBM Resource In-Place (Tcf)	CBM Recoverable Resource (Tcf)
Russia	450-2,000+	200
China	700-1,270	100
United States	500-1,500	140
Australia/New Zealand	500-1,000	120
Canada	360-460	90
Indonesia	340-450	50
Southern Africa (incl. Carbonaceous Shales)	90-220	30
Western Europe	200	20
Ukraine	170	25
Turkey	50-110	10
India	70-90	20
Kazakhstan	40-60	10
South American/Mexico	50+	10
Poland	20-50	5
TOTAL (Tcf)	3,540-7,630	830
TOTAL (Tcm)	(100-216)	(24)

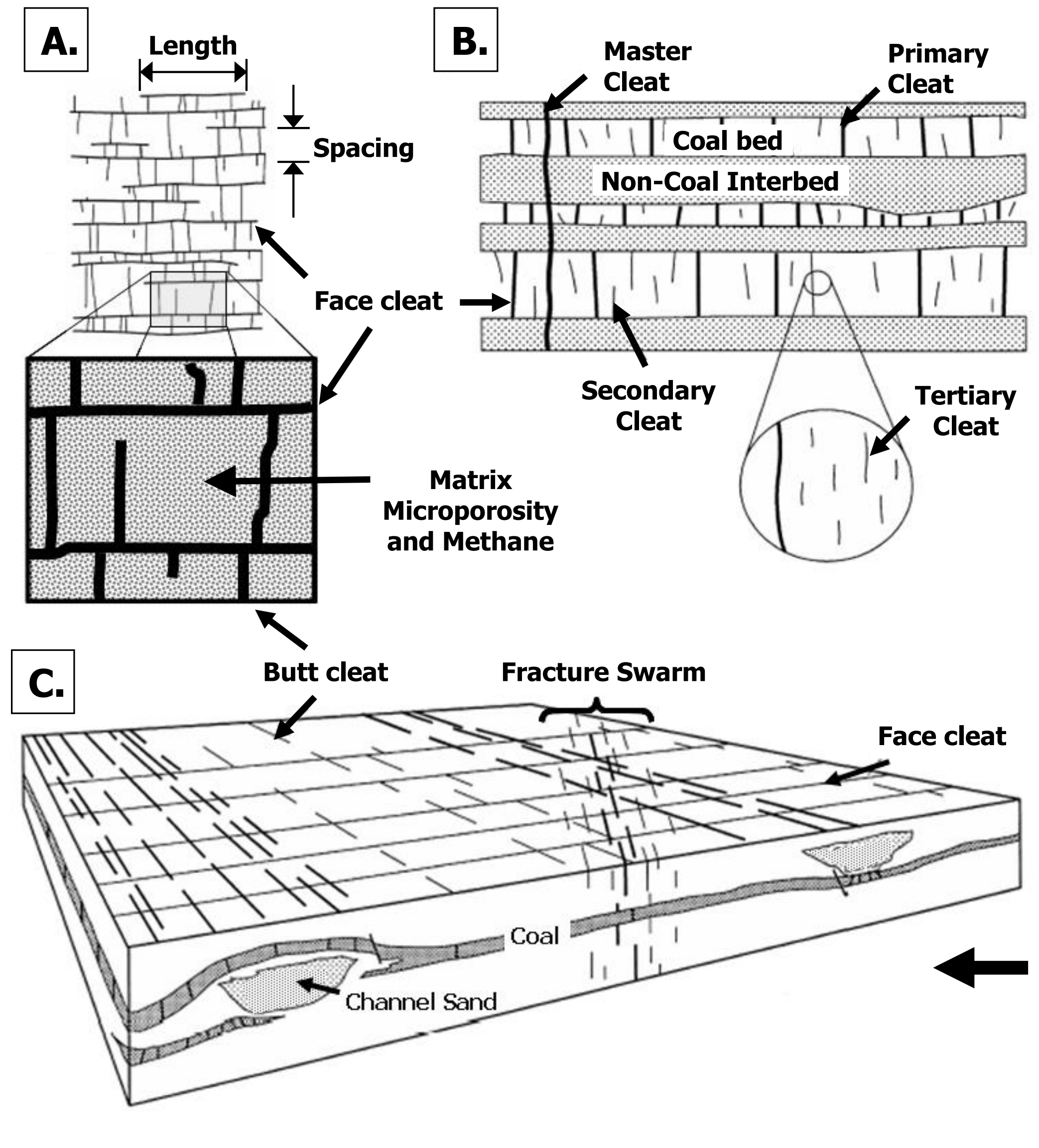
Worldwide CBM Resource Estimates

Deep (>5,000 ft.) Worldwide CBM Resource Estimates. Data from Kuuskraa.[6]

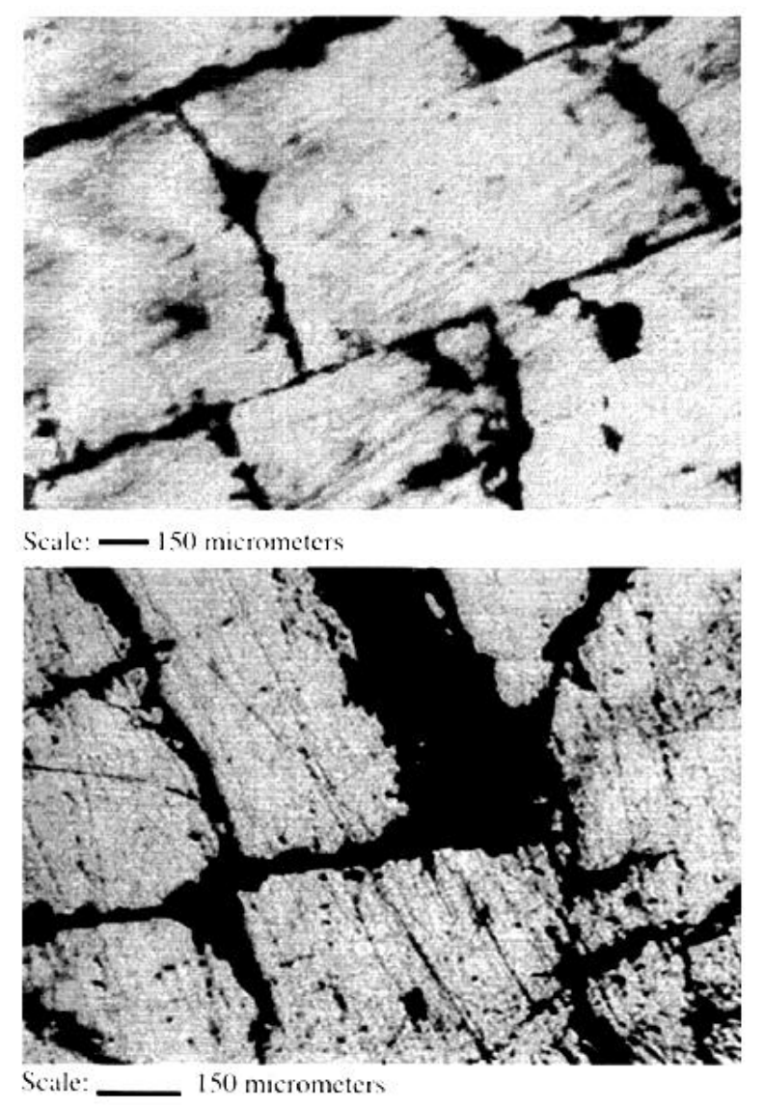


Adapted from Landis and Weaver, 1993, "Hydrocarbons From Coal," AAPG. Areas are approximate. Basins labeled contain >200 billion tonnes.

Coal Cleat Geometry

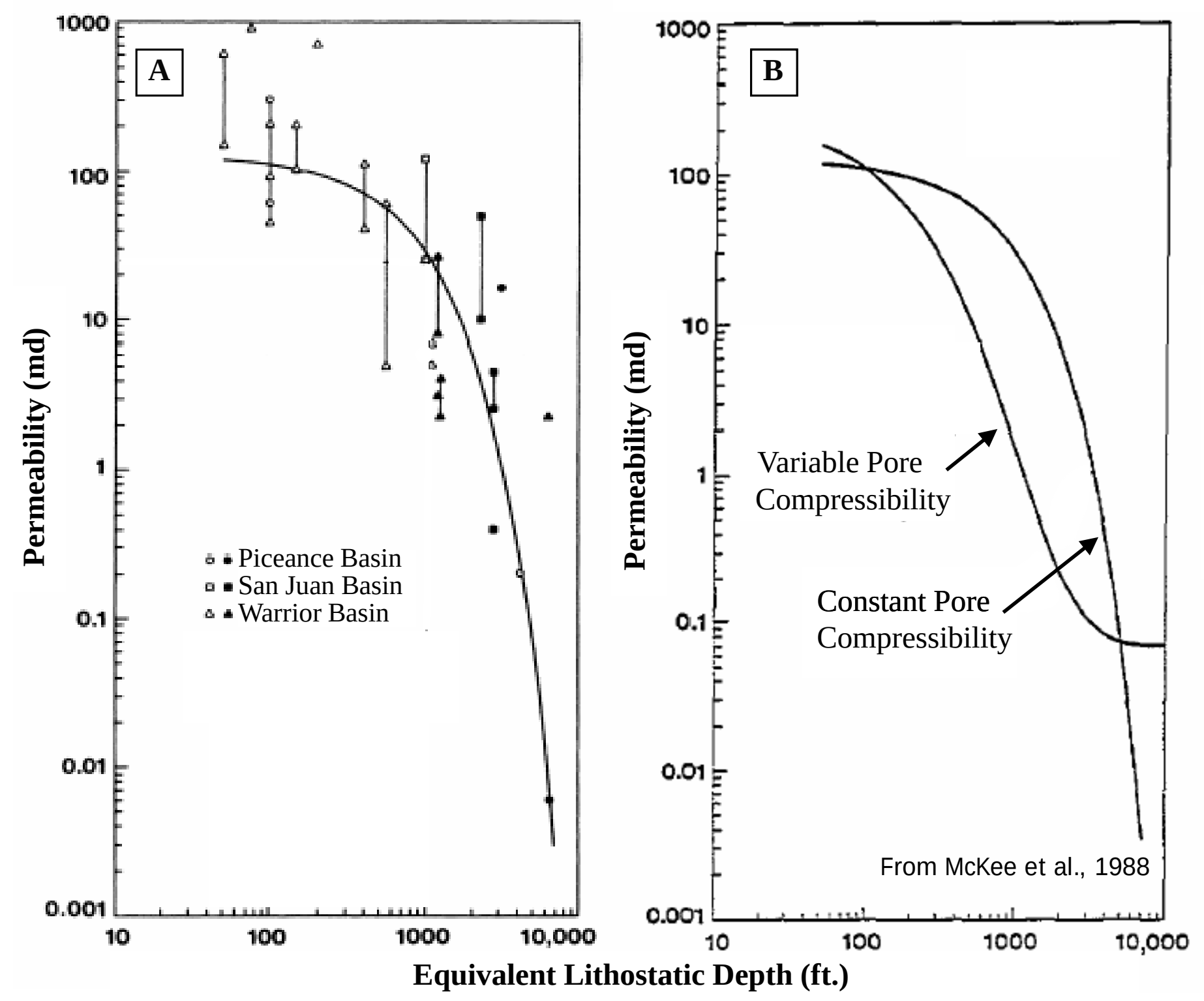


Digital images of the cleat system. The images show irregularities in the cleats that may remain open and connected despite cleat size reduction in higher stress environments. From Karacan and Okandan.[57]

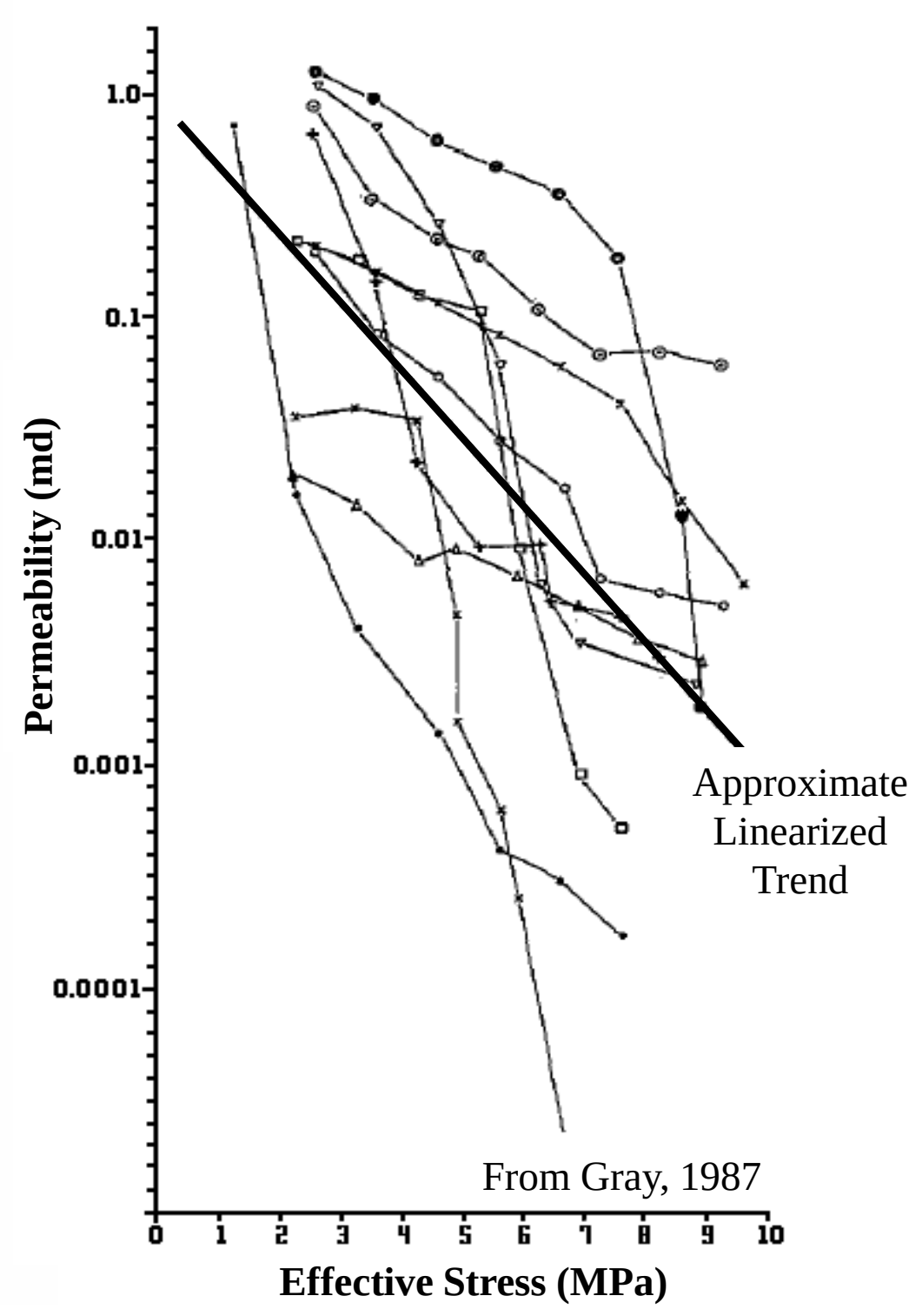


Relationships between the microporosity and macroporosity in a coal. (A) Plan view of a coal bed showing the relationship between face and butt cleats along with conventions used in classification of the cleat geometries. Also shows the matrix where the methane is stored in the micro-porosity of the coal. (B) Cross-sectional view showing cleat hierarchies from the tertiary cleats up to the primary and master cleats. (C) Plan view combined with a cross-sectional view showing relationships for the larger-scale cleat system. This includes enhanced cleat development associated with other structural elements including channel sandstones and fracture swarms. Modified from Laubach et al.[20] and Li et al.[23]

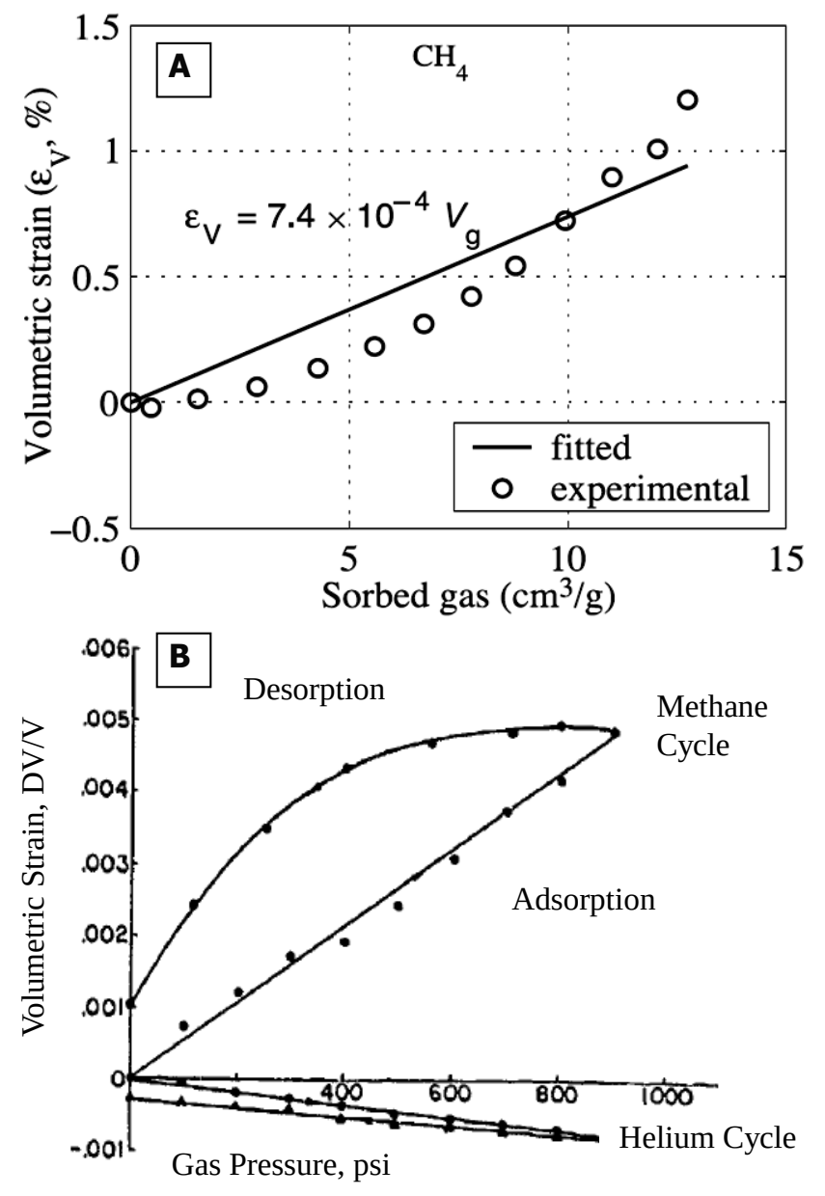
Permeability and Stress, Sorbed Gas and Strain



Permeability vs. effective stress. The 'Equivalent Lithostatic Depth' (D) equals the effective stress divided by the effective stress gradient (i.e. $\sigma_e = 0.572$ D for lithostatic conditions). (A) Well tests show permeability decreasing exponentially with depth. (B) Permeability comparison assuming constant and variable pore compressibility. When the assumption of variable pore volume compressibility is used, the permeability attains a relatively constant value as the stress increases (adapted from McKee et al.[13]).

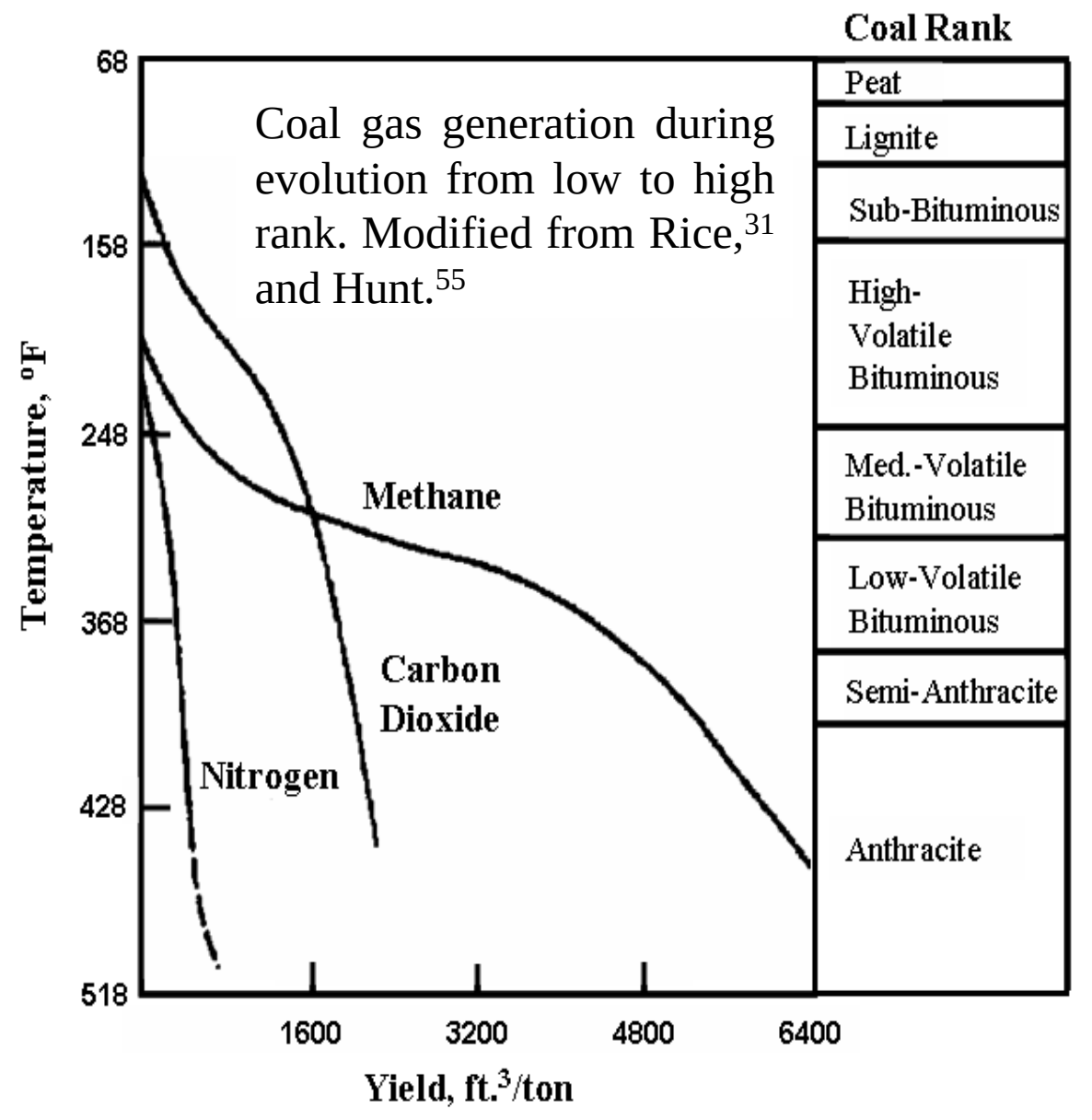


Data showing coal permeability measurements. Most coals do not show exponentially declining permeability as estimated by the linearized trend.

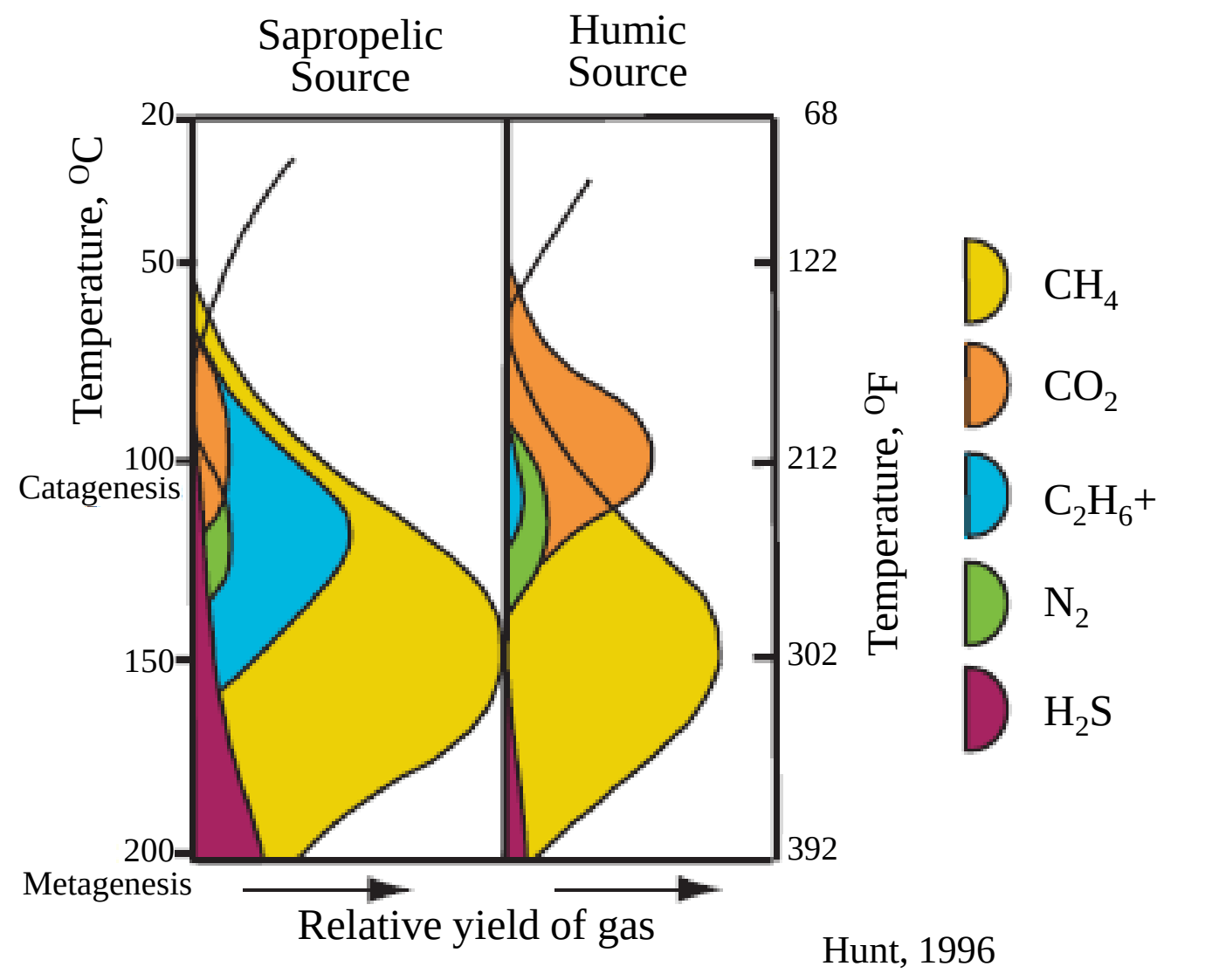


Experimental strain data vs. the volume of adsorbed gas and pressure. (A) From Cui and Bustin.[48] The C&B model assumes a linear relationship between volumetric strain and sorbed gas. (B) From Harpalani and Schraufnagel[36] Volumetric strain in the coal matrix for increasing and decreasing gas pressure for both helium and methane. One explanation for the obvious discrepancy in (A) between the experimental data and the linear approximation is the difference between adsorption or desorption strain measurements as shown in (B).

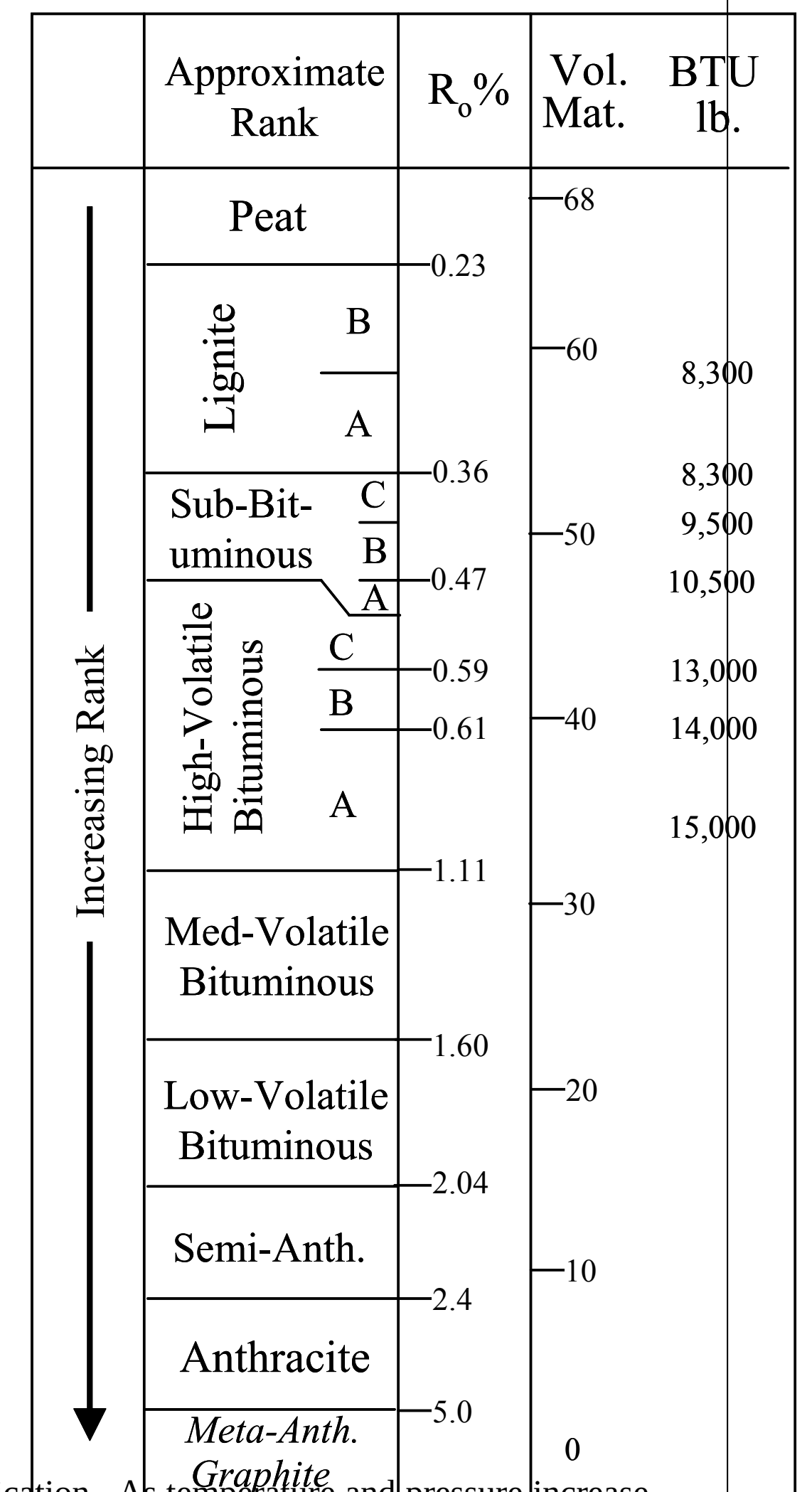
Coal Rank and Gas Generation



Coal gas generation during evolution from low to high rank. Modified from Rice,[31] and Hunt.[55]



Hunt, 1996



Coal rank classification. As temperature and pressure increase, the coal rank increases resulting in higher vitrinite reflectance values (R_o%), lower percentages of volatile matter (Vol. Mat.), and higher heating capacities (BTU/lb.). Adapted from Stach et al.[53] found in Mukhopadhyay and Hatcher.[54]

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Equations for Models

Palmer & Mansoori (P&M)

$$\frac{\phi}{\phi_0}=1+\frac{c_m}{\phi_0}(p-p_0)+\frac{\varepsilon_1}{\phi_0}\left(\frac{K}{M}-1\right)\times\left(\frac{bp}{bp+1}-\frac{bp_0}{bp_0+1}\right)$$

$$M=\frac{E(1-\upsilon)}{(1+\upsilon)(1-2\upsilon)}\qquad K=\frac{E}{3(1-2\upsilon)}\qquad \frac{k}{k_0}=\left(\frac{\phi}{\phi_0}\right)^3$$

- Most commonly used model
- Applies to static (constant pressure) case
- Highly sensitive to initial porosity estimation
  - Only handles small changes in porosity
  - Can become negative

Cui & Bustin (C&B)

$$\sigma-\sigma_0=\frac{2(1-2\upsilon)}{3(1-\upsilon)}\left[(p-p_0)+\frac{E}{3(1-2\upsilon)}(\varepsilon_V-\varepsilon_{V0})\right]$$

$$\varepsilon_V=\varepsilon_g V_g=\varepsilon_g V_L\frac{p}{p+p_L}=\varepsilon_g V_L\frac{bp}{bp+1}\qquad k=k_0e^{-3\bar{c}_p\Delta\sigma}$$

- Shown to be equivalent to P&M model
- Volumetric strain directly related to sorbed gas content

Shi and Durucan (S&D)

$$\sigma-\sigma_0=-\frac{\upsilon}{1-\upsilon}(p-p_0)+\frac{E\alpha_s V_L}{3(1-\upsilon)}\left(\frac{bp}{bp+1}-\frac{bp_0}{bp_0+1}\right)$$

$$k=k_0e^{-3\bar{c}_p\Delta\sigma}$$

- Matrix shrinkage proportional to volume of desorbed gas
- Changes in permeability are related to the effective *horizontal* stress
- May only apply to horizontal coalbeds

Compressibility Equation

$$\bar{c}_p=\frac{c_0}{\alpha\Delta\sigma}\left[1-e^{-\alpha\Delta\sigma}\right]$$

(From McKee et al., 1988)

Model Observations

$$\sigma-\sigma_0=\frac{1+\upsilon}{3(1-\upsilon)}(p_0-p)-\frac{2E}{9(1-\upsilon)}(\varepsilon_{V0}-\varepsilon_V)$$

C&B model

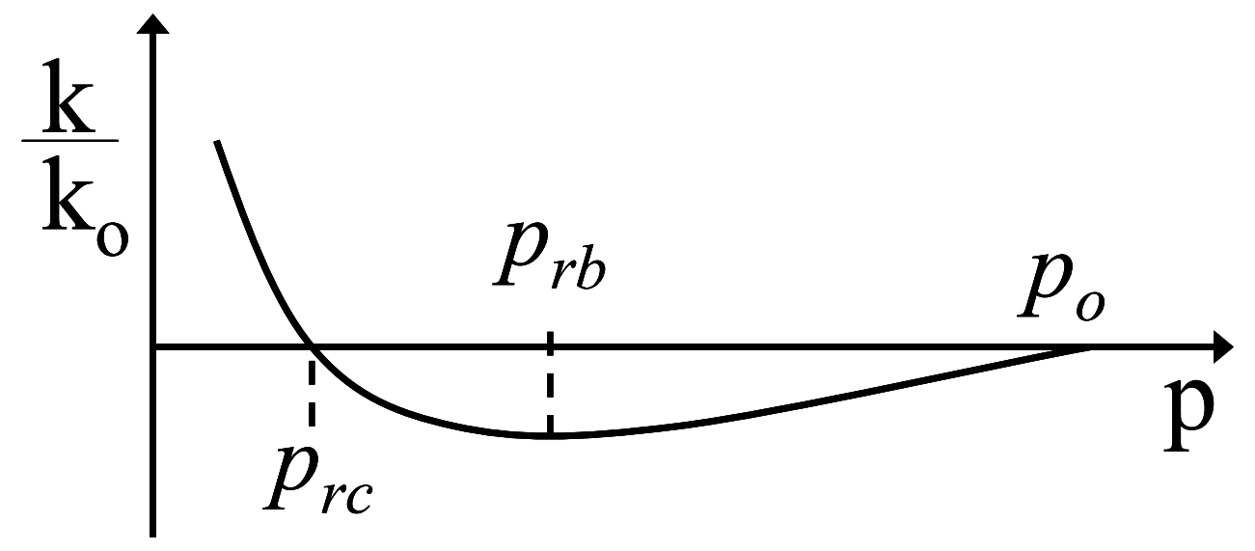
$$\sigma-\sigma_0=\frac{\upsilon}{(1-\upsilon)}(p_0-p)-\frac{3E}{9(1-\upsilon)}(\varepsilon_{V0}-\varepsilon_V)$$

S&D model

$$\frac{1+\upsilon}{3}\geq\upsilon$$

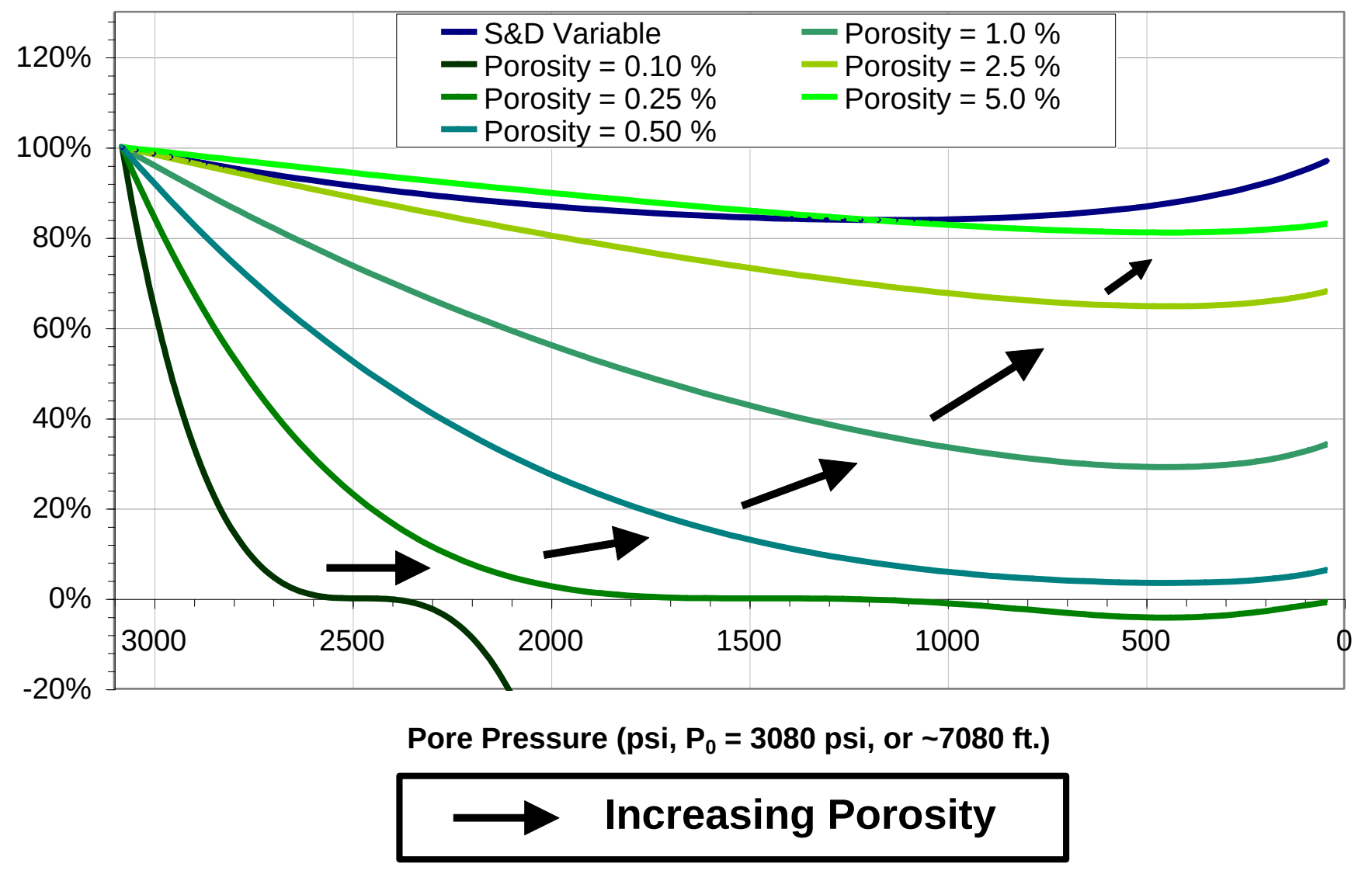
3 = 1.5 x 2

- 1st term is always smaller for S&D Model
  - Lower effective stress related to pressure
- 2nd term is 50% greater for S&D model
  - Greater shrinkage due to desorption



Recovery (P_{rc}) and rebound (P_{rb}) pressures in relation to the normalized permeability (k/k_o). As the pore pressure decreases during production, the coal permeability may eventually reach the rebound and recovery pressures. From Shi and Durucan.[39]

Permeability sensitivity of the P&M model to initial porosity estimation. The permeability ratio most similar to the S&D model results requires a porosity estimation of ~5%.



Simulation Model Inputs and Descriptors

Simulation Inputs for All Cases

		Case #1	Case #2	Case #3	
	Variable	**SJB Value**	**Piceance 1**	**Piceance 2**	**Units**
Stress Model	υ	0.39	0.31	0.31	
	E	4.45E+05	3.50E+05	3.50E+05	psi
	$1/P_L, b, \beta$	0.0016	0.00125	0.00125	psi^{-1}
	$\varepsilon_l, \alpha_S V_L$	0.0128	0.01	0.01	
	P_0	3080	3080	4350	psi
	$\varepsilon_{\upsilon 0}$	0.01064	0.00794	0.00845	
	f	0.5	0.5	0.5	
	γ	1.30E-06	1.30E-06	1.30E-06	psi^{-1}
	ϕ_0	0.001	0.005	0.005	
	K/M	0.76	0.633	0.633	
	M/E	1.995	1.386	1.386	
	c_m	7.89E-07	1.89E-06	1.89E-06	psi^{-1}
	? P_p =	0.435	0.435	0.435	psi/ft
	? σ_{ov}=	1	1	1	psi/ft
	k_0	0.1	0.1	0.1	md
Compressibilty Model	k_{0eff} =	0.14	40	40	md
	σ_0 =	0	500	500	psi
	c_0 =	2.20E-03	1.80E-03	1.80E-03	psi^{-1}
	α =	1.30E-03	2.95E-03	2.95E-03	psi^{-1}
Constant Compressibilty	c_p =	1.34E-03	1.00E-03	1.00E-03	psi^{-1}

GREEN = from Palmer and Mansoori,[49] RED = from Jeu et al.,[58] BLUE = fit for McKee et al.[13] data, BROWN = from McKee et al.,[13] PURPLE = assumed values, BLACK = calculated values.

Table 4.2. Base Values used for the Simulations.

Base Values Used for Simulation

Gas Gravity	0.55
Temperature	120°F
P_L*	625 psi
V_L*	550 scf
Grid Setup	41 x 41 x 1
Grid Size	5280 ft.^{2}
Thickness	20 ft.
Ash Content	0%
Skin Factor	-4
Wellhead Pressure	50 psi
# of Wells	1
Water Saturation	100%
Density*	1975 tons/acre-ft.
Wellbore Radius	0.2 ft.

*Based on (16).

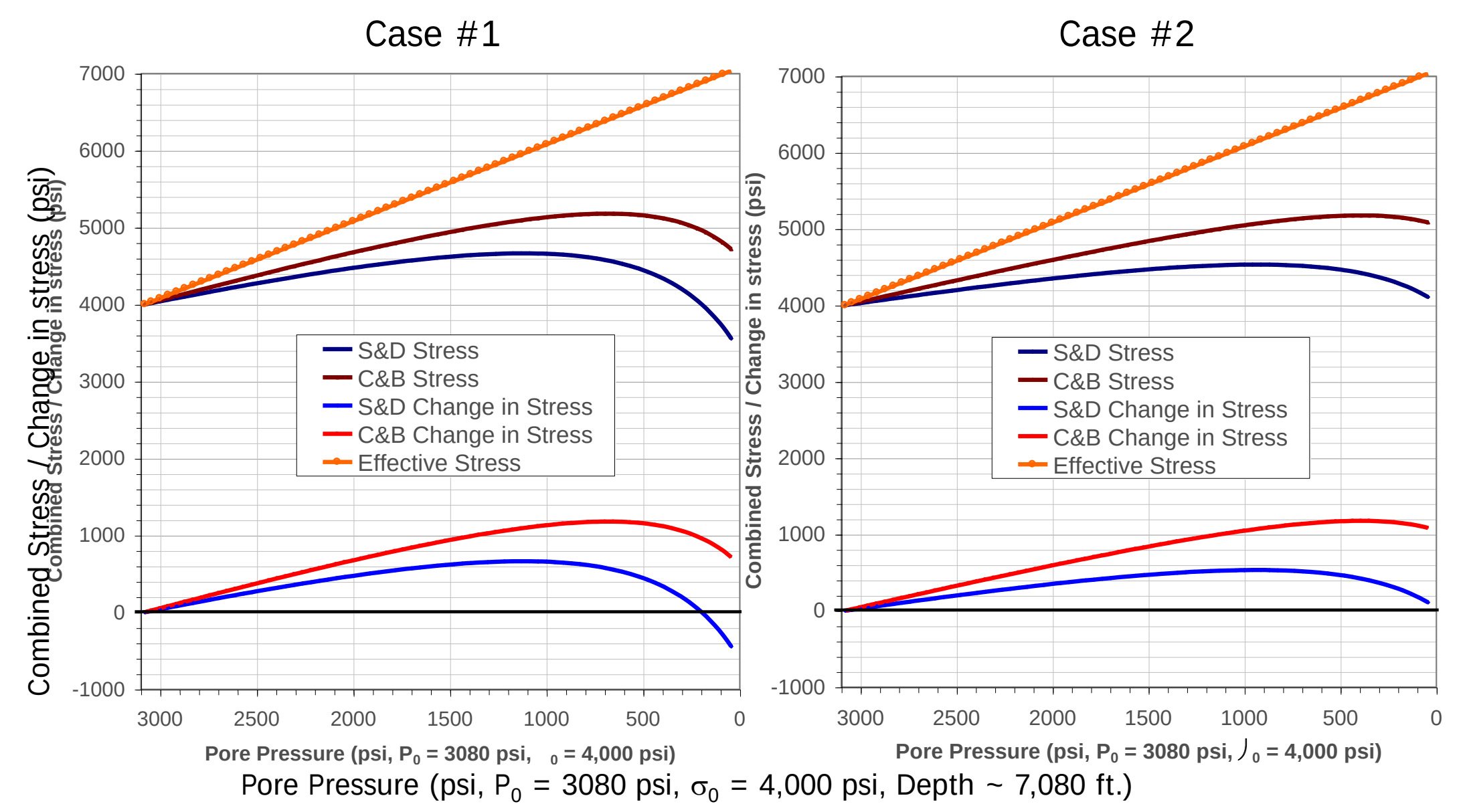
Table 5.2. Abbreviations for the Simulation Runs.

Abbreviations for the Simulations

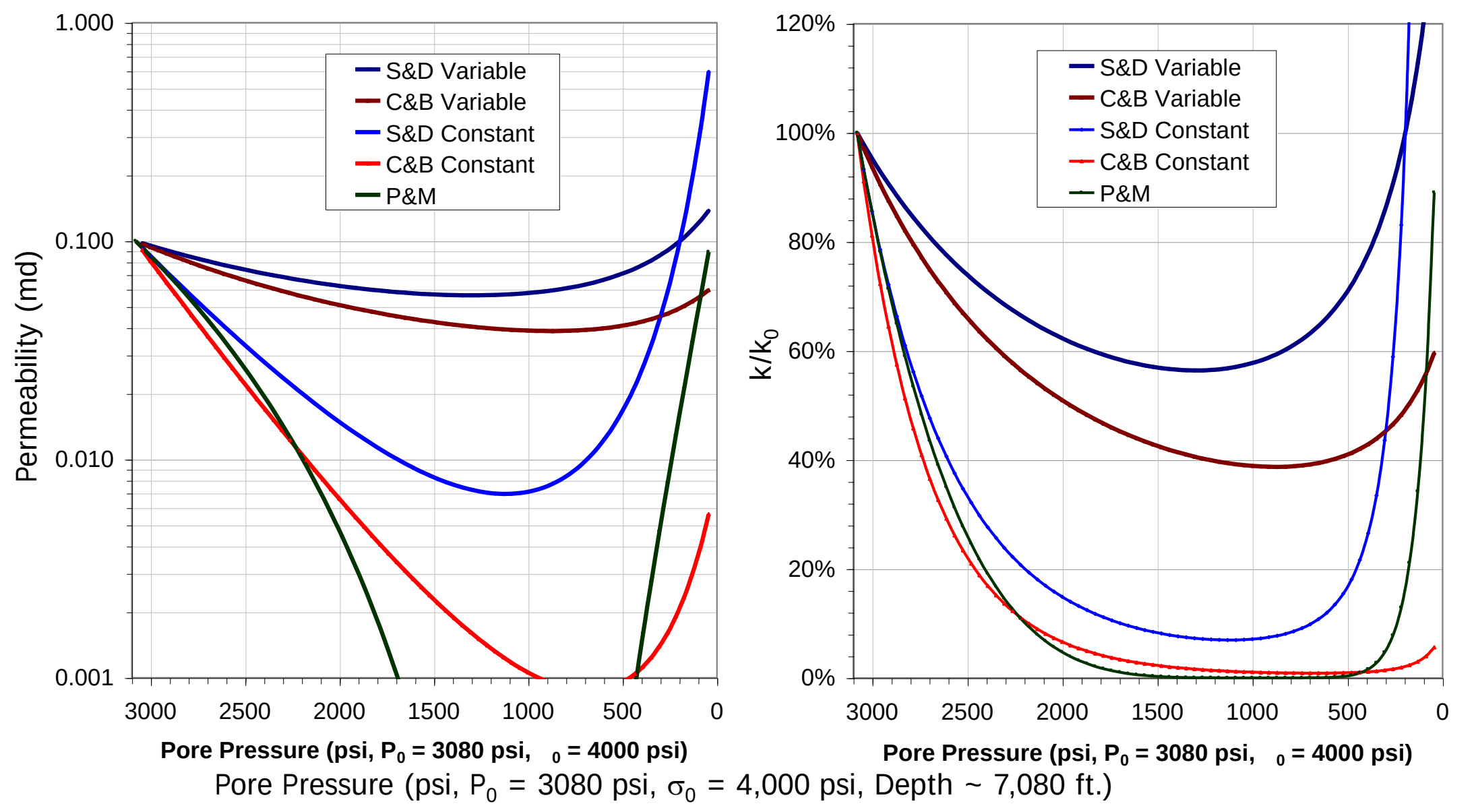
7080 = Example depth of 7,080 ft.
10000 = Example depth of 10,000 ft.
1(sp) = 1 well per 640 acres
16(sp) = 16 wells per 640 acres
32(sp) = 32 wells per 640 acres
4(sp) = 4 wells per 640 acres
8(sp) = 8 wells per 640 acres
AC = Anticline structure
ACS = Subtle anticline structure
BaseCase = Original model for PB or SJB
CB = Cui and Bustin model
COMPLOW = Lower rock compressibility
CONS, C = Constant pore volume compressiblity
GWATRP = Enhanced water relative permeability
IRR = Irriducible water saturation
LC = Lower rock compressibility
LPMIN = Well head pressure of 15 psi
P = Production graph
PB = Case #2 (Piceance Basin #1)
PB2 = Case #3 (Piceance Basin #2)
PGASRP = Poor gas relative permeability
PMINLOW = Well head pressure of 15 psi
RPGB = Poor gas relative permeability
RPWG = Enhanced water relative permeability
SD = Shi and Durucan model
SJB = Case #1 (San Juan Basin)
USAT = Undersaturated coal
VAR, V = Variable pore volume compressiblity
ZERO, 0 = Zero water saturation in the cleat volume

Permeability Rebound

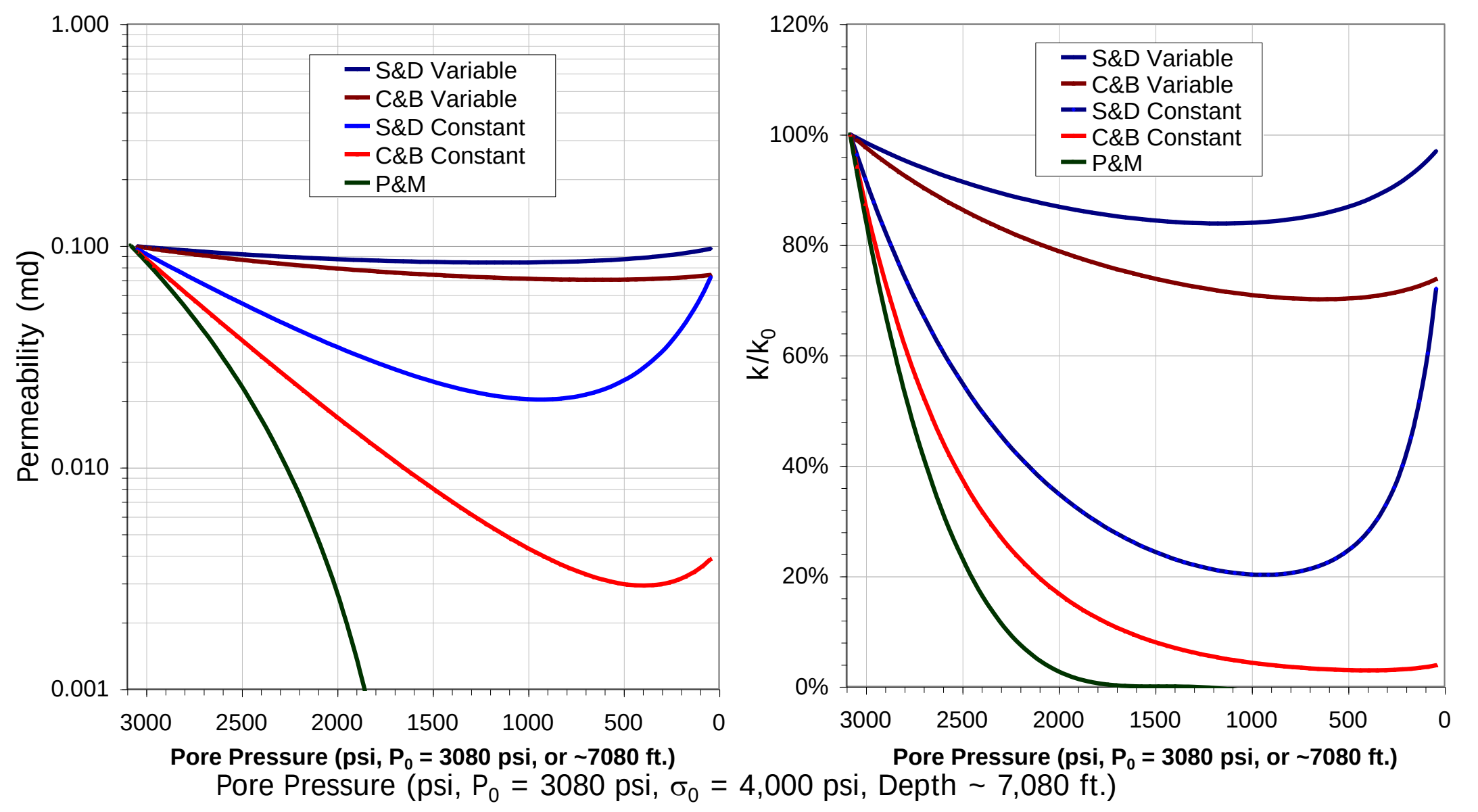
Change in effective stress compared to changes in combined effective stress. The orange line shows how the effective stress changes with decreasing pore pressure. The red and blue lines show the changes in combined effective stress calculated from the C&B and S&D models.



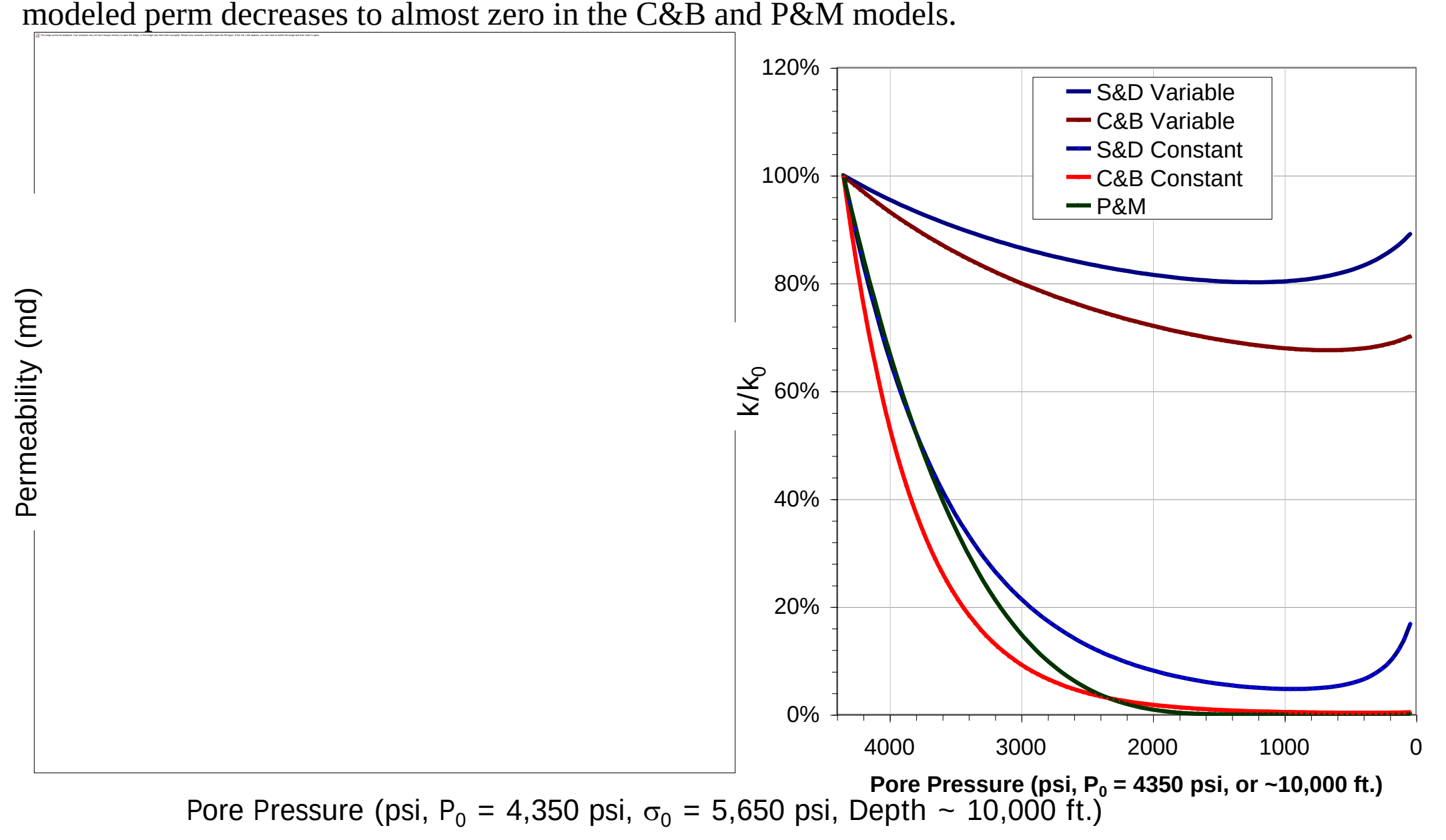
Case #1; San Juan Coals; Depth – 7,080 ft. With the assumption of variable compressibility, permeability does not decrease as much. As the stress increases, the compressibility decreases essentially making it harder and harder to close the coalbed's cleat volume system.



Case #2; Piceance Coal; Depth – 7,080 ft. The constant compressibility cases show more sensitivity to changes in stress during simulated production.



Case #3; Piceance Coal; Depth – 10,000 ft. When assuming an exponentially declining pore volume compressibility, permeability changes are minor. In comparison, when using a constant value, the modeled perm decreases to almost zero in the C&B and P&M models.



Simulation Results Tables

The impact of the pore volume compressibility assumption on simulated 25-year cumulative production.

C&B Model (25 year difference)			
MMSCF	Constant	Variable	Difference
Case #1	11	38	345%
Case #2	25	83	332%
Case #3	18	114	633%

S&D Model (25 year difference)			
MMSCF	Constant	Variable	Difference
Case #1	18	48	267%
Case #2	41	93	227%
Case #3	29	129	445%

The impact of the pore volume compressibility assumption on minimum permeability predictions and the simulated rebound pressure where lower pressures lead to increases in permeability within the reservoir.

C&B Model Minimum Permeability

	Constant			Variable			Difference	
	md	k/k_0	p_{rb}	md	k/k_0	p_{rb}	md	p_{rb}
Case #1	0.0009	0.9%	696	0.0387	39%	870	4448%	174
Case #2	0.0029	3%	392	0.0702	70%	631	2421%	239
Case #3	0.0003	0.3%	370	0.0676	68%	674	22533%	304

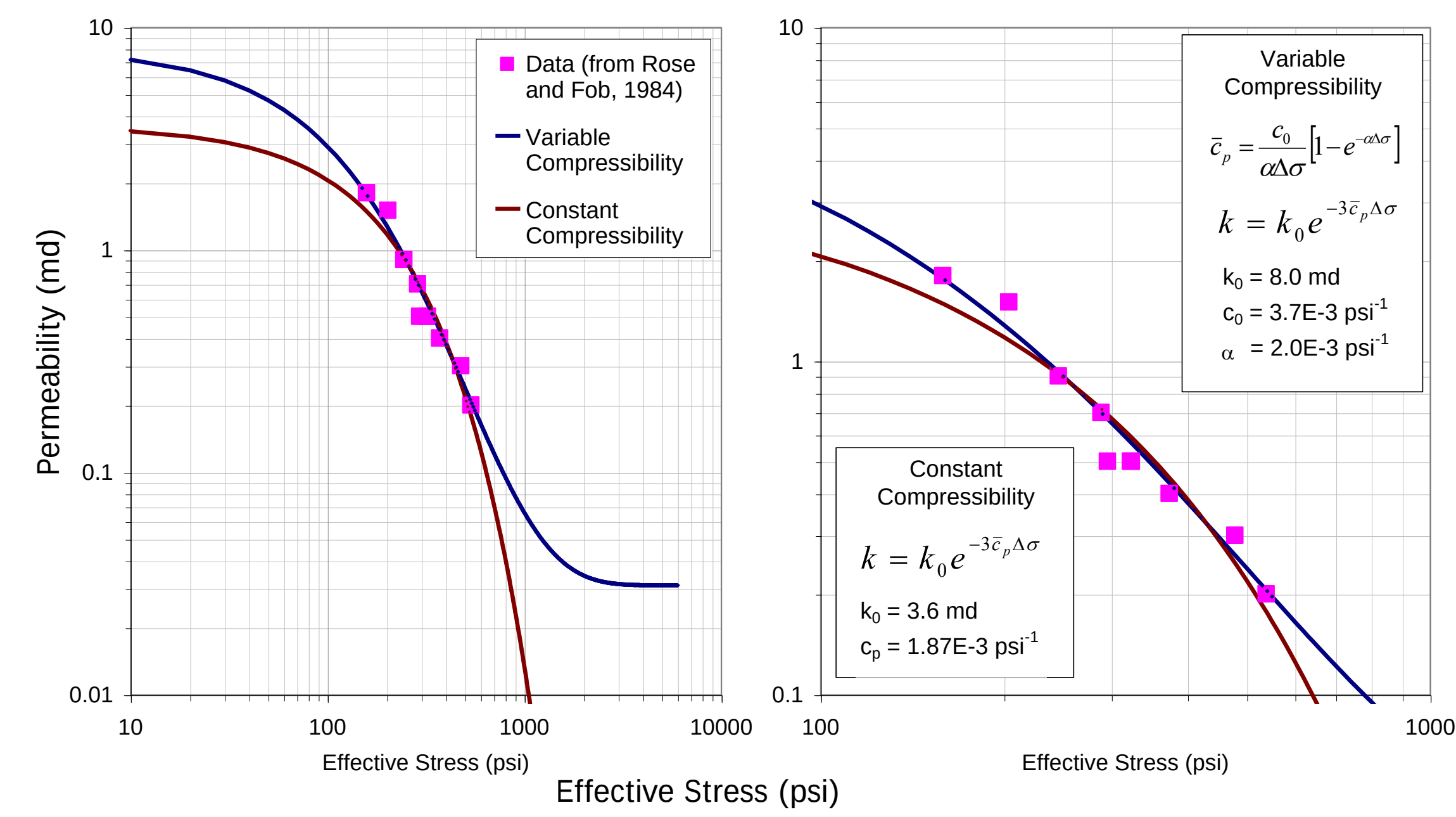
S&D Model Minimum Permeability

	Constant			Variable			Difference	
	md	k/k_0	p_{rb}	md	k/k_0	p_{rb}	md	p_{rb}
Case #1	0.0070	7%	1131	0.0564	56%	1305	812%	174
Case #2	0.0206	20%	935	0.0839	84%	1153	407%	218
Case #3	0.0047	5%	935	0.0802	80%	1218	1706%	283

Summary table of the simulations used for this study.

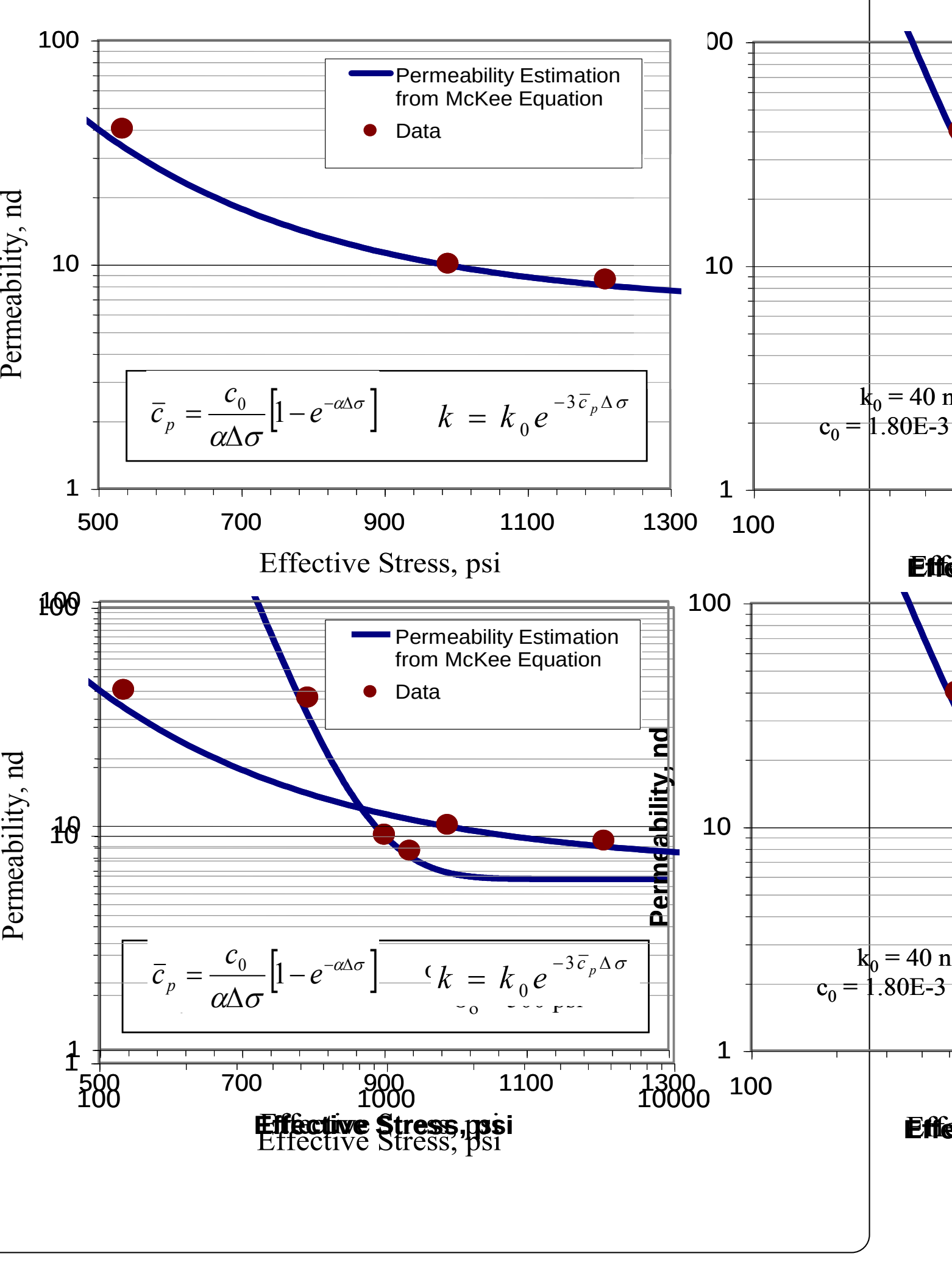
Reservoir characteristics after 25 years of simulated production	Average field pressure	Field gas rate	Field water rate	Field gas total	Field water total	Water in place	Remaining Gas in place	Number of wells
Input file	psia	mscf/day	stb/day	mmscf	mstb	mstb	bcf	
PB_BaseCase.dat	3014	2	1.5	25	16	231	11.0	1
PB_CB_CONS_7080.dat	3015	2	1.5	25	16	231	11.0	1
PB_CB_VAR_7080.dat	2931	8	2.1	83	23	224	10.9	1
PB_SD_CONS_7080.dat	2989	4	1.8	41	19	228	11.0	1
PB_SD_CONS_7080_16SPOT.dat	1984	99	3.5	1141	104	143	9.9	16
PB_SD_CONS_7080_8SPOT.dat	2470	54	3.3	535	76	171	10.5	8
PB_SD_CONS_7080_AC_16SPOT.dat	2984	4	1.8	42	19	228	11.0	1
PB_SD_CONS_7080_AC_8SPOT.dat	2475	54	3.3	529	76	171	10.5	8
PB_SD_CONS_7080_ZERO.dat	2162	70	0	1041	0	0	10.3	1
PB_SD_VAR_7080.dat	2917	9	2.1	93	23	223	10.9	1
PB_SD_VAR_7080_16SPOT.dat	1166	209	1.4	2770	78	168	8.2	16
PB_SD_VAR_7080_32SPOT.dat	893	225	1.2	3704	83	163	7.3	25
PB_SD_VAR_7080_4SPOT.dat	2382	79	2.0	597	53	193	10.4	4
PB_SD_VAR_7080_8SPOT.dat	1797	146	1.8	1392	66	181	9.6	8
PB_SD_VAR_7080_AC_16SPOT.dat	1174	208	1.4	2747	78	169	8.3	16
PB_SD_VAR_7080_AC_8SPOT.dat	1805	145	1.8	1379	66	181	9.6	8
PB_SD_VAR_7080_ZERO.dat	1675	117	0	1777	0	0	9.5	1
PB_SD_VAR_7080_ZERO_16SPOT.dat	420	181	0	6509	0	0	4.8	16
PB_SD_VAR_7080_ZERO_32SPOT.dat	330	171	0	7251	0	0	4.1	25
PB_SD_VAR_7080_ZERO_4SPOT.dat	908	170	0	3867	0	0	7.4	4
PB_SD_VAR_7080_ZERO_8SPOT.dat	639	182	0	5111	0	0	6.2	8
PB_CB_CONS_10000.dat	4268	1	1.8	18	20	228	11.7	1
PB_CB_VAR_10000.dat	4020	14	2.3	114	32	215	11.6	1
PB2_SD_CONS_10000.dat	4234	3	2.1	29	24	224	11.7	1
PB2_SD_VAR_10000.dat	3987	16	2.2	129	33	215	11.6	1
SJB_BaseCase.dat	3010	0	1.6	11	18	472	11.5	1
SJB_CB_CONS_7080.dat	3021	1	1.6	11	18	475	11.5	1
SJB_CB_VAR_7080.dat	2953	3	2.9	38	30	463	11.5	1
SJB_SD_CONS_7080.dat	2997	1	2.2	18	23	470	11.5	1
SJB_SD_CONS_7080_8SPOT.dat	2750	23	7.3	217	130	363	11.3	8
SJB_SD_CONS_7080_RPGB.dat	3039	0	0.6	2	8	486	11.5	1
SJB_SD_CONS_7080_RPWG.dat	2962	3	4.3	37	46	448	11.5	1
SJB_SD_VAR_7080.dat	2934	4	3.1	48	32	461	11.5	1
SJB_SD_VAR_7080_16SPOT_IRR2.dat	455	203	0	6210	0	0	5.9	16
SJB_SD_VAR_7080_8SPOT.dat	2209	79	5.0	681	127	366	10.8	8
SJB_SD_VAR_7080_8SPOT_IRR.dat	1438	115	0.4	2060	5	291	9.7	8
SJB_SD_VAR_7080_8SPOT_IRR2.dat	702	189	0	4691	0	0	7.4	8
SJB_SD_VAR_7080_AC.dat	2929	4	3.1	49	32	461	11.5	1
SJB_SD_VAR_7080_AC_16SPOT.dat	1588	152	4.2	1545	163	330	10.0	16
SJB_SD_VAR_7080_AC_16SPOT_2.dat	1583	153	4.2	1555	164	330	9.9	16
SJB_SD_VAR_7080_AC_16SPOT_2_ZERO.dat	456	203	0	6209	0	0	5.9	16
SJB_SD_VAR_7080_AC_8SPOT.dat	2215	78	5.0	674	126	367	10.8	8
SJB_SD_VAR_7080_COMPLOW.dat	2934	4	3.1	48	32	461	11.5	1
SJB_SD_VAR_7080_PMINLOW.dat	2933	4	3.1	49	33	461	11.5	1
SJB_SD_VAR_7080_RPGB.dat	3031	0	0.7	2	8	485	11.5	1
SJB_SD_VAR_7080_RPWG.dat	2820	11	7.4	114	76	417	11.4	1
SJB_SD_VAR_7080_USAT.dat	2282	3	3.1	18	48	445	11.0	1
SJB_SD_VAR_7080_ZERO.dat	1831	101	0	1498	0	0	10.6	1

Permeability Data and Compressibility Matching

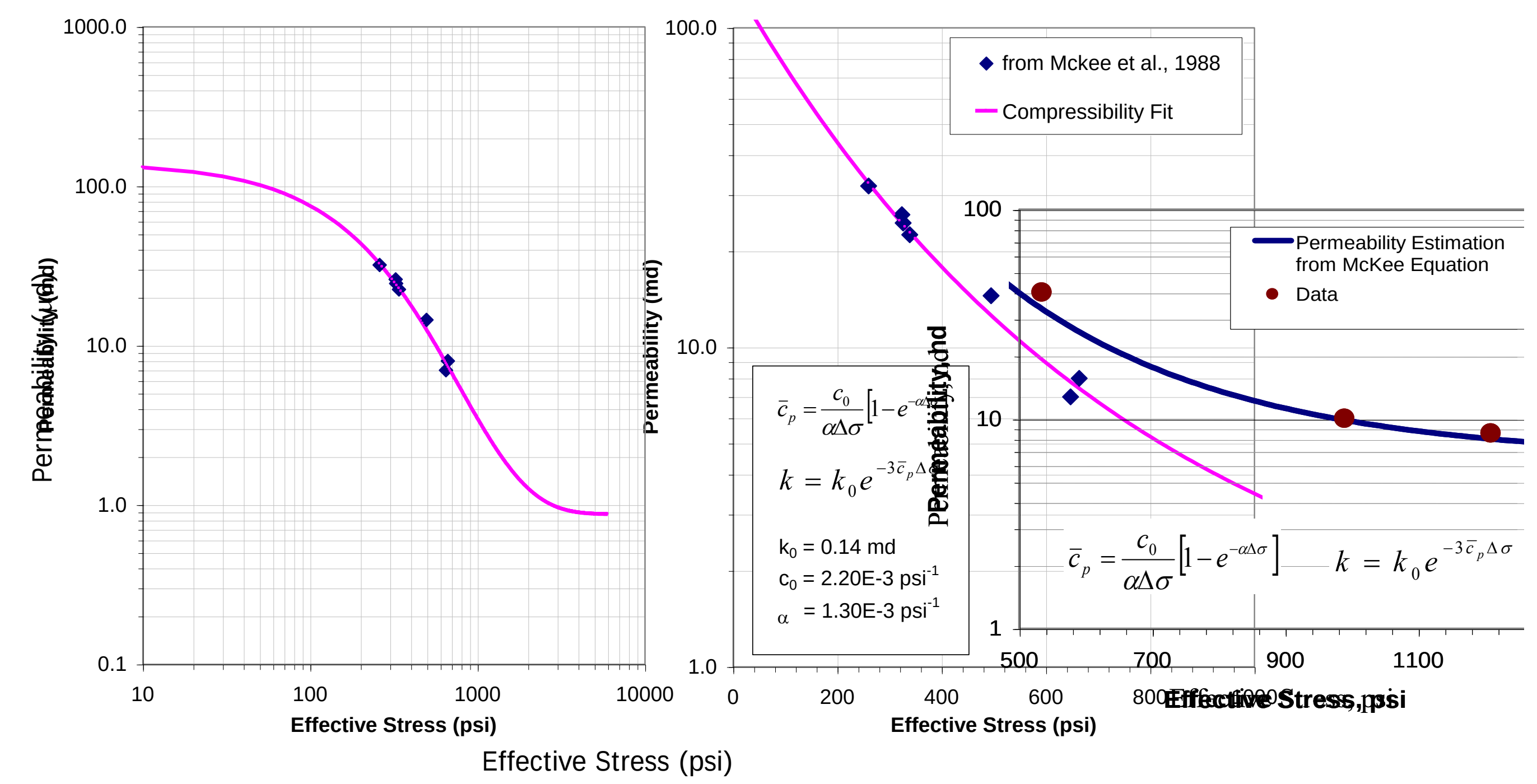


Example displaying the difference between permeability estimation assuming variable or constant pore volume compressibility. When variable compressibility is assumed, the permeability levels off to approximately 0.03 md beyond an effective stress of 3,000 psi, or beyond approximately 6,900 ft. Data from Rose and Fob.[11]

Matrix permeability estimation using the McKee equation. When using the assumption of exponentially declining pore volume compressibility, as the effective stress increases the permeability levels off to relatively constant values at approximately 2,000 psi, or approximately 4,600 ft. Data from McKee et al.[13]



Variable pore volume compressibility constants derived from best-fit of permeability data for Case #1. The solution determined from the data is non-unique. Data from McKee et al.[13]

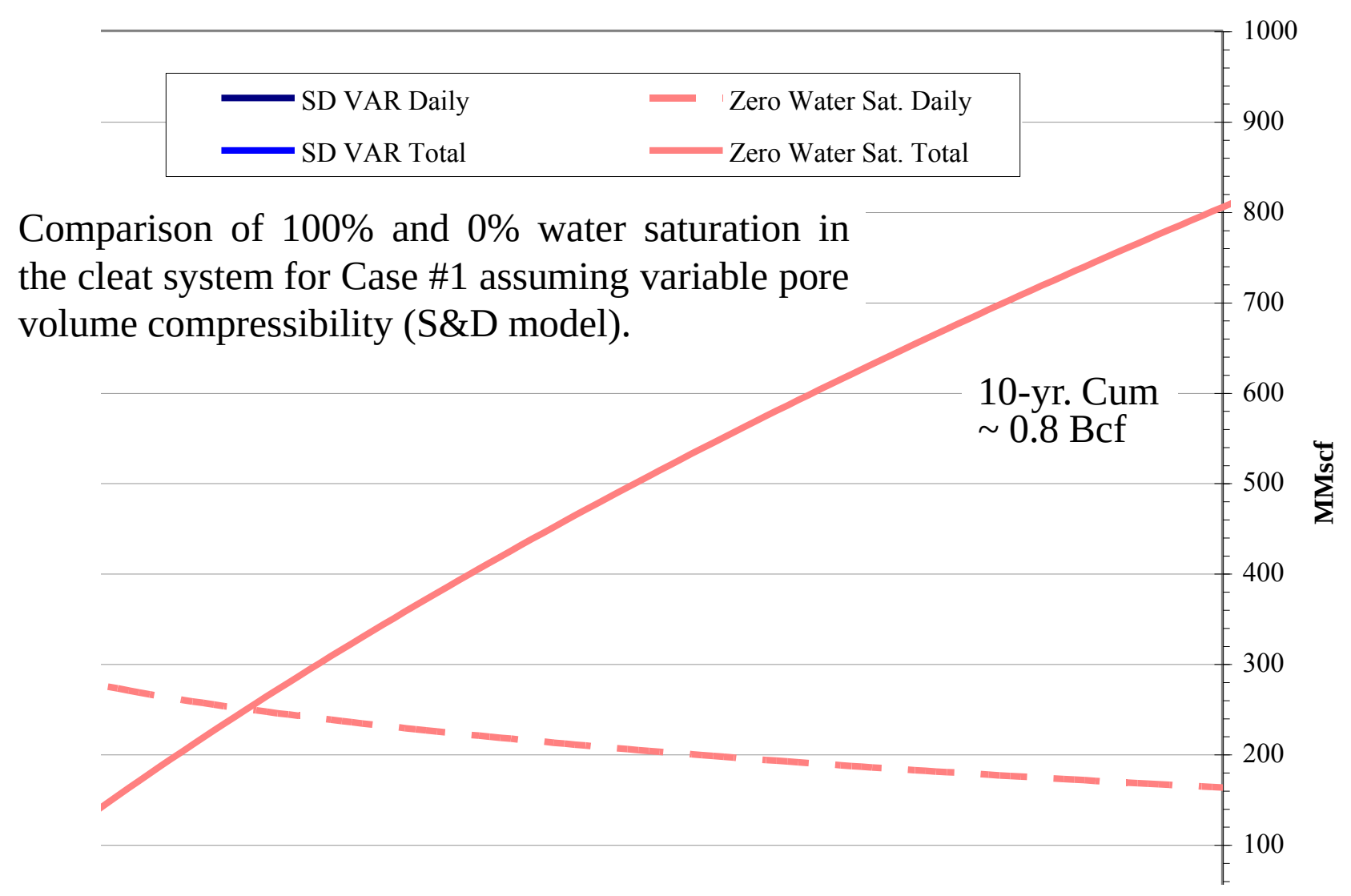


A Conventional Look at an Unconventional Reservoir: Coalbed Methane Production Potential in Deep Environments

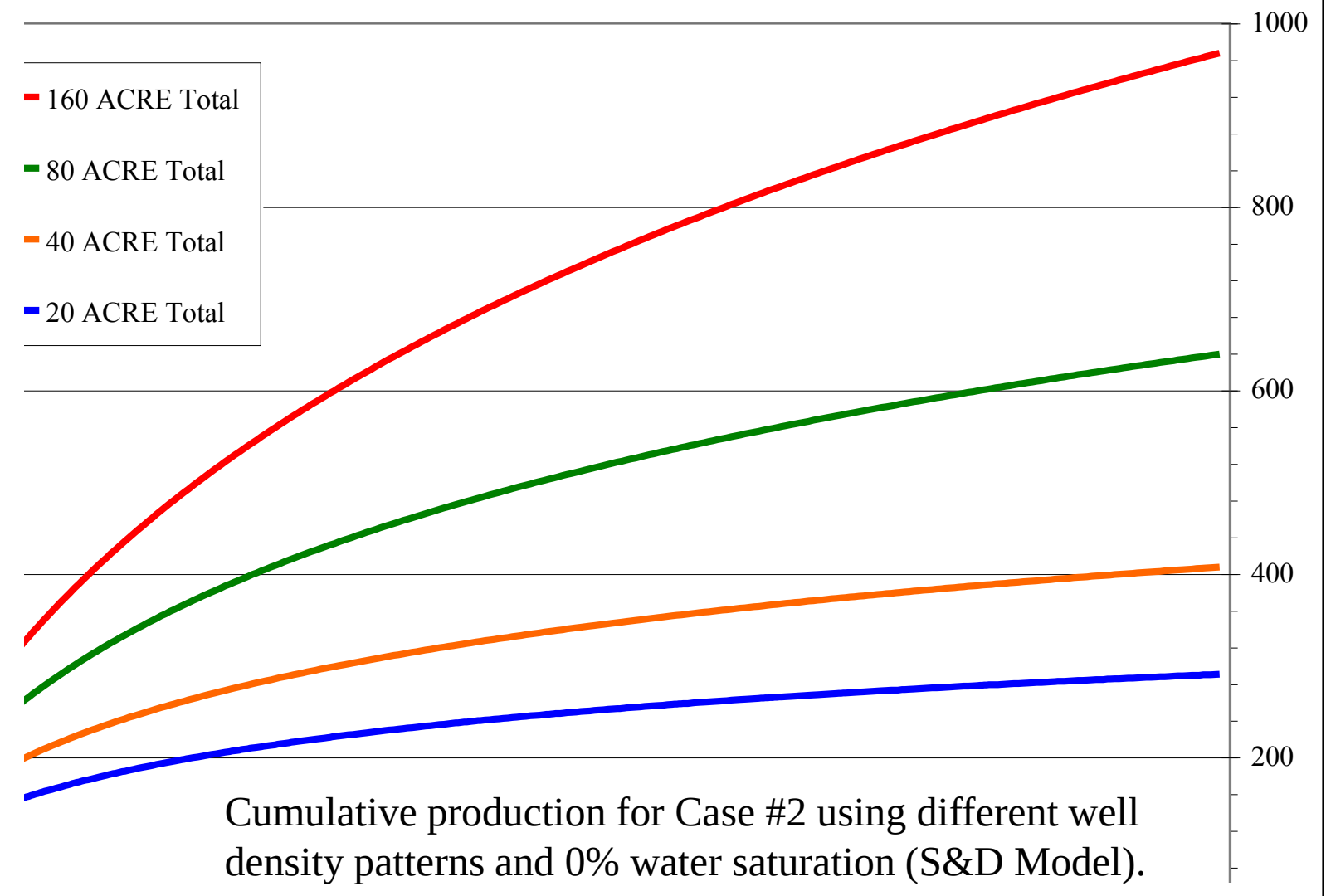
Robert R. Tonnsen, Petroleum Engineer, Golden, CO; Jennifer L. Miskimins, Colorado School of Mines, Golden, CO

FAST
Fracturing, Acidizing, & Stimulation Technology Consortium

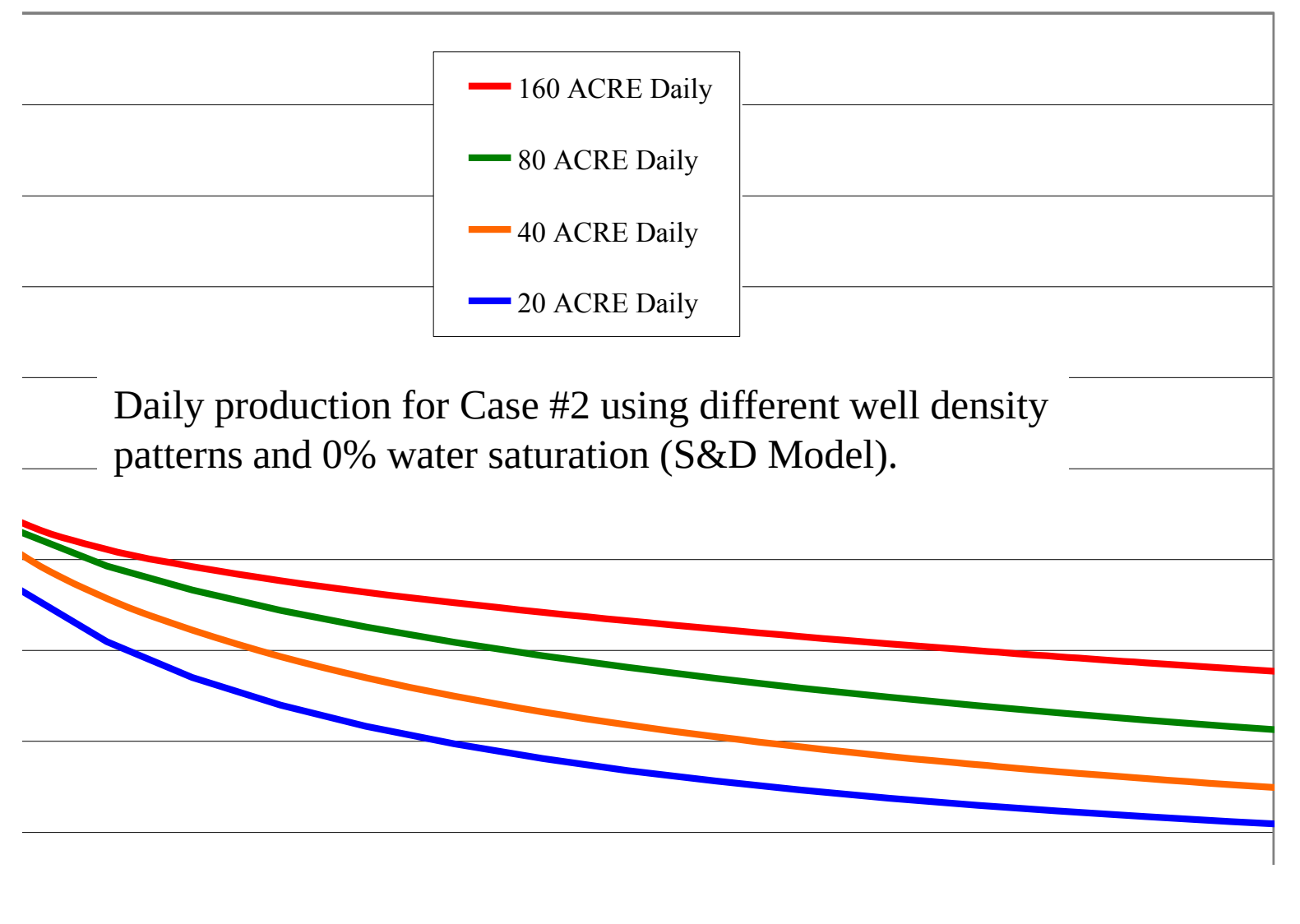
Zero Water Saturation in Cleats



Comparison of 100% and 0% water saturation in the cleat system for Case #1 assuming variable pore volume compressibility (S&D model).



Cumulative production for Case #2 using different well density patterns and 0% water saturation (S&D Model).



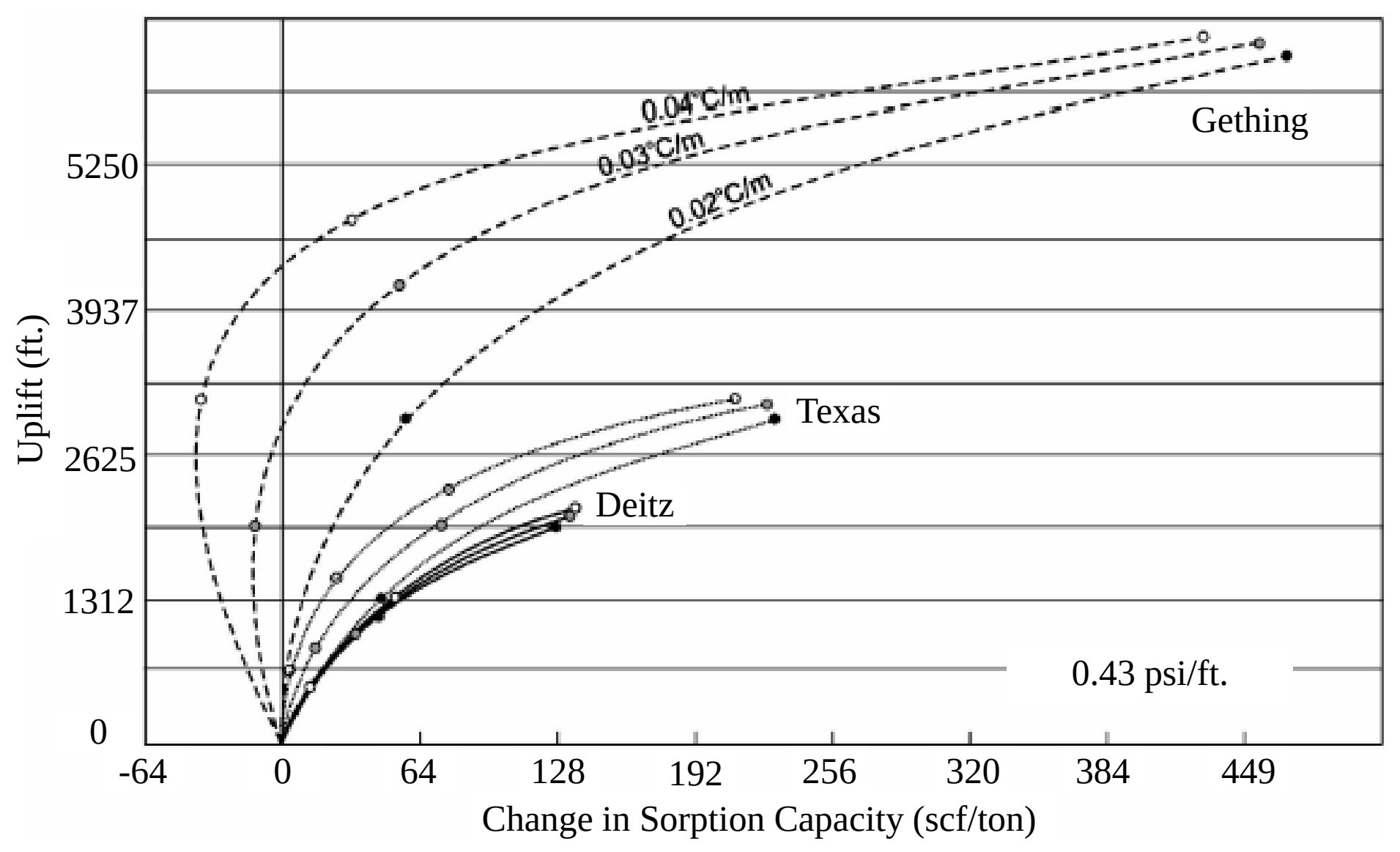
Daily production for Case #2 using different well density patterns and 0% water saturation (S&D Model).

Terms

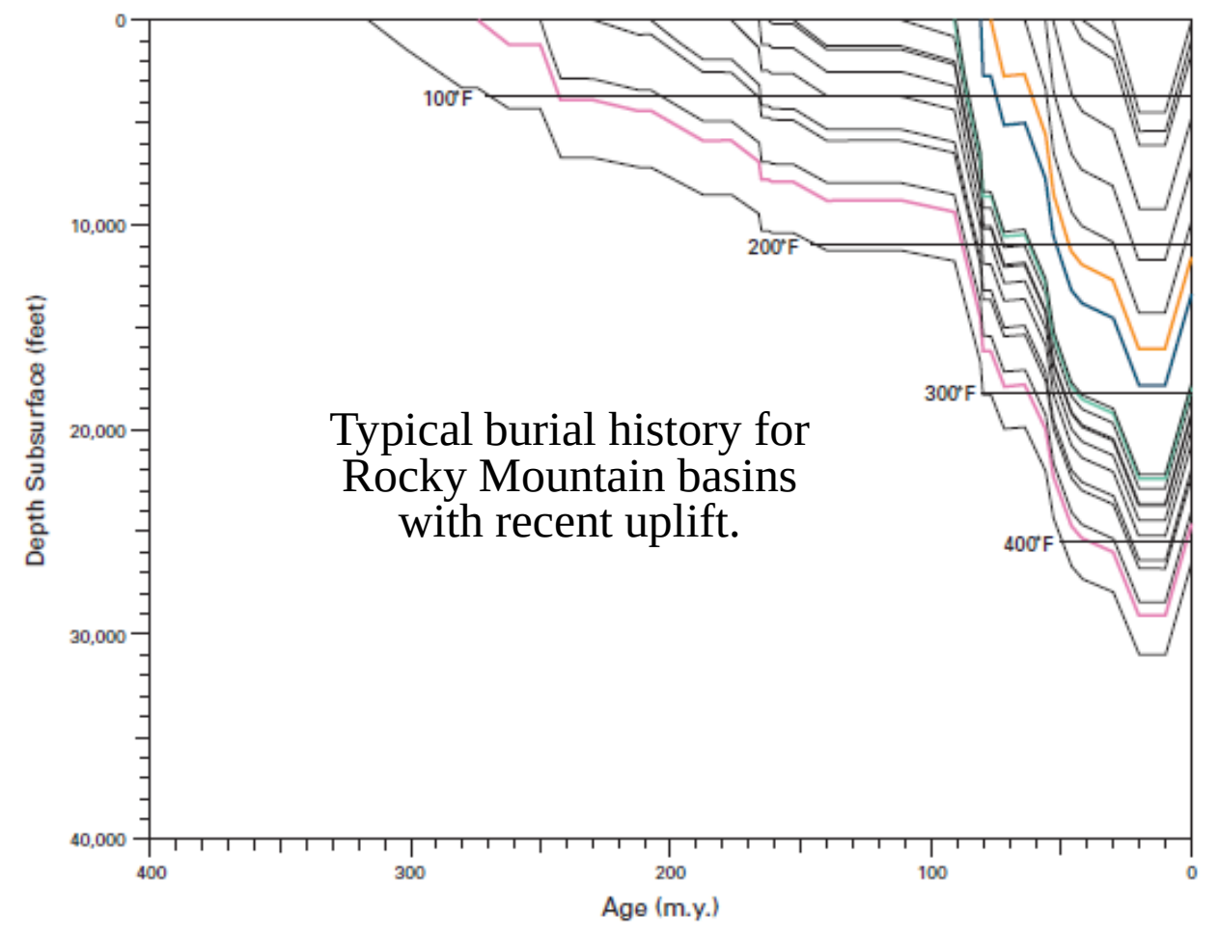
α = rate of decline of pore volume compressibility, psi-1
α_s = matrix shrinkage/swelling coefficient, ft3/scf
b, β, $1/P_L$ = Langmuir pressure constant, psi^{-1}
bcf = billion cubic feet
cm = centimeter
c_m = matrix compressibility, psi-1
c_p = pore volume compressibility, psi-1
c_0 = initial pore volume compressibility, psi-1
D = equivalent lithostatic depth
E = Young's Modulus, psi
ε_g = coefficient of sorption-induced volumetric strain, ton/scf
ε_l = maximum shrinkage strain at $V = V_L$
ε_V = sorption-induced volumetric strain
ε_{V0} = initial sorption-induced volumetric strain
ft. = feet
g = grams
ϕ = porosity
ϕ_0 = initial porosity
γ = grain compressiblity, psi-1
K = bulk modulus, psi
k = permeability, md, μd, nd
k_0 = initial permeability,md, μd, nd
M = constrained axial modulus
mi. = miles
mmscf = million cubic feet
mscf = thousand cubic feet
mstb = thousand standard barrels
p = reservoir pressure, psi
p_0 = initial reservoir pressure, psi
p_{ov} = confining (overburden) pressure, psi
p_p = pore pressure, psi
P_L = Langmuir pressure, psi
$\blacktriangledown p_p$ = pore pressure gradient, psi/ft
psi = pounds per square inch
psia = absolute pounds per square inch
R_o% = vitrinite reflectance
σ, σ_e = effective stress, psi

σ_0 = initial effective stress, psi
$\Delta\sigma$, $(\sigma - \sigma_0)$ = change in effective stress, psi
$\blacktriangledown\sigma_{ov}$ = overburden stress gradient, psi/ft
stb = standard barrels
Tcf = trillion cubic feet
υ = Poison's Ratio
V = volume
ΔV = change in volume
V_L = Langmuir volume, scf/ton or scf/ft^3
V_p = pore volume
7080 = Example depth of 7,080 ft.
10000 = Example depth of 10,000 ft.
1(sp) = 1 well per 640 acres
16(sp) = 16 wells per 640 acres
32(sp) = 32 wells per 640 acres
4(sp) = 4 wells per 640 acres
8(sp) = 8 wells per 640 acres
AC = Anticline structure
ACS = Subtle anticline structure
BaseCase = Original model for PB or SJB
CB = Cui and Bustin model
COMPLOW = Lower rock compressibility
CONS, C = Constant pore volume compressiblity
GWATRP = Enhanced water relative permeability
IRR = Irriducible water saturation
LC = Lower rock compressibility
LPMIN = Well head pressure of 15 psi
P = Production graph
PB = Case #2 (Piceance Basin #1)
PB2 = Case #3 (Piceance Basin #2)
PGASRP = Poor gas relative permeability
PMINLOW = Well head pressure of 15 psi
RPGB = Poor gas relative permeability
RPWG = Enhanced water relative permeability
SD = Shi and Durucan model
SJB = Case #1 (San Juan Basin)
USAT = Undersaturated coal
VAR, V = Variable pore volume compressiblity
ZERO, 0 = Zero water saturation in the cleat volume

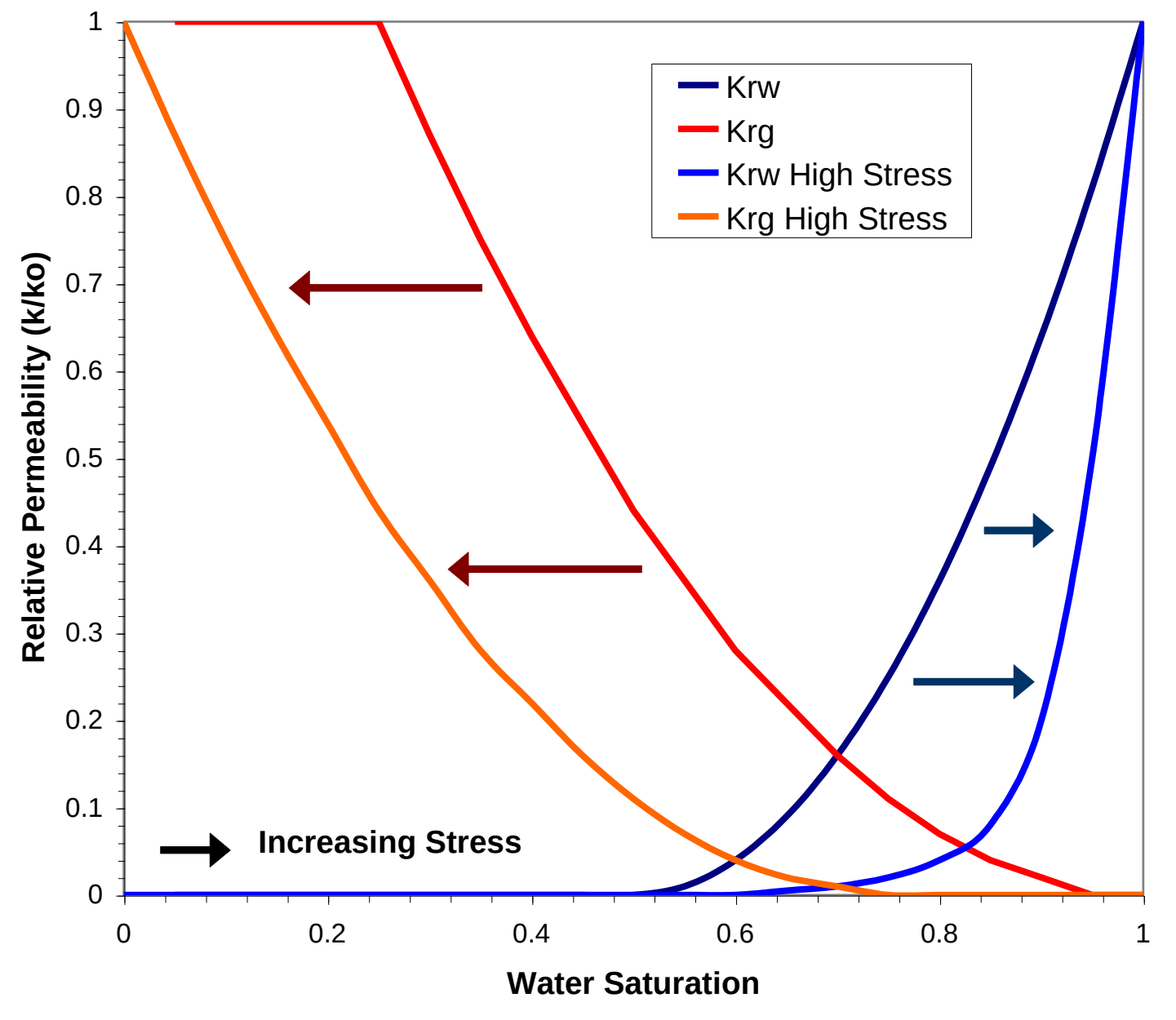
Deep CBM Exploration



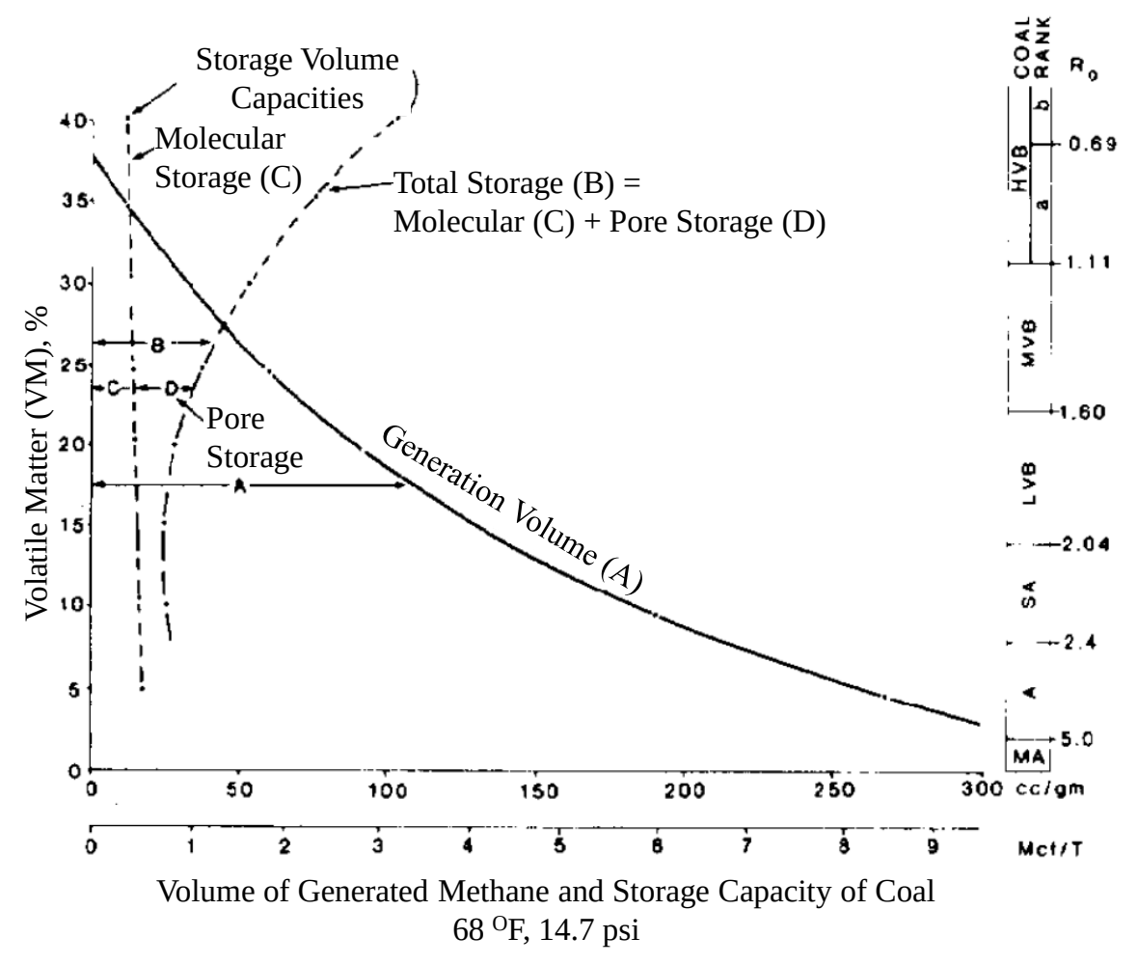
The change in sorption capacity of coals as they are uplifted from initial burial depths assuming geothermal gradients of 1.0, 1.6, and 2.2 °F/100 ft. (black, gray, and white dots, respectively).



Typical burial history for Rocky Mountain basins with recent uplift.



Relative permeability in coal. Deeper coals may contain relative permeability that causes a “permeability block” to occur where neither phase is mobile. In this example, this would occur with approximately 70% water saturation for the high stress curves. Data from (16).



Volume of Generated Methane and Storage Capacity of Coal 68 °F, 14.7 psi

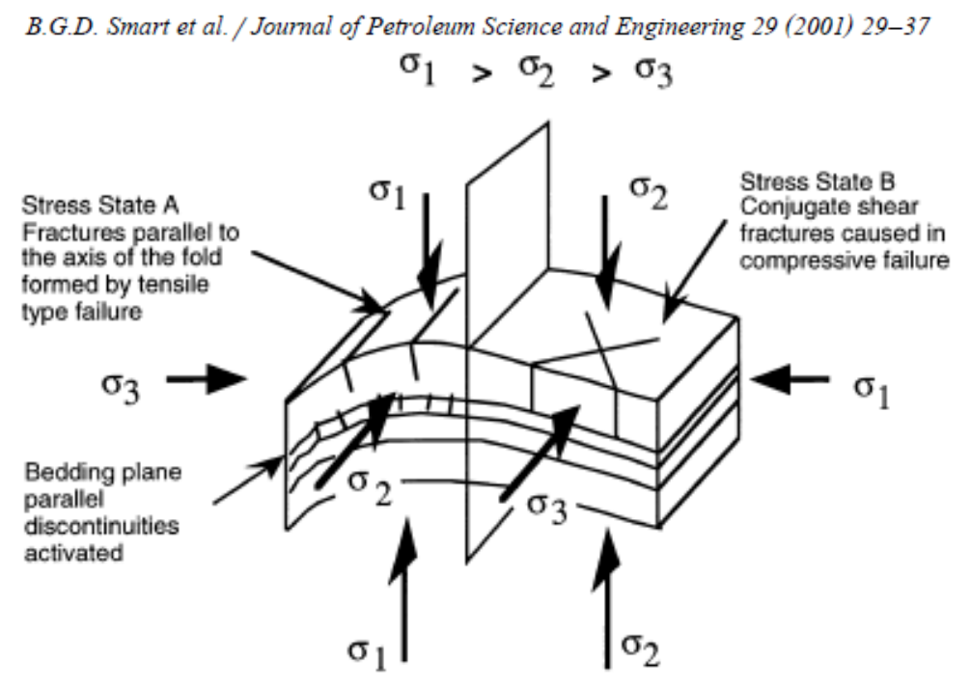
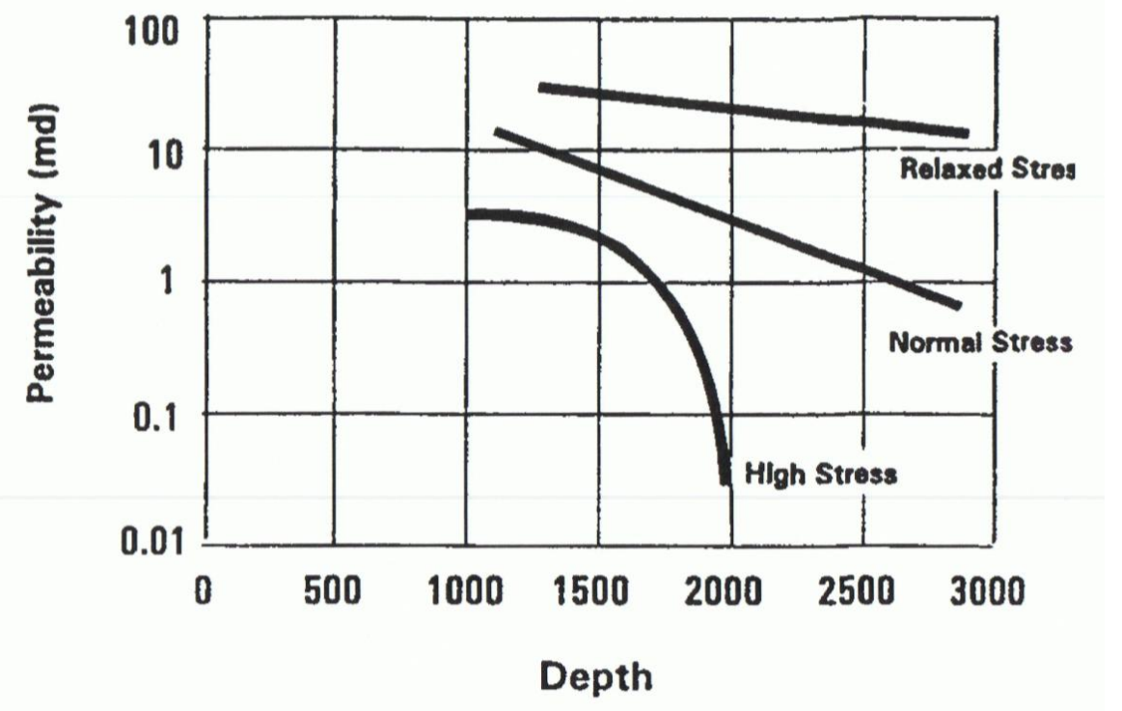
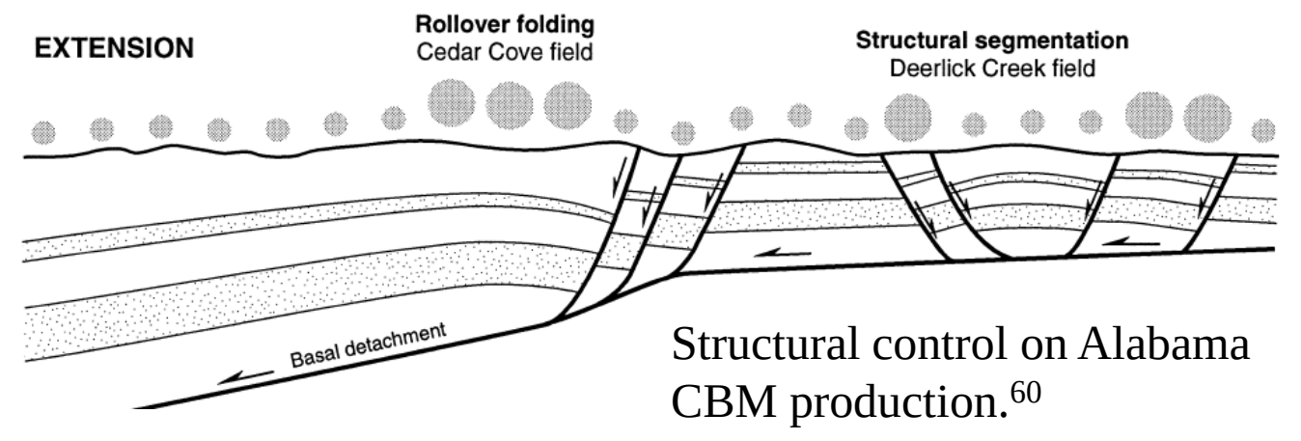


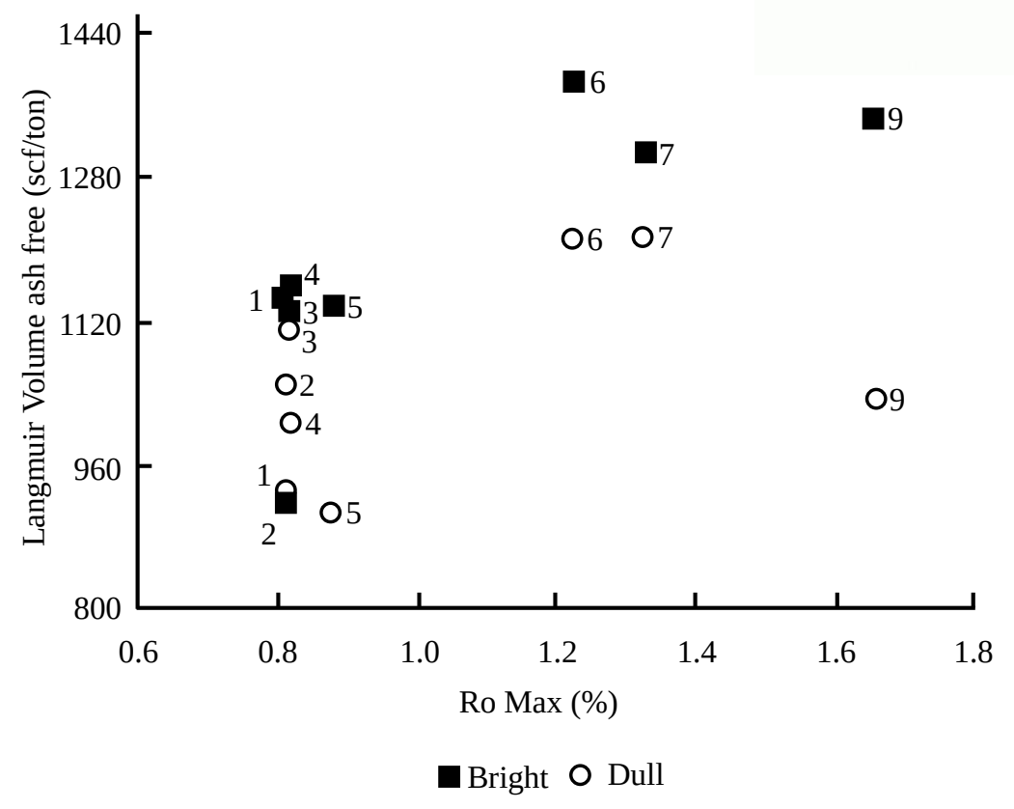
Fig. 1. In situ stress/strain state controls on fracture formation.

Relationship of Coal Permeability vs. Depth, Bowen Basin.[6]





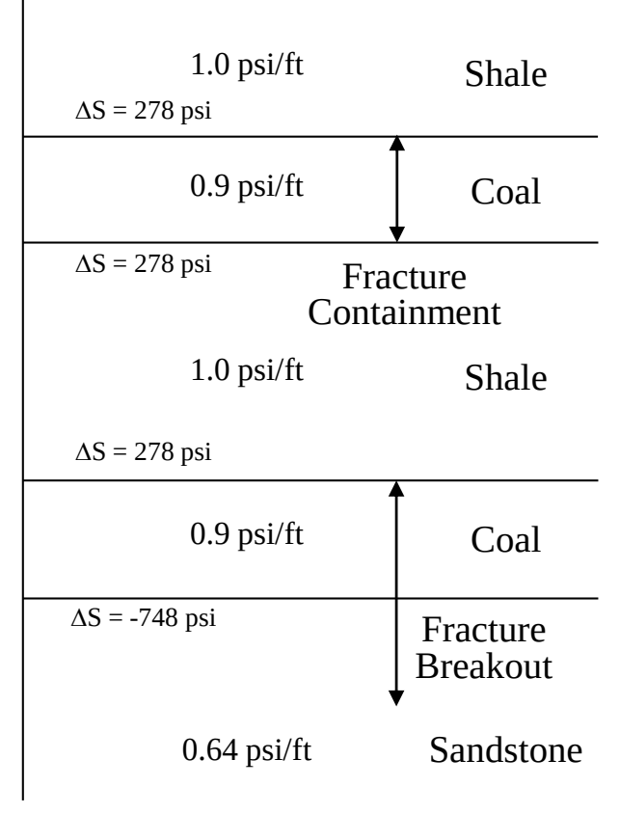
Structural control on Alabama CBM production.[60]

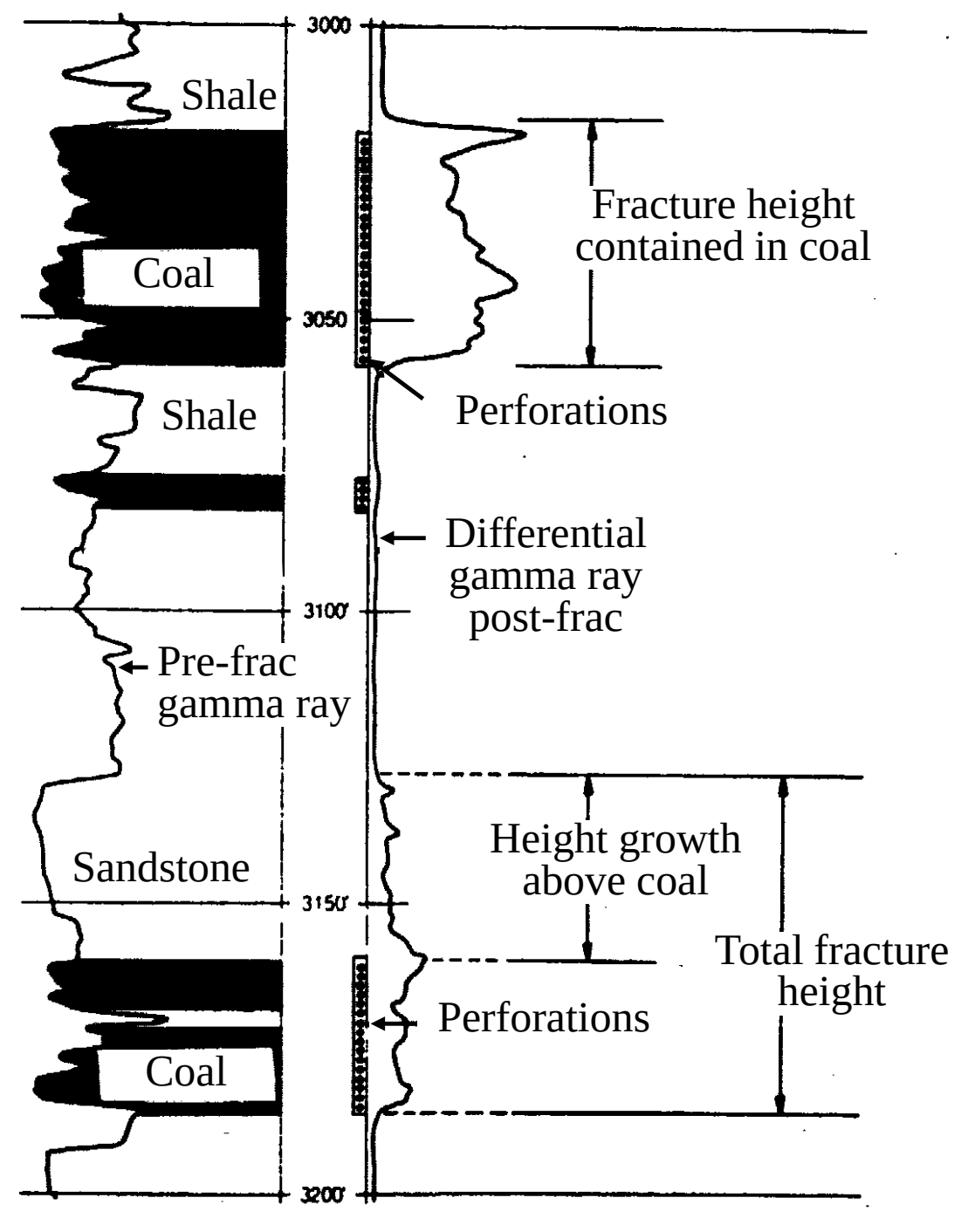


Relationship between Langmuir volume and rank for Bowen basin coals showing that vitrinite-rich bright coals have greater capacities to adsorb methane.

> “Coal is a soft rock with a low elasticity Modulus. This property facilitates the creation of relatively wide hydraulic fractures and the containment of fractures in the coal interval when the interfacial shear strength across the coal/bounding-rock interface is low.”
>
> - Dave Cramer

In situ stress profile in San Juan Basin (after Palmer et al., 1989)



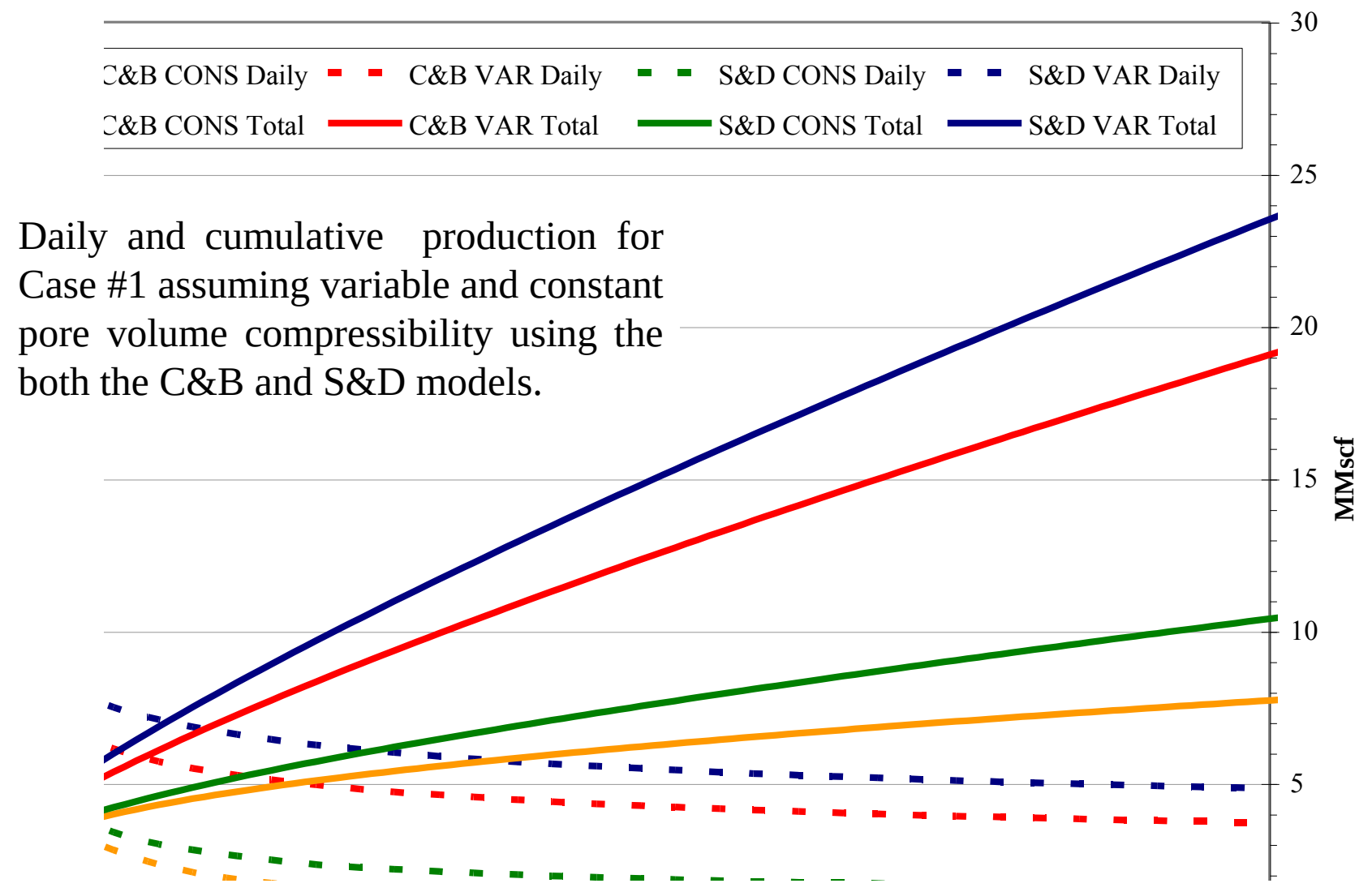


Post-Frac Gamma Ray Log (Logan et al., 1989)

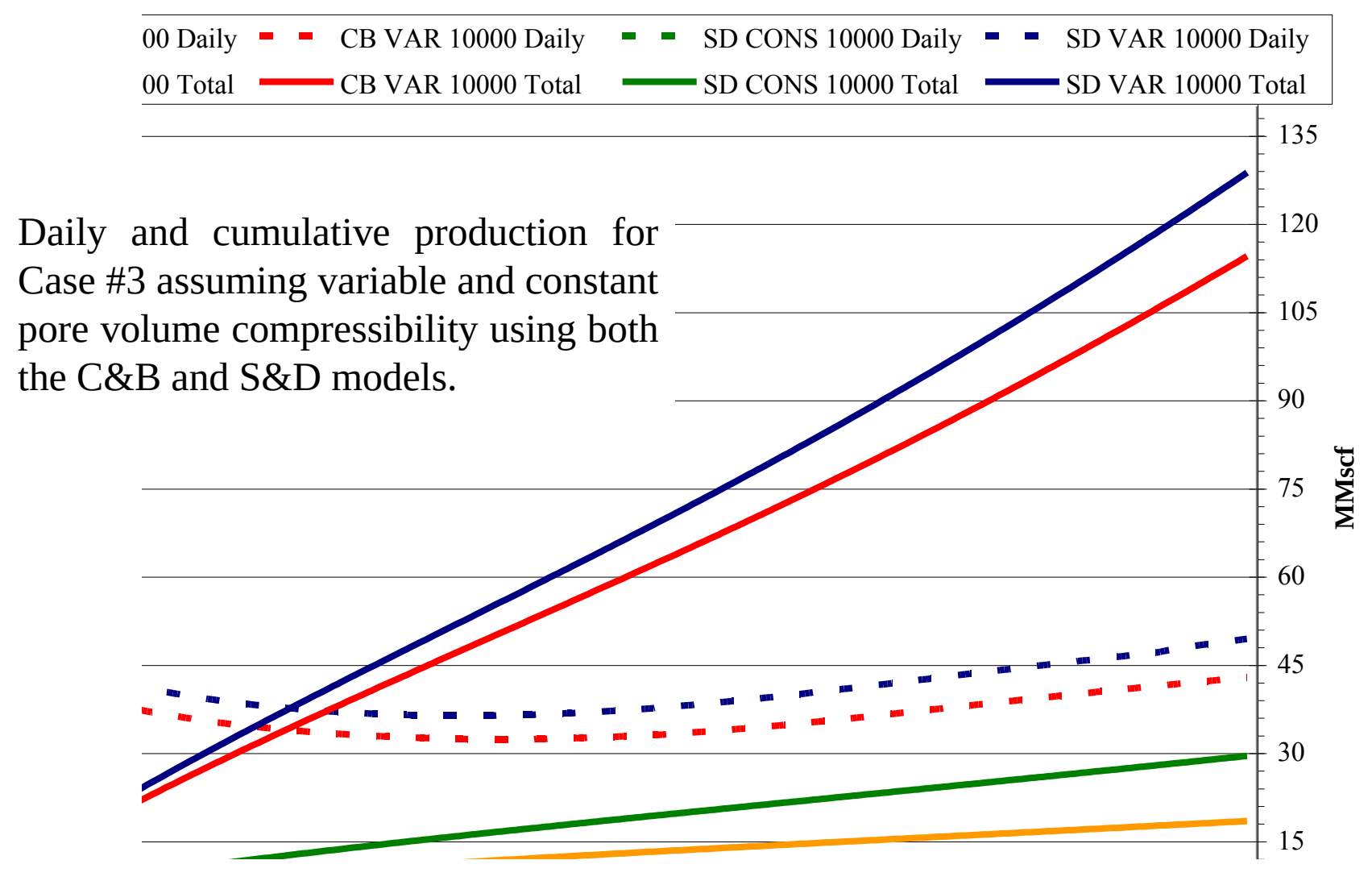
Conclusions

- Ideal reservoir characteristics for deep CBM exploration
  - Structural or stratigraphic closure
  - Bounded by shales
    - Fracture height containment, hydrocarbon seals
  - Rank of high-volatile A or higher (>R_m 0.8%)
    - Generation of hydrocarbons could drive water to irreducible levels and create overpressure
    - Maximum cleat frequency at ~1.35% vitrinite reflectance
  - Bright, Vitrinite-rich coals
    - Greater surface area in smaller pore system
    - Better development of fracture system
  - High Young‘s Modulus and Poison‘s ratio
    - Lower elasticity, more brittle
  - Moderate to Low stress conditions
  - Large Langmuir Pressure
    - Higher gas content
  - High in-situ porosity/permeability
  - Low ash content
- Summary
  - Permeability may exist at depth in coalbed reservoirs
  - Evidence supports using a declining pore volume compressibility for coals
  - Simulated permeability rebound and production are significantly affected by the PV compressibility assumption
  - A deep, unsaturated coal will not likely produce at economic rates
  - The S&D model is the most optimistic
- Future Work
  - Exploration into how dry coals could be created and where they may exist
  - Field testing of coal permeability in high stress environments
    - High-stress laboratory testing could provide insight into compressibility and permeability evolution, but it would not represent the in-situ fracture and cleat system
  - Due to its impact on production, insight into relative permeability and how it could change with production is needed

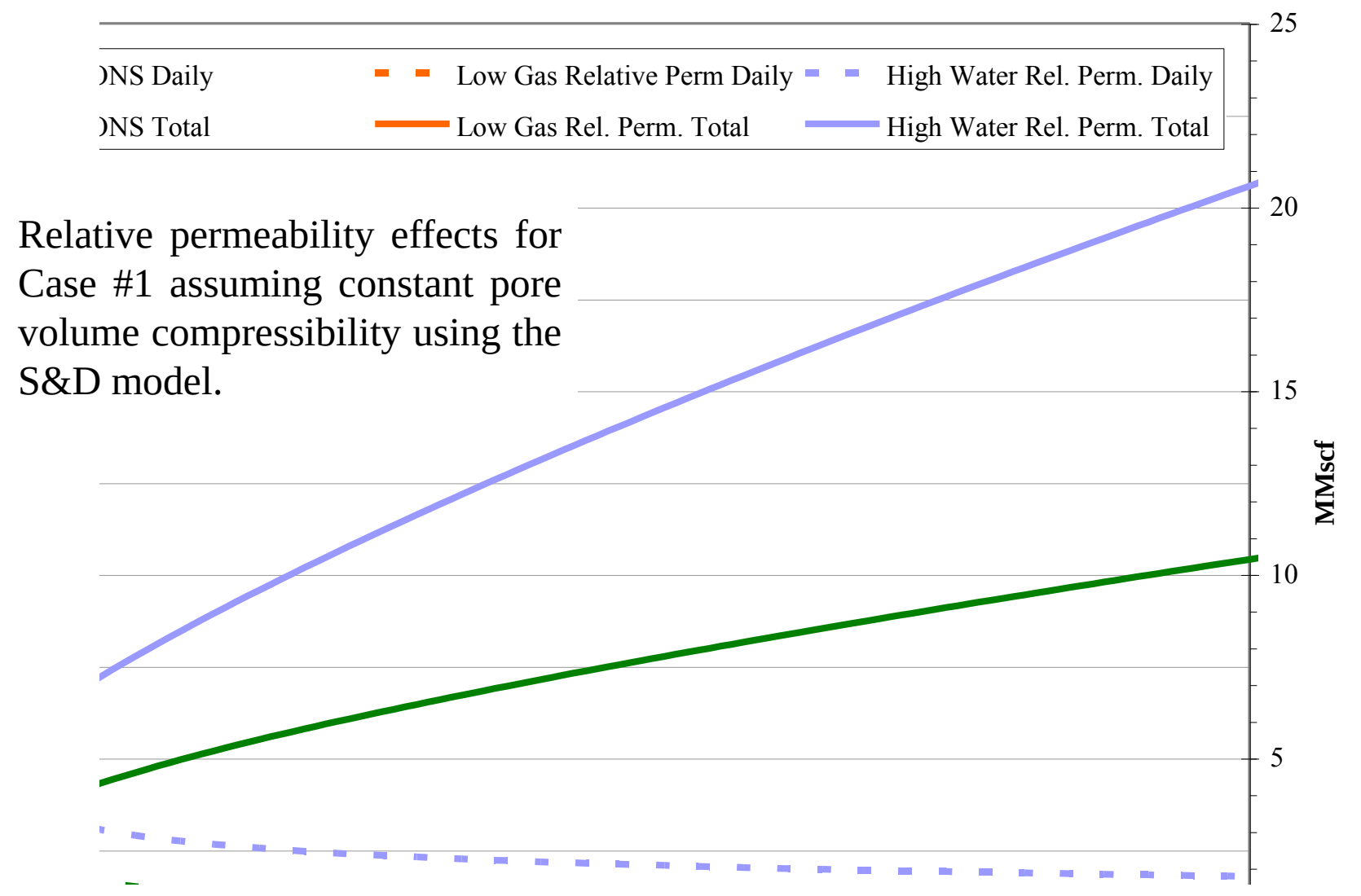
Variable and Constant PV Compressibility & Relative Permeability Results



Daily and cumulative production for Case #1 assuming variable and constant pore volume compressibility using the both the C&B and S&D models.

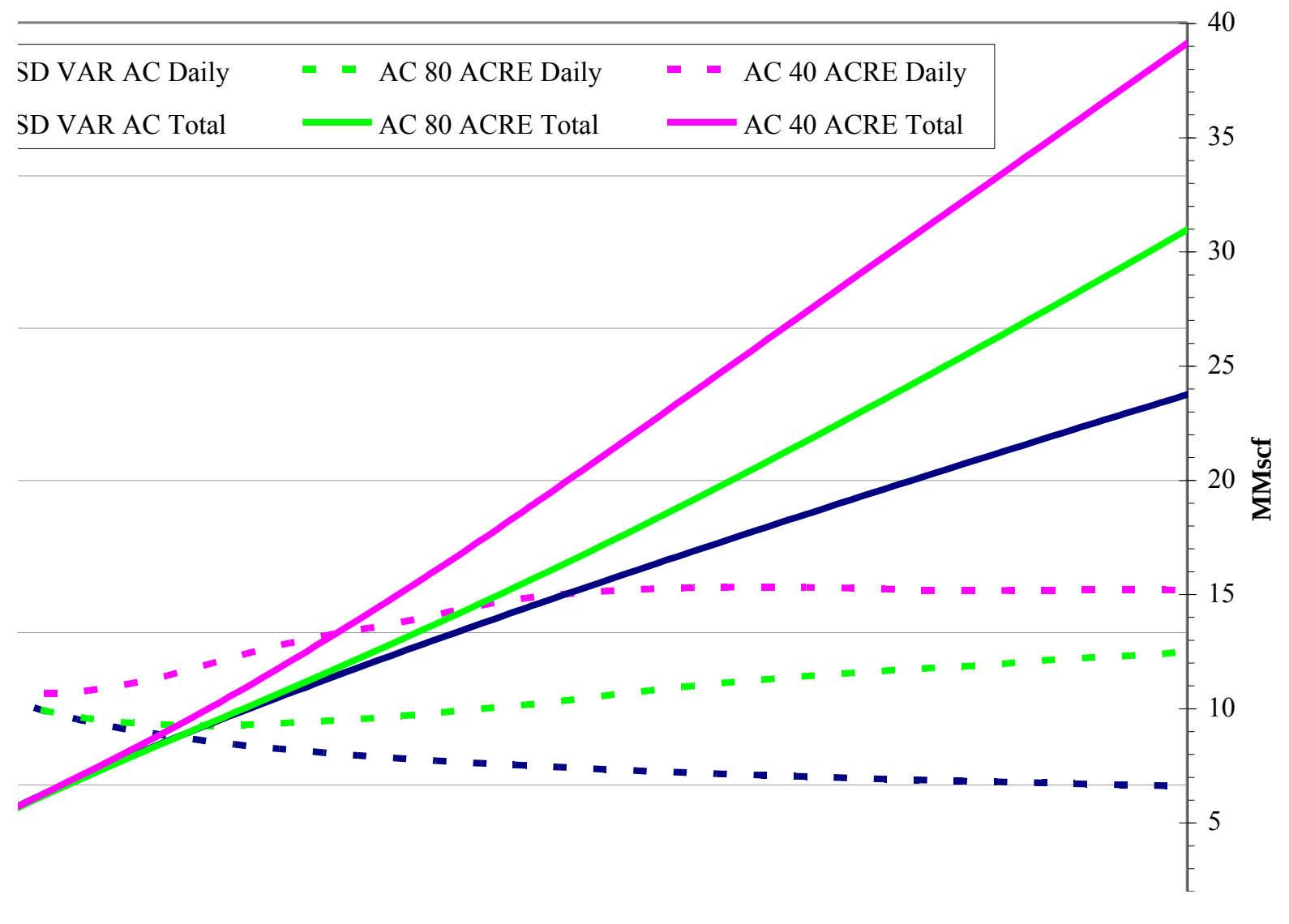


Daily and cumulative production for Case #3 assuming variable and constant pore volume compressibility using both the C&B and S&D models.

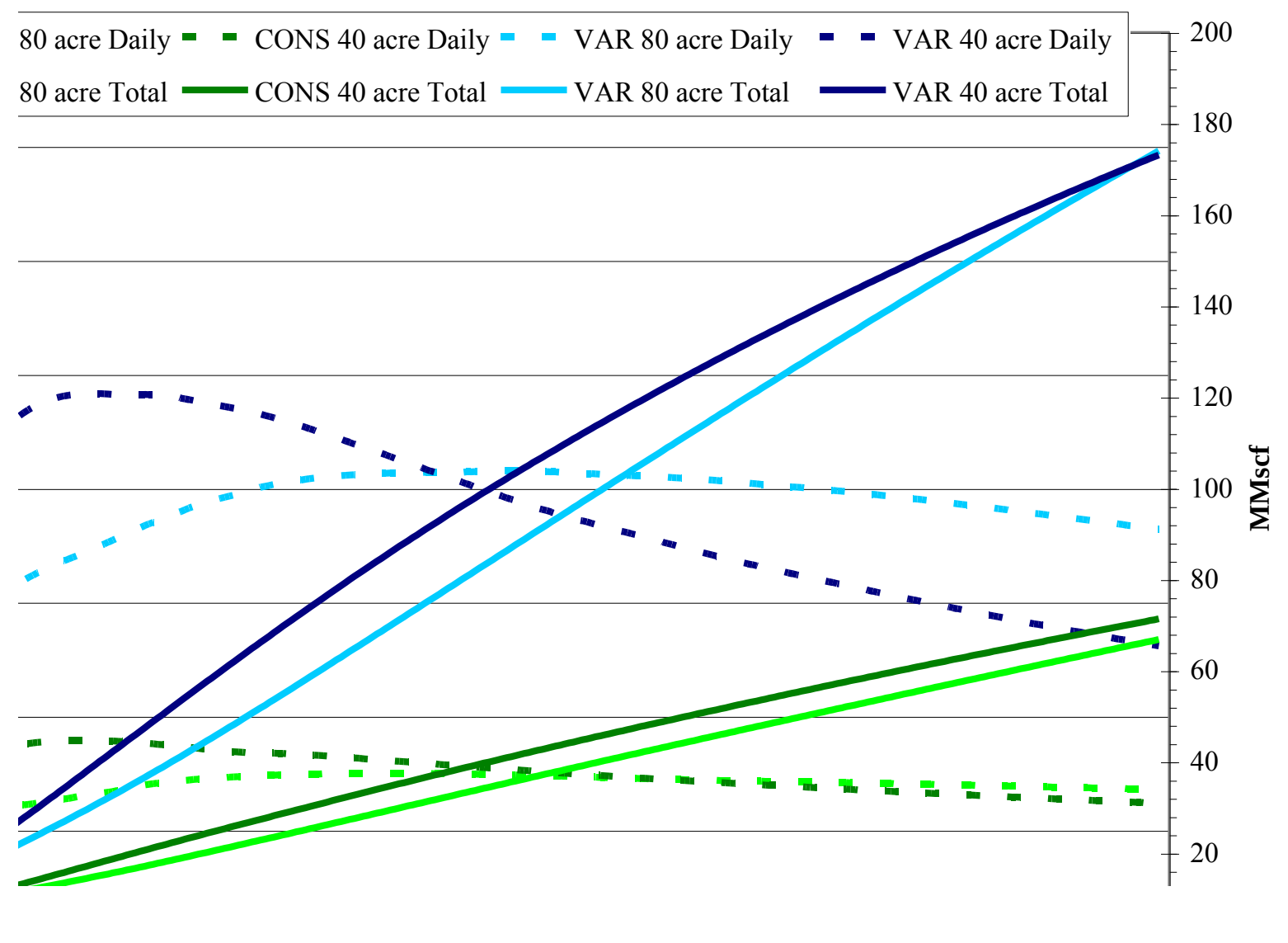


Relative permeability effects for Case #1 assuming constant pore volume compressibility using the S&D model.

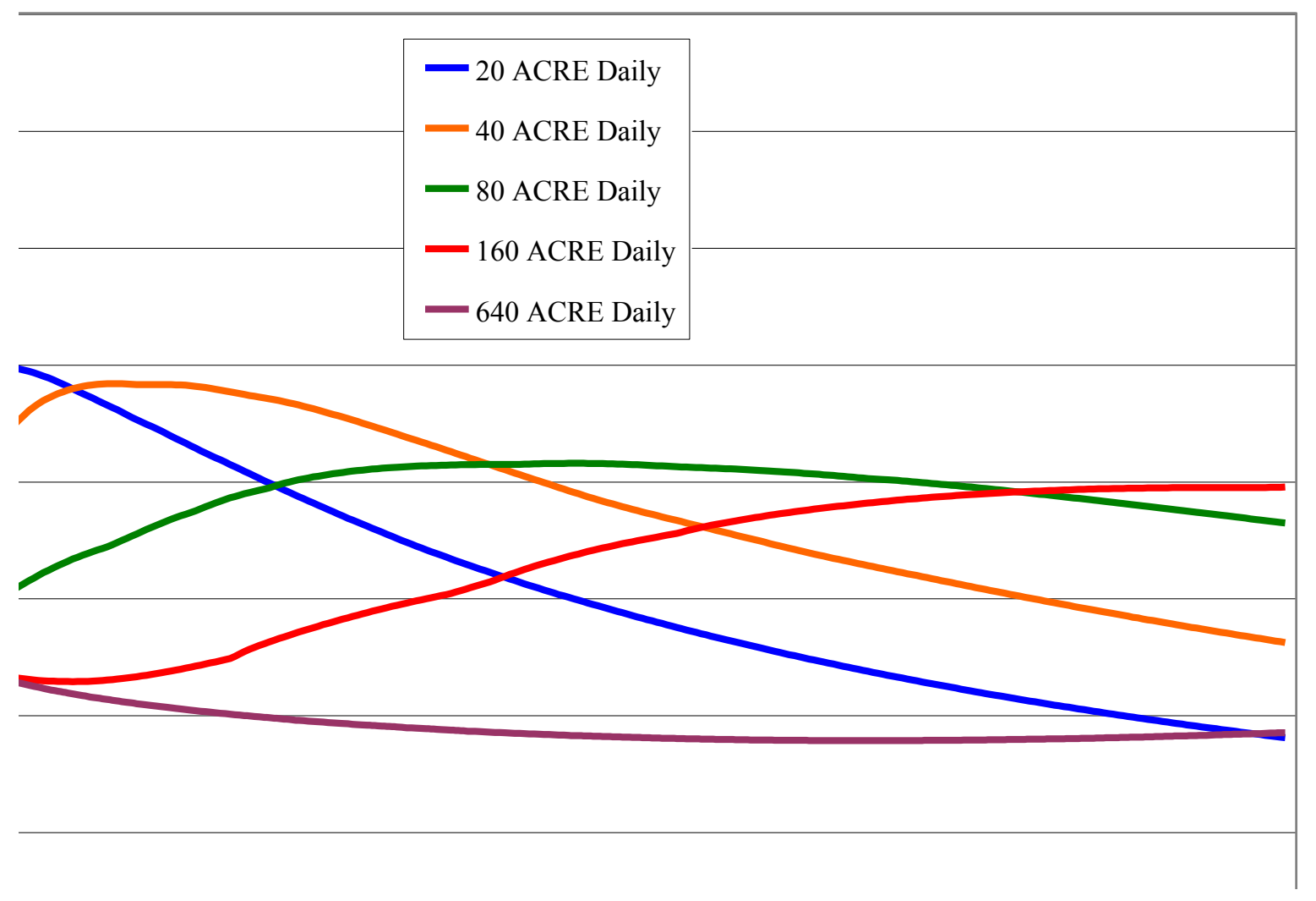
CBM Spacing Simulation Results



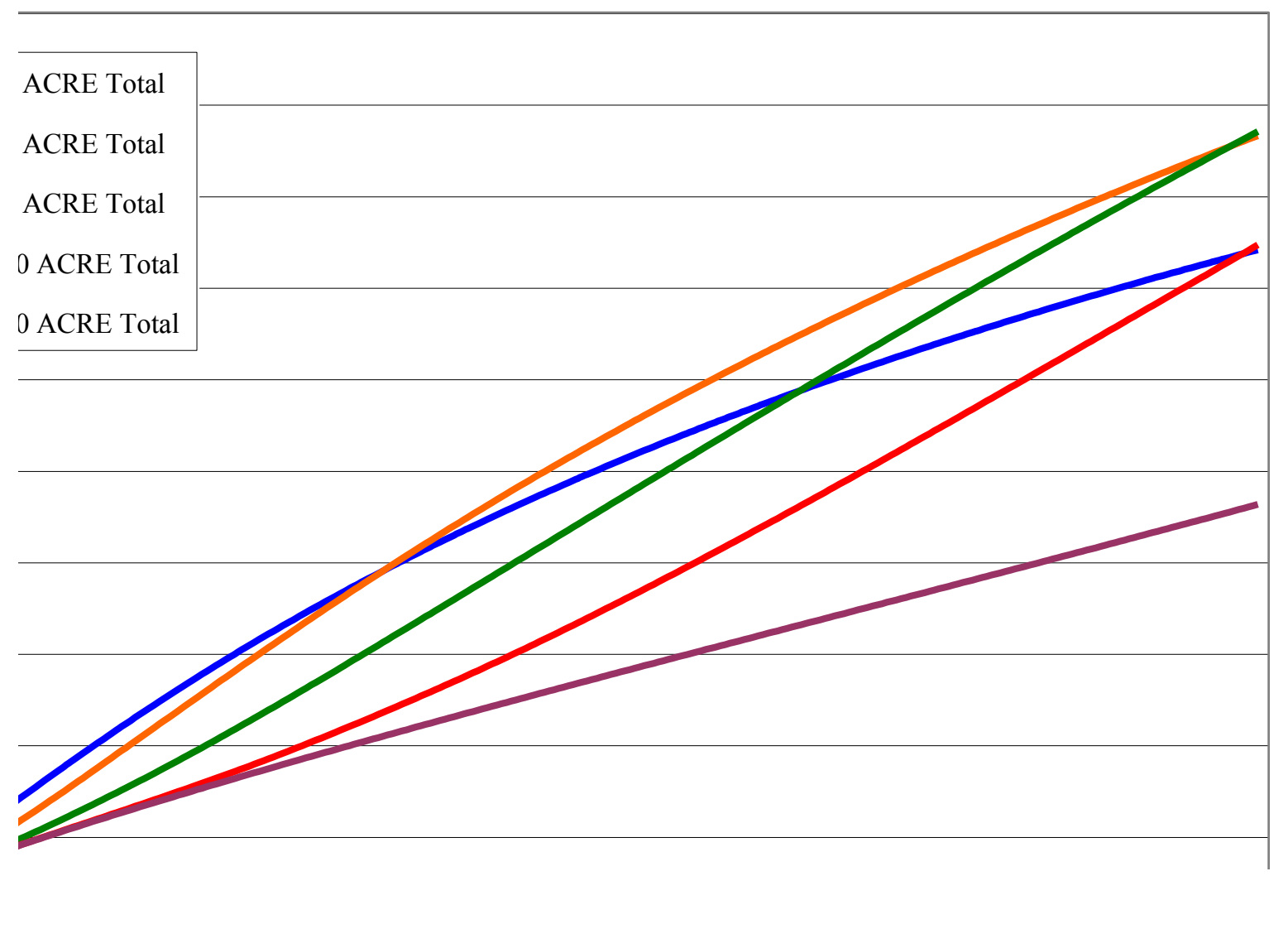
Daily and cumulative production for Case #1 assuming variable pore volume compressibility on 40 and 80 acre spacing using the S&D model.



Daily and cumulative production for Case #2 assuming variable and constant pore volume compressibility on 40 and 80 acre spacing using the S&D model.



Daily production for Case #2 assuming variable pore volume compressibility using the S&D model for varying well density patterns.



Cumulative production for Case #2 assuming variable pore volume compressibility using the S&D model for varying well density patterns.

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