INVESTIGATION of INTEGRATED SUBSURFACE PROCESSING of LANDFILL GAS and CARBON SEQUESTRATION, JOHNSON COUNTY, KANSAS

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ABSTRACT

The Johnson County Landfill in Shawnee, KS is operated by Deffenbaugh Industries and serves much of metropolitan Kansas City. Refuse, which is dumped in large plastic-underlined trash cells covering several acres, is covered over with shale shortly after burial. The landfill waste, once it fills the cell, is then drilled by Kansas City LFG, so that the gas generated by anaerobic decomposition of the refuse can be harvested.

Production of raw landfill gas from the Johnson County landfill comes from 150 wells. Daily production is approximately 2.2 to 2.5 mmcf, of which approximately 50% is methane and 50% is carbon dioxide and NMVOCs (non-methane volatile organic compounds). Heating value is approximately 550 BTU/scf. A upgrading plant, utilizing an amine process, rejects the carbon dioxide and NMVOCs, and upgrades the gas to pipeline quality (i.e., nominally a heating value >950 BTU/scf). The gas is sold to a pipeline adjacent to the landfill.

With coal-bearing strata underlying the landfill, and carbon dioxide a major effluent gas derived from the upgrading process, the Johnson County Landfill is potentially an ideal setting to study the feasibility of injecting the effluent gas in the coals for both enhanced coalbed methane recovery and carbon sequestration. To these ends, coals below the landfill were cored and then were analyzed for their thickness and sorbed gas content, which ranged up to 79 scf/ton. Assuming 1 1/2 square miles of land (960 acres) at the Johnson County Landfill can be utilized for coalbed and shale gas recovery, the total amount of in-place gas calculates to 946,200 mcf, or 946.2 mmcf, or 0.95 bcf (i.e., 985.6 mcf/acre X 960 acres). Assuming that carbon dioxide can be imbibed by the coals and shales on a 2:1 ratio compared to the gas that was originally present, then 1682 to 1720 days (4.6 to 4.7 years) of landfill carbon dioxide production can be sequestered by the coals and shales immediately under the landfill.

Three coal – the Bevier, Fleming, and Mulberry coals – are the major coals of sufficient thickness (nominally >1’) that can imbibe carbon dioxide gas with an enhanced coalbed injection. Comparison of the adsorption gas content of coals to the gas desorbed from the coals shows that the degree of saturation decreases with depth for the coals.

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EXECUTIVE SUMMARY

Three-inch diameter core samples from the Pennsylvanian Pleasanton, Marmaton, and Cherokee Groups were collected from the Kansas Geological Survey #1B Deffenbaugh Quarry core hole and the Kansas Geological Survey #2 Deffenbaugh Quarry core hole, sec. 1-T.12S.-R.23E., Johnson County, Kansas. The following gas contents were measured (not including residual gas), based on dry weight of the samples:

Deffenbaugh Quarry #1B

- 385.3' to 386.3' (black shale) (50.5 scf/ton)
- 420.5' to 421.9' (Anna Shale) (22.2 scf/ton)
- 455.5' to 456.5' (Little Osage Shale) (16.9 scf/ton)
- 458.7' to 459.1' (Summit coal) (63.5 scf/ton)
- 571.3' to 572.7' (Bevier coal) (70.3 scf/ton)
- 604.6' to 605.4' (black shale above Fleming coal) (6.0 scf/ton)
- 605.4' to 606.6' (Fleming coal) (76.1 scf/ton)
- 639.0' to 640.8' (Mineral coal) (57.6 scf/ton)
- 710.7' to 711.5' (? coal) (45.3 scf/ton)
- 742.9' to 743.9' (? coal) (42.0 scf/ton)

Deffenbaugh Quarry #2

- 388.0' to 389.0' (black shale) (46.4 scf/ton)
- 424.0' to 426.0' (Anna Shale) (19.3 scf/ton)
- 455.3' to 456.1' (Little Osage Shale) (14.2 scf/ton)
- 457.8' to 458.3' (Summit coal) (69.0 scf/ton)
- 469.6' to 471.0' (Excello Shale) (1.9 scf/ton)
- 569.7' to 571.3' (Bevier coal) (78.7 scf/ton)
- 605.0' to 606.0' (black shale above Fleming coal) (4.1 scf/ton)
- 606.0' to 607.3' (Fleming coal) (75.8 scf/ton)
- 637.6' to 638.9' (Mineral coal) (60.5 scf/ton)

The volume of in-place gas in the coals and shales underlying the Deffenbaugh Quarry can be calculated by using the average of the gas contents of the samples and the average thickness of the gas-bearing coal or shale at each well. A unit is discounted as a viable source of gas if it had less that 10 scf/ton or if it was not at least one foot thick at either of the two core holes.

? shale (385')	106.0 mcf/acre
Anna Shale (424')	95.1 mcf/acre
Little Osage Shale (455')	38.0 mcf/acre
Summit coal (456')	57.8 mcf/acre
Excello Shale (470')	0.0 mcf/acre
Bevier coal (570')	220.3 mcf/acre
shale above Fleming coal (605')	0.0 mcf/acre
Fleming coal (606')	169.0 mcf/acre

Mineral coal (638')	232.3 mcf/acre
? coal (711')	0.0 mcf/acre;
? coal (743')	67.0 mcf/acre
TOTAL GAS IN PLACE	**985.6 mcf/acre**

Proximate analysis of the coals indicates that they straddle the boundary between high-volatile B and high-volatile A bituminous rank coals. Comparison of adsorption isotherms to gas contents of coals indicates that the coals and associated gas shales are undersaturated with respect to their gas content. The degree of saturation decreases with depth.

Isotopic analysis and hydrocarbon wetness of three desorption gases from the Deffenbaugh Quarry #2 well indicates the gas is mixed biogenic/thermogenic in origin. Heating values are 950 BTU/scf, 935 BTU/scf, and 750 BTU/scf respectively for the Bevier coal (570'), Fleming coal (606'), and the Mineral coal (638'). The decrease in saturation with depth is consistent with a biogenic influence in the origin of these gases.

Assuming 1 1/2 square miles of land (960 acres) at the Deffenbaugh Quarry/Johnson County Landfill can be utilized for coalbed and shale gas recovery, the total amount of in-place gas calculates to 946,200 mcf, or 946.2 mmcf, or 0.95 bcf (i.e., 985.6 mcf/acre X 960 acres).

Production of raw landfill gas from the Johnson County landfill comes from 150 wells. Daily production is approximately 2.2 to 2.5 mmcf, of which approximately 50% is methane and 50% is carbon dioxide and NMVOCs (non-methane volatile organic compounds). Assuming that carbon dioxide can be imbibed by the coals and shales on a 2:1 ratio compared to the gas that was originally present, then 1682 to 1720 days (4.6 to 4.7 years) of landfill carbon dioxide production can be sequestered by the coals and shales immediately under the landfill.

Three coal – the Bevier, Fleming, and Mulberry coals – are the major coals of sufficient thickness (nominally >1') that can imbibe carbon dioxide gas with an enhanced coalbed injection. These coals are the likely candidates for subsequent injection experiments and modeling.

Adsorption isotherms indicate that the coals have an adsorption capacity of carbon dioxide that is approximately three times that of methane. Rigging of the gas plant to inject the carbon dioxide into the coals for enhanced coalbed gas recovery would cost approximately $1.2 million, with a monthly operating cost estimated to be $25,000. Financial modeling is now necessary to determine if the added income form enhanced coalbed gas recovery would justify the expense of injecting the effluent of the gas plant into the coals underlying the landfill.

BACKGROUND

The Kansas Geological Survey Deffenbaugh Quarry #1B core hole and the Kansas Geological Survey Deffenbaugh Quarry #2 core hole were selected for desorption tests in association with Department of Energy research project to study the feasibility of injecting landfill gas into coals for carbon sequestration and enhanced coalbed gas recovery. The location of the core holes are in the Western Interior Coal Basin in eastern Kansas, notably on the southern and eastern flank of the Forest City basin (Figure 1). The core holes were drilled in the Deffenbaugh Quarry, which is also the location of the Johnson County Landfill (Figure 2).

The samples (2-inch-diameter core) for the Deffenbaugh Quarry #2 core hole were gathered November 19th through November 21st, 2004 by K. David Newell and W. Matt Brown of the Kansas Geological Survey. Coordinates for this well are: 870.6' KB elevation; lat. 39° 2' 08.697", long. 94° 48' 33.663".

The second core hole drilled, the Kansas Geological Survey Deffenbaugh Quarry #1B, was spudded 1536' south-southeast of the Deffenbaugh Quarry #2 well (Figure 2). Coordinates for this well are: 877.6' KB elevation; lat. 39° 1' 59.280", long. 94° 48' 18.452". The samples (2-inch-diameter core) for the #1B Deffenbaugh Quarry core hole were gathered May 3rd through May 6th, 2005 by K. David Newell, W. Matt Brown, and Kenneth Stalder of the Kansas Geological Survey.

Desorption samples were obtained for both wells during wireline coring. The wells were drilled by Kansas Geological Survey employees Joe Anderson and Matt Wedel, using an Acker wireline rig owned and operated by the Kansas Geological Survey.

Lithologies encountered for both wells were essentially identical, with minor changes in coal thickness at each well. A lithologic summary from the KGS Deffenbaugh Quarry #2 well is shown in Figure 3. A detailed summary of the lithologies encountered in this core hole are in Brown (2006). In general, the southeastern well (Deffenbaugh Quarry #1B) registered stratigraphic horizons 6 to 8 feet higher than in the Deffenbaugh Quarry #2 well.

For desorption measurements, bottom-hole times (i.e., the time the core sample was lifted from the bottom of the hole) and canistering times (i.e., the time the sample was placed in the desorption canister) were noted in order to determine lost gas and start of desorption. Approximate wet weight of the sample was determined by subtraction of the weight of the empty canister from the weight of the canister with the sample in it, with compensation for formation water added to the canister. After the sample was removed from the canister, it was weighed again before air- or oven-drying, then weighed after drying. The weight loss due to drying is noted in the desorption table (Tables 1, 2).

Temperature baths for the desorption canisters were on site, with temperatures at 65 degrees F for all samples. The canistered samples were later transported to the laboratory at the Kansas Geological Survey in Lawrence, KS and desorption measurements were continued. Desorption measurements were periodically made until the canisters produced no more gas upon testing for at least two successive measurements.

DESORPTION MEASUREMENTS

The equipment and method for measuring desorption gas is that prescribed by McLennan and others (1995). The volumetric displacement apparatus is a set of connected dispensing burettes, one of which measures the gas evolved from the desorption canister. The other burette compensates for the compression that occurs when the desorbed gas displaces the water in the measuring burette. This compensation is performed by adjusting the cylinders so that their water levels are identical, then figuring the amount of gas that evolved by simply reading the difference in water level using the volumetric scale on the side of the burette.

The desorption canisters were both home-made (i.e., Brady canisters) and commercially obtained (i.e., all others). The former were made with 3"-diameter (7.5-cm) PVC pipe and plumbing materials available at hardware stores. These canisters were 15 inches (38 cm) in length and enclosed a volume of 108 cubic inches (1740 cm^3). The commercial canisters were obtained from SSD, Inc. in Grand Junction, CO. The commercial canisters were approximately 12.5 inches in length (32 cm), 3 1/2 inches (9 cm) in diameter, and enclosed a volume of approximately 150 cubic inches (2450 cm^3).

The desorbed gas that collected in the desorption canisters was periodically released into the volumetric displacement apparatus and measured as a function of time, temperature and atmospheric pressure.

The time and atmospheric pressure were measured in the field using a portable weather station. The atmospheric pressure was displayed in millibars on this instrument, and later correlated to atmospheric pressure (in psi) read from a pressure transducer in the Petrophysics Laboratory in the Kansas Geological Survey in Lawrence, Kansas.

A spreadsheet program written by K.D. Newell (Kansas Geological Survey) was used to convert all gas volumes to standard temperature and pressure. Conversion of gas volumes to standard temperature and pressure was by application of the perfect-gas equation, obtainable from basic college chemistry texts:

$$n = PV/RT$$

where n is moles of gas, T is degrees Kelvin (i.e., absolute temperature), V is in liters, and R is the universal gas constant, which has a numerical value depending on the units in which it is measured (for example, in the metric system R = 0.0820 liter atmosphere per degree mole). The number of moles of gas (i.e., the value n) is constant in a volumetric conversion, therefore the conversion equation, derived from the ideal gas equation, is:

$(P_{stp}V_{stp})/(RT_{stp}) = (P_{rig}V_{rig})/(RT_{rig})$

Customarily, standard temperature and pressure (STP) for gas volumetric measurements in the oil industry are 60 ˚F and 14.7 psi (see Dake, 1978, p. 13), therefore P_{stp}, V_{stp}, and T_{stp}, respectively, are pressure, volume and temperature at standard temperature and pressure, where standard temperature is degrees Rankine (˚R = 460 + ˚F). P_{rig}, V_{rig}, and T_{rig}, respectively, are ambient pressure, volume and temperature measurements taken at the rig site or in the desorption laboratory.

The universal gas constant R drops out as this equation is simplified and the determination of V_{stp} becomes:

$V_{stp} = (T_{stp}/T_{rig})\ (P_{rig}/P_{stp})\ V_{rig}$

The conversion calculations in the spreadsheet were carried out in the English metric system, as this is the customary measure system used in American coal and oil industry. V is therefore converted to cubic feet; P is psia; T is ˚R. The desorbed gas was summed over the time period for which the coal samples evolved all of their gas.

Lost gas (i.e., the gas lost from the sample from the time it was drilled, brought to the surface, to the time it was canistered) was determined using the direct method (Kissel and others, 1975; also see McLennan and others, 1995, p. 6.1-6.14) in which the cumulative gas evolved is plotted against the square root of elapsed time. Time zero is assumed to be instant the core sample is lifted from the bottom of the hole. Characteristically, the cumulative gas evolved from the sample, when plotted against the square root of time, is linear for a short time period after the sample reaches ambient pressure conditions, therefore lost gas is determined by a line projected back to time zero. The period of linearity generally is about two hours for core samples.

LITHOLOGIC ANALYSIS

Upon removal from the canisters, the cores were washed of drilling mud, and air-dried for 2 to 6 weeks. After drying, the cores were weighed again to obtain a dry-weight based gas content. Selected samples were sent for proximate analysis at Luman's Laboratories in Chetopa, KS, and for adsorption studies at TerraTek in Salt Lake City, UT. Density measurements were also made on each sample at the Kansas Geological Survey.

DATA PRESENTATION

Data and analyses accompanying this report are presented in the following order: 1) data tables for the desorption analyses, 2) lost-gas graphs, 3) desorption graph for all samples at a common scale.

Data Tables of the Desorption Analyses (Table 1, 2)
These are the basic data used for lost-gas analysis and determination of total gas desorbed from the core samples. Basic temperature, volume, and barometric measurements are listed at left. Farther to the right, these are converted to standard temperature, pressure and volumes. The volumes are cumulatively summed, and converted to scf/ton based on the total weight of coal (or) dark shale in the sample. At the right of the table, the time of the measurements are listed and converted to hours (and square root of hours) since the sample was drilled.

Lost-Gas Graphs (Figures 4-22)
Gas lost prior to the canistering of the sample was estimated by extrapolation of the first few data points after the sample was canistered. The linear characteristic of the initial desorption measurements was usually lost within the first two hours after canistering, thus data are presented in the lost-gas graphs for only up to 9 hours after canistering. Lost-gas volumes derived from this analysis are incorporated in the data tables described above.

Desorption Graph (Figure 23)
This is the desorption graph (gas content per weight vs. square root of time) for all the samples.

RESULTS and DISCUSSION

Sorbed Gas Contents
The following gas contents (not including residual gas) were calculated for three-inch sore samples collected from the Kansas Geological Survey Deffenbaugh Quarry core holes. Samples were collected if the coal or shale were least 10 inches thick. Summit coal samples were from a seam less that 10 inches thick, but they were underlying the black Little Osage Shale, and thus the combination of this shale and the Summit coal constitute a substantial reservoir unit.

Deffenbaugh Quarry #1B
- 385.3' to 386.3' (black shale) (50.5 scf/ton)
- 420.5' to 421.9' (Anna Shale) (22.2 scf/ton)
- 455.5' to 456.5' (Little Osage Shale) (16.9 scf/ton)
- 458.7' to 459.1' (Summit coal) (63.5 scf/ton)
- 571.3' to 572.7' (Bevier coal) (70.3 scf/ton)
- 604.6' to 605.4' (black shale above Fleming coal) (6.0 scf/ton)
- 605.4' to 606.6' (Fleming coal) (76.1 scf/ton)
- 639.0' to 640.8' (Mineral coal) (57.6 scf/ton)
- 710.7' to 711.5' (? coal) (45.3 scf/ton)
- 742.9' to 743.9' (? coal) (42.0 scf/ton)

Deffenbaugh Quarry #2
- 388.0' to 389.0' (black shale) (46.4 scf/ton)

- 424.0' to 426.0' (Anna Shale) (19.3 scf/ton)
- 455.3' to 456.1' (Little Osage Shale) (14.2 scf/ton)
- 457.8' to 458.3' (Summit coal) (69.0 scf/ton)
- 469.6' to 471.0' (Excello Shale) (1.9 scf/ton)
- 569.7' to 571.3' (Bevier coal) (78.7 scf/ton)
- 605.0' to 606.0' (black shale above Fleming coal) (4.1 scf/ton)
- 606.0' to 607.3' (Fleming coal) (75.8 scf/ton)
- 637.6' to 638.9' (Mineral coal) (60.5 scf/ton)

Volume of Gas in Place per Acre

Thickness data, density data, and gas content data can be utilized for calculating the volume of gas in place per acre. Thickness measurements for gas-in-place calculations represent the average thickness of the coal or shale derived from the thickness measurements made at each well. Gas content data (see above) were also averaged from the two wells. Density measurements were made on each sample. These measurements are based on the dry weight of the sample. The volumetric measurement was made by weighing the water displaced out of a beaker by immersing the sample in the beaker.

SAMPLE	DEPTH (feet *and* meters)	ESTIMATED GAS CONTENT (scf/ton *and* cm^3/gram)	DENSITY (gram/cm^3)	THICKNESS (inches *and* cm)	VOLUME OF GAS PER SURFACE AREA (thousand cubic feet per acre and $meter^3$ per hectare)
? shale	385'; 117.4 m	48.4 scf/ton; 1.51 cm^3/gram	1.61	12"; 30.5 cm	106.0 mcf/acre; 7415 m^3/hectare
Anna Shale	424'; 129.2 m	20.7 scf/ton; 0.65 cm^3/gram	2.08	19.5"; 49.5 cm	95.1 mcf/acre; 6658 m^3/hectare
Little Osage Shale	455'; 138.7 m	15.5 scf/ton; 0.48 cm^3/gram	2.06	10.5"; 26.7 cm	38.0 mcf/acre; 2658 m^3/hectare
Summit coal	456'; 140.0 m	66.3 scf/ton; 2.07 cm^3/gram	1.40	5.5"; 14.0 cm	57.8 mcf/acre; 4048 m^3/hectare
Excello Shale	470'; 143.1 m	1.9 scf/ton; 0.06 cm^3/gram	NA	18"; 45.7 cm	0 mcf/acre; 0 m^3/hectare (GAS

					CONTENT TOO LOW)
Bevier coal	570'; 173.7 m	74.5 scf/ton; 2.33 cm^3/gram	1.45	18"; 45.7 cm	220.3 mcf/acre; 15,419 m^3/hectare
Shale above Fleming coal	605'; 184.4 m	6.0 scf/ton; 0.19 cm^3/gram	NA	14"; 35.6 cm	0 mcf/acre; 0 m^3/hectare (GAS CONTENT TOO LOW)
Fleming coal	606'; 184.7 m	75.9 scf/ton; 2.37 cm^3/gram	1.31	15"; 38.1 cm	169.0 mcf/acre; 11,826 m^3/hectare
Mineral coal	638'; 194.5 m	59.0 scf/ton; 1,84 cm^3/gram	1.39	25"; 63.5 cm	232.3 mcf/acre; 16,257 m^3/hectare
? coal	711'; 216.7 m	45.3 scf/ton; 1.41 cm^3/gram	NA	10"; 25.4 cm	0 mcf/acre; 0 m^3/hectare (<1'; TOO THIN)
? coal	743'; 226.5 m	42.0 scf/ton; 1.31 cm^3/gram	1.28	11"; 27.9 cm	67.0 mcf/acre; 4689 m^3/hectare
TOTAL					**985.6 mcf/acre; 68,970 m^3/hectare**

Sorption Times
Relative permeability of each of the gas-bearing units underlying the Deffenbaugh Quarry can be determined by their sorption time, which is the time necessary to evolve 63.2% of the total gas evolved from the sample (McLennan, 1995, p. 2.9). Sorption times for the Deffenbaugh samples are as follows:

GAS-BEARING UNIT	***Avg. Gas Content (scf/ton)***	***Gas-in-Place (scf/acre)***	***Sorption Time (days)***	
			DQ1B	***DQ2***
? black shale @ 388'	48.4	106,000	6.24	8.84
Anna Shale @ 424'	20.7	95,100	74.45	101.12
Little Osage Shale @ 455'	15.5	38,000	26.03	50.26
Summit coal @ 458'	66.3	57,800	19.88	15.23

Bevier coal @ 570'	74.5	220,300	19.27	31.20
Fleming coal @ 606'	75.9	169,000	12.65	28.59
Mineral coal @ 638'	59.0	232,300	18.50	31.90
? coal @ 711'	45.3	----------	18.61	
? coal @ 742'	42.0	67,000	8.71	

In general, sorption times are shorter at Deffenbaugh Quarry #1B than at Deffenbaugh Quarry #2. The reason for this is not clear, but better cleats and more fractures may be present in the former well.

A synoptic comparison of the gas content and the sorption time is best accomplished with a crossplot of sorption time vs. the calculated gas per acre (Figure 24). From this diagram, the Mineral and Bevier coals will likely have almost identical reservoir characteristics, and are the best units with respect to their gas-in-place. The Fleming coal has less gas in place, but better sorption time than the Mineral and Bevier coals. All units except the shales have nearly identical sorption times, although the re is a tendency for the minor coals deeper than 700 ft to have shorter sorption times. By its sorption time, the unidentified shale at 388 ft. is, for all means and purposes, a coal. Its moisture-free ash content (32.48% to 37.26%) is slightly greater than coals encountered in the core holes (12.71% to 27.59%), but it is considerably less than that of other black shales (76.32% to 78.47%).

Proximate Analyses

Proximate analyses were made for selected samples. The core was cut down its vertical axis and half was preserved for future analyses. The proximate analyses were performed on the following samples by Luman's Laboratory, Chetopa, KS:

? shale at 385.3' (DQ1B)	**As Received**	**Moisture Free**	**Moisture, Ash Free**
Moisture	4.44%		
Ash	31.04%	32.48%	
Volatile Matter	27.28%	28.55%	
Fixed Carbon	37.24%	38.97%	
BTU/lb.	8,602	9,002	13,332
Sulfur	5.14%	5.38%	

? shale at 388.0' (DQ2)	**As Received**	**Moisture Free**	**Moisture, Ash Free**
Moisture	4.51%		
Ash	35.58%	37.26%	
Volatile Matter	24.40%	25.55%	
Fixed Carbon	35.51%	37.19%	
BTU/LB	7,909	8,283	13,203
Sulfur	3.73%	3.90%	

Anna Shale (DQ1B)	**As Received**	**Moisture Free**	**Moisture, Ash Free**
Moisture	2.69%		
Ash	73.14%	75.16%	

Volatile Matter	15.96%	16.40%	
Fixed Carbon	8.21%	8.44%	
BTU/LB.	2,986	3,069	12,354
Sulfur	1.70%	1.74%	

Anna Shale (DQ2)	**As Received**	**Moisture Free**	**Moisture, Ash Free**
Moisture	2.11%		
Ash	74.72%	76.32%	
Volatile Matter	16.98%	17.34%	
Fixed Carbon	6.19%	6.34%	
BTU/LB.	2,811	2,872	12,128
Sulfur	1.82%	1.86%	

Little Osage Shale (DQ1B)	**As Received**	**Moisture Free**	**Moisture, Ash Free**
Moisture	2.80%		
Ash	75.58%	77.76%	
Volatile Matter	14.43%	14.84%	
Fixed Carbon	7.19%	7.40%	
BTU/LB.	2,441	2,511	11,294
Sulfur	1.16%	1.19%	

Little Osage Shale (DQ2)	**As Received**	**Moisture Free**	**Moisture, Ash Free**
Moisture	1.58%		
Ash	77.23%	78.47%	
Volatile Matter	15.26%	15.50%	
Fixed Carbon	5.93%	6.03%	
BTU/LB.	2,250	2,286	10,620
Sulfur	1.25%	1.27%	

Summit coal (DQ1B)	**As Received**	**Moisture Free**	**Moisture, Ash Free**
Moisture	4.78%		
Ash	26.27%	27.59%	
Volatile Matter	32.73%	34.37%	
Fixed Carbon	36.22%	38.04%	
BTU/LB.	9.874	10.370	14,322
Sulfur	2.36%	2.48%	

Summit coal (DQ2)	**As Received**	**Moisture Free**	**Moisture, Ash Free**
Moisture	5.04%		
Ash	21.97%	23.14%	
Volatile Matter	33.48%	35.64%	
Fixed Carbon	39.15%	41.22%	
BTU/LB.	10,298	10,845	14,109
Sulfur	1.92%	2.03%	

Excello Shale (DQ2)	**As Received**	**Moisture Free**	**Moisture, Ash Free**

Moisture	2.60%		
Ash	91.00%	93.42%	
Volatile Matter	5.84%	6.00%	
Fixed Carbon	0.56%	0.58%	
BTU/LB.	301	309	4,706
Sulfur	0.17%	0.17%	

Bevier coal (DQ1B)	**As Received**	**Moisture Free**	**Moisture, Ash Free**
Moisture	4.70%		
Ash	17.36%	18.21%	
Volatile Matter	34.96%	36.68%	
Fixed Carbon	42.98%	45.11%	
BTU/LB.	10,825	11,358	13,888
Sulfur	9.56%	10.03%	

Bevier coal (DQ2)	**As Received**	**Moisture Free**	**Moisture, Ash Free**
Moisture	3.86%		
Ash	16.44%	17.10%	
Volatile Matter	37.25%	38.75%	
Fixed Carbon	42.45%	44.15%	
BTU/LB.	11,418	11,876	14,326
Sulfur	6.84%	7.11%	

sh above Fleming (DQ1B)	**As Received**	**Moisture Free**	**Moisture, Ash Free**
Moisture	3.02%		
Ash	83.38%	85.98%	
Volatile Matter	7.96%	8.21%	
Fixed Carbon	5.64%	5.81%	
BTU/LB.	1,150	1,186	8,460
Sulfur	2.26%	2.33%	

sh above Fleming (DQ2)	**As Received**	**Moisture Free**	**Moisture, Ash Free**
Moisture	2.15%		
Ash	85.41%	87.28%	
Volatile Matter	9.92%	10.14%	
Fixed Carbon	2.52%	2.58%	
BTU/LB.	842	860	6.765
Sulfur	4.76%	4.87%	

Fleming coal (DQ1B)	**As Received**	**Moisture Free**	**Moisture, Ash Free**
Moisture	3.95%		
Ash	12.21%	12.71%	
Volatile Matter	37.86%	39.42%	
Fixed Carbon	45.98%	47.87%	
BTU/LB.	12,103	12,601	14,435
Sulfur	4.65%	4.85%	

Fleming coal (DQ2)	**As Received**	**Moisture Free**	**Moisture, Ash Free**
Moisture	5.61%		
Ash	13.44%	14.24%	
Volatile Matter	38.97%	41.29%	
Fixed Carbon	41.98%	44.47%	
BTU/LB.	11,830	12,533	14,614
Sulfur	3.52%	3.74%	

Mineral coal (DQ1B)	**As Received**	**Moisture Free**	**Moisture, Ash Free**
Moisture	5.38%		
Ash	22.98%	24.29%	
Volatile Matter	33.02%	34.90%	
Fixed Carbon	38.62%	40.81%	
BTU/LB.	10,025	10,595	13,995
Sulfur	4.57%	4.83%	

Mineral coal (DQ2)	**As Received**	**Moisture Free**	**Moisture, Ash Free**
Moisture	5.06%		
Ash	14.90%	15.70%	
Volatile Matter	36.22%	38.16%	
Fixed Carbon	43.82%	46.14%	
BTU/LB.	11,562	12,178	14,445
Sulfur	4.47%	4.71%	

coal at 710.0' (DQ1B)	**As Received**	**Moisture Free**	**Moisture, Ash Free**
Moisture	4.72%		
Ash	22.76%	23.89%	
Volatile Matter	32.01%	33.59%	
Fixed Carbon	40.51%	42.52%	
BTU/LB.	9,969	10,464	13,748
Sulfur	10.26%	10.76%	

coal at 742.9' (DQ1B)	**As Received**	**Moisture Free**	**Moisture, Ash Free**
Moisture	2.98%		
Ash	14.32%	14.77%	
Volatile Matter	36.53%	37.65%	
Fixed Carbon	46.17%	47.58%	
BTU/LB.	11,614	11,971	14,045
Sulfur	6.68%	6.89%	

According to the BTU/lb. (dry, ash-free) determinations, all the samples can be classified as high-volatile B and A bituminous coal. Most samples plot along the boundary of these two coal rankings (Figure 25).

Using the equation from McLennan and others (1995):

$G_c = G_{pc}\,(1\text{-}a_d)$

where:
G_c = gas content, scf/ton, dry basis
G_{pc} = "pure coal", gas content, scf/ton
a_d = dry ash content, weight fraction

the gas content of the samples converts to:

Deffenbaugh Quarry #1B

unit	*depth*	*moisture-free ash*	G_c	G_{pc}
? black shale	385.3'	32.48%	50.5 scf/tn	80.1 scf/tn
Anna Shale	420.5'	75.16	22.2 scf/tn	100.0 scf/tn
Little Osage Shale	455.5'	77.76%	16.9 scf/tn	86.9 scf/tn
Summit coal	458.7'	27.59%	63.5 scf/tn	93.8 scf/tn
Bevier coal	571.3'	18.21%	70.3 scf/tn	91.2 scf/tn
shale over Fleming	604.6'	85.98%	6.0 scf/tn	54.1 scf/tn
Fleming coal	605.4'	12.71%	76.1 scf/tn	91.3 scf/tn
Mineral coal	639.0'	24.29%	57.6 scf/tn	81.8 scf/tn
? coal	710.7'	23.89	45.3 scf/tn	63.5 scf/tn
? coal	742.9'	14.77%	42.0 scf/tn	51.0 scf/tn

Deffenbaugh Quarry #2

unit	*depth*	*moisture-free ash*	G_c	G_{pc}
? black shale	388.0'	37.26%	46.4 scf/tn	79.6 scf/tn
Anna Shale	424.0'	76.32%	19.3 scf/tn	89.5 scf/tn
Little Osage Shale	455.3'	78.47%	14.2 scf/tn	71.2 scf/tn
Summit coal	457.8'	23.14%	69.0 scf/tn	96.1 scf/tn
Excello Shale	469.6'	93.42%	1.9 scf/tn	46.5 scf/tn
Bevier coal	569.7'	17.10%	78.7 scf/tn	99.6 scf/tn
shale over Fleming	605.0'	87.28%	4.1 scf/tn	39.0 scf/tn
Fleming coal	606.0'	14.24%	75.8 scf/tn	94.6 scf/tn
Mineral coal	637.6'	15.70%	60.5 scf/ton	76.4 scf/tn

Isotherms

A methane adsorption isotherm was determined for Mineral coal at the Deffenbaugh #2 well by TerraTek, Salt Lake City, UT. This isotherm, as well as two other isotherms from Mineral coal samples from elsewhere in eastern Kansas (e.g., Layne-Christensen #13-38 Beurskens well in Montgomery County, Colt Energy #2-6 Spencer well in Franklin County; see Fig. 1 for locations), are presented in Figure 26. The Mineral coal in the Spencer #2-6 well and Beurskens #13-38 well is high-volatile A bituminous coal, which is slightly higher rank than at the Deffenbaugh Quarry (see Figure 25). The ash content at the Spencer #2-6 well and Beurskens #13-38 well is lower than at Deffenbaugh

Quarry, and the isotherms were determined at slightly higher reservoir temperatures at these two wellsites (see Figure 26).

Water would overnight rise to within a foot of the surface in both of the wellbores. Assuming that the hydrostatic gradient is 0.476 psi/ft (i.e., the gradient for salt water), the Mineral coal at 638 ft depth in the Deffenbaugh Quarry #2 well, would be under 304 psi pressure. According to the isotherm in Figure 26, methane in the Mineral coal at that pressure would be at saturation at a gas content of 109 scf/ton. As-received gas content for the Mineral at that locality is 60.5 scf/ton, so the Mineral coal is roughly 56% saturated.

Assuming that the PVT behaviors of other coals and shales at the Deffenbaugh Quarry are similar to that of the Mineral coal, the moisture, ash free (MAF) gas content of all the samples (see above) can be compared to the MAF isotherm determined for the Mineral coal (Figure 27). This comparison indicates that all samples from the two Deffenbaugh Quarry core holes are undersaturated.

The degree of undersaturation can be semi-quantitatively compared by determining the ratio of the MAF gas content to saturated gas content from the MAF isotherm (see Figure 28 and table below). The degree of saturation decreases with depth, and is somewhat lower for shale than for coals.

Deffenbaugh Quarry #1B

unit	*depth (ft.)*	*pressure (psi)*	G_{pc} *(scf/tn)*	$G_{pc(saturated)}$ *(scf/tn)*	$G_{pc}/G_{pc(saturated)}$ *(%)*
? black shale	385.3'	183	80.1	117.6	68.5
Anna Shale	420.5'	200	NA	125.0	NA
Little Osage Shale	455.5'	217	86.9	132.7	65.5
Summit coal	458.7'	218	93.8	133.4	70.4
Bevier coal	571.3'	272	91.2	156.0	58.5
shale over Fleming	604.6'	288	54.1	162.2	33.4
Fleming coal	605.4'	288	91.3	162.3	56.2
Mineral coal	639.0'	304	81.8	168.4	48.6
? coal	710.7'	338	NA	180.5	NA
? coal	742.9'	354	51.0	185.7	27.5

Deffenbaugh Quarry #2

unit	*depth (ft.)*	*pressure (psi)*	G_{pc} *(scf/tn)*	$G_{pc(saturated)}$ *(scf/tn)*	$G_{pc}/G_{pc(saturated)}$ *(%)*
? black shale	388.0'	185	79.6	117.6	67.7
Anna Shale	424.0'	202	89.5	125.8	71.2
Little Osage Shale	455.3'	217	71.2	132.6	53.7
Summit coal	457.8'	218	96.1	133.2	72.2
Excello Shale	469.6'	224	46.5	135.7	34.3
Bevier coal	569.7'	271	99.6	155.7	64.0
shale over Fleming	605.0'	288	39.0	162.3	24.0

Fleming coal	606.0'	288	94.6	162.5	58.2
Mineral coal	637.6'	303	76.4	168.1	45.4

Gas Chemistry

Compositional and isotopic chemistry were performed on three desorption gas samples from the Deffenbaugh Quarry #2 well. These analyses are in Appendix II and were performed by Isotech Laboratories in Champaign, IL.

Isotopic Analyses

Analysis	**Bevier (571.3')**	**Fleming (605.4')**	**Mineral (639.0')**
$\delta^{13}C_{methane}$	-61.61	-62.66	-64.93
$\delta^{13}C_{ethane}$	-38.78	-37.30	-36.51
$\delta^{13}C_{propane}$	-28.57	-28.67	-29.09
$\delta D_{methane}$	-216.1	-211.6	-201.1

Chemical Analyses (as reported; red = hydrocarbons; blue = non hydrocarbons, green = oxygen)

Component (%)	**Bevier**	**Fleming**	**Mineral**
Methane	84.11	74.60	51.57
Ethane	0.343	0.312	0.224
Propane	0.206	0.187	0.129
n-Butane	0.0383	0.0288	0.0191
iso-Butane	0.0332	0.0273	0.0172
n-Pentane	0.0054	0.0021	0
iso-Pentane	0.0091	0.0049	0.0023
Hexane+	0.0052	0.0030	0.0016
Nitrogen	13.79	21.27	41.16
Oxygen	1.11	3.00	6.27
Argon	0.164	0.234	0.435
Hydrogen	0	0	0
Carbon Dioxide	0.18	0.33	0.17
Helium	0.0032	0.0048	0.0059

Chemical Analyses (recalculated after removing atmospheric contamination; red = hydrocarbons; blue = non hydrocarbons)

Component (%)[1]	**Bevier**	**Fleming**	**Mineral**
Methane	88.81	87.05	73.56
Ethane	0.362	0.364	0.320
Propane	0.218	0.218	0.184
n-Butane	0.0404	0.0336	0.0272
iso-Butane	0.0351	0.0319	0.0245
n-Pentane	0.0057	0.0025	0
iso-Pentane	0.0096	0.0057	0.0033
Hexane+	0.0055	0.0035	0.0023
Nitrogen	10.20	11.79	25.41

Argon	0.121	0.118	0.223
Hydrogen	0	0	0
Carbon Dioxide	0.19	0.38	0.23
Helium	0.0034	0.0055	0.0082

[1]atmospheric component (based on oxygen content) subtracted from the analysis, with components recalculated to 100%

Other Gas Data

	Bevier	**Fleming**	**Mineral**
Specific Gravity	0.625	0.668	0.767
Calculated BTU	955	935	790
Total % non-HCs	10.51	12.29	25.88
HC Wetness (%)	0.76	0.75	0.76

Plotting of the isotopes and gas wetness (Figure 28) indicates that the gas is of mixed biogenic and thermogenic origin. Although isotopically the gases are mostly biogenic, the hydrocarbon wetness indicates minor thermogenic influence. Coals are farther from their outcrop the deeper they are, hence the deeper the coal, the more remote they are to freshwater that largely encourages biogenesis. The decreasing gas saturation with the deeper coals could be caused by waning influence of biogenesis with depth. Lighter (more negative) $\delta C^{13}_{methane}$ isotopes (thereby possibly indicating more biogenic than thermogenic origin), with depth, however, contradicts this conclusion based on the gas saturations.

With present data, a rough mass balance can be made for sequestration of carbon dioxide from the gas operations at the Deffenbaugh Quarry/Johnson County Landfill. Assuming 1 1/2 square miles of land (960 acres) at the Deffenbaugh Quarry/Johnson County Landfill can be utilized for coalbed and shale gas recovery, the total amount of in-place gas calculates to 946,200 mcf, or 946.2 mmcf, or 0.95 bcf (i.e., 985.6 mcf/acre X 960 acres).

Production of raw landfill gas from the Johnson County landfill comes from 150 wells. Daily production is approximately 2.2 to 2.5 mmcf ((Luke Morrow, SouthTex Treaters, personal communication to KDN, 2005), of which approximately 50% is methane and 50% is carbon dioxide and NMVOCs (non-methane volatile organic compounds). Daily carbon dioxide available to be sequesters therefore ranges from 1.1 to 1.25 mmcf. Assuming that carbon dioxide can be imbibed by the coals and shales on a 2:1 ratio compared to the gas that was originally present, then there is 1,892,000 mcf (1892.4 mmcf) capacity (i.e., 2 X 946.2 mmcf GIP). If 1.1 to 1.25 mmcf of carbon dioxide is injected per day, then 1682 to 1720 days (4.6 to 4.7 years) of landfill carbon dioxide production can be sequestered by the coals and shales immediately under the landfill.

Modeling Parameters

Three wells in the quarry provide correlation depths for the major coals and shales underlying the quarry. The following table lists these well and subsea depths.

DEPTH TO COMMON HORIZONS -- DEFFENBAUGH QUARRY WELLS

	KGS DQ #2		KGS DQ #1B		#2 SWD	
	datum= (ft.)	870.6	datum= (ft.)	876.9	datum= (ft.)	852.5
UNIT	**well depth**	**depth, S.L. datum**	**well depth**	**depth, S.L. datum**	**well depth**	**depth, S.L. datum**
Stark Shale	158.0	712.6	160.1	716.8	135.0	717.5
Hushpuckney Shale	184.2	686.4	187.1	689.8	161.5	691.0
shale (canistered)	388.0	482.6	384.5	492.4	346.8	505.7
Anna Shale (canistered)	424.0	446.6	420.5	456.4	397.5	455.0
Little Osage Shale (canistered)	455.5	415.1	455.5	421.4	433.0	419.5
Summit coal (canistered)	457.8	412.8	458.7	418.2	436.0	416.5
top of sand	481.0	389.6	490.0	386.9	456.8	395.7
top of sand's oil zone	481.0	389.6	504.0	372.9	not present	not present
base of sand	506.0	364.6	519.7	357.2	454.5	398.0
thin coal (3 1/2")	529.1	341.5	533.1	343.8	507.1	345.4
Bevier coal (canistered)	569.8	300.8	571.3	305.6	544.6	307.9
black shale	579.1	291.5	580.0	296.9	553.1	299.4
shale above Fleming coal (canistered)	604.6	266.0	604.6	272.3	577.6	274.9
Fleming coal (canistered)	606.0	264.6	605.1	271.8	579.0	273.5
Mineral coal (canistered)	638.3	232.3	638.9	238.0	612.0	240.5
thin coal under thin black shale	687.1	183.5	not present	not present	662.0	190.5
coal (canistered at DQ #1B)	709.4	161.2	710.7	166.2	not present	not present
coal (canistered at DQ #1B)	743.1	127.5	742.9	134.0	716.8	135.7
black shale	759.4	111.2	759.2	117.7	not present	not present
thin coal	826.3	44.3	826.4	50.5	not present	not present
thin coal	842.9	27.7	843.2	33.7	827.0	25.5
top Mississippian	866.0	4.6	870.3	6.6	867.9	-15.4

From this table, as series of structure maps (Figures 35-41) on the major coals and dark shales were constructed. Dips generally are to the north and west at 25 to 50 ft per mile. The structure derived are simple planes, for only three wells in the vicinity of the Deffenbaugh Quarry (i.e., KGS Deffenbaugh Quarry #1B, KGS Deffenbaugh Quarry #2, and Deffenbaugh Industries Waste Water Disposal #2) have geological information useful for structural and isopach mapping. The structure and isopach maps are therefore solutions in planar form, since three points define a plane XYZ space. Superimposed on these maps are thicknesses of the coals, and an isopach is the thicknesses are amenable to constructing a logical solution to the three-point problem.

Adsorption isotherms provide basic data for modeling purposes. All coals have similar adsorption properties. Carbon dioxide adsorbs on an approximate 2 to 3:1 basis compared to methane. Comparison of the adsorption gas content to the gas desorbed from the coals shows that the degree of saturation decreases with depth for the coals. Injected carbon dioxide gas will more readily be injected into these deeper coals.

The cost for utilizing effluent carbon dioxide gas from the gas processing plant on site at the Johnson County landfill also needs to be factored into economic considerations for an enhanced coalbed methane recovery operation. Cost estimates (Luke Morrow, personal communication, South-Tex Treaters, Inc.) are as follows:

Piping (on site)	$95,000
Screw Compressor	$900,000
Installation	$200,000

Monthly operating cost (electricity, oil, parts) $25,000/mo.

A simple economic justification to inject effluent gas from the gas plant into the ground will therefore cost $1,195,000. Incremental amounts of gas necessary to offset these extra costs are dependent on the price of natural gas, with lesser production needed with higher prices. The amount of production needed can then be compared to the amount of gas in-place to figure an incremental amount of recovery necessary to justify the expense. Assuming 1 1/2 square miles of land (960 acres) at the Johnson County Landfill can be utilized for coalbed and shale gas recovery, the total amount of in-place gas calculates to 946,200 mcf. The table below indicates that an ECBM project would have to bring in 15% to 28% extra recovery, depending on the price of gas (which is modeled to be between $4.50 to 8.50/mcf).

Price of Gas	*Production needed = $1,195,000 (mcf)*	*% extra recovery needed (prod. needed/in-place gas)*
$4.50/mcf	265,556 mcf	28%
$5.00/mcf	239,000 mcf	25%
$5.50/mcf	217,273 mcf	23%
$6.00/mcf	199,167 mcf	21%
$6.50/mcf	183,846 mcf	19%
$7.50/mcf	159,333 mcf	17%
$8.00/mcf	149,375 mcf	16%
$8.50/mcf	140,488 mcf	15%

Estimated operating costs of $25,000 per month need to be offset with production ranging from 5556 mcf/month (185.2 mcf/day) for gas priced at $4.50, to 2941 mcf/month (98 mcf/day) for gas priced at $8.50/mcf. Assuming a 5-spot production configuration (4 producing wells surrounding one injector), additional production per well would have to average 1389 mcf/month/well (46.3 mcf/day/well) to 735 mcf/month/well (24.5 mcf/day/well) just to account for operating costs.

CONCLUSIONS

The Johnson County Landfill, a major urban landfill serving the Kansas City metropolitan area, has several coals of sufficient thickness and gas content beneath it that can be utilized for possibly profitable coalbed gas recovery. This coalbed gas operation can supplement landfill gas that is currently upgraded to pipeline specifications at an upgrading plant located on site. Effluent carbon dioxide and other gases from the upgrading plant can possibly be injected into the coals with the dual goal of carbon sequestration and enhanced coalbed gas recovery. Costs of re-rigging the gas plant for injection of its effluent gases, which are currently vented to the atmosphere, would require additional ultimate coalbed gas recoveries of 15% to 28% before profitability of the operation is realized, depending on the price of natural gas. About 4½ to 5 years of current landfill carbon dioxide production can be sequestered by the coals and shales immediately under the landfill.

FIGURES and TABLES

REFERENCES

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Kissel, F.N., McCulloch, C.M., and Elder, C.H., 1975, The direct method of determining methane content of coals for ventilation design: U.S. Bureau of Mines, Report of Investigations, RI7767.

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LIST OF ACRONYMS AND ABBREVIATIONS

°	degrees, when used in context of location coordinates
'	minutes, when used in context of location coordinates; foot, when used in context of length measurement
"	seconds, when used in context of location coordinates; inch, when used in context of length measurement
>	greater than
%	percent, percentage
@	at
a_d	dry ash content, weight fraction
bcf	billion cubic feet
BTU/scf	BTU (British Thermal Units) per standard cubic foot of gas
C	Centigrade temperature
CBM	coalbed methane
cm	centimeter
DQ1B	shorthanded designation for Deffenbaugh Quarry #1B core hole
DQ2	shorthanded designation for Deffenbaugh Quarry #2 core hole
E	east, used in conjunction with township
ECBM	enhanced coalbed methane (recovery)
F	Fahrenheit temperature
ft	foot
G_c	gas content, scf/ton, dry basis
G_{pc}	"pure coal", gas content, scf/ton
GIP	gas in place
GR	gamma ray, as in gamma ray log
HCs	hydrocarbons
IL	Illinois
KGS	Kansas Geological Survey
KS	Kansas
lb.	pound weight
LFG	landfill gas
m	meters
MAF	moisture, ash-free (in context of coal analysis)
mcf	thousand cubic feet
mmcf	million cubic feet
n	moles
NMVOCs	non-methane volatile organic compounds
psi	pounds per square inch pressure
PVC	polyvinyl chloride
PVT	pressure-volume-temperature
R	range, when used ion context of location; universal gas constant, when used in contest of gas law equations; universal gas constant, when used in context of gas laws
S	south, used in conjunction with township

scf/ton	standard cubic feet (i.e., one cubic foot of gas at 60 degrees F and sea level) per ton
sec.	section
stp	standard temperature and pressure (60 degrees F and sea level for oil and gas industry
T.	township, when used in context of location, degrees Kelvin (K) when used in context of temperature
UT	Utah
V	volume, usually in liters or scf

LOCATION MAP FOR STUDY

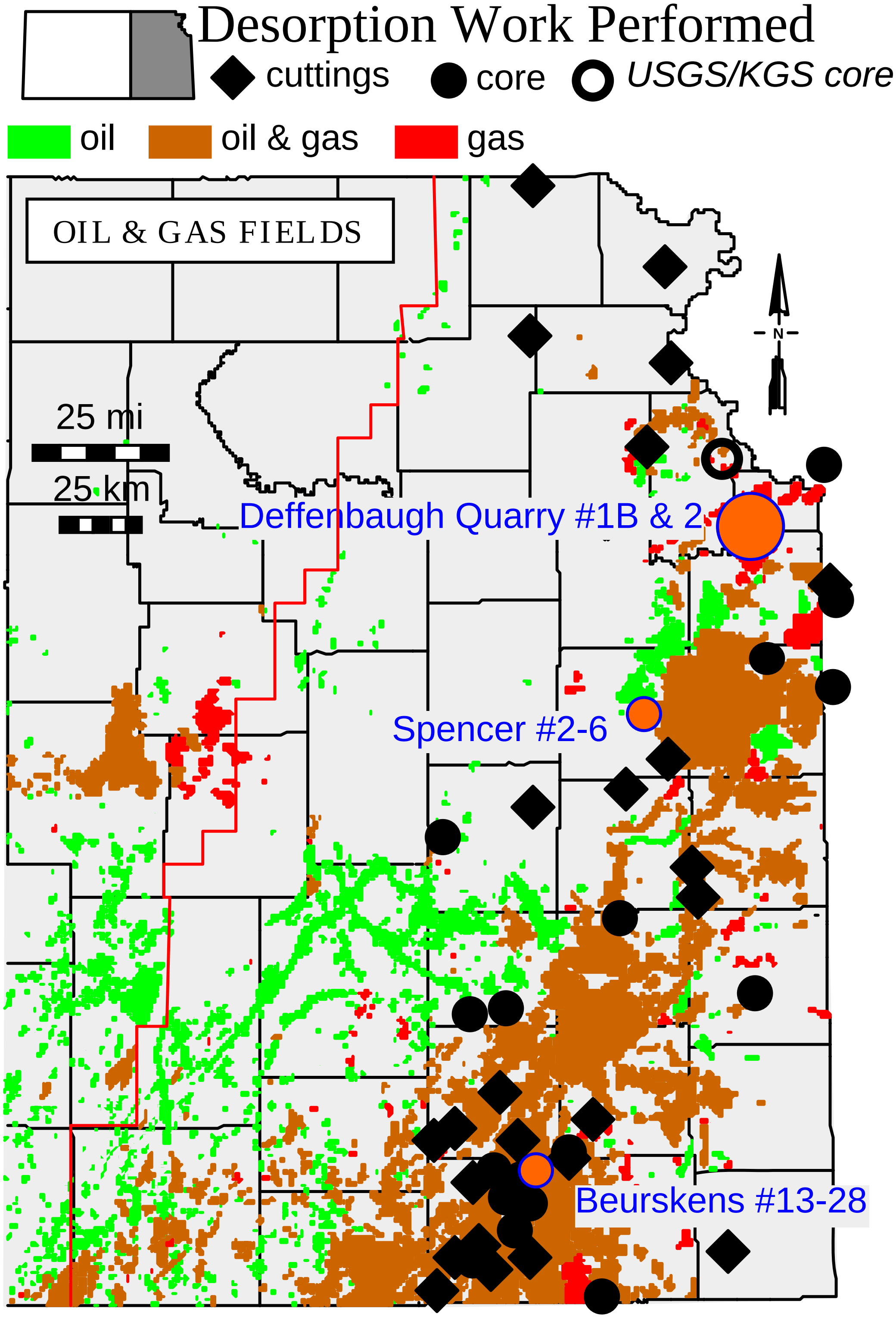


Figure 1.

DEFFENBAUGH QUARRY AND LOCATION OF CORE HOLES

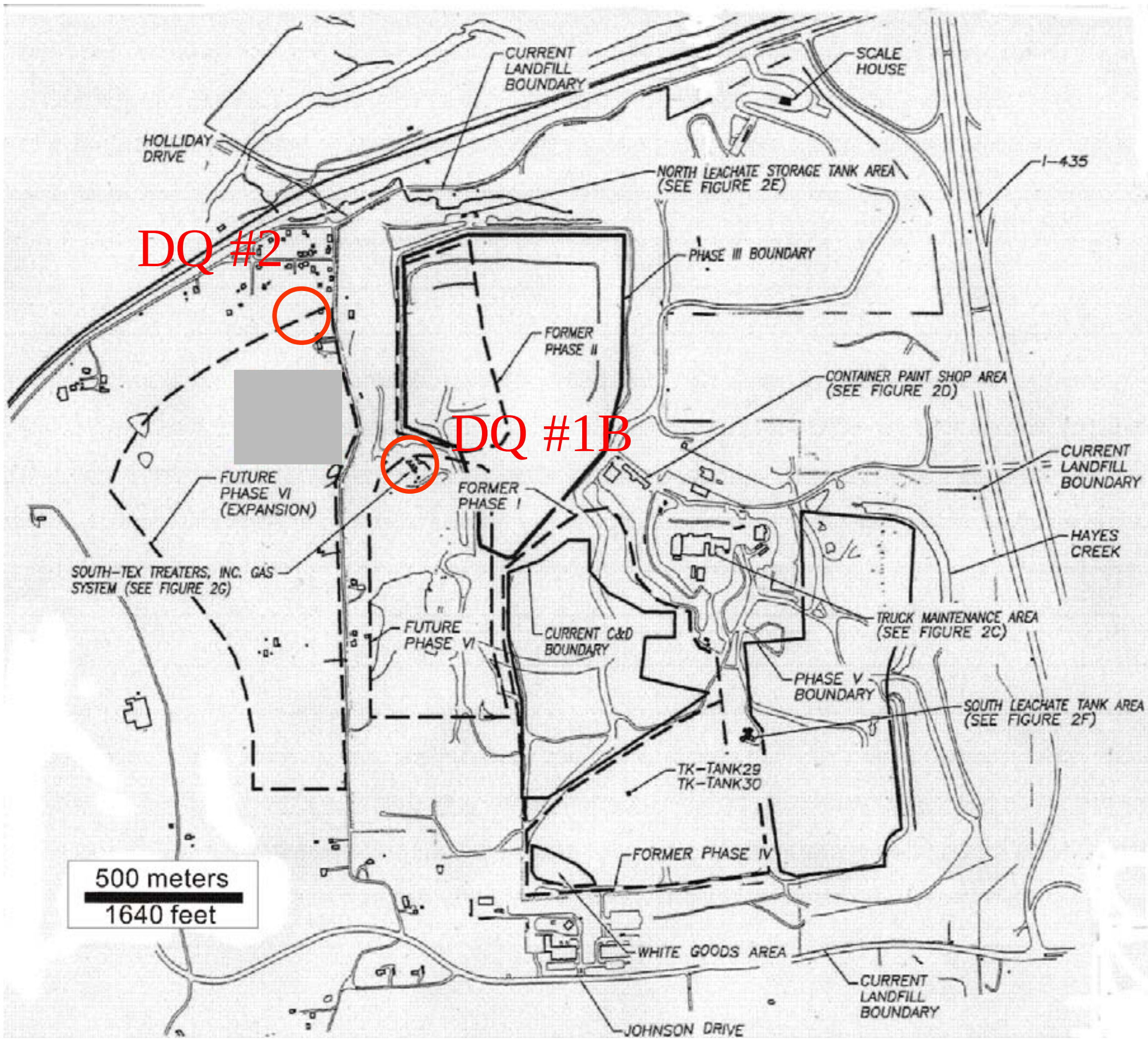


Figure 2.

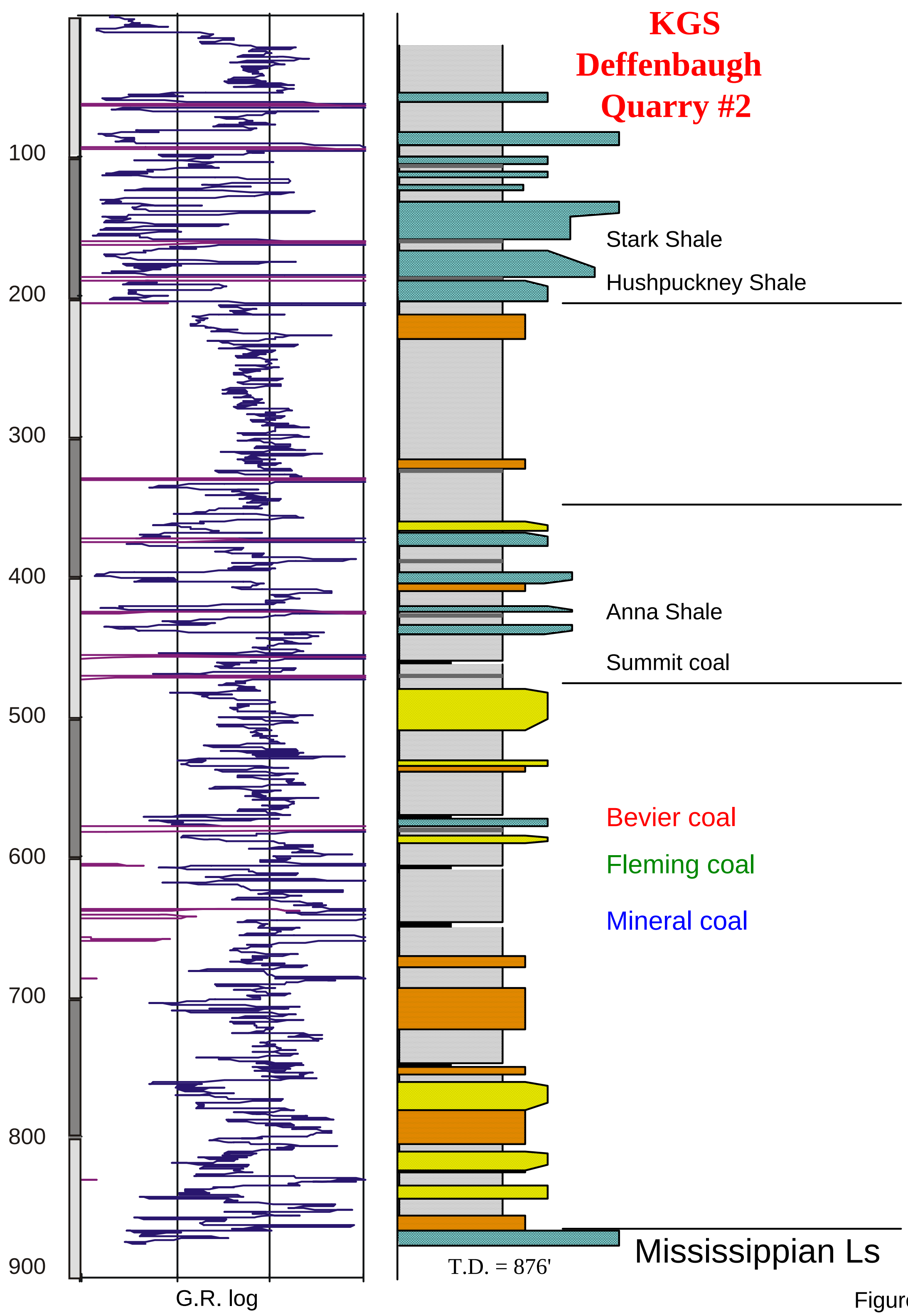

KGS Deffenbaugh Quarry #2
100
200
300
400
500
600
700
800
900
G.R. log
Stark Shale
Hushpuckney Shale
Anna Shale
Summit coal
Bevier coal
Fleming coal
Mineral coal
Mississippian Ls
T.D. = 876'

Figure 3.

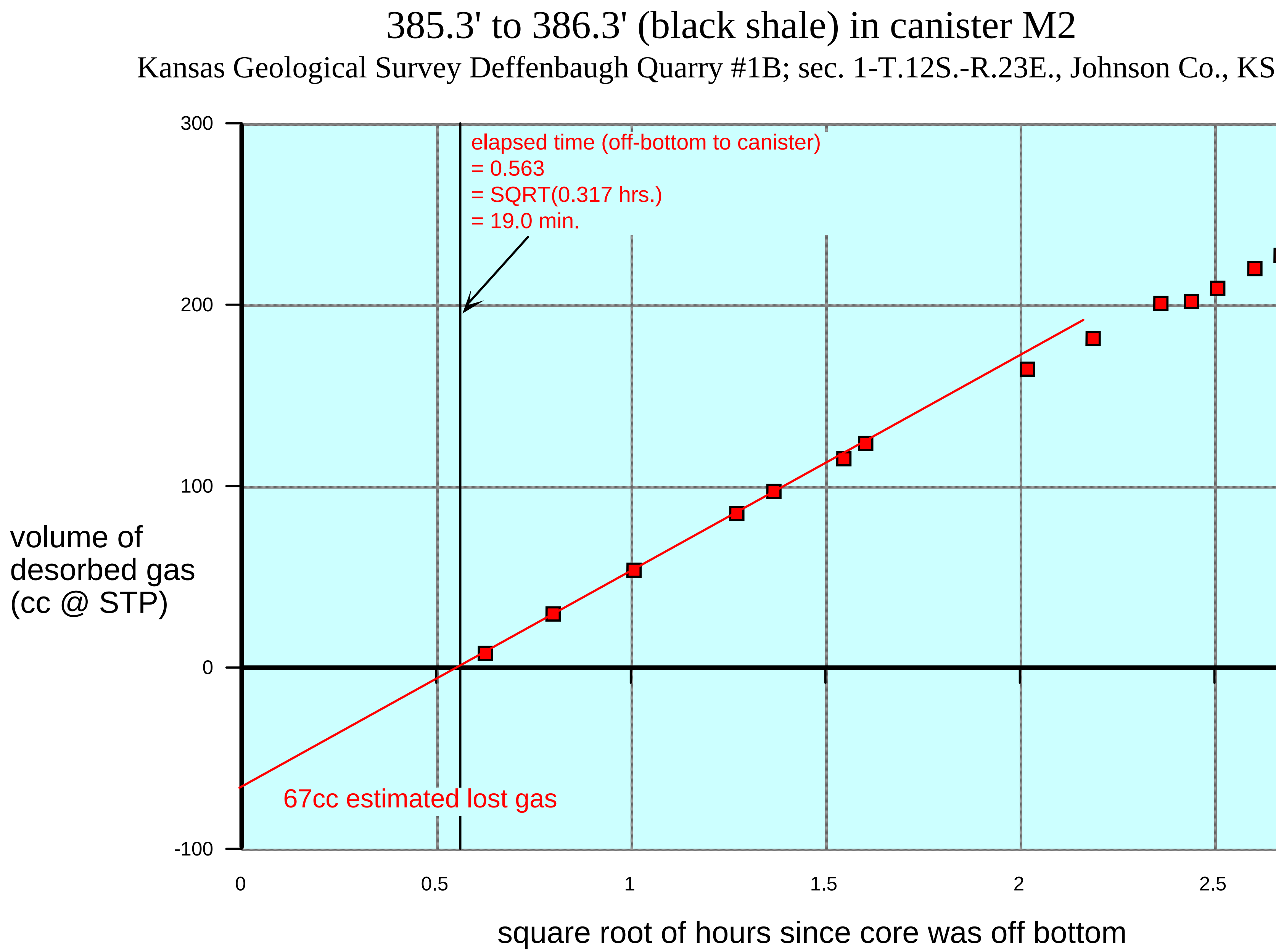

385.3' to 386.3' (black shale) in canister M2
Kansas Geological Survey Deffenbaugh Quarry #1B; sec. 1-T.12S.-R.23E., Johnson Co., KS
elapsed time (off-bottom to canister)
= 0.563
= SQRT(0.317 hrs.)
= 19.0 min.
67cc estimated lost gas
volume of desorbed gas (cc @ STP)
300
200
100
0
-100
0
0.5
1
1.5
2
2.5
3
square root of hours since core was off bottom

Figure 4.

420.5' to 421.9' (Anna Shale) in canister DG1B

Kansas Geological Survey Deffenbaugh Quarry #1B; sec. 1-T.12S.-R.23E., Johnson Co., KS

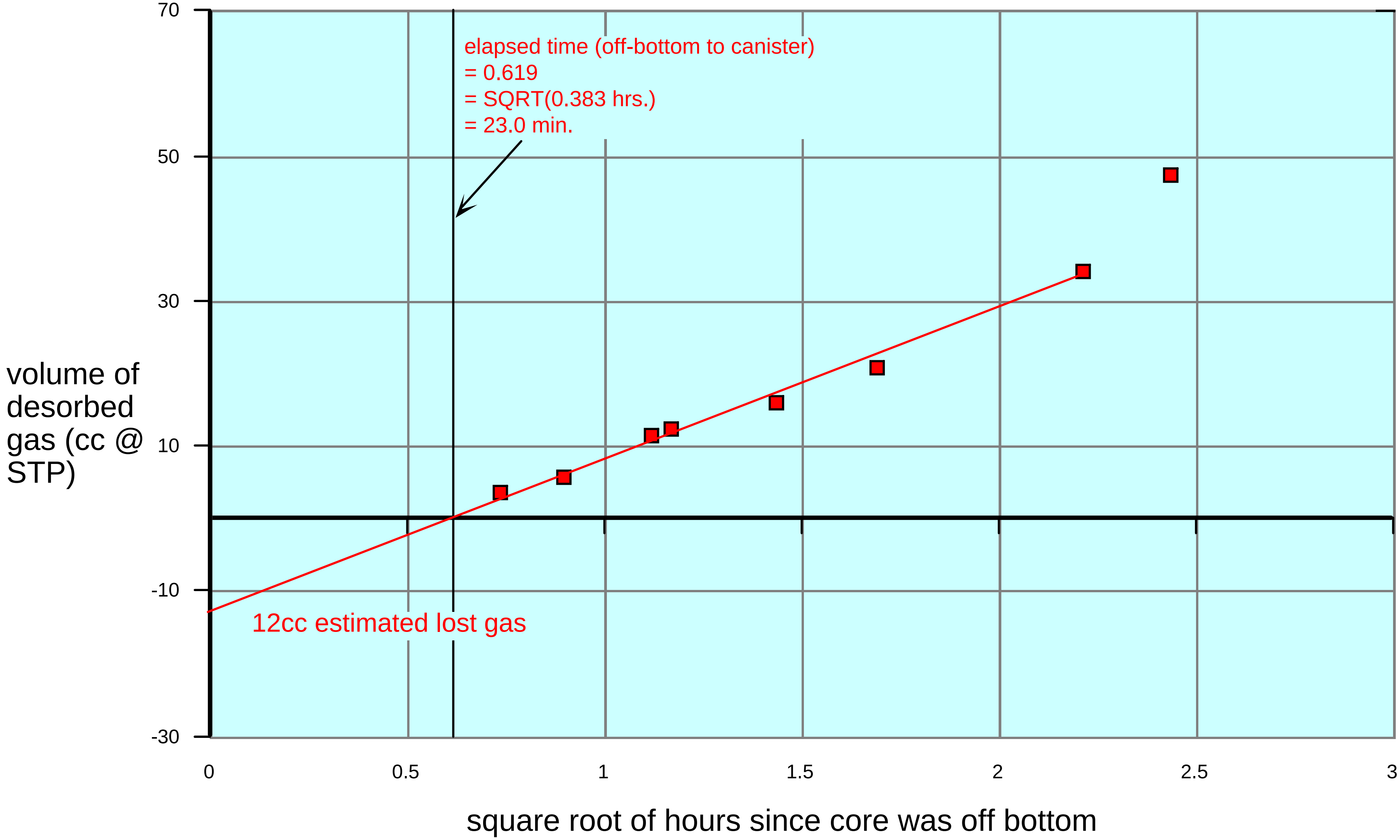


Figure 5.

455.5' to 456.5' (Little Osage Shale) in canister M3

Kansas Geological Survey Deffenbaugh Quarry #1B; sec. 1-T.12S.-R.23E., Johnson Co., KS

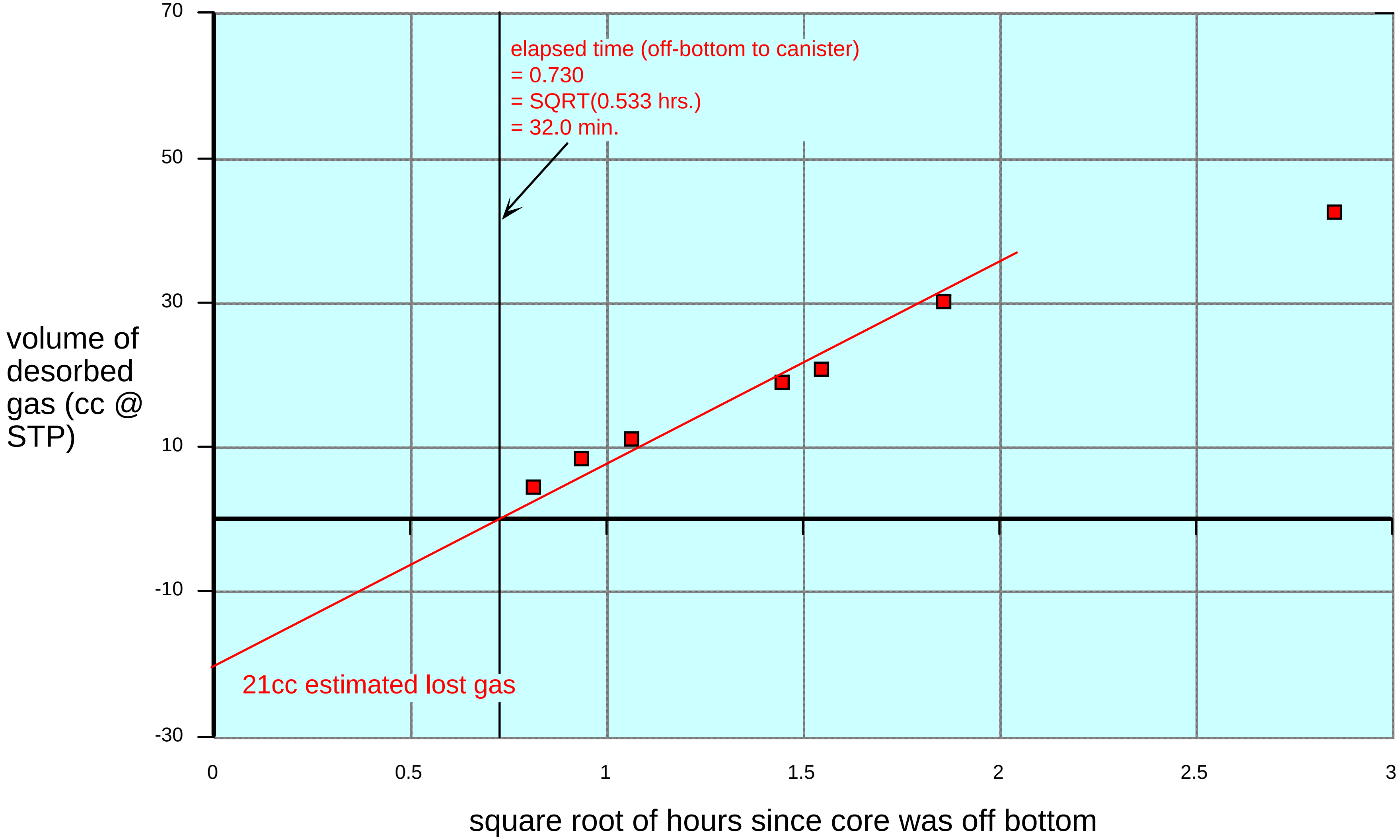


Figure 6.

458.7' to 459.1' (Summit coal) in canister Brady 31

Kansas Geological Survey Deffenbaugh Quarry #1B; sec. 1-T.12S.-R.23E., Johnson Co., KS

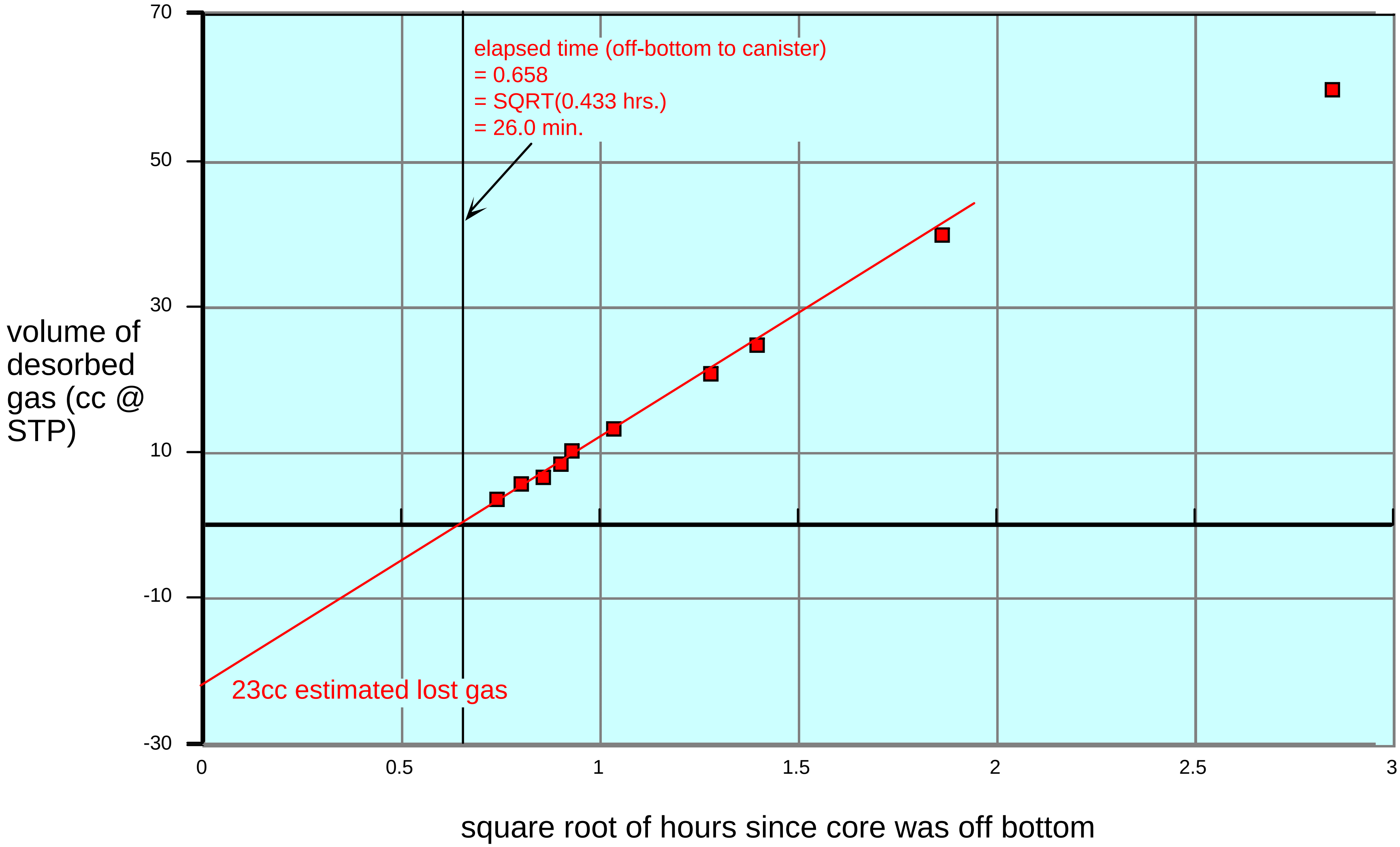
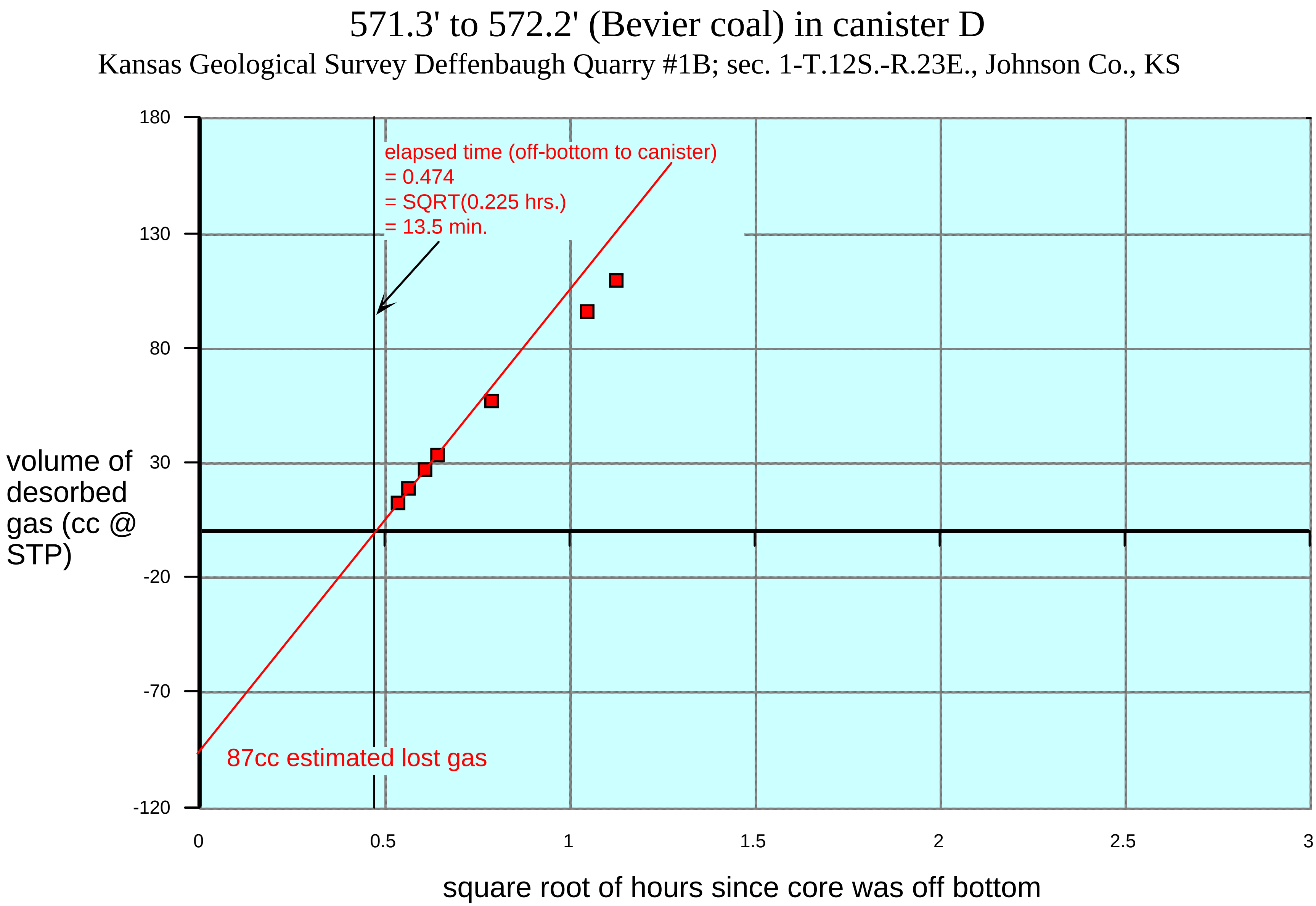
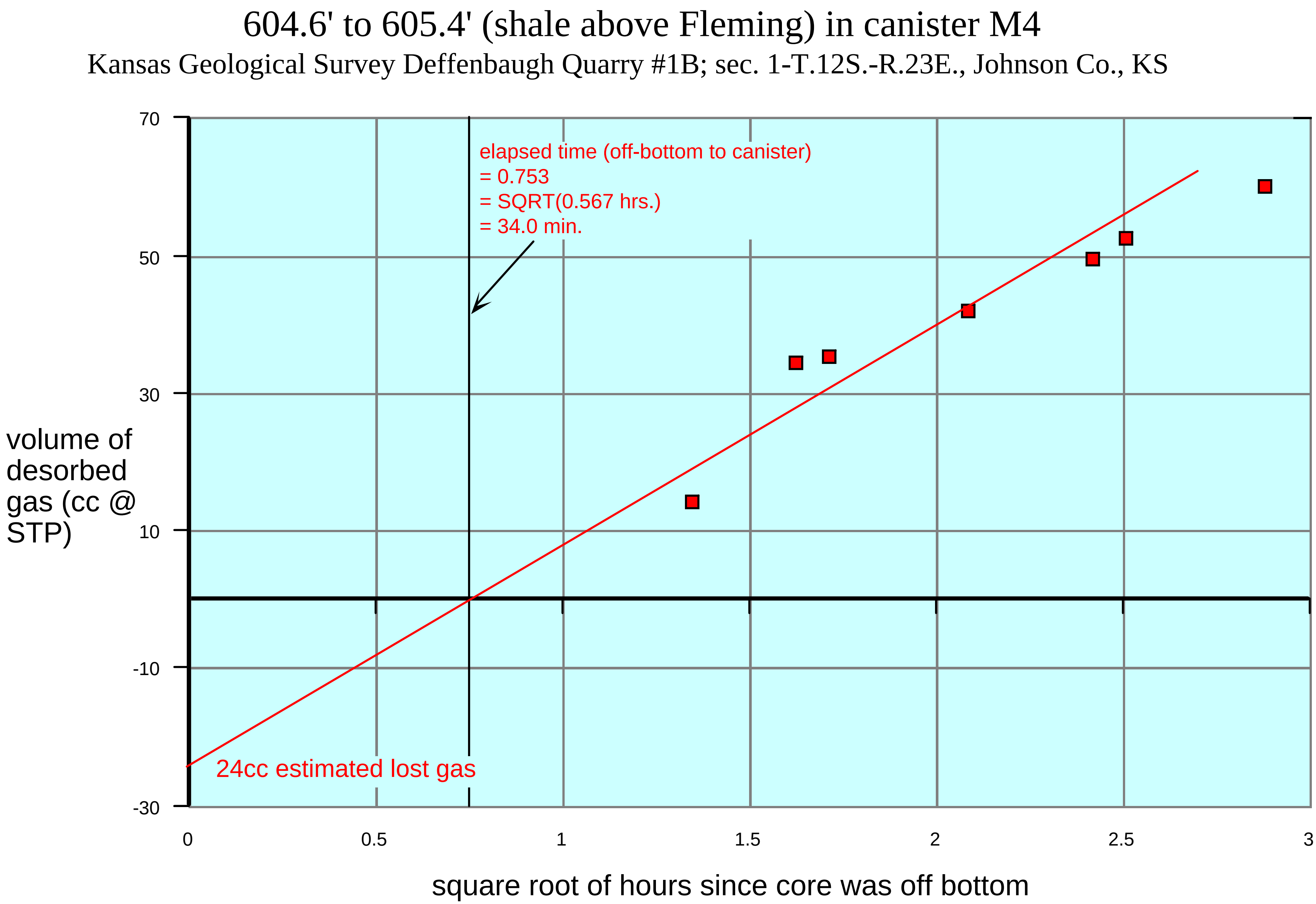


Figure 7.



571.3' to 572.2' (Bevier coal) in canister D
Kansas Geological Survey Deffenbaugh Quarry #1B; sec. 1-T.12S.-R.23E., Johnson Co., KS
elapsed time (off-bottom to canister)
= 0.474
= SQRT(0.225 hrs.)
= 13.5 min.
87cc estimated lost gas
volume of desorbed gas (cc @ STP)
180
130
80
30
-20
-70
-120
0
0.5
1
1.5
2
2.5
3
square root of hours since core was off bottom

Figure 8.



604.6' to 605.4' (shale above Fleming) in canister M4
Kansas Geological Survey Deffenbaugh Quarry #1B; sec. 1-T.12S.-R.23E., Johnson Co., KS
elapsed time (off-bottom to canister)
= 0.753
= SQRT(0.567 hrs.)
= 34.0 min.
24cc estimated lost gas
volume of desorbed gas (cc @ STP)
70
50
30
10
-10
-30
0
0.5
1
1.5
2
2.5
3
square root of hours since core was off bottom

Figure 9.

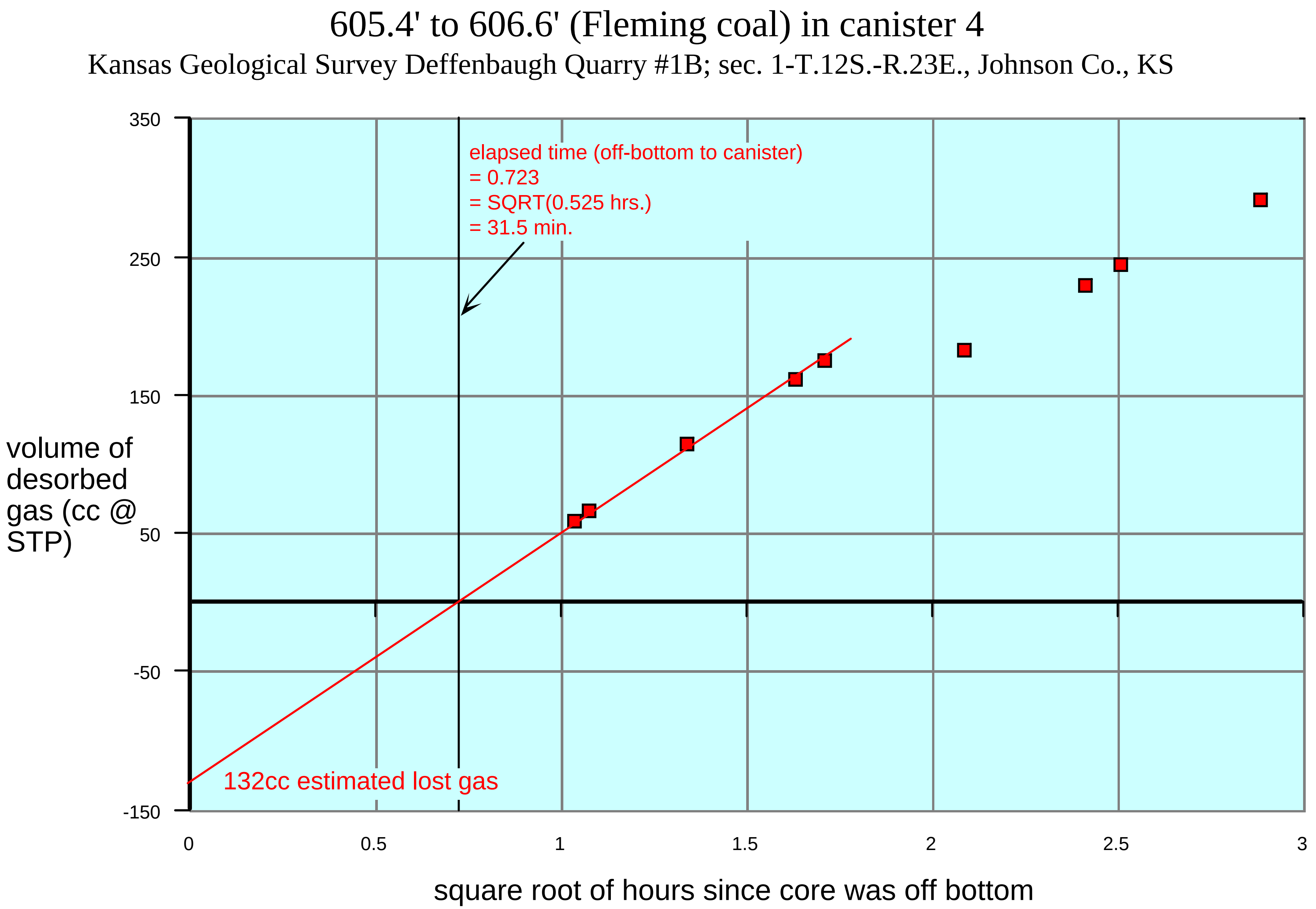

605.4' to 606.6' (Fleming coal) in canister 4
Kansas Geological Survey Deffenbaugh Quarry #1B; sec. 1-T.12S.-R.23E., Johnson Co., KS
elapsed time (off-bottom to canister)
= 0.723
= SQRT(0.525 hrs.)
= 31.5 min.
132cc estimated lost gas
volume of desorbed gas (cc @ STP)
350
250
150
50
-50
-150
0
0.5
1
1.5
2
2.5
3
square root of hours since core was off bottom

Figure 10.

639.0' to 640.8' (Mineral coal) in canister L

Kansas Geological Survey Deffenbaugh Quarry #1B; sec. 1-T.12S.-R.23E., Johnson Co., KS

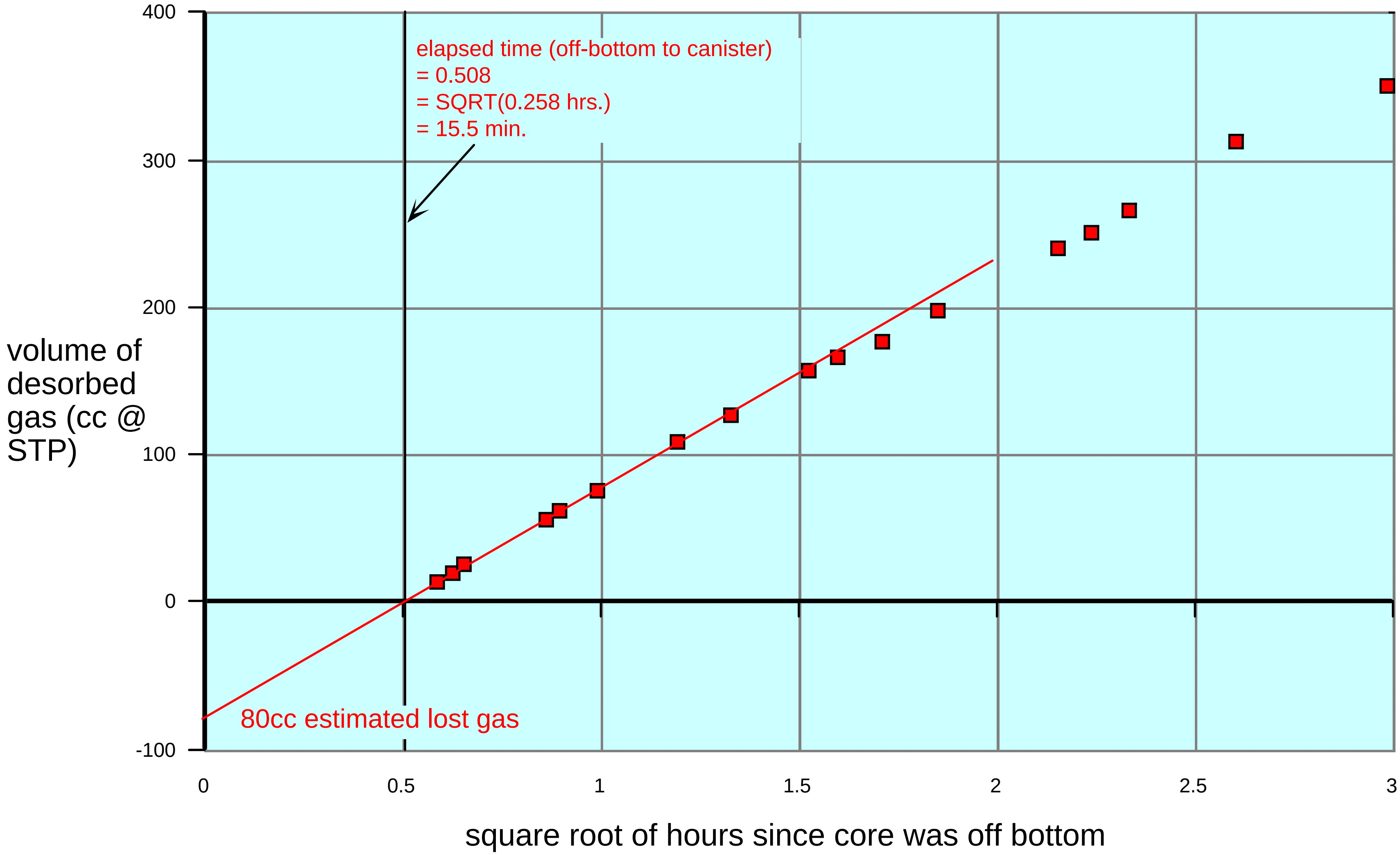


Figure 11.

710.7' to 711.5' (? coal) in canister Brady 24

Kansas Geological Survey Deffenbaugh Quarry #1B; sec. 1-T.12S.-R.23E., Johnson Co., KS

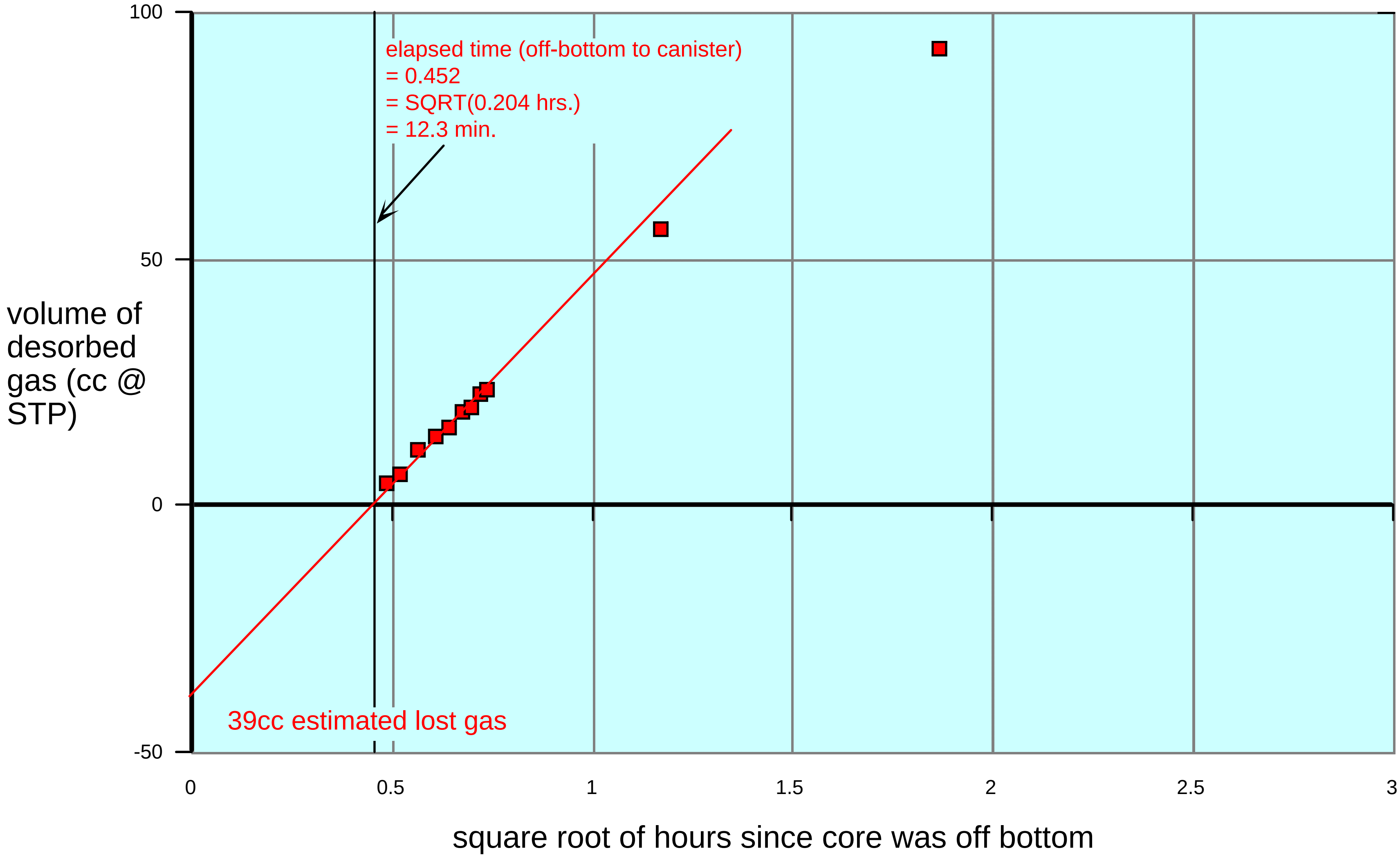


Figure 12.

742.9' to 743.9' (? coal) in canister Brady 25

Kansas Geological Survey Deffenbaugh Quarry #1B; sec. 1-T.12S.-R.23E., Johnson Co., KS

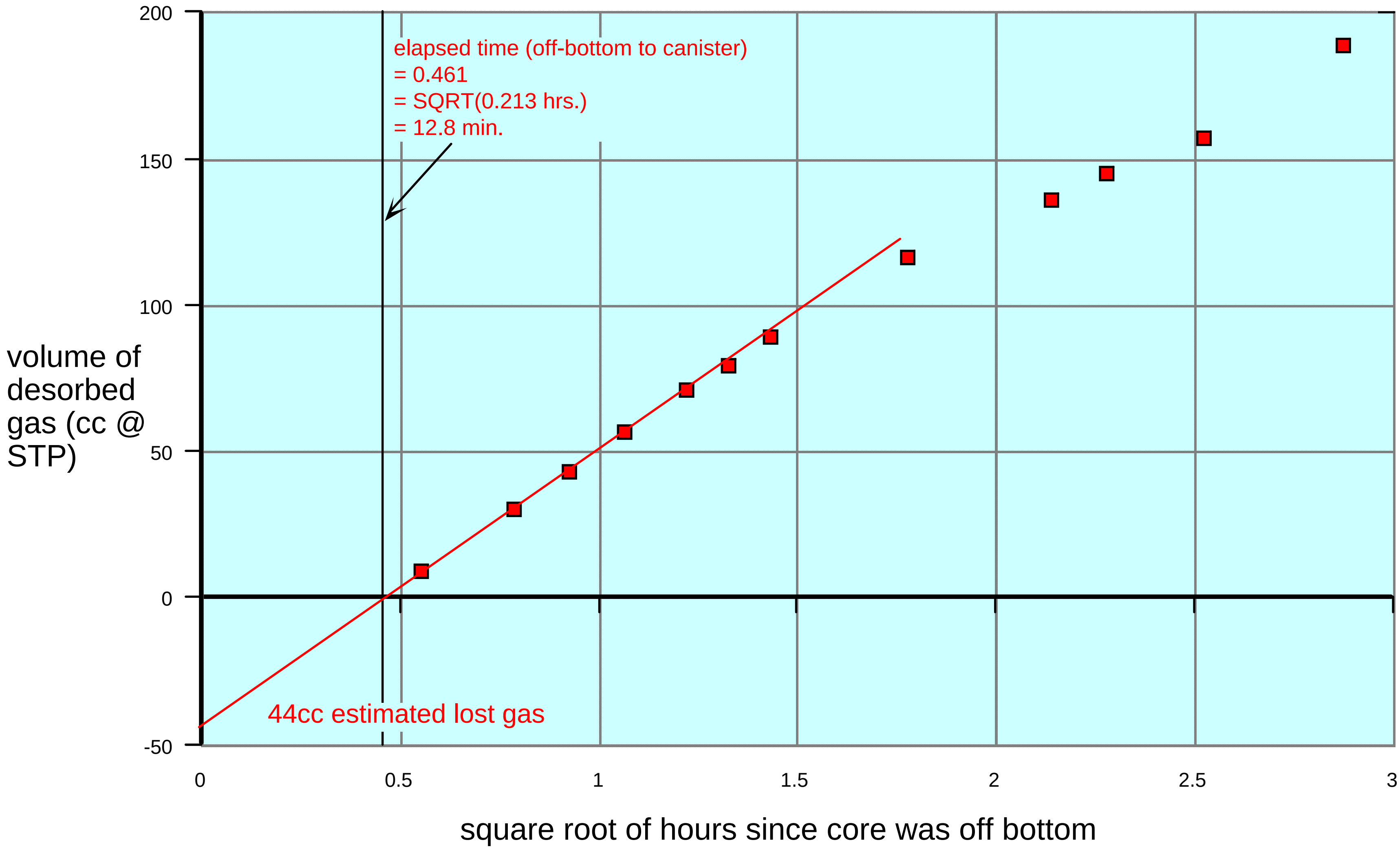


Figure 13.

388.0' to 389.0' (black shale) in canister DQ1

Kansas Geological Survey Deffenbaugh Quarry #2; sec. 1-T.12S.-R.23E., Johnson Co., KS

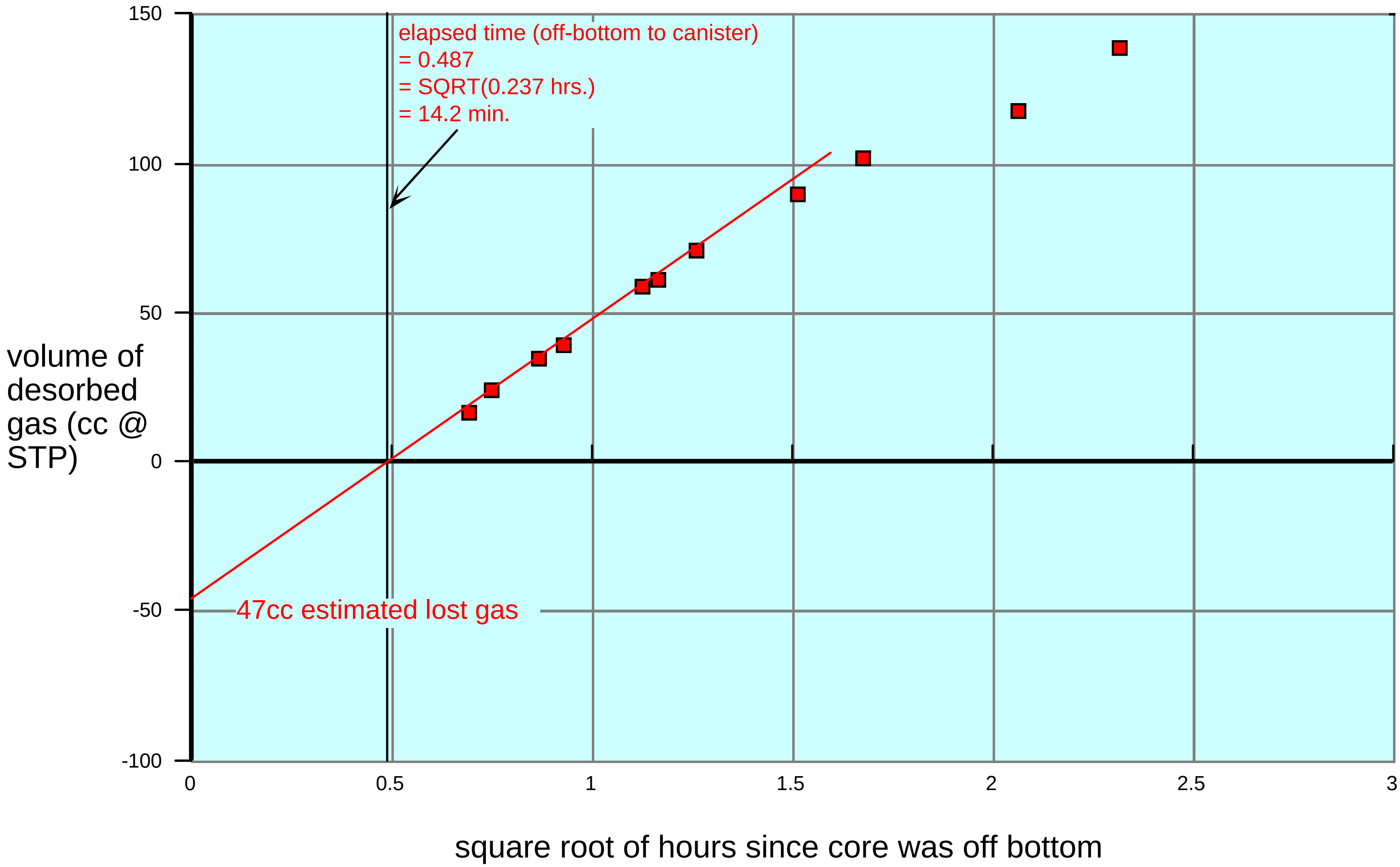


Figure 14.

424.0' to 426.0' (Anna Shale) in canister DQ2

Kansas Geological Survey Deffenbaugh Quarry #2; sec. 1-T.12S.-R.23E., Johnson Co., KS

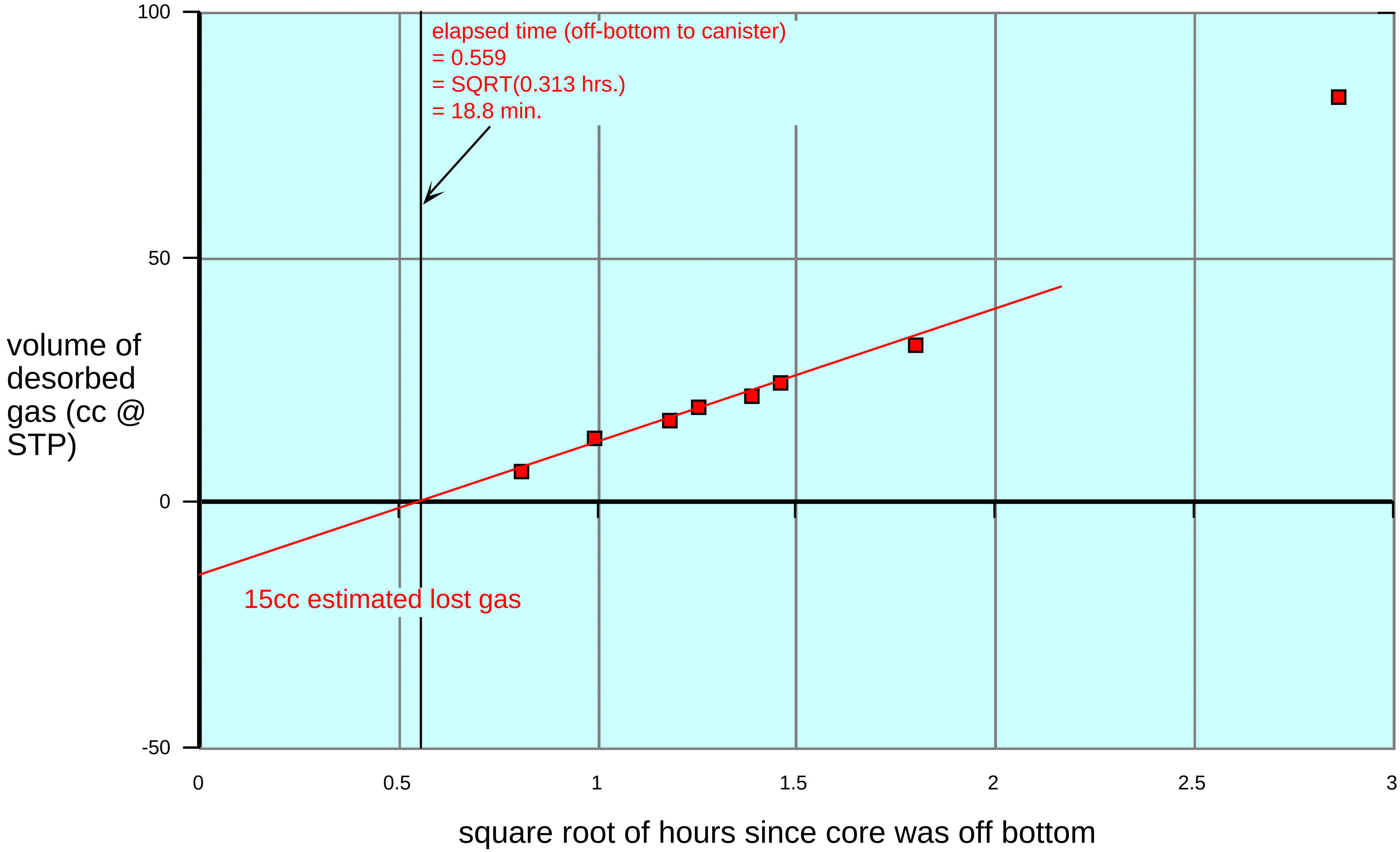


Figure 15.

455.3' to 456.1' (Little Osage Shale) in canister DQ3

Kansas Geological Survey Deffenbaugh Quarry #2; sec. 1-T.12S.-R.23E., Johnson Co., KS

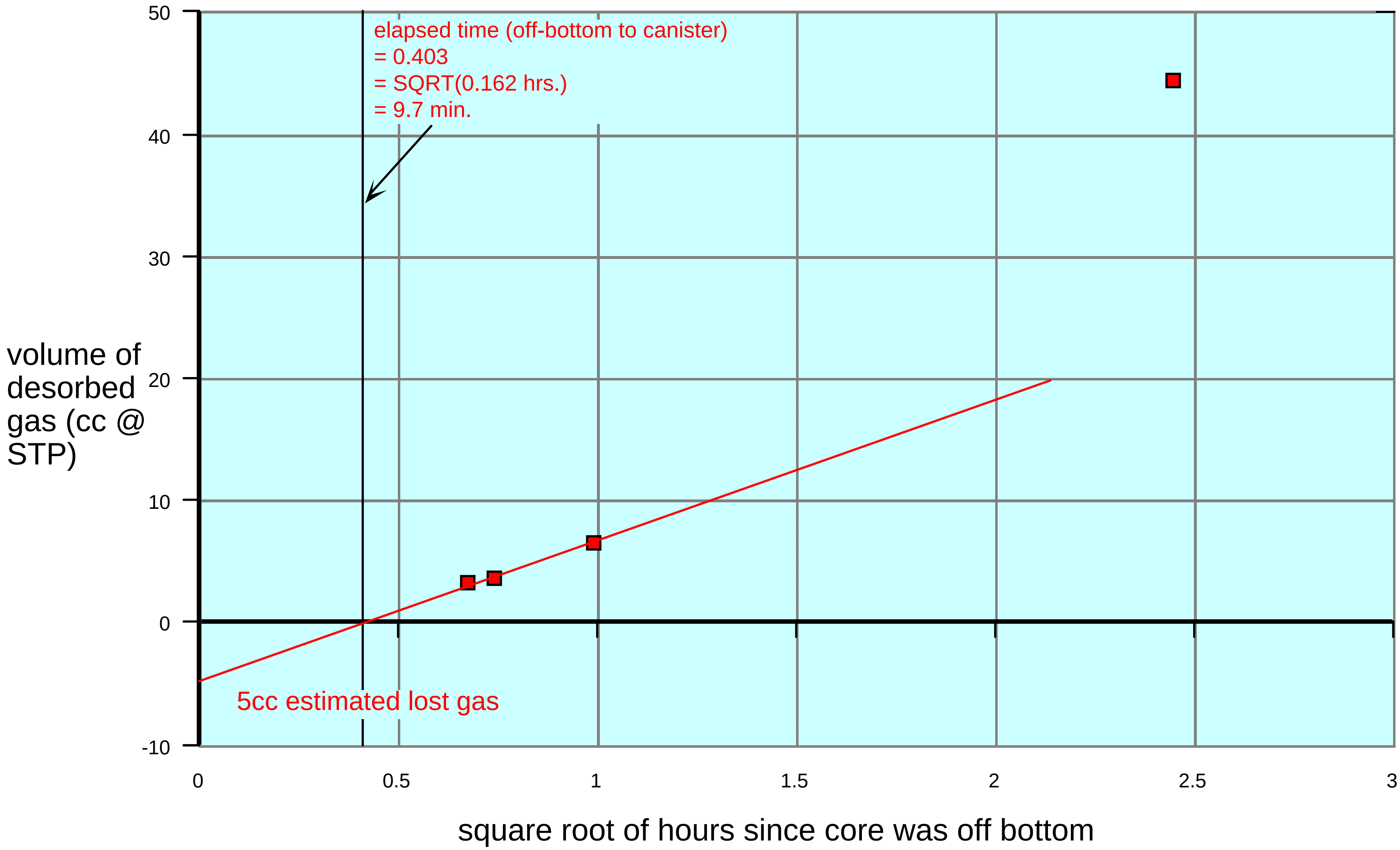


Figure 16.

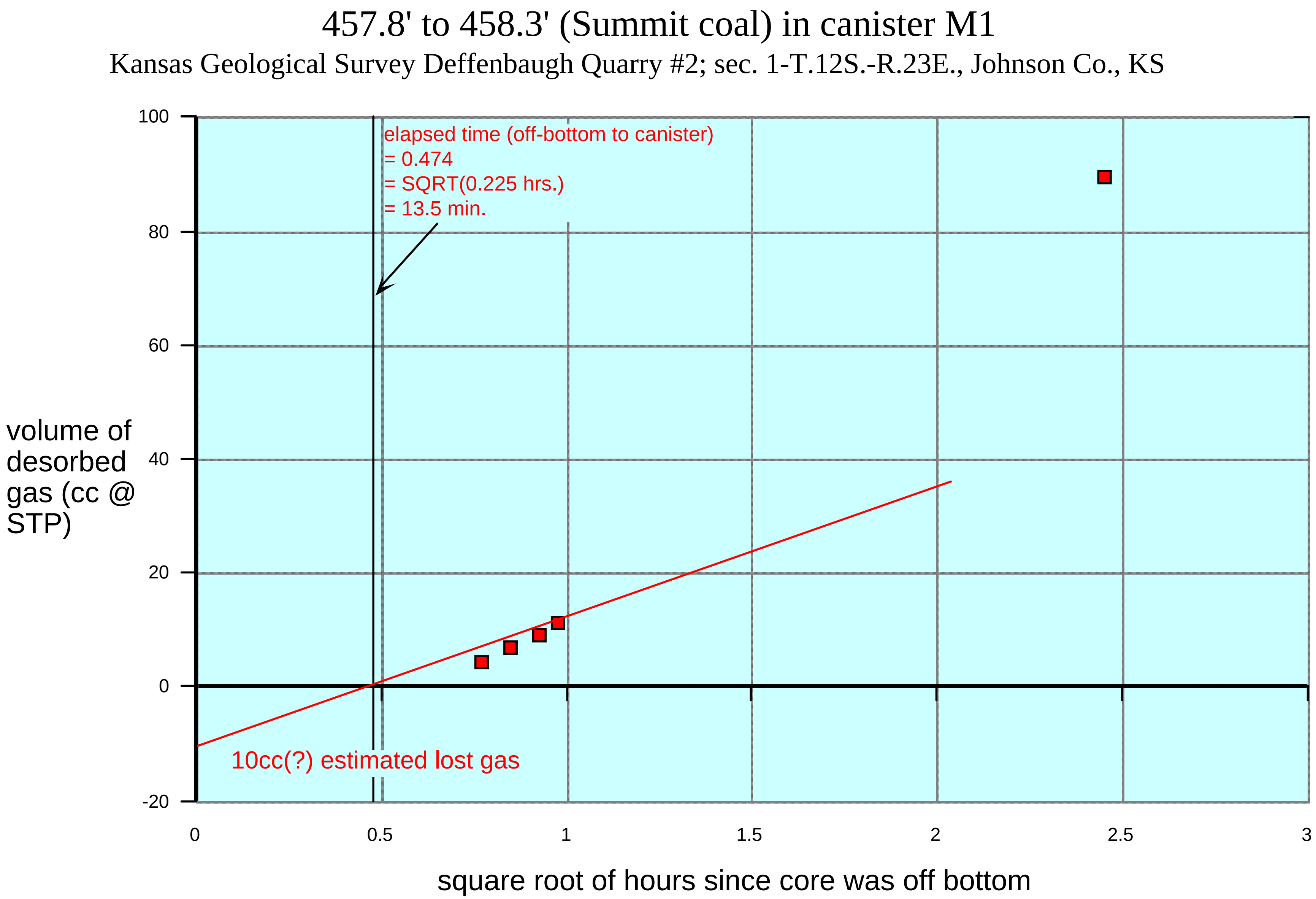

457.8' to 458.3' (Summit coal) in canister M1
Kansas Geological Survey Deffenbaugh Quarry #2; sec. 1-T.12S.-R.23E., Johnson Co., KS
100
80
60
40
20
0
-20
volume of desorbed gas (cc @ STP)
elapsed time (off-bottom to canister)
= 0.474
= SQRT(0.225 hrs.)
= 13.5 min.
10cc(?) estimated lost gas
0
0.5
1
1.5
2
2.5
3
square root of hours since core was off bottom

Figure 17.

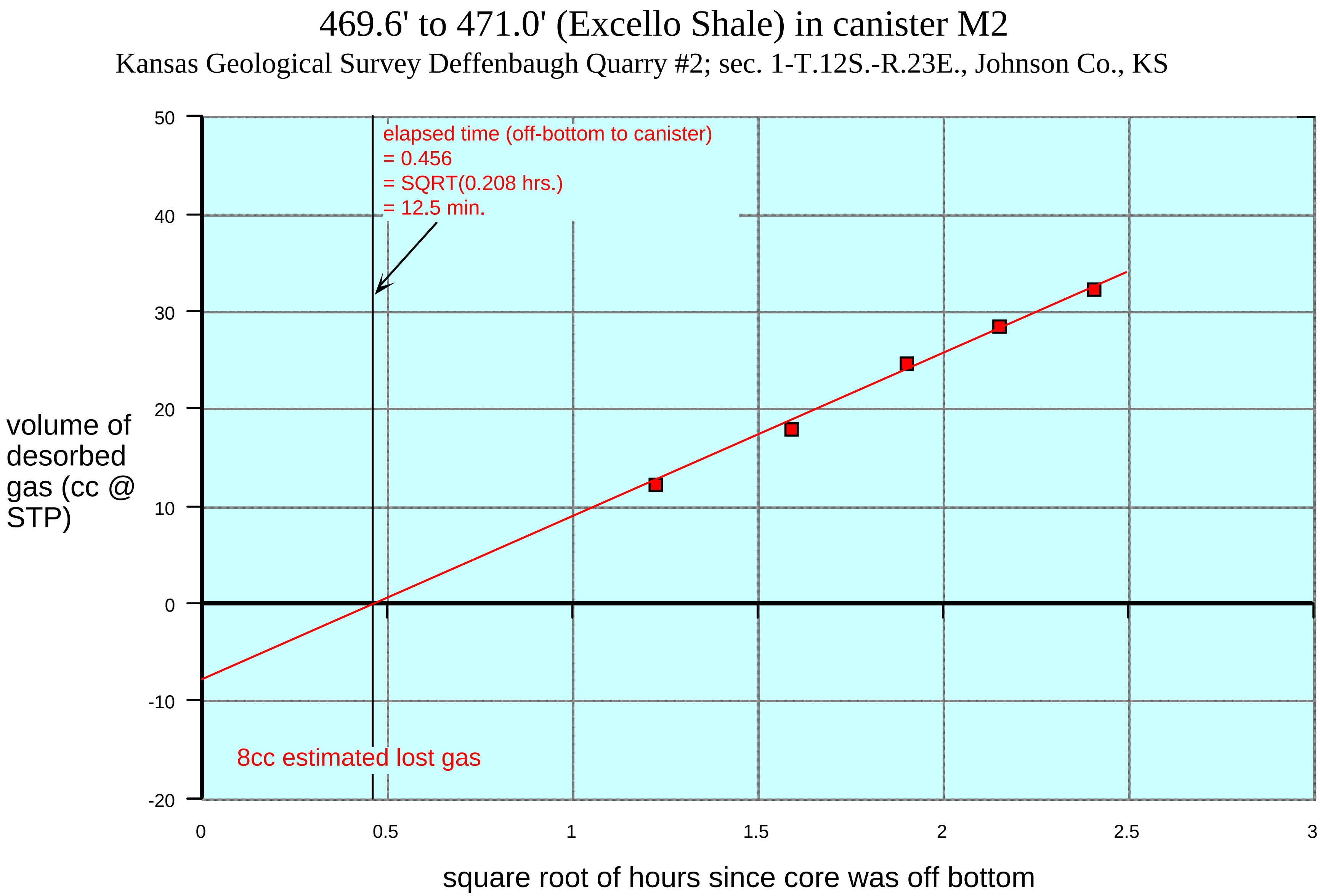

469.6' to 471.0' (Excello Shale) in canister M2
Kansas Geological Survey Deffenbaugh Quarry #2; sec. 1-T.12S.-R.23E., Johnson Co., KS
elapsed time (off-bottom to canister)
= 0.456
= SQRT(0.208 hrs.)
= 12.5 min.
8cc estimated lost gas
volume of desorbed gas (cc @ STP)
50
40
30
20
10
0
-10
-20
0
0.5
1
1.5
2
2.5
3
square root of hours since core was off bottom

Figure 18.

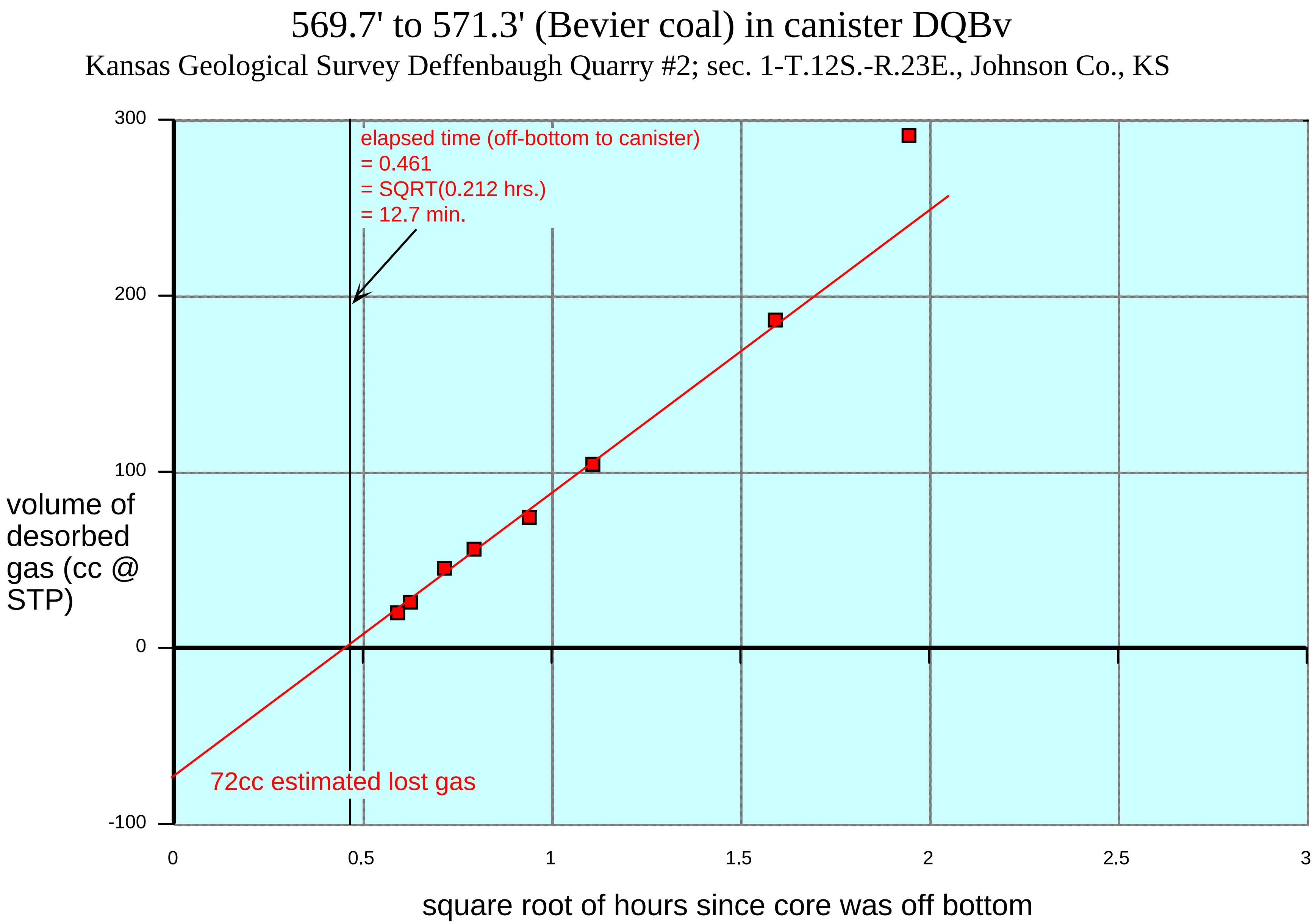

569.7' to 571.3' (Bevier coal) in canister DQBv
Kansas Geological Survey Deffenbaugh Quarry #2; sec. 1-T.12S.-R.23E., Johnson Co., KS
elapsed time (off-bottom to canister)
= 0.461
= SQRT(0.212 hrs.)
= 12.7 min.
72cc estimated lost gas
300
200
100
0
-100
0
0.5
1
1.5
2
2.5
3
volume of desorbed gas (cc @ STP)
square root of hours since core was off bottom

Figure 19.

605.0' to 606.0' (black shale above the Fleming coal) in canister M4

Kansas Geological Survey Deffenbaugh Quarry #2; sec. 1-T.12S.-R.23E., Johnson Co., KS

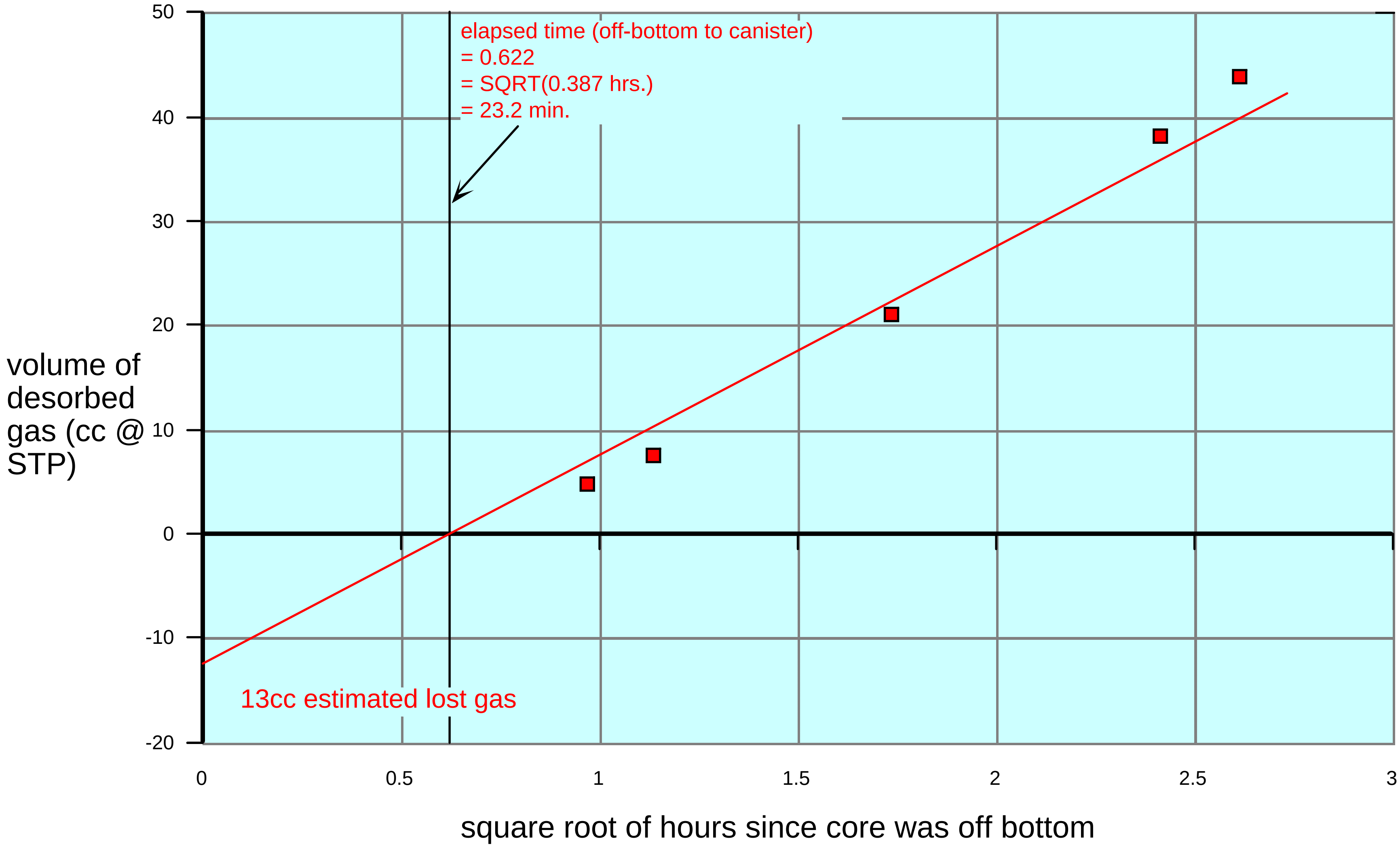


Figure 20.

606.0' to 607.3' (Fleming coal) in canister 6

Kansas Geological Survey Deffenbaugh Quarry #2; sec. 1-T.12S.-R.23E., Johnson Co., KS

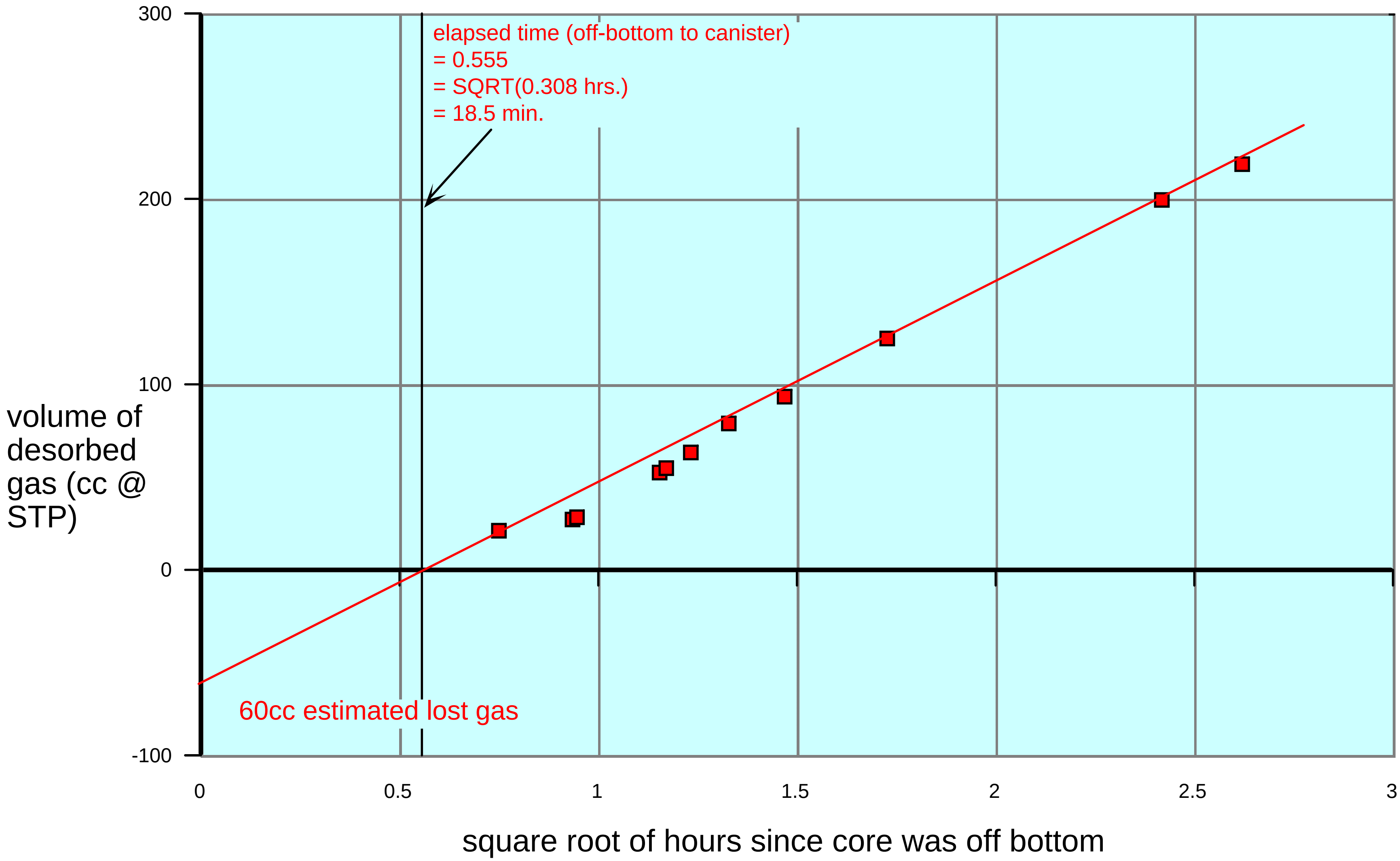


Figure 21.

637.6' to 638.0' and 638.3' to 638.9' (Mineral coal) in canister DQM

Kansas Geological Survey Deffenbaugh Quarry #2; sec. 1-T.12S.-R.23E., Johnson Co., KS

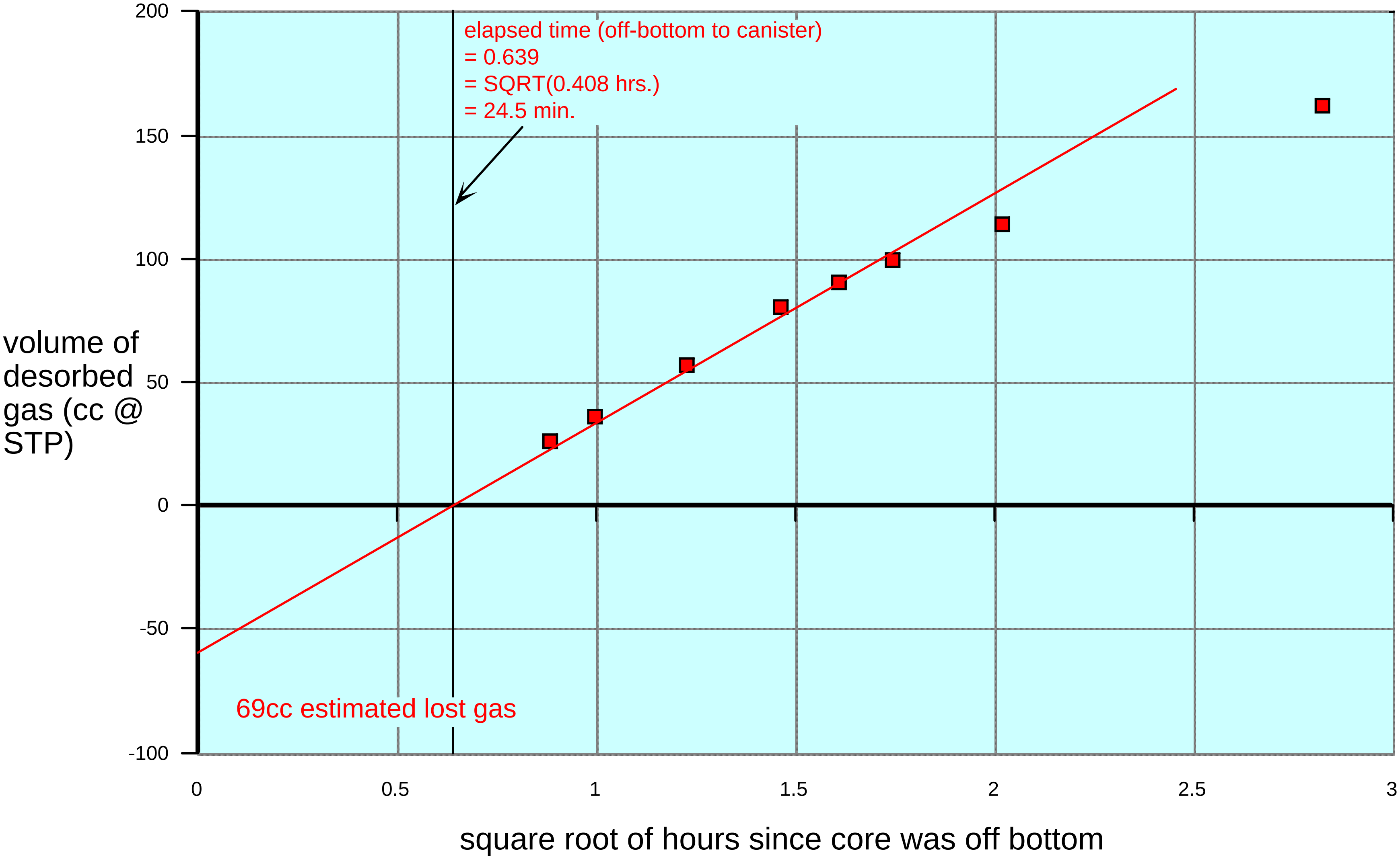
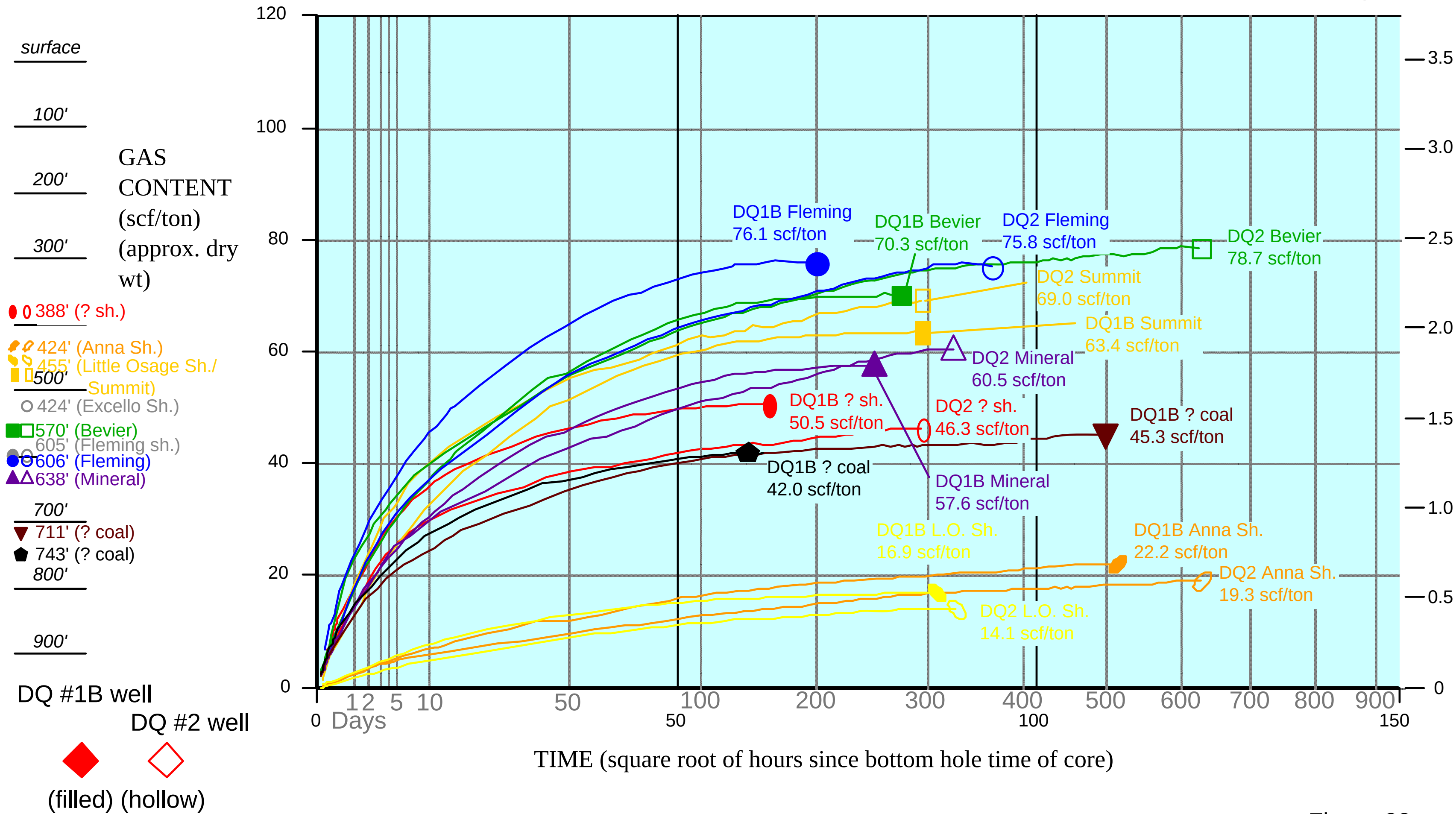


Figure 22.

DESORPTION CURVES for CORE SAMPLES
KANSAS GEOLOGICAL SURVEY
DEFFENBAUGH QUARRY WELLS #1B and #2



TIME (square root of hours since bottom hole time of core)

Figure 23.

Gas-in-Place and Relative Deliverablity
Kansas Geological Survey Deffenbaugh Quarry #1B & 2;
sec. 1-T.12S.-R.23E., Johnson Co., KS

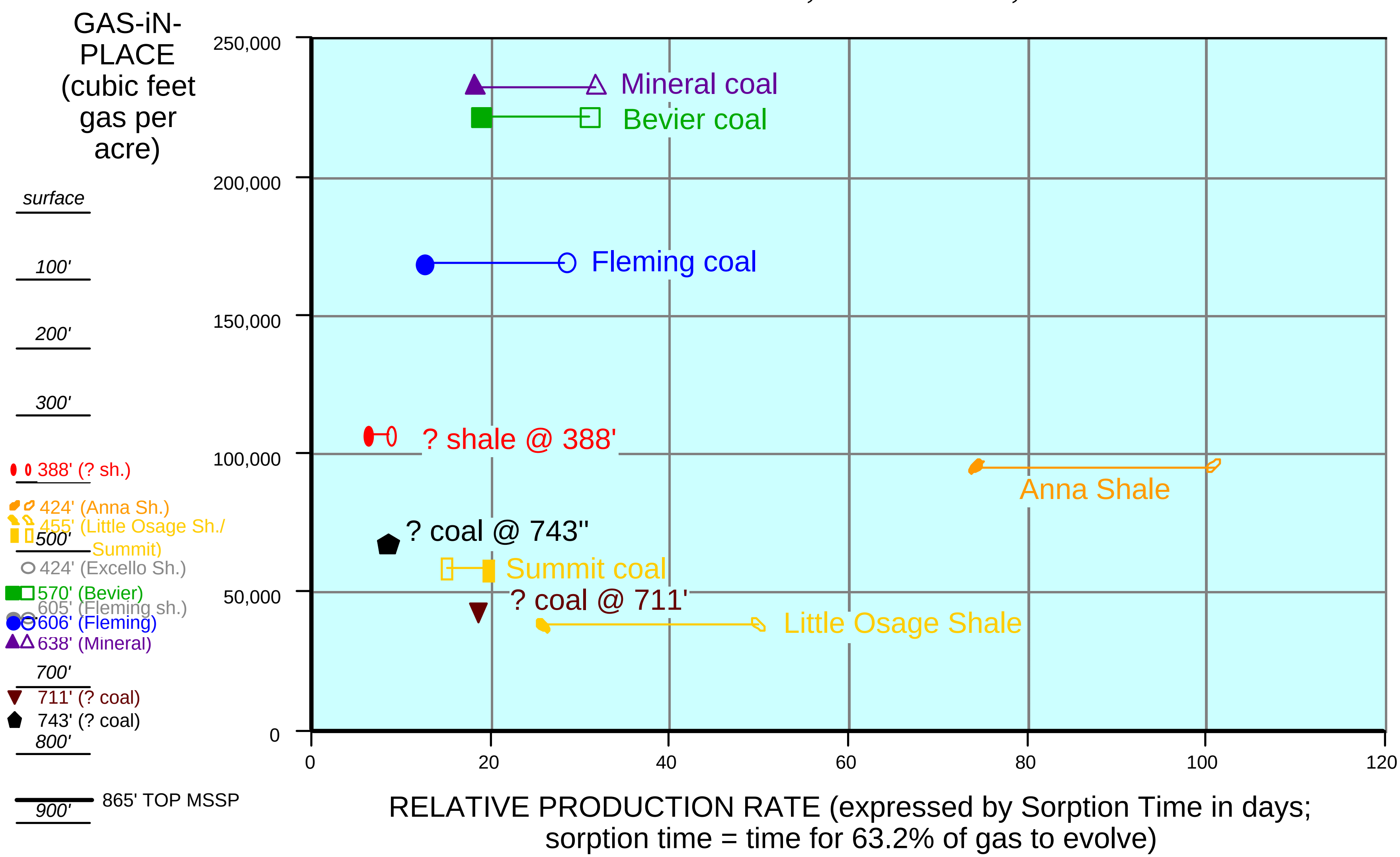
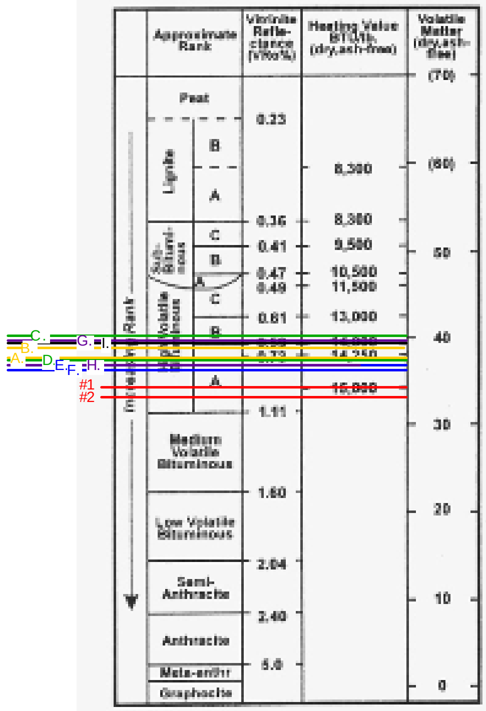


FIGURE 24.

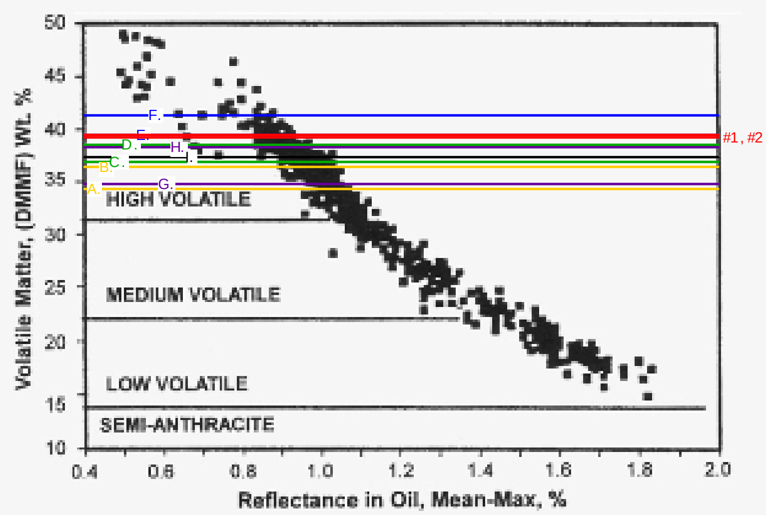
ASTM Classification of coals by rank

(from McLennan and others, 1995, p. 10.19)

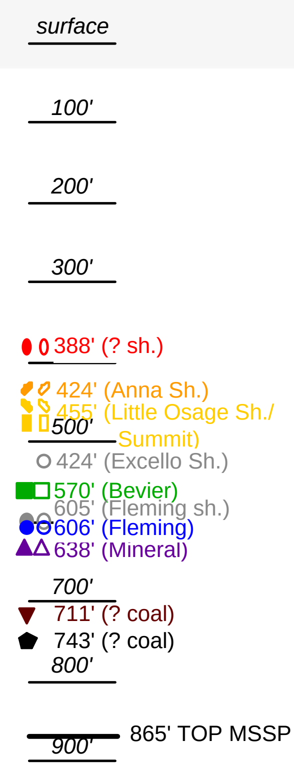


A. Coal Rank Classification Chart.

1. Spencer #2-6 Mineral coal (14,942 BTU/lb. (MAF); 38.30% volatile matter)
2. Beurskens #13-28 Mineral coal (15,239 BTU/lb. (MAF); 39.46% volatile matter)



B. Relation Between the Rank of U.S. Coals and Vitrinite Reflectance.



CHARACTERISTICS of DEFFENBAUGH QUARRY SAMPLES (from proximate analysis)

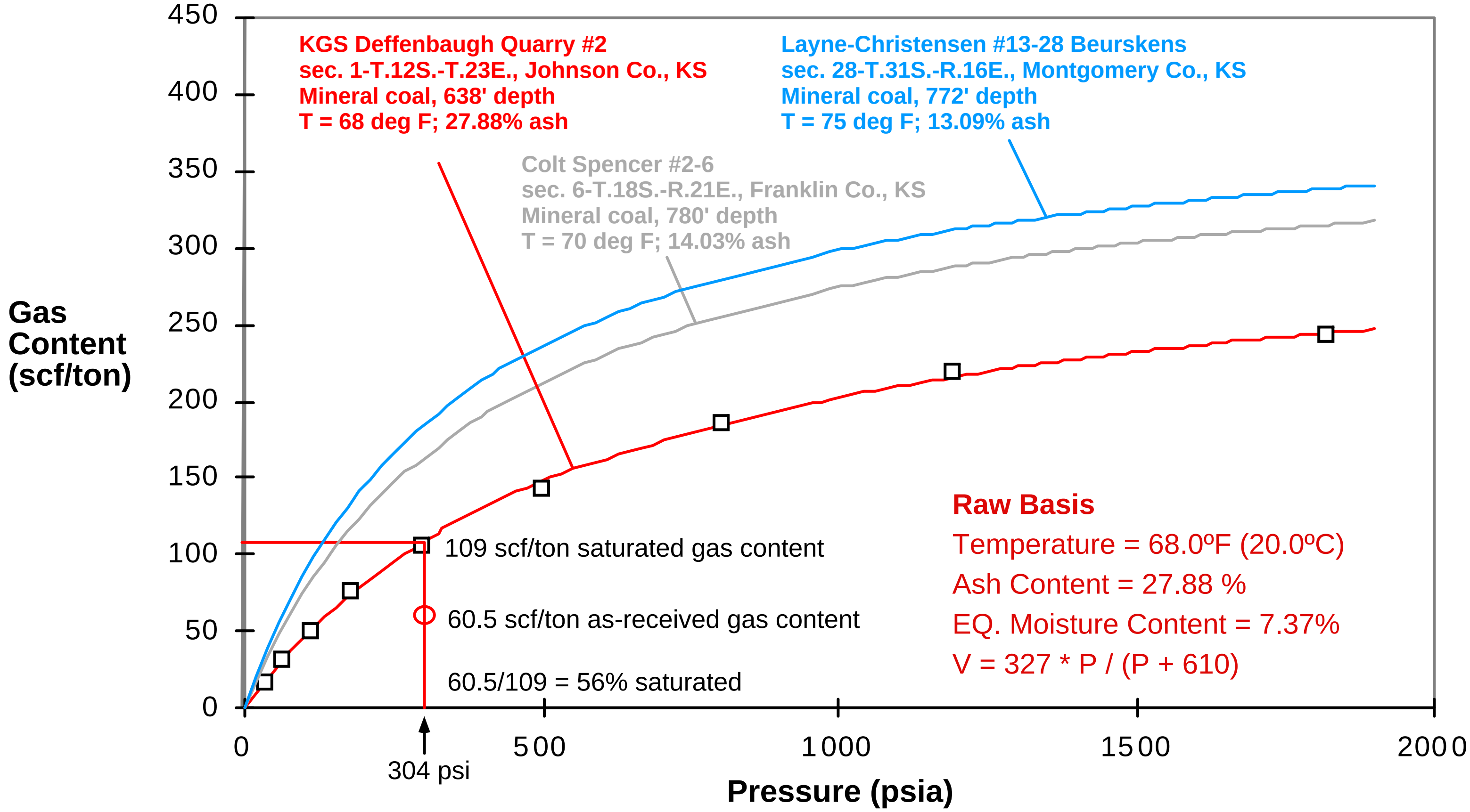
BTU/lb. (MAF)
A. 14,322 BTU/lb. DQ1B Summit coal
B. 14,108 BTU/lb. DQ2 Summit coal
C. 13,888 BTU/lb. DQ1B Bevier coal
D. 14,326 BTU/lb. DQ2 Bevier coal
E. 14,435 BTU/lb. DQ1B Fleming coal
F. 14,614 BTU/lb. DQ2 Fleming coal
G. 13,995 BTU/lb. DQ1B Mineral coal
H. 14,445 BTU/lb. DQ2 Mineral coal
I. 14,045 BTU/lb. DQ1B coal at 711'

% VOLATILE MATTER (MAF)
A. 34.37% DQ1B Summit coal
B. 35.64% DQ2 Summit coal
C. 36.68% DQ1B Bevier coal
D. 38.75% DQ2 Bevier coal
E. 39.42% DQ1B Fleming coal
F. 41.29% DQ2 Fleming coal
G. 39.90% DQ1B Mineral coal
H. 38.16% DQ2 Mineral coal
I. 37.65% DQ1B coal at 711'

Figure 25.

Methane Adsorption Isotherms for Mineral coal in Eastern Kansas

compared to Mineral coal gas content and pressure at Deffenbaugh Quarry #2



0.476 psi/ft X 638 ft depth = 304 psi reservoir pressure for Mineral coal

(0.476 psi/ft is hydrostatic gradient for salt water)

Figure 26.

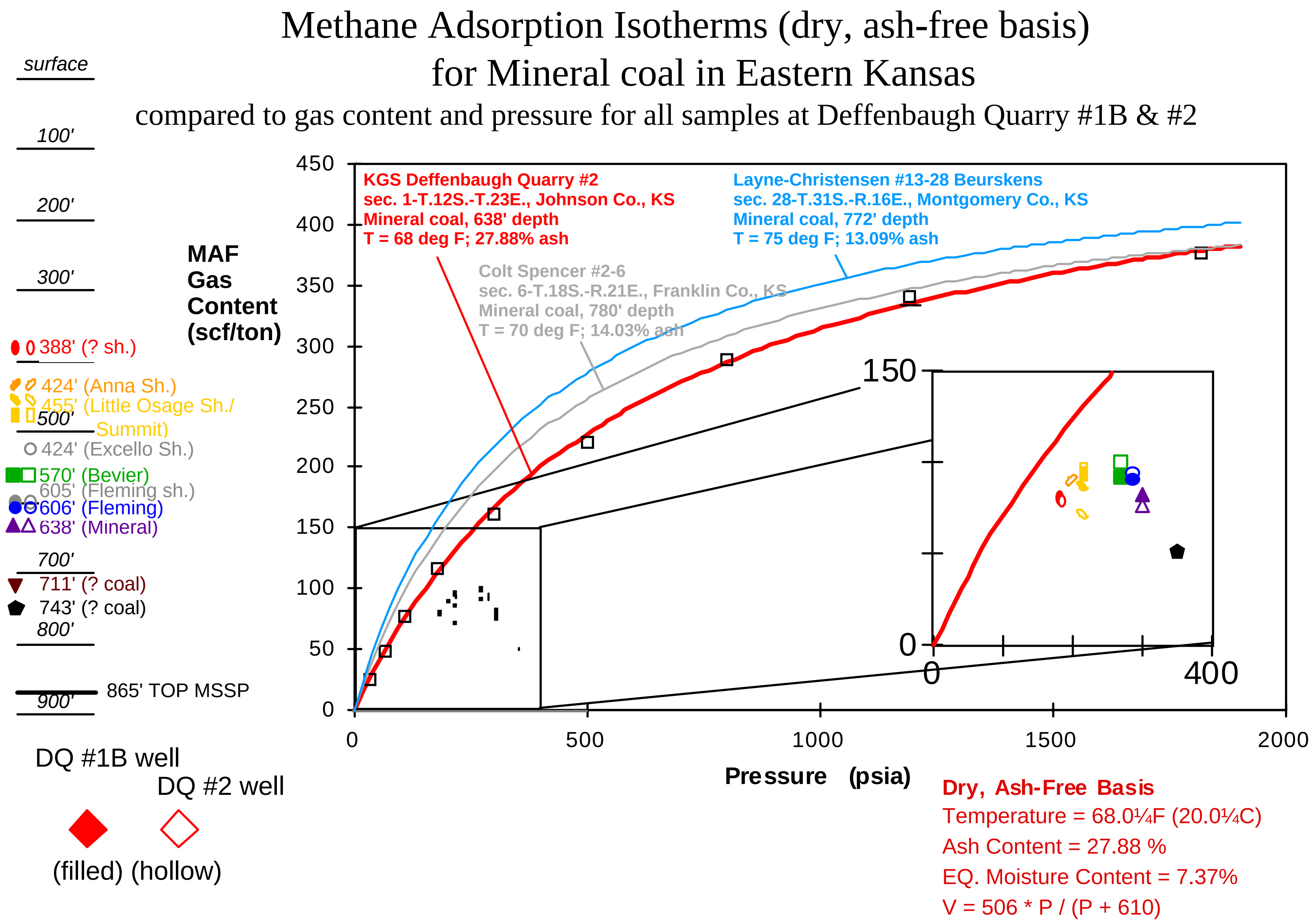
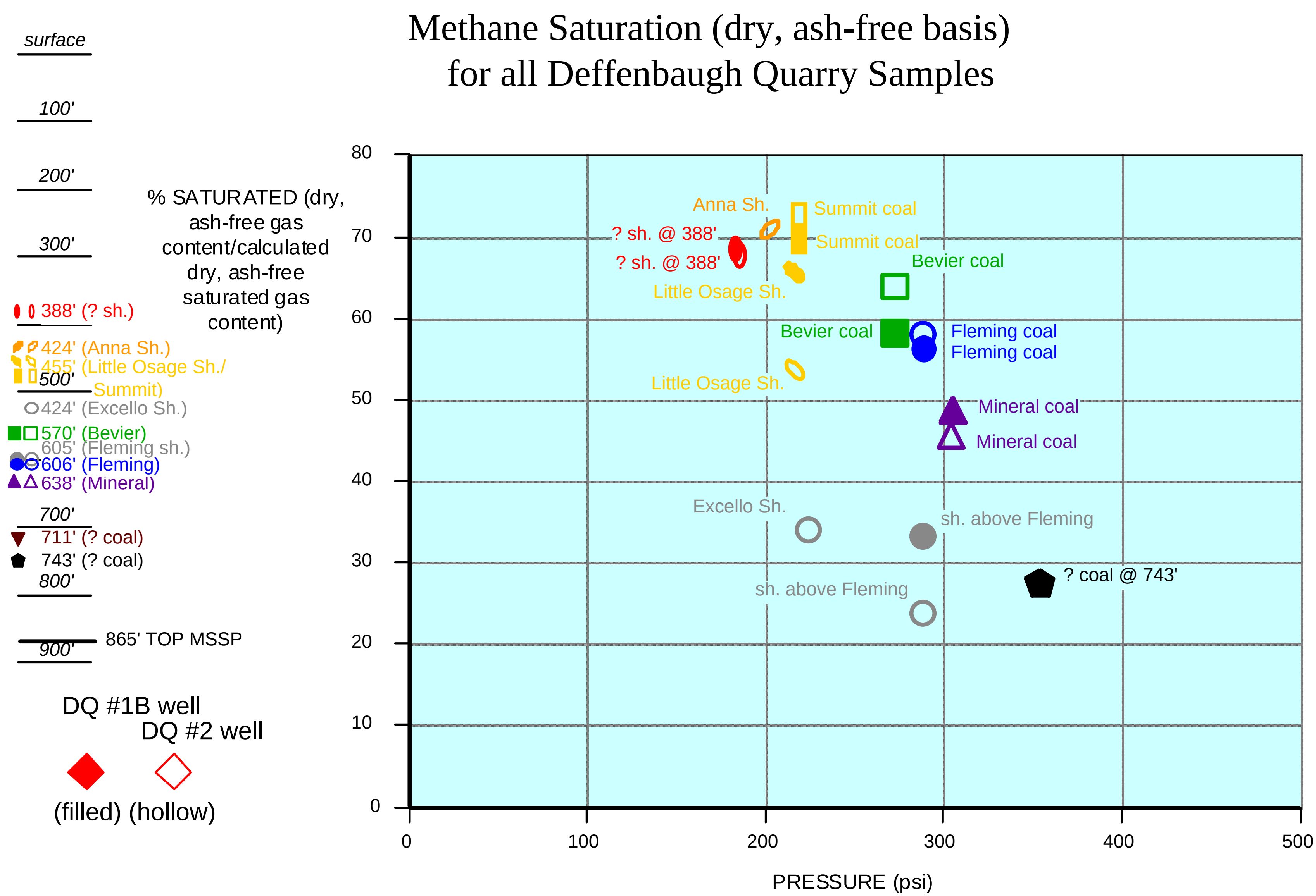

Methane Adsorption Isotherms (dry, ash-free basis)
for Mineral coal in Eastern Kansas
compared to gas content and pressure for all samples at Deffenbaugh Quarry #1B & #2
surface
100'
200'
300'
500'
700'
800'
900'
865' TOP MSSP
388' (? sh.)
424' (Anna Sh.)
455' (Little Osage Sh./ Summit)
424' (Excello Sh.)
570' (Bevier)
605' (Fleming sh.)
606' (Fleming)
638' (Mineral)
711' (? coal)
743' (? coal)
DQ #1B well
DQ #2 well
(filled) (hollow)
MAF Gas Content (scf/ton)
Pressure (psia)
KGS Deffenbaugh Quarry #2
sec. 1-T.12S.-T.23E., Johnson Co., KS
Mineral coal, 638' depth
T = 68 deg F; 27.88% ash
Layne-Christensen #13-28 Beurskens
sec. 28-T.31S.-R.16E., Montgomery Co., KS
Mineral coal, 772' depth
T = 75 deg F; 13.09% ash
Colt Spencer #2-6
sec. 6-T.18S.-R.21E., Franklin Co., KS
Mineral coal, 780' depth
T = 70 deg F; 14.03% ash
Dry, Ash-Free Basis
Temperature = 68.0¼F (20.0¼C)
Ash Content = 27.88 %
EQ. Moisture Content = 7.37%
V = 506 * P / (P + 610)

Figure 27.

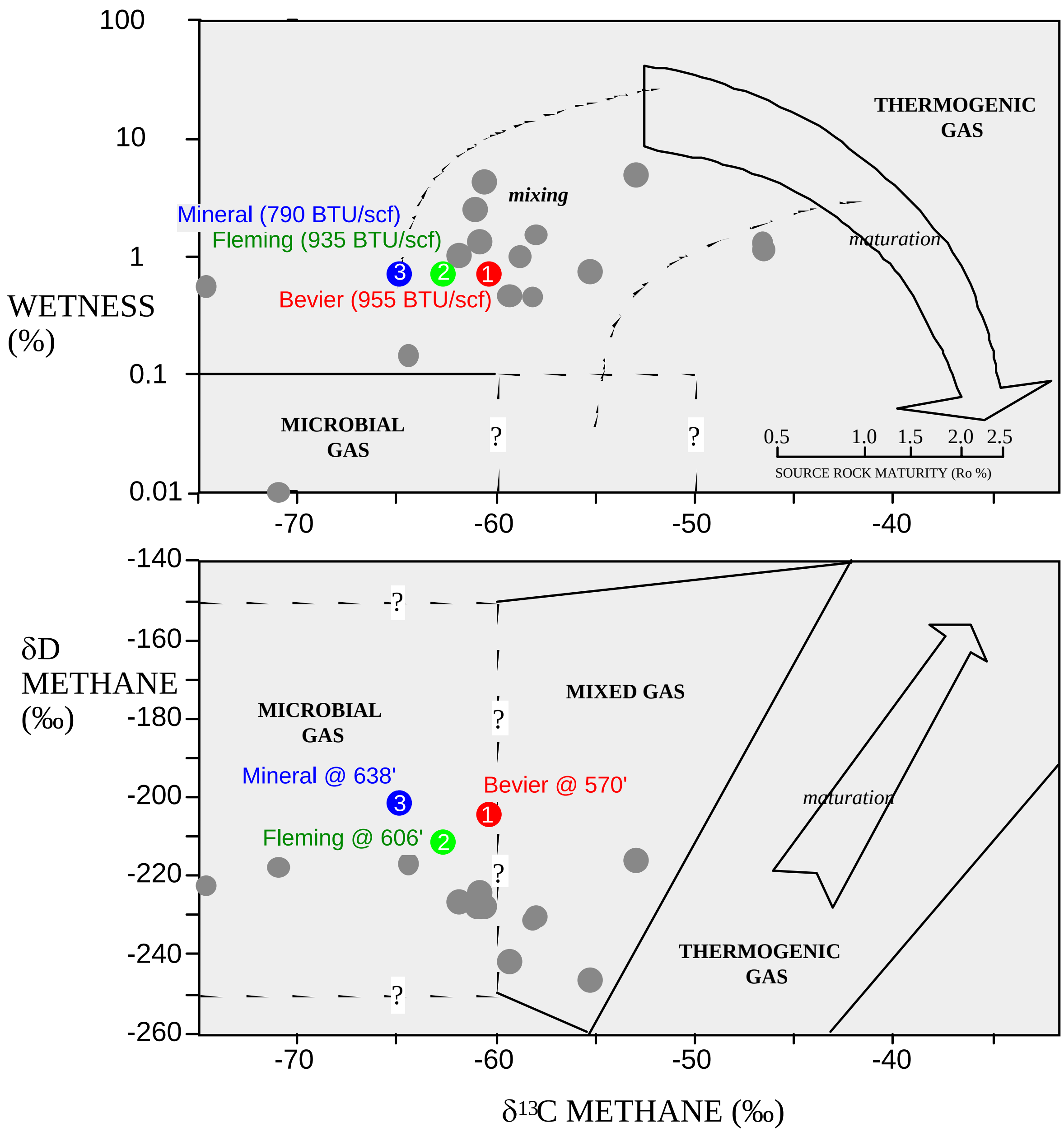


Methane Saturation (dry, ash-free basis)
for all Deffenbaugh Quarry Samples
surface
100'
200'
300'
500'
700'
800'
900'
388' (? sh.)
424' (Anna Sh.)
455' (Little Osage Sh./
Summit)
424' (Excello Sh.)
570' (Bevier)
605' (Fleming sh.)
606' (Fleming)
638' (Mineral)
711' (? coal)
743' (? coal)
865' TOP MSSP
DQ #1B well
DQ #2 well
(filled) (hollow)
% SATURATED (dry, ash-free gas content/calculated dry, ash-free saturated gas content)
PRESSURE (psi)
Anna Sh.
Summit coal
Summit coal
? sh. @ 388'
? sh. @ 388'
Little Osage Sh.
Bevier coal
Bevier coal
Fleming coal
Fleming coal
Little Osage Sh.
Mineral coal
Mineral coal
Excello Sh.
sh. above Fleming
sh. above Fleming
? coal @ 743'
0
10
20
30
40
50
60
70
80
0
100
200
300
400
500

Figure 28

Isotopic Characteristics and Hyrocarbon Wetness of Kansas Geological Survey Deffenbaugh Quarry #2 Coal Core Desorption Gas Samples

sec. 1-T.12S.-R.23E., Johnson Co., KS



●●● analysis of coalbed desorption gas from Deffenbaugh Quarry well

● analysis of other Forest City basin coalbed desorption gas

Figure 29.

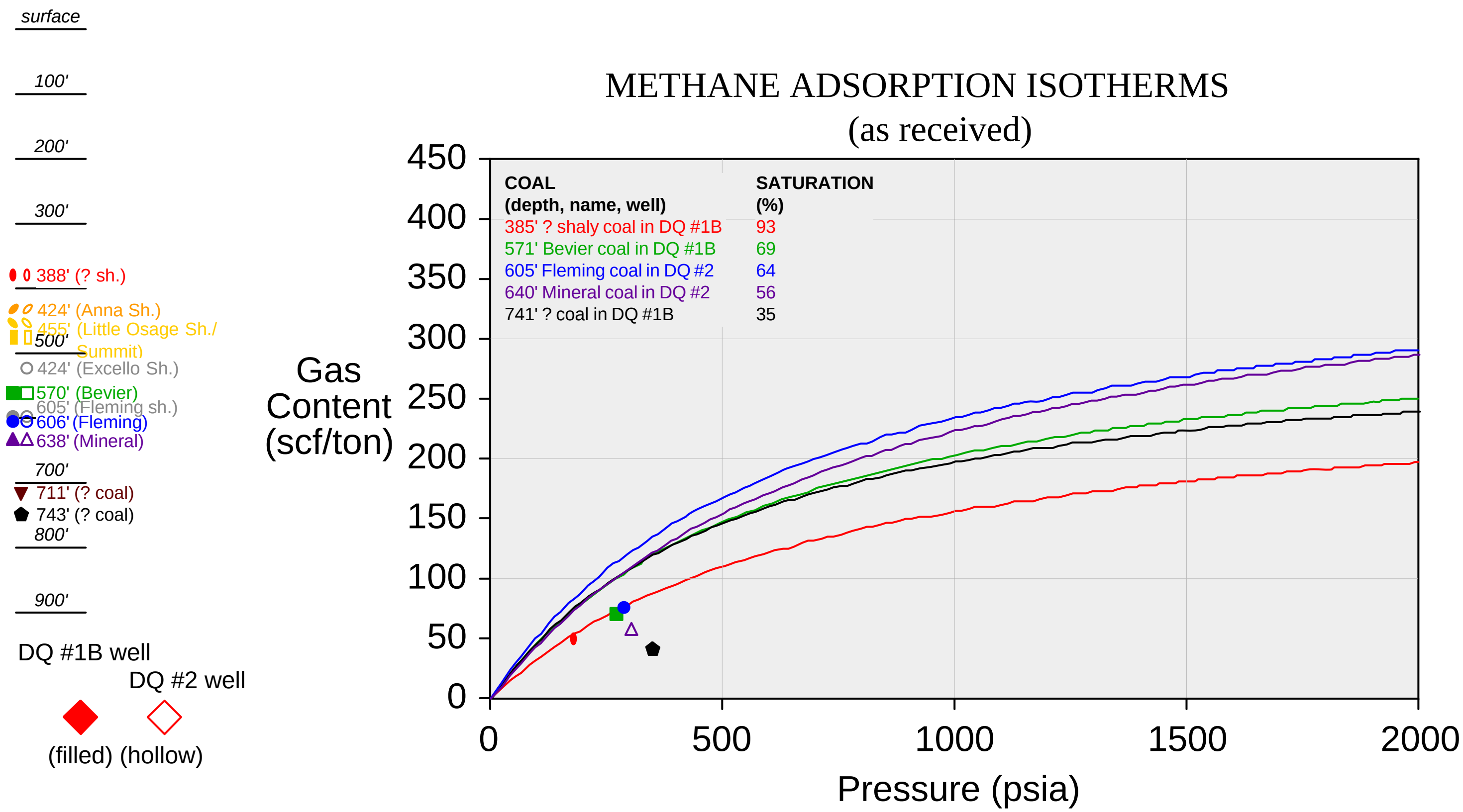

surface
100'
200'
300'
388' (? sh.)
424' (Anna Sh.)
455' (Little Osage Sh./ Summit)
500'
424' (Excello Sh.)
570' (Bevier)
605' (Fleming sh.)
606' (Fleming)
638' (Mineral)
700'
711' (? coal)
743' (? coal)
800'
900'
DQ #1B well
DQ #2 well
(filled) (hollow)
METHANE ADSORPTION ISOTHERMS
(as received)
Gas Content (scf/ton)
Pressure (psia)
COAL (depth, name, well)
SATURATION (%)
385' ? shaly coal in DQ #1B 93
571' Bevier coal in DQ #1B 69
605' Fleming coal in DQ #2 64
640' Mineral coal in DQ #2 56
741' ? coal in DQ #1B 35
0
50
100
150
200
250
300
350
400
450
500
1000
1500
2000

Figure 30.

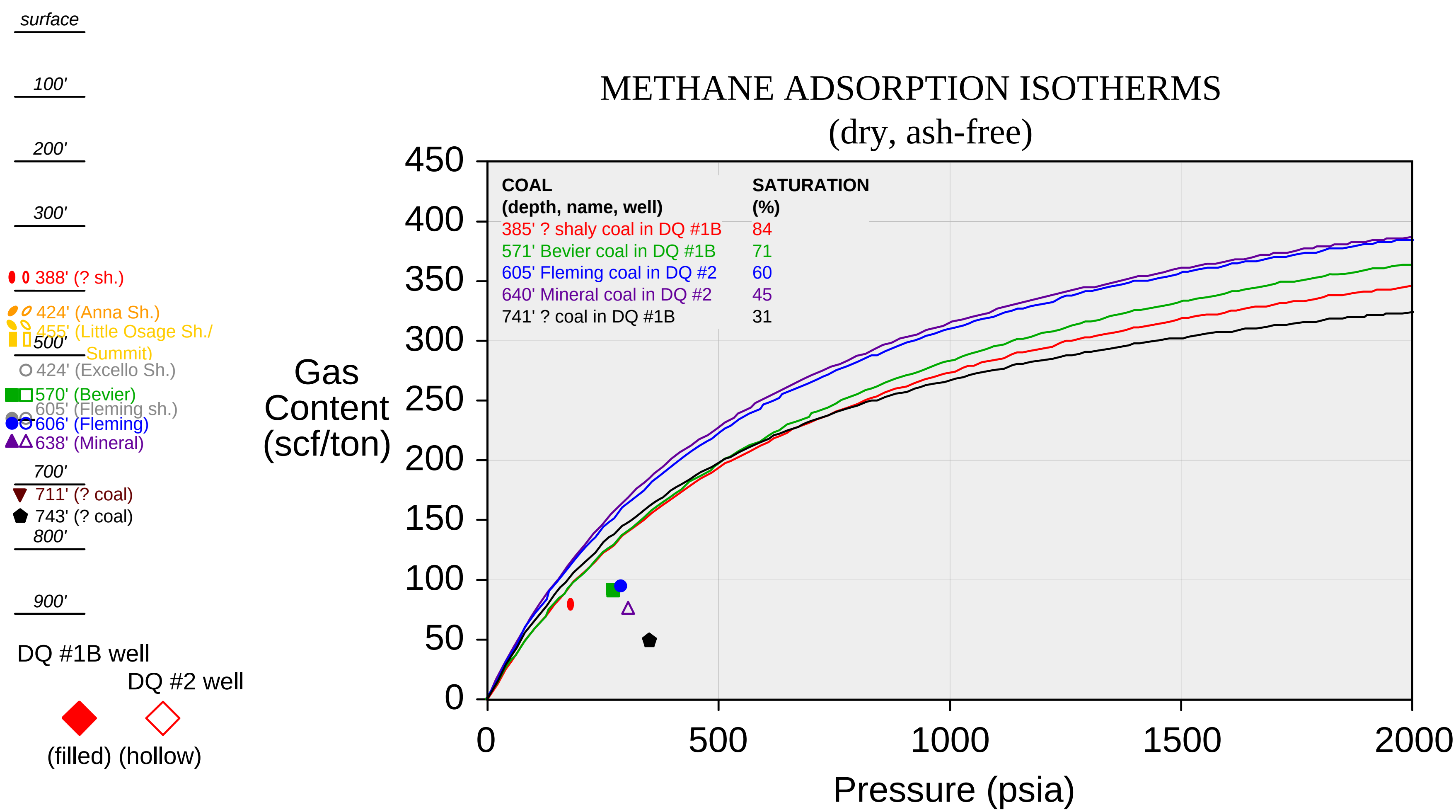
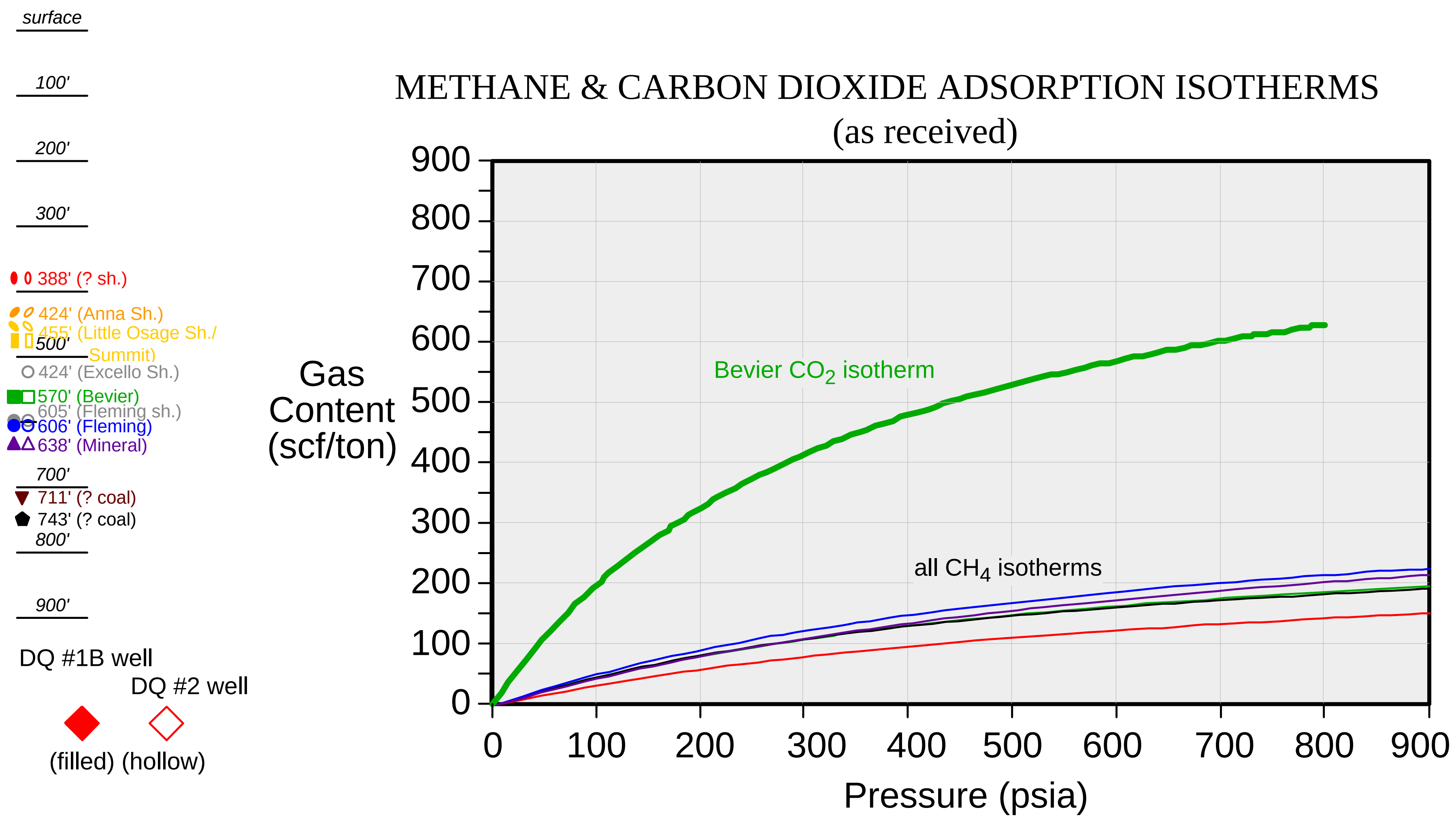

surface
100'
200'
300'
388' (? sh.)
424' (Anna Sh.)
455' (Little Osage Sh./ Summit)
500'
424' (Excello Sh.)
570' (Bevier)
605' (Fleming sh.)
606' (Fleming)
638' (Mineral)
700'
711' (? coal)
743' (? coal)
800'
900'
DQ #1B well
DQ #2 well
(filled) (hollow)
METHANE ADSORPTION ISOTHERMS
(dry, ash-free)
Gas Content (scf/ton)
COAL
(depth, name, well)
SATURATION
(%)
385' ? shaly coal in DQ #1B 84
571' Bevier coal in DQ #1B 71
605' Fleming coal in DQ #2 60
640' Mineral coal in DQ #2 45
741' ? coal in DQ #1B 31
0
50
100
150
200
250
300
350
400
450
0
500
1000
1500
2000
Pressure (psia)

Figure 31.



surface
100'
200'
300'
388' (? sh.)
424' (Anna Sh.)
455' (Little Osage Sh./ Summit)
500'
424' (Excello Sh.)
570' (Bevier)
605' (Fleming sh.)
606' (Fleming)
638' (Mineral)
700'
711' (? coal)
743' (? coal)
800'
900'
DQ #1B well
DQ #2 well
(filled) (hollow)
METHANE & CARBON DIOXIDE ADSORPTION ISOTHERMS
(as received)
Gas Content (scf/ton)
Bevier CO_2 isotherm
all CH_4 isotherms
Pressure (psia)
0
100
200
300
400
500
600
700
800
900

Figure 32.

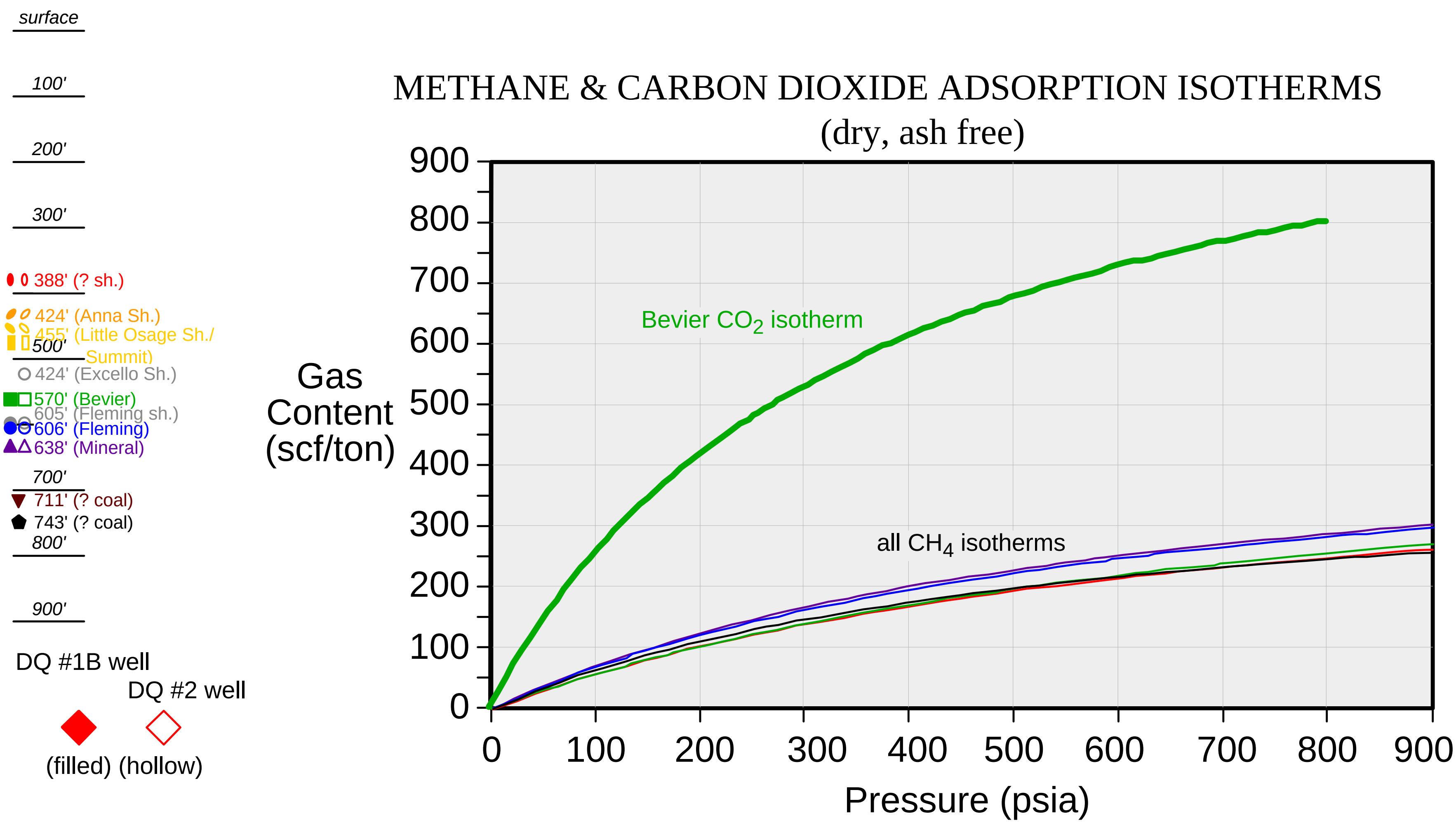

surface
100'
200'
300'
388' (? sh.)
424' (Anna Sh.)
455' (Little Osage Sh./ Summit)
500'
424' (Excello Sh.)
570' (Bevier)
605' (Fleming sh.)
606' (Fleming)
638' (Mineral)
700'
711' (? coal)
743' (? coal)
800'
900'
DQ #1B well
DQ #2 well
(filled) (hollow)
METHANE & CARBON DIOXIDE ADSORPTION ISOTHERMS
(dry, ash free)
Gas Content (scf/ton)
Bevier CO_2 isotherm
all CH_4 isotherms
Pressure (psia)
0
100
200
300
400
500
600
700
800
900

Figure 33.

Index Map --
Deffenbaugh Quarry/
Johnson County Landfill

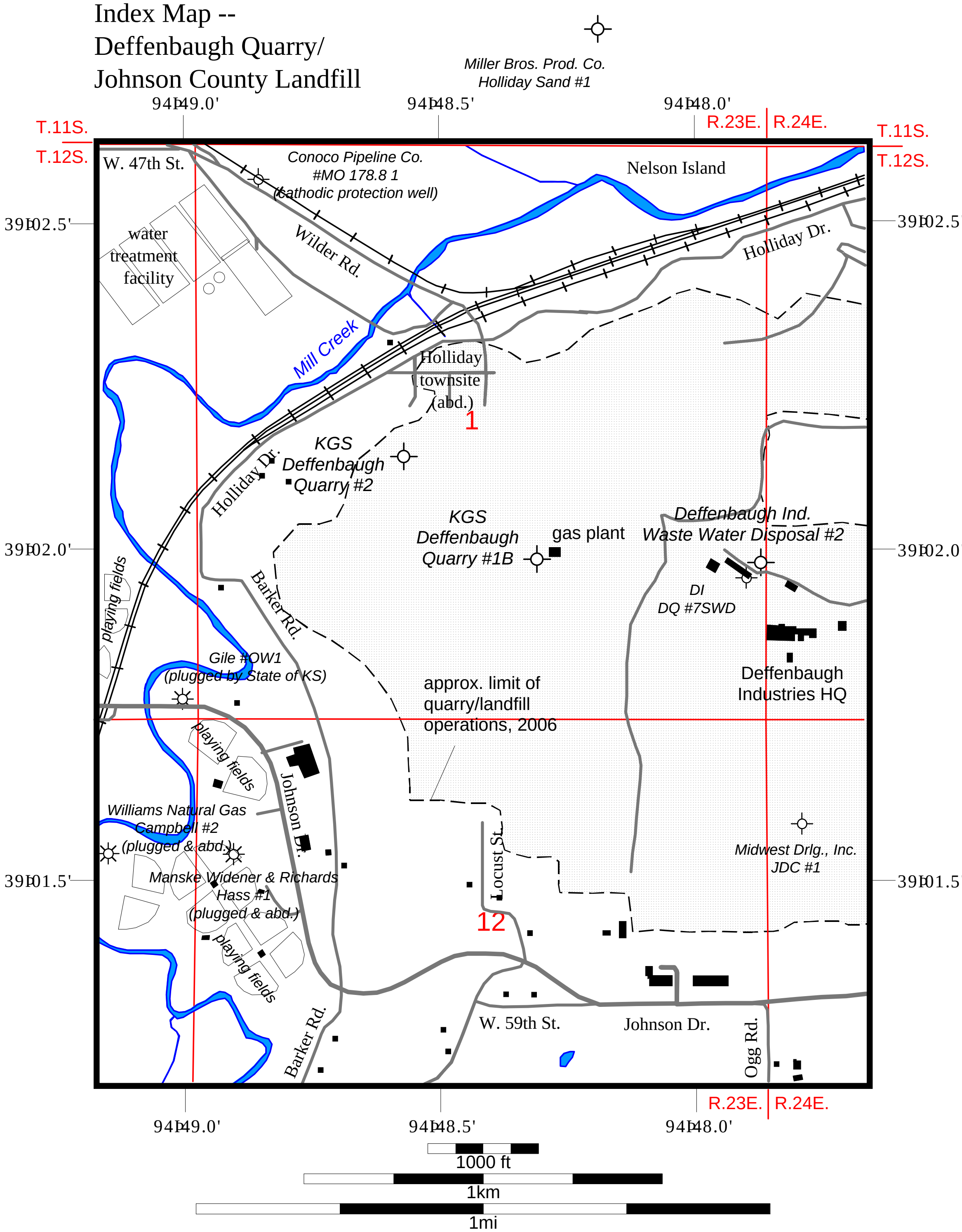


Figure 34.

unidentified shaly coal (top) structure
(ft. relative to sea-level)

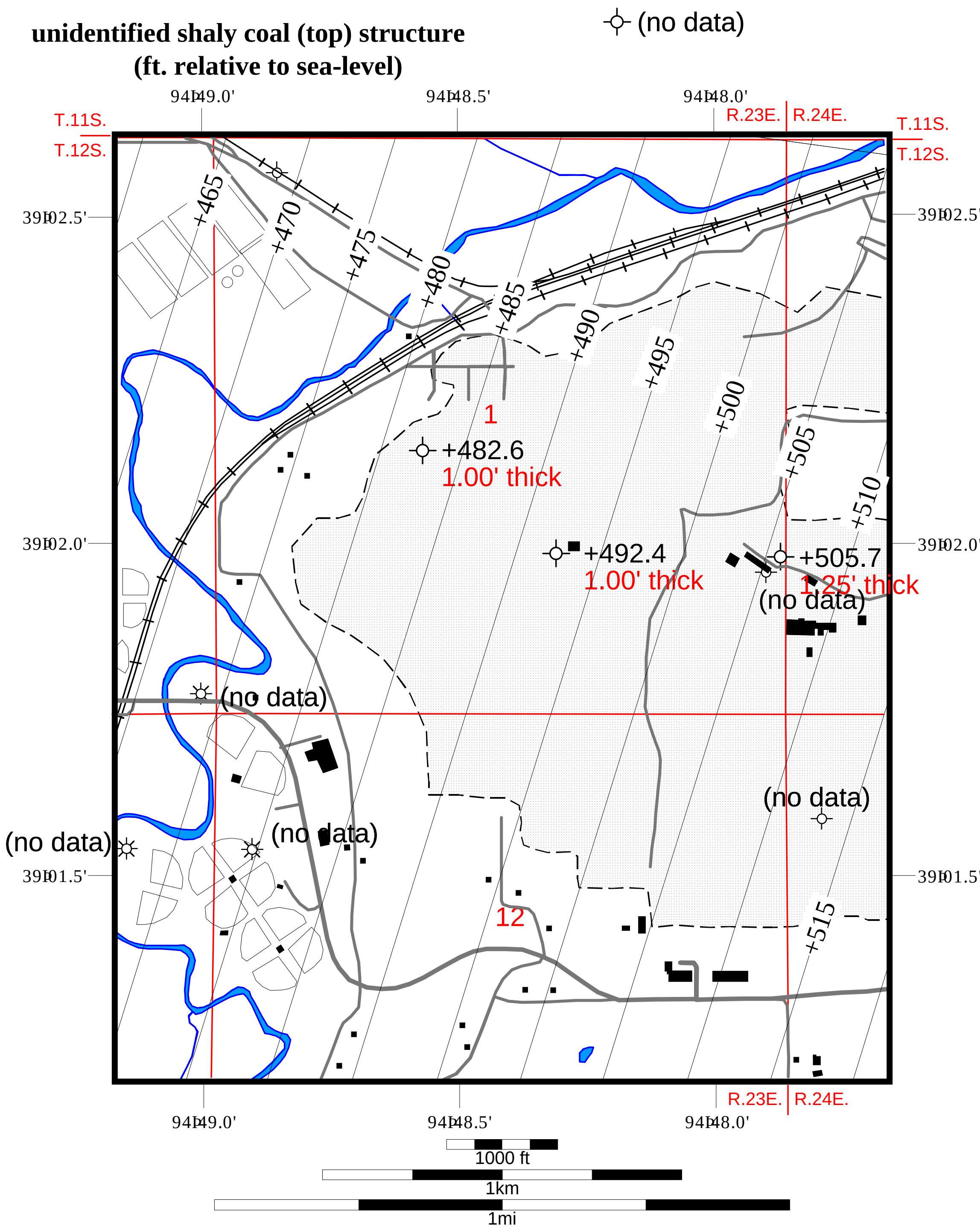


Figure 35.

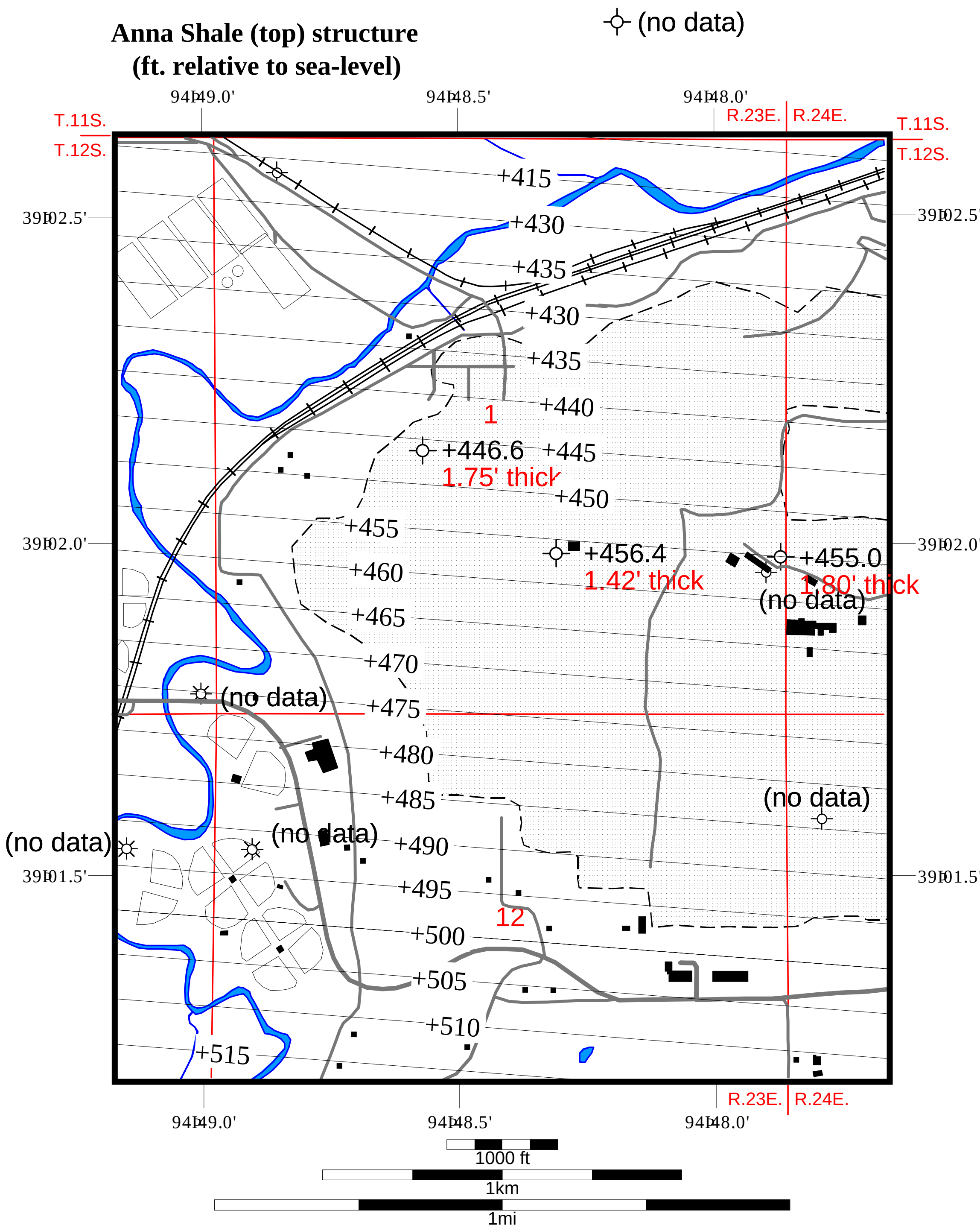
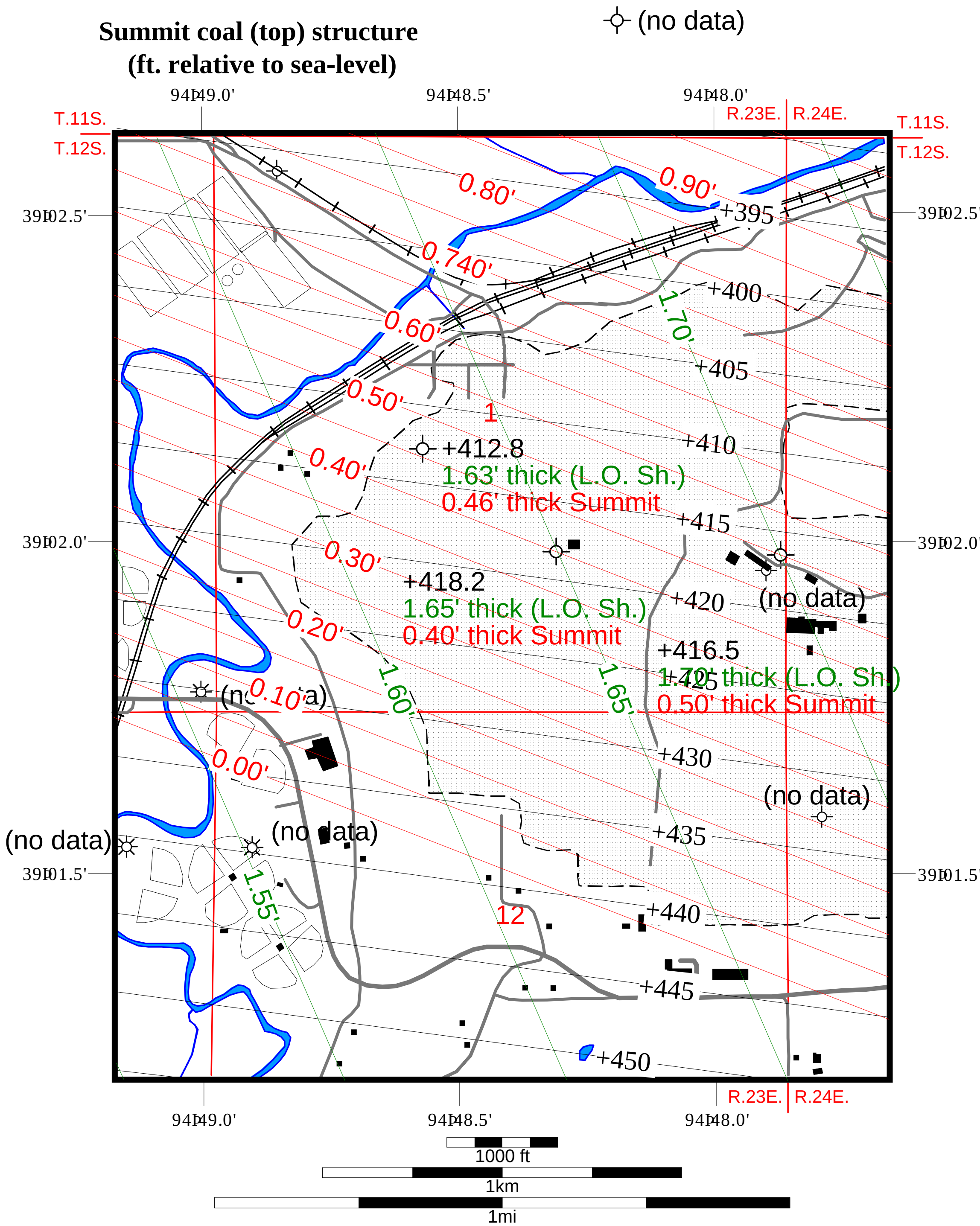

(no data)
Anna Shale (top) structure
(ft. relative to sea-level)
94ᴉ49.0'
94ᴉ48.5'
94ᴉ48.0'
T.11S.
T.12S.
R.23E.
R.24E.
39ᴉ02.5'
39ᴉ02.0'
39ᴉ01.5'
+415
+430
+435
+430
+435
+440
+445
+450
+455
+460
+465
+470
+475
+480
+485
+490
+495
+500
+505
+510
+515
1
12
+446.6
1.75' thick
+456.4
1.42' thick
+455.0
1.80' thick
(no data)
(no data)
(no data)
(no data)
(no data)
1000 ft
1km
1mi

Figure 36.



Summit coal (top) structure
(ft. relative to sea-level)
(no data)
94°49.0'
94°48.5'
94°48.0'
R.23E.
R.24E.
T.11S.
T.12S.
39°02.5'
39°02.0'
39°01.5'
0.90'
0.80'
+395
0.740'
+400
0.60'
1.70'
+405
0.50'
1
+410
0.40'
+412.8
1.63' thick (L.O. Sh.)
0.46' thick Summit
+415
0.30'
+418.2
1.65' thick (L.O. Sh.)
0.40' thick Summit
+420
(no data)
0.20'
+416.5
1.72' thick (L.O. Sh.)
0.50' thick Summit
1.60'
1.65'
0.10'
0.00'
+430
(no data)
(no data)
+435
(no data)
1.55'
12
+440
+445
+450
1000 ft
1km
1mi

Figure 37.

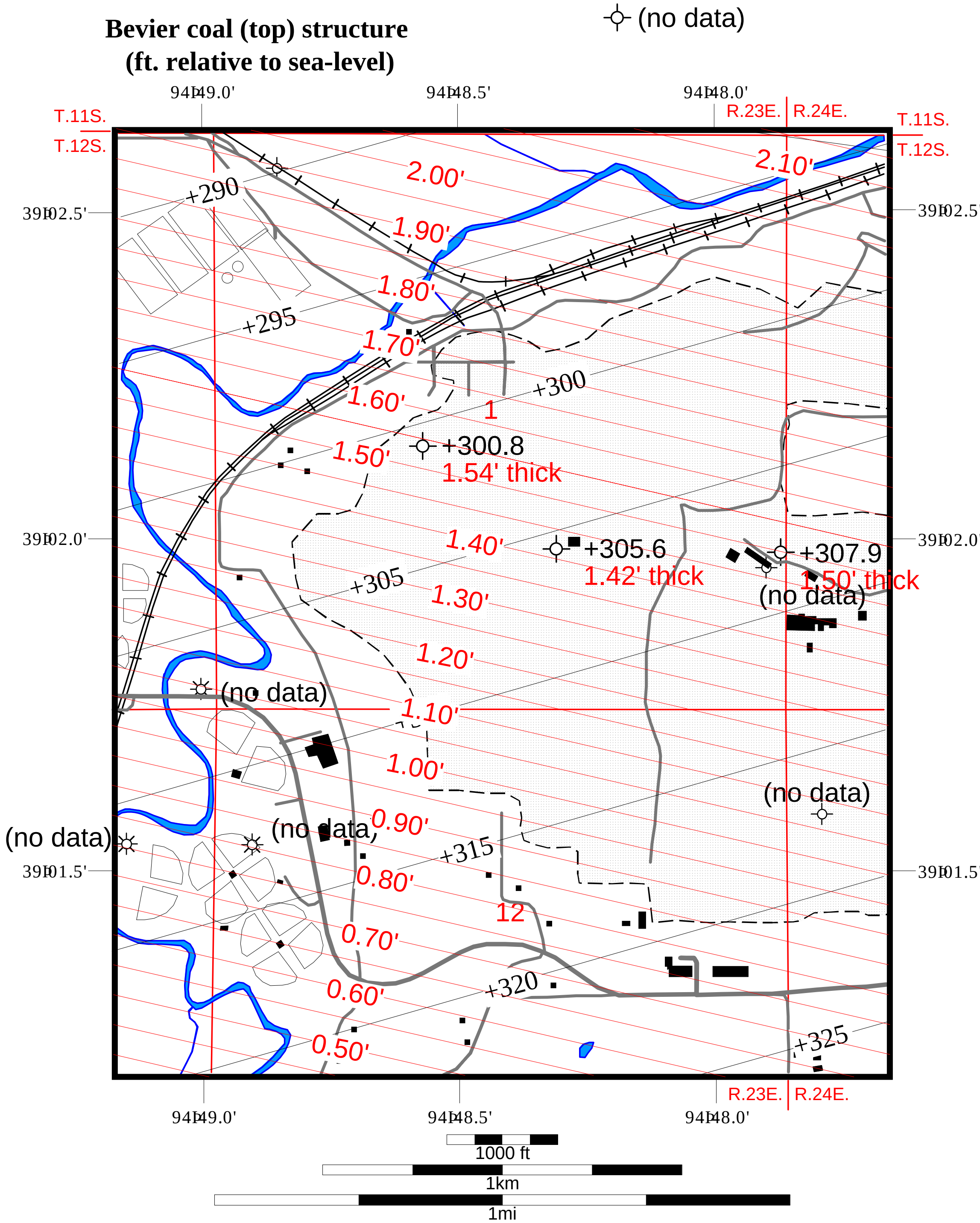
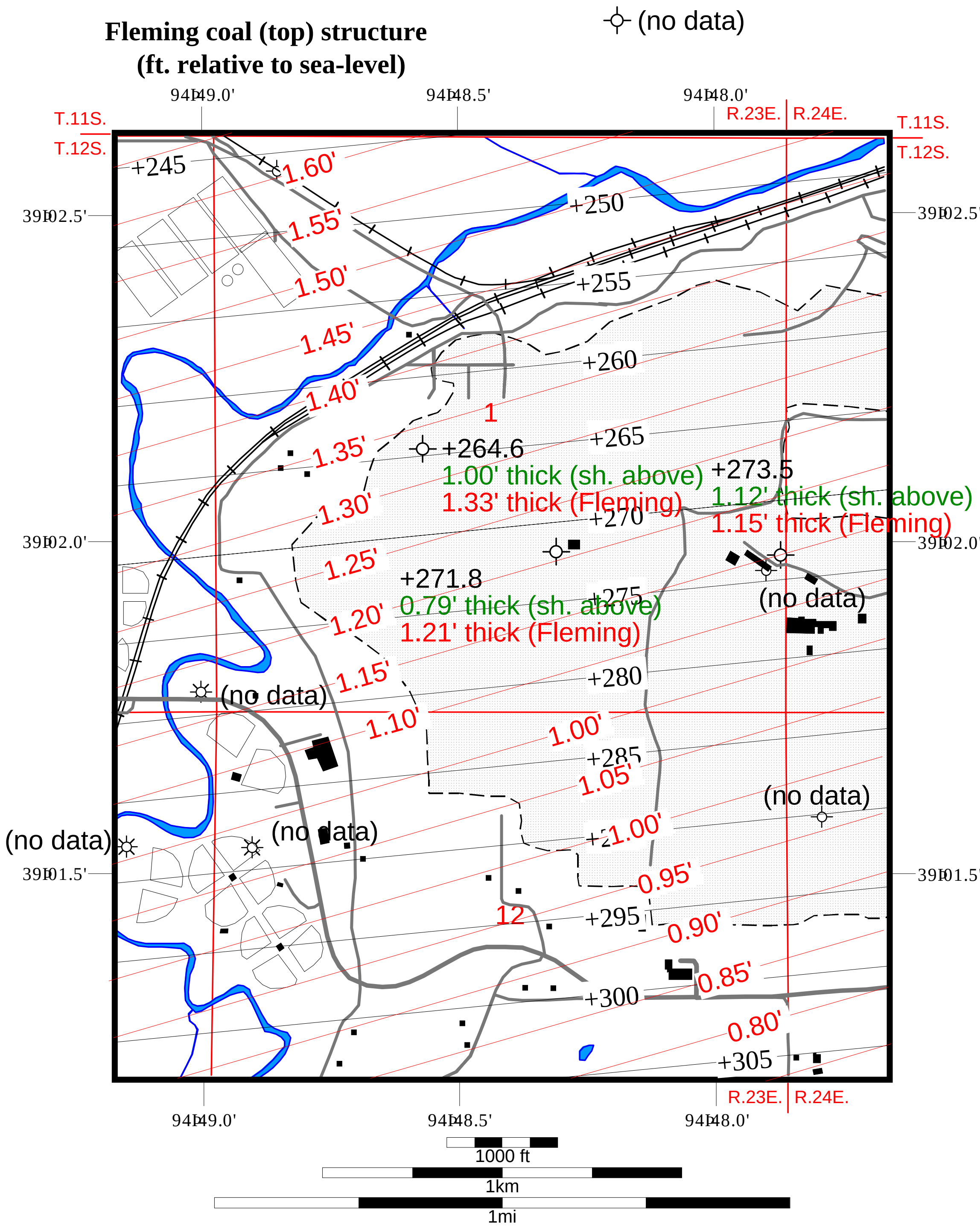

Bevier coal (top) structure
(ft. relative to sea-level)
(no data)
94°49.0'
94°48.5'
94°48.0'
T.11S.
T.12S.
R.23E.
R.24E.
39°02.5'
39°02.0'
39°01.5'
+290
+295
+300
+300.8
1.54' thick
+305
+305.6
1.42' thick
+307.9
1.50' thick
+315
+320
+325
2.10'
2.00'
1.90'
1.80'
1.70'
1.60'
1.50'
1.40'
1.30'
1.20'
1.10'
1.00'
0.90'
0.80'
0.70'
0.60'
0.50'
1
12
1000 ft
1km
1mi

Figure 38.



Fleming coal (top) structure
(ft. relative to sea-level)
(no data)
T.11S.
T.12S.
R.23E.
R.24E.
+245
1.60'
1.55'
1.50'
1.45'
1.40'
1.35'
1.30'
1.25'
1.20'
1.15'
1.10'
1.00'
1.05'
0.95'
0.90'
0.85'
0.80'
+250
+255
+260
+265
+270
+275
+280
+285
+295
+300
+305
+264.6
1.00' thick (sh. above)
1.33' thick (Fleming)
+273.5
1.12' thick (sh. above)
1.15' thick (Fleming)
+271.8
0.79' thick (sh. above)
1.21' thick (Fleming)
(no data)
1000 ft
1km
1mi

Figure 39.

Mineral coal (top) structure (ft. relative to sea-level)

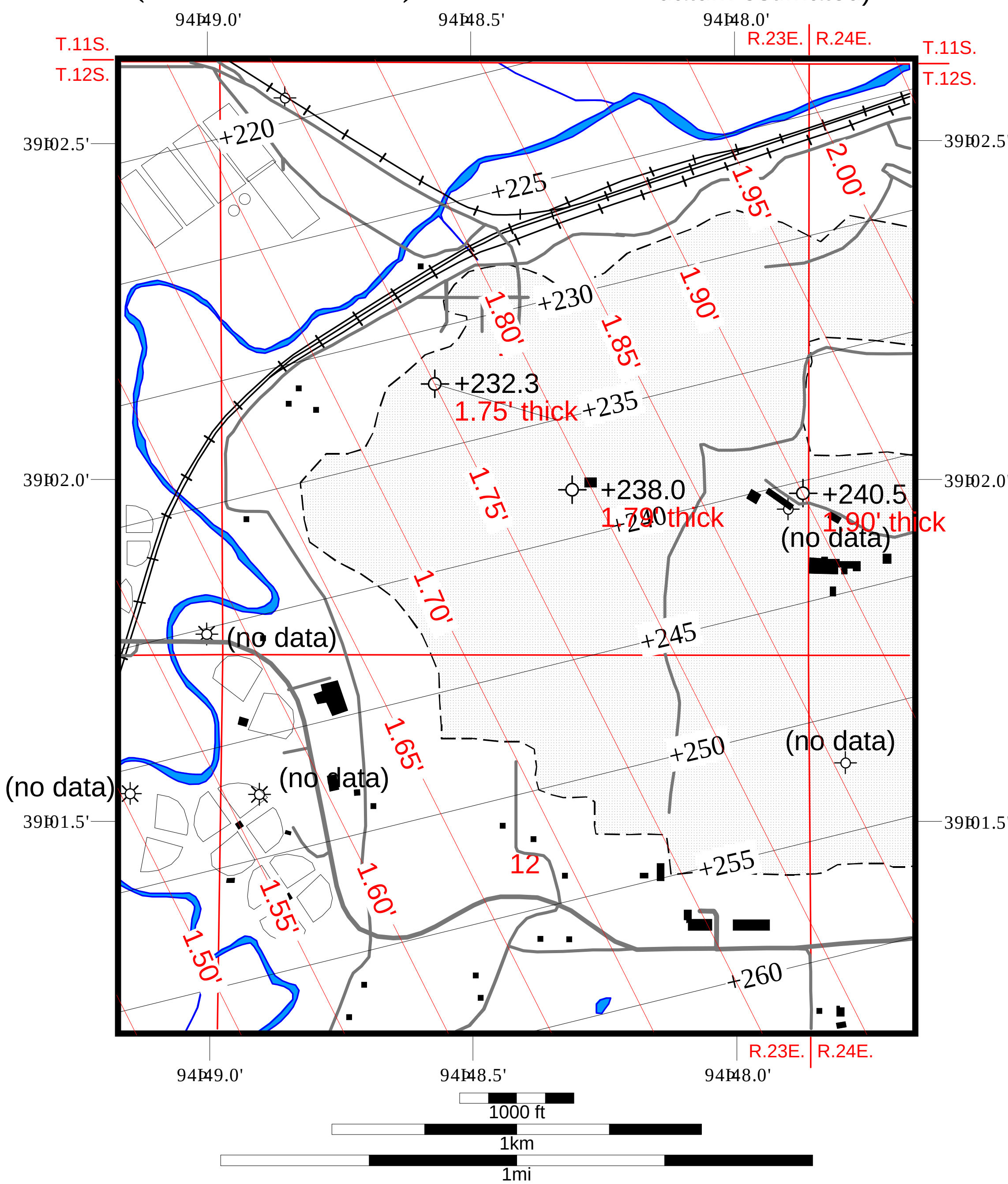


Figure 40.

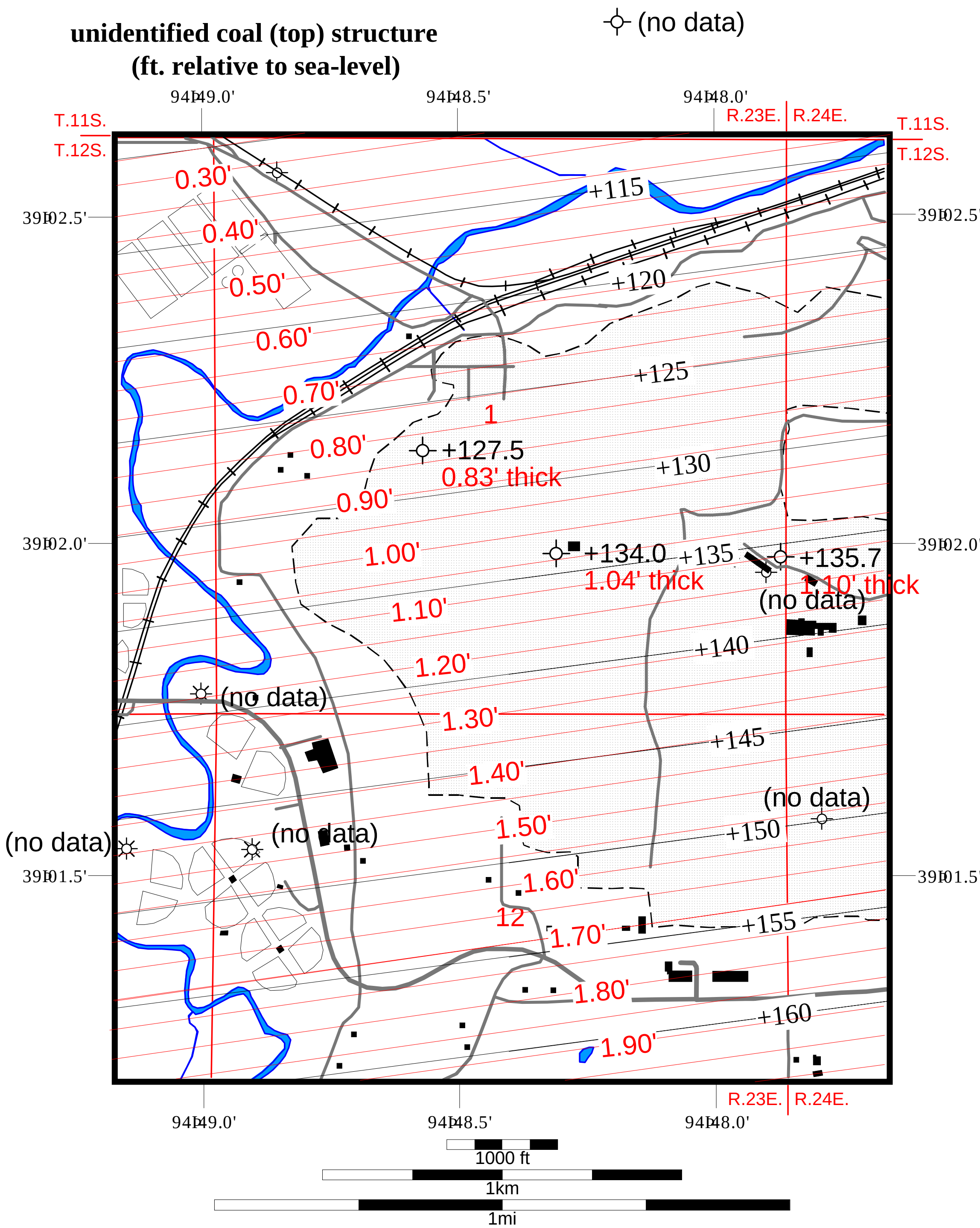

unidentified coal (top) structure
(ft. relative to sea-level)
(no data)
94°49.0'
94°48.5'
94°48.0'
T.11S.
T.12S.
R.23E.
R.24E.
39°02.5'
39°02.0'
39°01.5'
0.30'
0.40'
0.50'
0.60'
0.70'
0.80'
0.90'
1.00'
1.10'
1.20'
1.30'
1.40'
1.50'
1.60'
1.70'
1.80'
1.90'
+115
+120
+125
+127.5
0.83' thick
+130
+134.0
1.04' thick
+135
+135.7
1.10' thick
+140
+145
+150
+155
+160
(no data)
1000 ft
1km
1mi

Figure 41.