P1-91

Barcode 002636

Box 34

APPENDIX 7.3-C

CHEMICAL ANALYSES OF WATER SAMPLES, WDW NO. 3

ENVIROCORP SERVICES & TECHNOLOGY, INC.

BEREA FORMATION

Formation Water Analysis Sample Collected From

Repeat Formation Test

Completed April 14, 1989

Depth 707 feet MD

oc JFT
cc EHW REI
JAS
WK.

Technical Testing Laboratories Inc.

LABORATORY ANALYSIS REPORT

ARISTECH CHEMICAL CORPORATION

WDW #3 ICD LAB GRAB WATER
707 FT DEPTH

Date Sampled 04/14/89

Laboratory Number J0457

Sampled by CLIENT
Date Received 04/17/89

Respectfully Submitted:

ANALYSIS FOR REQUESTED PARAMETERS
ALL RESULTS ARE ON AN AS RECEIVED BASIS

PARAMETER	RESULT	MDL	UNITS	METHOD	ANALYZED DATE/TIME/ANALYST
TOTAL DISSOLVED SOLIDS	54,000	100	MG/L	E160.1	04/24/89 22:30 TS
ALKALINITY	33	1	MG/L	E310.1	04/17/89 18:00 CMC
TOTAL SUSPENDED SOLIDS	52	5	MG/L	E160.2	04/19/89 21:20 NF
SULFATES	82	5	MG/L	E375.4	05/05/89 09:30 SG
CHLORIDE	29,000	1	MG/L	E325.3	04/25/89 21:00 CMC
HEXAVALENT CHROMIUM	ND	0.01	MG/L	SM312B	04/18/89 18:00 CMC
ALKALINITY, CARBONATE	ND	1	MG/L	E310.1	04/17/89 18:00 CMC
ALKALINITY, BICARBONATE	33	1	MG/L	E310.1	04/17/89 18:00 CMC
NITROGEN, AMMONIA	51	0.5	MG/L	E350.2	04/20/89 13:00 TF
NITROGEN, NITRATE	ND	0.06	MG/L	E353.3	04/18/89 21:00 SK
Acetone[67-64-1]	450	10	ug/L	EPA624	04/24/89 22:54 SLH
Toluene[108-88-3]	1000	10	ug/L	EPA624	04/24/89 22:54 SLH
Dimethylbenzyl alcohol	ND	25	ug/L	SW8270	15/14/89 14:06 RCM
Phenol[108-95-2]	29	25	ug/L	SW8270	15/14/89 14:06 RCM
Diphenylamine[122-3-4]	ND	25	ug/L	SW8270	15/14/89 14:06 RCM
alpha-Picoline	ND	25	ug/L	SW8270	15/14/89 14:06 RCM
Acetophenone[98-86-2]	ND	25	ug/L	SW8270	15/14/89 14:06 RCM
Aniline[62-53-3]	ND	25	ug/L	SW8270	05/14/89 14:06 RCM
Formic Acid[64-18-6]	1100	50	MG/L	GC/FID	05/16/89 11:00 RCM

ND: Not detected at a concentration greater than or equal to the MDL - Method Detection Limit

FID1: Analysis by GC/FID using the method 8010 column(SP1000/Carbopack).

REF: USEPA; Test Methods For Evaluating Solid Waste; SW-846,3rd Ed.;Nov,1986.

D: Result was obtained from the 1/10 dilution analyzed on 5/02/89 at 18:56.

IS**: Insufficient Sample to complete analysis

REF: USEPA; Methods For Chemical Analysis Of Water And Wastes; March,1983.

Technical
Testing
Laboratories Inc.

LABORATORY ANALYSIS REPOR

I. [illegible]CH CHEMICAL CORPORATION

Laboratory Number J0457

Respectfully
Submitted:

W #3 ICD LAB GRAB WATER
7 FT DEPTH

Sampled by CLIENT
Date Received 04/17/89

te Sampled 04/14/89

PAGE

ANALYSIS FOR RE[illegible]ED PARAMETERS
ALL RESULTS ARE ON [illegible] RECEIVED BASIS

RAMETER	RESULT	MDL	UNITS	METHOD	DATE [illegible] ANALYST
iene Hydroperoxide	ND	25	ug/L	SW8270	05/14 [illegible] RCM
COSITY	IS**				05/19 [illegible] TS
SOLVED OXYGEN(Lab.Determination)	IS**	0.5	MG/L	E360.1	05/19 [illegible] TS

Not detected at a concentration greater than or equal to the MDL - Method Detection Limit

: Analysis by GC/FID using the method 8010 column(SP1000/Carbopack).

USEPA; Test Methods For Evaluating Solid Waste; SW-846,3rd Ed.;Nov,1986.

Result was obtained from the 1/10 dilution analyzed on 5/02/89 at 18:56.

: Insufficient Sample to complete analysis

USEPA; Methods For Chemical Analysis Of Water And Wastes; March,1983.

Technical
Testing
Laboratories Inc.

LABORATORY ANALYSIS REPORT

RISTECH CHEMICAL CORPORATION

WDW #3 ICD LAB GRAB WATER
707 FT DEPTH

Date Sampled 04/14/89

Laboratory Number J0457

Sampled by CLIENT
Date Received 04/17/89

Respectfully
Submitted:

ANALYSIS FOR REQUESTED METALS

PARAMETER	RESULT	MDL	UNITS	METHOD	ANALYZED DATE/TIME/ANALYST
BARIUM(Total)	9.2	0.01	MG/L	E200.7	05/04/89 18:00 MS
CHROMIUM(Total)	ND	0.025	MG/L	E200.7	05/04/89 18:00 MS
LEAD(Total)	ND	0.08	MG/L	E200.7	05/04/89 18:00 MS
IRON(Total)	2.7	0.015	MG/L	E200.7	05/05/89 18:00 MS
MANGANESE(Total)	0.5	0.004	MG/L	E200.7	05/05/89 18:00 MS
ALUMINUM(Total)	ND	0.1	MG/L	E200.7	05/05/89 18:00 MS
CALCIUM(Total)	3000	0.2	MG/L	E200.7	05/05/89 18:00 MS
MAGNESIUM(Total)	730	0.2	MG/L	E200.7	05/05/89 18:00 MS
POTASSIUM(Total)	96	0.1	MG/L	E258.1	05/05/89 12:00 DK
SODIUM(Total)	9900	0.02	MG/L	E273.1	05/05/89 12:00 DK

ND: Not detected at a concentration greater than or equal to the MDL - Method Detection Limit

REF: USEPA; Test Methods For Evaluating Solid Waste; SW-846,3rd Ed.;Nov,1986.

REF: USEPA; Methods For Chemical Analysis Of Water And Wastes; March,1983.

NIAGARAN FORMATION (SALINA)

Formation Water Analysis Sample Collected From

Swab Test

Completed July 18, 1989

Depth 1500 feet - 1570 feet MD

Aristech WDW #3 Niagaran Formation Sample
Lancaster Laboratory Incorporated No.: WW 1414238
Date Submitted: 7/20/89

ANALYSIS	RESULT AS RECEIVED		LIMIT OF QUANTITATION	
Sodium	42,500.	mg/L	0.5	mg/L
Potassium	1,210.	mg/L	0.5	mg/L
Calcium	36,400.	mg/L	0.05	mg/L
Magnesium	8,970.	mg/L	0.05	mg/L
Temperature (Measured in the field, value reported separately)				
Barium	1.1	mg/L	0.5	mg/L
Alkalinity to pH 8.3	<1.	mg/L	1.	mg/L
Alkalinity to pH 4.5	68.	mg/L	1.	mg/L
Aluminum	12.9	mg/L	0.1	mg/L
pH (Measured in the field, value reported separately)				
Specific Gravity	1.17			
Specific Conductance	445,000.	µmhos/cm	1.	µmhos/cm
Total Dissolved Solids	277,000.	mg/L	100.	mg/L
Dimethyl Benzyl Alcohol	0.19 J	mg/L	0.02	mg/L
Phenol	0.14	mg/L	0.02	mg/L
Diphenylamine	N.D.		0.02	mg/L
Alpha-Picoline	N.D.		0.02	mg/L
Total Suspended Solids	337.	mg/L	7.	mg/L
Sulfate	180.	mg/L	50.	mg/L
Chloride	139,000.	mg/L	20.	mg/L
Nitrate Nitrogen	<10.	mg/L	10.	mg/L
Carbonate	<1.	mg/L	1.	mg/L
Bicarbonate	68.	mg/L	1.	mg/L
Dissolved Oxygen	5.9	mg/L	0.5	mg/L
Iron	122.	mg/L	0.05	mg/L
Manganese	2.3	mg/L	0.2	mg/L
Viscosity	2.	cps	1.	cps
Acetone	0.11	mg/L	0.01	mg/L
Cumene Hydroperoxide*				
Acetophenone	N.D.		0.02	mg/L
Ammonia Nitrogen	133.	mg/L	0.5	mg/L
Aniline	<0.02	mg/L	0.02	mg/L
Total Chromium	0.25	mg/L	0.05	mg/L
Formic Acid	<5.	mg/L		
Toluene	0.26	mg/L	0.005	mg/L
Lead	<0.3	mg/L	0.3	mg/L

* - Cumene hydroperoxide could not be determined due to impure reference material, as well as what appeared to be degradation in the chromatographic system.

< - Indicates the result is less than the smallest amount which can be accurately quantitated.

N.D. - Indicates none detected.

J - Indicates this value is an estimate.

Note: These results have been transcribed by ERM, Inc. from the Lancaster Laboratories Inc. analysis report for the Niagaran Formation sample (LLI# WW 1414238).

P1-91

Barcode 00263

Box 34

APPENDIX 7.3-D

CHEMICAL ANALYSES, FORMATION SAMPLES IN SCIOTO COUNTY BRINE WELLS

No. 20

Brine Sample No. 20

D. S Lab No 182

GEOLOGICAL SURVEY OF OHIO

WILBER STOUT, State Geologist
COLUMBUS

BULLETIN 37

TESTS ON SAMPLES

Material sampled Brine
Name of bed Berea sand

Sampled by W. M. Knight, Portsmouth
Date of sampling March, 1931
Tests made by Downs Schaaf, analyst

County Scioto
Township Jefferson
Section 9 (Houston Hollow)
Property owner Chas. Ziegler lease #2
Operator Local company, Edward Kleffner, president, W. M. Knight, secretary, 502 Union S Portsmouth

1,0770 @ 20°C

Specific gravity, 1.078 at 15°C. Mineral sediment, none.

	Composition of saline matter	
Cl	62.78	— 68,95 Gr/Liter
Br	0.47	— .5140 Gr/Liter
SO_4	0.05	
CO_3	none	
HCO_3	0.02	
Na	22.86	— 25,15 gr/Liter
K	0.20	— ,220
Ca	10.80	
Mg	2.65	
$(Al.Fe)_2O_3$	0.15	
SiO_2	0.02	
Sr	----	
	100.00	

Total dissolved solids
110.0 grams per liter
109.86 gm/L @ 1.0770
102.0 " " kilogram

Driller's record

Elevation of well head, 655 ft.

	Top	Bottom
Berea sand	256	315
Total depth		339

Bumps about one-inch stream of brine regularly. Water 8 feet in sand or at 264 feet.

Brine Sample No. 46
DS Lab. No. 263

No.

GEOLOGICAL SURVEY OF OHIO
WILBER STOUT, State Geologist
COLUMBUS

BULLETIN 37

TESTS ON SAMPLES

Material sampled	Brine	County	Lawrence
Name of bed	Second Water of Big Lime	Township	Elizabeth
		Section	25
Sampled by	W. R. Maxey	Property owner	Ceramic Clay Co. No.
Date of sampling	Oct., 1931	Operator	Ohio Fuel Gas Co.
Tests made by	Downs Schaaf 1.159 @ 20°C		

Specific gravity, 1.16 at 15°C. Mineral sediment, none

Composition of saline matter

Cl	152,218	62.69	— [illegible] Gr/Liter
Br	1,967	0.81	1.9670 gr/Liter
SO_4	291	0.12	.29
CO_3	—	none	
HCO_3	486	0.02	
Na	45,211	18.62	[illegible]
K	1,627	0.67	— 1.628 Gr/Liter
Ca	31,857	13.12	
Mg	8,110	3.34	
$(Al.Fe)_2O_3$	85	0.035	
SiO_2	12	0.005	
Sr	1,384	0.57	
		100.000	

Total dissolved solids
243.02 grams per liter
242.81 g/L
209.5 grams per kilogram

Drillers record

Brine from a depth of about 2,800 ft.

[illegible]

	Top	Bottom	
Sand	520	540	No water
Sand	585	597	25,500 cu.ft.at 592
Salt sand	665	710	½ bbl. water 675-680
Sand	720	760	3 " " 740
Maxton sand	760	770	
Big Injun sand	865	1078	
Hamden sand	1340	1350	
Berea grit sand	1480	1528	Hole full water. No oi or gas
Niagara lime	2340	2948	Brine sample about 2800
Clinton sand	3199	3207	94,560 cu.ft. No oil o water
Total depth		3252	

Sample #121

82751

GEOLOGICAL SURVEY OF OHIO
JOHN H. MELVIN, State Geologist
COLUMBUS

TESTS ON SAMPLES

Material sampled	Brine
Name of bed	Trempealeau Depth 3840' Bailer sample
Sampled by	
Date of sampling	Nov. 1964
Tests made by	Dow Chemical W7-512

Quad.	Sciotoville
County	Scioto
Township	Harrison
Section	SE 17
Property owner	Albert E. Will #
Operator	Young & Henneberger
Well permit #202	

Brine Bottle No. 93

	1.17725 at 20/20°C
Sp. Gr. at 25/25°C	1.1771
°Be'	21.8
% $CaCl_2$	6.04
% $MgCl_2$	2.17
Ratio % $CaCl_2$/% $MgCl_2$	2.78
% NaCl	12.76
% KCl	0.53
	21.50
	215.0 gm/kgm
	253.38 gm/l

FORM 66 7-62

PAN AMERICAN PETROLEUM CORPORATION

RESEARCH DEPARTMENT

WATER ANALYSIS

Note – This is OGS Brine Sample #121

W-398-D

ie Albert R. Will Well No. 1 Lab. No. T-16758
County Scioto State Ohio
Blk. Section 17 T. R.
Quarter or Survey Twp. Harrison 1/4 SE Sample Series No.
Exact Location PBTD Total Depth
Producing Stratum From To
Stratum Yielding Sample Trampealeau
Condition of Well Method Used Bailer Cable Tool
Sample Collected From Date Collected Date Received
Collected by Date File
Transmittal Letter by

(Central Division)

Radicle	Per Cent by Analysis	(a) P. P. M.	(b)	(a) X (b)	Per Cent Reacting Value	Calculated Compound	P. P. M.
						Na_2SO_4	
Na	23.19	55,397	.0435	2,409.85	28.27	NaCl	140,828
Ca	10.50	25,100	.0499	1,252.49	14.69	Na_2CO_3	
Mg	3.05	7,300	.0822	600.06	7.04	$NaHCO_3$	47
Fe						$CaSO_4$	248
						$CaCl_2$	69,311
						$CaCO_3$	
SO_4	.07	175	.0208	3.64	.04	$Ca(HCO_3)_2$	
Cl	63.18	151,000	.0282	4,258.20	49.95	$MgSO_4$	
CO_3	0	0	.0333	0	0	$MgCl_2$	28,572
HCO_3	.01	34	.0164	.56	.01	$MgCO_3$	
H_2S						$Mg(HCO_3)_2$	

Total solids as a summation of radicles 239,006 P.P.M.
Total solids by evaporation and ignition of residue at low red heat 259,760 P.P.M.
Sample as received: Resistivity: ohms/M²M .046 at 77°F. pH Value 5.4 Specific Gravity 60°/60°F. 1.178

PROPERTIES OF REACTION IN PER CENT

PRIMARY SALINITY: SO_4 + Cl = with equal value Na (K) = 56.54
SECONDARY SALINITY: If SO_4 + Cl is greater than Na (K) =
Then SO_4 + Cl = with equal value of Ca + Mg = 43.44
PRIMARY ALKALINITY: Excess Na (K) over SO_4 + Cl = with equal value of CO_3 + S =
SECONDARY ALKALINITY: Excess Ca + Mg over SO_4 + Cl = with equal value of CO_3 + = .02
CHLORIDE SALINITY: Cl ÷ (SO_4 + Cl) = X 100% = 99.92
SULPHATE SALINITY: SO_4 ÷ (SO_4 + Cl = X 100% = .08

NOTE: Multiply Parts per Million by .0583 to obtain Grains per Gallon.

REMARKS:

K. W. Bolt
R. S. Tremaine
G. W. Schmidt (4)

mg/l (ppm)

Iodide	0
Bromide	520

Analyst James J. Elliott Date 12-15-

STATE OF OHIO
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF GEOLOGICAL SURVEY

File No. 308

County Scioto

Township Bloom

Section 35.

15' Quad. Oak Hill

7½' Quad.

TESTS ON SAMPLES

Material sampled Brine

Tests made by Dow Chemical

Name of bed depths of 1000', 1500' and 1900'

Laboratory number SSR 184-613

Sampled by

Property owner Dow Ironton #3 T.D. 2030

Date of sampling 1-4-53

Operator

Samples taken at completion of bailing

First Day 1910-1940 Second Day 1950-1972

Sample No.	2	2	1
Depth from top of well	1900	1500	1000
Sp. Gr. at 20°C	1.1967	1.1967	1.1967
°Be'	23.83	23.83	23.83
% $CaCl_2$	9.30		
% $MgCl_2$	3.09		
$\frac{\%CaCl_2}{\%MgCl_2}$	3.0		
%KCl	0.26		
% NaCl	10.3		
% Br	.1521		
% I_2	.0012		

STATE OF OHIO
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF GEOLOGICAL SURVEY

File No. 305
County Scioto
Township Green
Section Lot 29
15' Quad. Greenup
7½' Quad.

TESTS ON SAMPLES

Material sampled Brine
Name of bed
Sampled by
Date of sampling 3/12/53

Tests made by Dow Chemical
Laboratory number SSR 186-831
Property owner Dow Ironton Well 5 T.D. 16
Operator

Located 4 miles south of Wheelersburg on U. S. 52

Sample depth from surface	200	1500
Sp. Gr. at 20°C	1.1817	1.1817
°Be'	22.30	22.30
% $CaCl_2$	8.67	8.64
% $MgCl_2$	2.98	3.00
Ratio $\frac{\%CaCl_2}{\%MgCl_2}$	2.9	2.9
% NaCl	9.4	9.4
% KCl	0.22	0.24
% Br_2	0.1372	0.1371
% I_2	0.0010	0.0010

Samples taken at completion of bailing.

STATE OF OHIO
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF GEOLOGICAL SURVEY

File No. 306
County Lawrence
Township Hamilton
Section 5
15' Quad. Greenup
7½' Quad.

TESTS ON SAMPLES

Material sampled Brine
Name of bed Depth
Sampled by
Date of sampling 12-4-62

Tests made by Dow Chemical
Laboratory number SSR 183-620
Property owner Dow Irontonu #2
Operator

#2 Ironton - Section 7, Hamilton Twp., Lawrence County, Ohio, Total depth 2031 ft. The Sp. Gr. on this sample appears low indicating some dilution.

Spec. Gr. at 20/20C°	1.1897
°Be'	23.12
% $CaCl_2$	3.99
% $MgCl_2$	2.88
% NaCl	9.90
% KCl	0.21
Ratio $\frac{\%CaCl_2}{\%MgCl_2}$	3.12
% Br	0.1496
% I	0.0011

STATE OF OHIO
DEPARTMENT OF NATURAL RESOURCES
DIVISION OF GEOLOGICAL SURVEY

File No. 307

County Lawrence

Township Elizabeth

Section 4

15' Quad. Ironton

7½' Quad.

TESTS ON SAMPLES

Material sampled Brine

Name of bed depth 250' and 2250'

Sampled by

Date of sampling 3-16-53

Tests made by Dow Chemical

Laboratory number SS^{u} 186-217

Property owner Dow Ironton well 4 T.D.2

Operator

Sample taken from bailer at depth indicated after acidifying and com etion of bailing.

Sample depth from surface (ft.)	250	2250
Sp. Gra. at 20°C	1.2045	1.2062
°Be'	24.62	24.79
% $CaCl_2$	9.84	9.82
% $MgCl_2$	3.52	3.39
Ratio $\frac{\%CaCl_2}{\%MgCl_2}$	2.80	2.90
% NaCl	9.9	10.5
% KCl	0.24	0.24
% Br	0.1485	0.1525
% I_2.	0.0013	0.0013

APPENDIX M

ASSESSMENT OF HAVERHILL FLUID CHEMISTRY
(BY DR. DONALD LANGMUIR, 1991)

P4-91

002639

Box 37

Assessment of Haverhill Fluid Chemistry

by

Dr. Donald Langmuir
Hydrochem Systems Corp.

1. Injectate Chemistry

The more general composition of injectate through time is given in Tables 1a and 1b. Data for several organic and inorganic species are available beginning in 1981. Because of the relatively high phenol levels in injectate up to 1984, and much lower and declining phenol concentrations in post-1984 injectate, the data in Table 1 have been analyzed in two different ways. The 1981 to 1984 data are averaged in Table 1a, while the overall data averages for 1981 to 1989 are listed in Table 1b.

Mean concentrations in the injectate based on the data in Table 1, are summarized in Table 2. Only a few values are available for certain species such as Na, Cl, SO_4, and formic acid, for example. In addition, the variability of existing data, as evident from its standard deviation, is usually quite large. Nevertheless, several tentative conclusions seem reasonable. First, TDS, and Na, Ca, and SO_4 are relatively constant between 1981 and 1989. The data for Cl suggest that values may have increased through time, however, given that only four analyses are available, such a conclusion cannot be argued with confidence.

Table 1a

Injectate Composition Through Time
(in parts per million)

Species	4/12/81	7/9/81	1/4/83	1/20/83	9/26/83	10/1/84	10/22/84	10/29/84	11/15/84	No. of Samples Through 11/15/84	Mean	SD
Na	-	-	9000	10000	-	-	-	-	-	2	9500	707
Ca	-	-	28	13	-	-	-	-	-	2	21	11
Cl	-	-	640	1170	-	-	-	-	-	2	905	375
SO_4	-	-	9100	10250	-	-	-	-	-	2	9680	813
NH_3-H	600	-	800	1600	-	27	1400	900	1000	-	-	-
TDS	-	-	21000	23000	-	18000	21000	12000	18000	6	18800	3870
SpC	-	-	-	-	-	-	-	-	-			
SpG	-	-	-	-	1.02	-	-	-	-			
pH	-	9.5	10.3	10.5	-	10.2	7.2	6.9	10.5	-	-	-
Acetic Acid	-	-	-	-	-	970	620	500	580	4	668	208
Acetone	306	540	700	1000	380	300	900	270	800	9	577	281
Acetophenone	350	1140	-	120	240	150	240	390	120	8	344	337
Aniline	350	-	-	54	20	30	80	250	80	7	123	126
Formic Acid	-	-	-	-	-	-	1100	950	980	3	1010	79
Phenol	4220	6600	-	2540	4500	2565	4200	4400	2400	8	3930	1410

Table 1b

Injectate Composition Through Time (con't)
(in parts per million)

Species	1/3/85	2/23/87	4/20/87	12/7/87	3/1/88	6/13/88	8/22/88	12/5/88	2/20/89	6/5/89	6/15/89	11/20/89	3/28/90	No. of Samples Through 3/28/90	Mean	SD
Na	-	-	-	-	-	-	-	-	-	-	5080	11000	-	4	8770	2590
Ca	-	49	12.4	26	23	20	19	-	17	30	21	38	-	12	25	11
Cl	-	-	-	-	-	-	-	-	-	-	2790	1900	-	4	1625	933
SO_4	-	-	-	-	-	-	-	-	-	-	1790	14000	-	4	8790	5100
NH_3-H	190	818	-	1590	563	640	-	-	1000	570	81	560	-	-	-	-
TDS	19000	-	25000(?)	36000	25000	25000	19000	25000	14000	-	-	-	-	14	21500	5850
SpC	-	-	20000	24000	22450	22500	15000	24000	20000	-	-	-	-	-	-	-
SpG	-	-	1015	-	1.0158	1.0174	1.0085	1.0172	-	-	1.01	-	-	-	-	-
pH	10.6	-	10.3	10.1	10.5	10.9	10.6	10.7	10.7	-	12.4	11.56	-	-	-	-
T(C)	-	-	28.3	24.8	24	25	25	26	27	-	-	-	-	-	-	-
Acetic Acid	320	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Acetone	420	410	1500	2000	2700	500	82	-	1300	880	-	600	770	20	818	641
Acetophenone	80	200	70	140	130	110	110	-	22	190	94	-	-	12	216	249
Aniline	140	110	45	-	78	58	26	-	40	54	18.8	-	-	16	90	90
Formic Acid	1100	-	-	-	-	-	-	-	1800	3900	1681(?)	-	-	7	1430	1190
Phenol	4000	97	520	2300	3600	1200	1100	-	1200	2000	1300	250	-	19	2580	1755

Table 2

Mean concentrations of species in the injectate used in mixing calculations in ppm. (See discussion of phenol in the footnote). SD denotes one standard deviation of the mean. Mean injectate concentrations were computed from all the available data for the period 1981-1989. Mean concentrations of species in the injectate samples obtained during the period 1981-1984 are also shown separately because of their relatively high phenol concentrations. (See Table 1 and Fig. 1).

	1981-1984			1981-1989			
Species	No. of Anals.	Mean	SD	No. of Anals.	Mean	SD	Remarks
Na	2	9500	707	4	8770	2590	Inorganics probably relatively constant 81-89'
Ca	2	21	11	12	25	11	
Cl	2	905	375	4	1625	933	"
SO_4	2	9680	813	4	8790	5100	"
TDS	6	18800	3870	14	21500	5850	"
Acetone	9	577	281	20	818	641	Incr. 84-89' (?)
Acetophenone	8	344	337	18	216	249	Decr. 84-89' (?)
Analine	7	123	126	16	90	90	Decr. 84-89' (?)
Formic Acid	3	1010	79	7	1430	1190	Slight incr. after 1984 (?)
Phenol*	8	3930	1410	19	2580	1755	Decr. 84-89'

*Based on the graph of phenol in injectate with time in Fig. 1, the 'grand' average from 1978-1984 is 5800 ± 1900 ppm, and from 1974-1984 is 5100 ± 2100 ppm. The latter figure has been used in all mixing calculations.

Although data variability is large, the data for phenol in Table 2 suggests that its concentrations decreased after 1984, consistent with the plot in Figure 1. Because the number of phenol analyses used to derive the mean values plotted in Figure 1 greatly exceeds the number in Table 1, mean phenol concentrations based on Figure 1 data are considered the more representative, and an average 1981-1989 value of 5100+2100 ppm for phenol in the injectate is assumed in subsequent mixing calculations.

2. Groundwater Geochemistry

Very limited information is available regarding the natural composition of groundwaters underlying the Haverhill Area prior to the start of injection in 1968. What is known is based on drill stem tests conducted in WDW No. 1 in 1968, which collected samples from several formations, including the Mt. Simon and Rose Run. Sampling from the Berea sand under the site at a depth of 713-733 ft, indicated that the water was brackish with Na, Cl and TDS concentrations of 1730, 3480 and 6600 ppm, respectively. Evidence discussed in Section D.2.4.2 of this report indicates that these concentrations were lower than actually present in the formation, and had been diluted by drilling-mud fluids. Based upon the same 1968 sampling effort, the Lockport (Newburg) Formation at 1795-1835 ft contained brines with respective Na, Ca, Cl SO_4, and TDS concentrations of 46,900, 39,600, 170,000, and 266,000 ppm. These Lockport concentrations differ little from values for the same

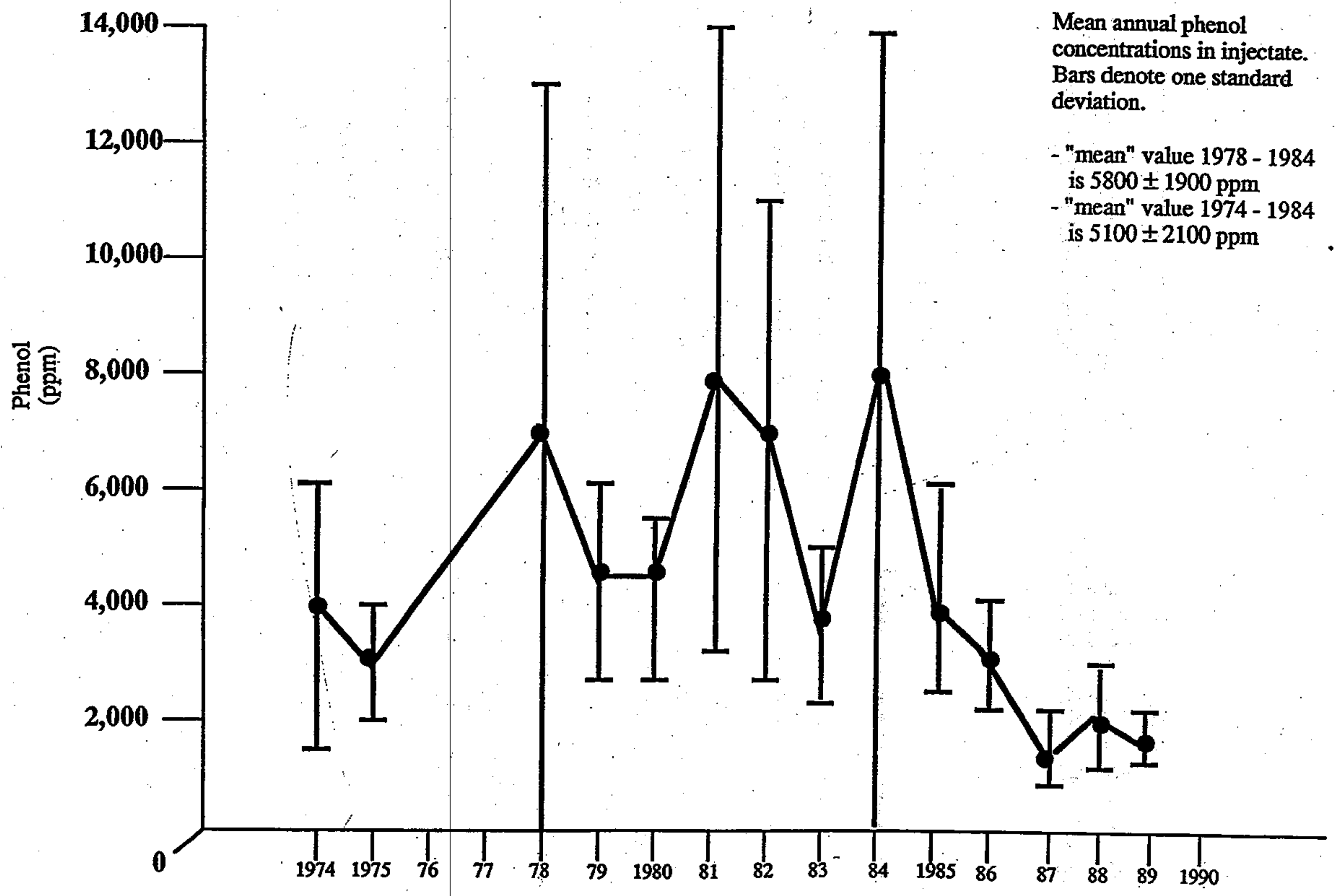

Figure 1. Mean Annual Phenol Concentrations in Injectate with Standard Deviations from 1974 to 1989

Table 3

Compositions of waters used in mixing calculations involving the 1968 and 1989 Mt Simon and Rose Run Formations, in ppm. Average injectate concentrations of organic species are for the period 1981-1984 (see Table 2) unless otherwise indicated. Uncertainties are one standard deviation of the mean. See Table 2 for the number of injectate sample analyses used in the averages. When June 15, 1989 analyses of Rose Run No. 1 and No. 2 wells were reported for a given species, the two analyses have been averaged. Average Mg and Br in the injectate are estimates.

	Mt. Simon		Rose Run		
Species	1968	1989	1968	1989	Average Injectate
Na	58,300	14,000	54,100	45,600±1340	8770±2590
Mg	7080	424	7610	5490±830	10 (est)
Ca	50,600	2850	39,800	38,500	25±11
Cl	200,000	21,200	176,000	165,000±7070	1630±933
Br	2160	200	1950	1630	5 (est)
SO_4	140	2490	74	355±35	8790±5100
TDS	316,000	48,400	278,000	279,000±12,000	21,500±5850
Acetone	-	800	-	141±98	577±281 (81-84) 818±641 (81-89)
Acetophenone	-	35	-	6.3±0.4	344±337
Analine	-	3.1	-	-	123±126
Formic Acid	-	1335	-	175±8	1010±79 (81-84) 1430±1190 (81-89)
Phenol	-	940	-	460±85	5100±2100 (74-84)

No chemical analyses to determine the presence of dissolved organic species in the Mt. Simon, Rose Run and other groundwaters was performed on the samples collected in 1968. Consequently, the possible existence of anthropogenically derived organic substances in these formation prior to injection is unknown. However, concentrations of natural organic substances in these brines, which are not associated with petroleum deposits, are unlikely to have exceeded 15 ppm, and were probably below 2 ppm (cf. p. 14, in Thurman, E. M., 1985, Organic Geochemistry of Natural Waters, Martinus Nijhoff/Dr. W. Junk Publishers, Boston. 497 pp).

The remarkable chemical similarity of brines in the Newburg, Beekmantown (Upper Knox), Rose Run, Copper Ridge (Lower Knox) and Mt. Simon Formations, which span a total vertical depth of from about 1800 to 5600 ft., indicates that these groundwaters are either interconnected or have similar histories of evolution. Hydrogeologic data suggests that vertical interconnection is highly unlikely given the presence of several low permeability shale horizons separating these formations in the stratigraphic column. More likely is a similar evolutionary history for these groundwaters. The practically identical stable oxygen and deuterium isotope compositions of Beekmantown, Rose Run and Copper Ridge groundwaters, which have an average delta-^{18}O of -0.9±0.3 per mil, and delta-deuterium of -28.8±1.3 per mil, indicates that these waters have a very similar origin.

Examination of Figure 3 in the text, the Generalized Stratigraphic Column, Haverhill Area, shows that between the Lockport and Mt. Simon Formations, the geology is comprised of interbedded carbonates (limestone and dolomite), with minor shales and sandstones. Petrographic data in Table 1 of the text, indicate the presence of anhydrite ($CaSO_4$) in the Precambrian basement and overlying Mt. Simon and Rome Formations. If anhydrite saturation limits Ca and SO_4, concentrations, then the molal product of these species should remain roughly constant, regardless of changes in their relative concentrations, in brines of roughly the same salinity. Thus, in 1968 Mt. Simon groundwaters, in which Ca = 50,600 ppm and SO_4 = 140 mg/l, the molal product $(mCa)(mSO_4) = (1.26)(8.33E-4) = 1.8E-3$. In 1989 Mt. Simon groundwaters, which have been altered by mixing with injectate (see Table 3), Ca and SO_4 concentrations are 2850 and 2490 ppm, respectively, but the molal product $(mCa)(mSO_4)$ still equals 1.8E-3, indicating that Ca and SO_4 concentrations are limited by anhydrite saturation. The anhydrite molal product equals 0.8E-3 in 1968 Rose Run groundwaters, suggesting undersaturation with respect to anhydrite, consistent with the lack of anhydrite reported in the Rose Run. However, 1989 Rose Run groundwater, which has a slightly elevated SO_4 concentration, probably because of mixing with sulfate-rich injectate, has an anhydrite molal product of 3.6E-3, at or just above anhydrite saturation.

Because of anhydrite saturation in 1968 and 1989 Mt. Simon groundwaters and in 1989 Rose Run groundwater, it is clear that neither Ca, SO_4, nor TDS concentrations can be assumed conserved in mixtures of these waters. Thus, although mixing calculations involving TDS are shown in Tables 4 and 6, the results are not used in arguments regarding hypothetical mixing proportions. The ubiquitousness of limestone ($CaCO_3$) in the stratigraphic column with which all the groundwaters must therefore be at saturation, also limits Ca concentrations, and argues against the use of Ca as a groundwater tracer.

Although Mg is also considered in the mixing calculations summarized in Tables 4 and 5, it too is a poor groundwater tracer. This is because of its tendency to coprecipitate with $CaCO_3$, and to be adsorbed as pH increases when low pH groundwater mixes with high pH injectate.

All the groundwaters are substantially undersaturated with respect to halite (NaCl), and at these high ionic strengths, Na is unlikely to be significantly involved in adsorption reactions. For such reasons Na is a good groundwater tracer. Also for reasons of non-reactivity, Cl and Br are excellent groundwater tracers. Based upon the above discussion, the species given the most weight in mixing discussions are Na, Cl and Br.

Table 4a

Simple dilution of 1989 Mt. Simon groundwater composition relative to its 1968 composition is given in Column 2. Column 3 lists the volume ratios (R_V) of average injectate to 1968 Mt. Simon that would produce the 1989 chemical analyses of the groundwater, shown in Column 4. Column 5 gives concentrations of the listed species that would be present in 1989 groundwater if the average R_V value of 9.2 ± 0.8 (± 97%) for the relatively unreactive species Na, Cl and Br are assumed for all species.

Species	Dilution 68' to 89'	R_V	Mt. Simon 89' Conc.	Average Conc. if $R_V = 9.2$
Na	4.2	8.5	14,000	13,600
Mg	.17	16	424	703
Cl	9.4	9.1	21,200	21,100
Br	10.8	10	200	217
TDS	6.5	9.9	48,400	50,300
Acetone	-	undefined (see text)	800	520 (81-84) 737 (81-89)
Acetophenone	-	0.11	35	310
Analine	-	0.03	3.1	111
Formic Acid	-	undefined (see text)	1335	910 (81-84) 1288 (81-89)
Phenol	-	0.23	940	4600

Table 4b

Simple dilution of 1989 Rose Run groundwater composition relative to its 1968 composition is given in Column 2. Column 3 lists the volume ratios (R_v) of average injectate to 1968 Rose Run groundwater that would produce the 1989 chemical analyses of the groundwater shown in Column 4. Column 5 gives concentrations of the listed species that would be present in 1989 groundwater if the average R_v value of 0.17 ± 0.09 (± 53%) for Na, Cl and Br is assumed for all species. See text.

Species	Dilution 68' to 89'	R_v	Rose Run 89' Conc.	Average Conc. if R_v = 0.17
Na	1.19	0.23	45,600±1340	47,300
Mg	1.39	0.39	549±830	6470
Cl	1.07	0.07	165,000±7070	150,000
Br	1.20	0.20	1630	1660
TDS	1.00	undefined	279,000±12000	240,000
Acetone	-	0.32	141±98	87 or 123
Acetophenone	-	0.02	6.3±0.4	52
Formic Acid	-	0.14(81-84) 0.21(81-89)	175±8 175±8	152 215
Phenol	-	0.10	460±85	765

Table 5

Volume ratio (R_v) of 1968 Rose Run to 1989 Mt. Simon groundwaters, which would produce the average concentrations of solute species reported in the 1989 Rose Run groundwater analysis given in Column 3, and the average concentrations of the same species expected in 1989 Rose Run groundwaters, assuming $R_v = 0.19 \pm 0.10$ (± 53%), the average of the R_v values for Na, Cl, and Br. Concentrations are in ppm.

Species	R_v	Rose Run 89' Conc.	Average Conc. if $R_v = 0.19$
Na	0.27	45,600±1340	47,700
Mg	0.42	5490±830	6460
Cl	0.08	165,000±7070	151,000
Br	0.22	1630	1670
Acetone	0.21	141±98	128
Acetophenone	0.21	6.32±0.4	5.6
Formic Acid	0.15	175±8	214
Phenol	0.96	460±85	150

Table 6

Volume ratio (R_v) of 1968 Mt. Simon groundwater to average injectate, which would displace Rose Run groundwaters, producing the average concentrations of solute species reported in the 1989 Rose Run groundwater analysis given in Column 3, and the average concentrations of the same species expected in 1989 Rose Run groundwaters, assuming $R_v = 0.29 \pm 0.07$ (± 24%), the average of the R_v values computed for Na, Cl, and Br. Concentrations are in ppm.

Species	R_v	Rose Run 89'Conc.	Average Conc. if $R_v = 0.34$
Na	0.34	45,600±1340	47,400
Mg	0.29	5490±830	5520
Cl	0.21	165,000±7070	160,000
Br	0.33	1630	1690
TDS	0.14	279,000±12,000	251,000
Acetone	0.32	141±9	127 (81-84) 180 (81-89)
Acetophenone	0.02	6.3±0.4	76
Formic Acid	0.21 (81-84) 0.14 (81-89)	175±8	222 (81-84) 315 (81-89)
Phenol	0.10	460±85	1120

3. Mixing of Fluids

3.1 Proof of Mixing with Injectate

Proof that mixing or original groundwaters with injectate or with injectate-affected groundwaters has taken place must be based on two observations. First, such a mixture must be more dilute than original groundwaters, and second, it must contain organic substances which are specific to the Aristech injectate, at high enough concentrations to only have been derived from mixing with injectate.

That dilution of inorganic species concentrations will occur upon mixing with injectate, reflects the fact that except for sulfate concentrations, which are high in the injectate, injectate concentrations of inorganic species are much lower than they are in natural groundwaters from the Haverhill area. (Compare the concentration data in Table 6 and Fig. 7 of the text). Thus any mixing of injectate with natural groundwaters will cause dilution in the concentrations of these species in the mixtures. Consequently, if a comparison of chemical analyses from the same formation at different times does not show significant dilution of the inorganics, then mixing with injectate cannot have occurred.

3.2 Theoretical Basis

A useful approach to evaluating the possibility that 1989 Mt. Simon and Rose Run groundwaters have resulted from mixing with injectate, is to compare hypothetical mixtures involving the 1968 compositions of these waters, with their 1989 compositions. The comparison is done for individual chemical species or properties whose concentrations are known or can be assumed in each water.

If there are no additions or losses of a chemical species upon mixing of injectate and initial groundwater, that species' concentration in the mixture (C_M) is related to its concentration in the injectate (C_I) and in the initial groundwater (C_G) by the equation:

$$C_M \; V_M = C_I \; V_I \; + \; C_G \; V_G \qquad (1)$$

where the V terms are the corresponding volumes. If we assume for simplicity that $V_M = V_I + V_G = 1$, then algebraically we can manipulate equation (1) to solve for the ratio of the volume of injectate that would be mixed with a volume of initial groundwater, to produce the species concentration in the resultant groundwater. Labeling this ratio, R_V, we find it equals:

$$R_V = \frac{V_I}{V_G} = \frac{C_G - C_M}{C_M - C_I} \qquad (2)$$

Equation (2) is the basis for calculating the volume ratios (R_v values) in Tables 4-6, which are discussed in following sections of this report.

The uncertainties shown with the R_v values in following text and tables equal one standard deviation of the mean value shown. Following parenthetic values are the percentage uncertainties that those standard deviations represent. In general, those hypothetical mixing processes which have the smallest percentage uncertainties are more likely to have occurred than processes having larger percentage uncertainties.

3.3 Assumed Compositions of Injectate, and Mt. Simon, Rose Run and Copper Ridge Groundwaters Used in Mixing Calculations

Calculation of the hypothetical composition of mixtures and of mixing volumes requires that concentrations of certain chemical species in all the waters involved in the calculation be known. Listed in Table 3 are concentrations of those chemical species for which data exist for average injectate, and for 1968 and 1989 Mt. Simon and Rose Run groundwaters. It is assumed in all mixing calculations that concentrations of acetone, acetophenone, analine, formic acid and phenol in the 1968 groundwaters were zero. Even if a few tens of ppm of these species were present before deep well injection, it would not significantly change the results of the mixing calculations.

3.4 1989 Mt. Simon Groundwaters

That Mt. Simon groundwaters have been substantially diluted with respect to their inorganic species is evident from the dilution factors listed in column 2 of Table 4a. The dilution factor is the ratio of a species concentration in the 1968 analysis to its concentration in the 1989 analysis in Table 3. The most convincing species to define the extent of dilution are Na, Cl and Br, which are practically inert in this groundwater system.

A more useful exercise, however, is to compute the volumes of 1968 Mt. Simon groundwater and average injectate, which upon mixing would create 1989 Mt. Simon groundwater. Using the water compositions given in Table 3, and equations from Section C.3.1, we can determine R_V, the volume ratio of injectate to 1968 Mt. Simon groundwater that would produce the concentrations of each species found in the 1989 Mt. Simon. The results are shown in column 3 of Table 4a. The inorganic species Cl, Br and Na, are among the least reactive in the groundwater. Their R_V values in Table 4a suggest that 1989 Mt. Simon groundwaters were probably created by the mixing of about 9.2 parts injectate with 1 part initial (1968) groundwater. The R_V value of 9.2 corresponds to the following mixture:

89′ Mt. Simon = 90% (injectate) + 10% (68′ Mt. Simon)

Acetophenone, analine and phenol all have lower R_V values than 9.2, consistent with their attenuation in the groundwater system. The extent of attenuation is suggested by comparing their measured concentrations in 1989 Mt. Simon groundwaters (column 4 of Table 4a) to concentrations predicted assuming they all have an R_V value of 9.2 (column 5 of Table 4a). For TDS, Na, Cl and Br, the predicted values based on $R_V = 9.2$ are all within analytical uncertainties of measured 1989 concentrations. (The TDS agreement is probably fortuitous. See discussion of anhydrite saturation in the Mt. Simon in Section 2 of this Appendix). Among the organic species, acetone and formic acid concentrations in the 1989 Mt. Simon are slightly higher than predicted assuming the highest injectate concentrations of these species. This suggests that 'average' injectate concentrations of acetone and formic acid contributing to the mixture with Mt. Simon groundwaters, may be somewhat higher than suggested in Table 3. Among the remaining organic species, all have been attenuated relative to their injectate concentrations, with the extent of attenuation increasing from phenol (80% lost), to acetophenone (89% lost), to analine (97% lost). The logic of these overall results, especially the almost identical R_v values for Na, Cl and Br, is quite consistent with the conclusion that 1989 Mt. Simon groundwaters have been formed by mixing average injectate with the original Mt. Simon groundwater, as sampled in 1968.

One can probably assume that the extent of attenuation of organic substances from the injectate as evidenced by analyses of 1989 Mt. Simon fluids is relatively minimal, given the proximity of these waters to the injection well and their short residence times. One might expect then, that any mixing with injectate which also involved fluid migration and more time in the formations would show equal or greater attenuation of injectate organic compound concentrations that observed in 1989 Mt. Simon fluids.

3.5 1989 Rose Run Groundwaters

That 1989 Rose Run groundwaters may have formed by mixing of injectate and original Rose Run waters as sampled in 1968, is less convincing. Table 4b gives the results of such a mixing calculation. The R_v average for Na, Cl, and Br is 0.17±0.09(±53%) This corresponds to the following mixture:

89'Rose Run = 15% (injectate) + 85% (68' Rose Run)

The data for Na and Br agree and yield an average R_V value of 0.22. However Cl, which should also be conserved, gives inconsistent mixing results, and greatly exceeds its expected concentration in 1989 groundwater. This may, however, reflect an inaccurate chloride analysis of the 1968 Rose Run fluid. Consistent with the above injectate/Mt. Simon mixing calculation, acetone and formic acid show little or no evidence of attenuation upon mixing, whereas the mixing results suggest increasing attenuation of phenol (50% lost) and acetophenone (90% lost).

Calculations can also be performed to test whether 1989 Rose Run groundwaters could have been formed by mixing of 1989 Mt. Simon and original (1968) Rose Run groundwaters. The results of such an exercise are given in Table 5. The resultant average R_V value of $0.19 \pm 0.10 (\pm 53\%)$ corresponds to the following mixture:

89' Rose Run = 16% (89' Mt. Simon) + 84% (68' Rose Run)

Again, the R_V values for Na and Br are consistent with such a possibility. However, the Cl and phenol data are not. Concentrations of these species in the 1989 groundwater are too high to be explained by such a simple origin, although as noted above the chloride mismatch may reflect an error in the chloride analysis of the 1968 Rose Run groundwater.

If injectate mixed with 1968 (pre-injectate) Mt. Simon groundwaters has <u>displaced</u> preexistent Rose Run groundwaters, then this mixture should approach the composition of 1989 Rose Run groundwaters. A test of this possibility is shown in Table 6. As with the previous hypothetical mixture, R_V values for Na and Br are practically identical. Assuming an average $R_V = 0.29 \pm 0.07 (\pm 24\%)$, concentrations of Cl, Mg, and acetone are also consistent with such an origin for 1989 Rose Run groundwater. This R_V is equivalent to the following mixture:

89′ Rose run = 22% (injectate) + 78% (68′ Mt. Simon)

3.6 1991 Copper Ridge Groundwaters

Organic species concentrations found in groundwaters from the Copper Ridge member of the Lower Knox Formation in the Test/Monitoring Well in 1991, indicate that small amounts of Aristech injectate have found their way into the Copper Ridge. Because Copper Ridge groundwaters have not been previously sampled and analyzed, there is no information to determine the composition of these waters prior to their mixing with injectate. However, the similarity in composition of groundwaters from the Copper Ridge and the overlying, uncontaminated Rose Run Formation in the test well, suggested that the latter might be considered as a proxy for the pre-injection Copper Ridge. Mixing calculations based upon this assumption are given in Table 7. The average $R_v = 18$ computed from the values for Na, Cl, and Br, is also consistent with the values

Table 7

Mixing calculations to test whether the slightly contaminated groundwater collected in 1991 from the Copper Ridge Member of the Knox Formation at the Test/Monitoring Well could have been formed by mixing of uncontaminated Copper Ridge groundwater and average injectate. Lacking data on the composition of the uncontaminated Copper Ridge, it is assumed in the calculation that the uncontaminated Rose Run groundwaters collected from the test well in 1991 have the same composition as the uncontaminated Copper Ridge. Chemical analytical concentrations are in ppm. R_v is the ratio of volumes of uncontaminated Copper Ridge (91' Rose Run) to average injectate needed to form the 91' Copper Ridge. $R_v = 18 \pm 3$ is the average of the values for the Na, Cl, and Br. Based upon this value, the 91' Copper Ridge = 5% injectate + 95% uncontaminated Copper Ridge.

Species	R_v Assuming 91' Rose Run + Injectate Produced the Copper Ridge	91' Copper Ridge	91' Copper Ridge Less Injectate ($R_v = 18$)	91' Rose Run
Na	14	48,200	50,300	51,000
Ca	17.5	35,000	36,900	37,000
Cl	20.6	208,000	219,000	218,000
Br	19	2090	2180	2200
TDS	16.9	293,000	297,000	309,000
Acetone	6.4	110	82	0
Phenol	20.2	240	0	0

for TDS and phenol. However, the elevated acetone value in the Copper Ridge suggests that the injectate reaching that formation contained much more acetone than the 818 ppm assumed present in the injectate.

Also shown in Table 7 is a back-calculated composition of the original Copper Ridge groundwater, assuming $R_v = 18$. Its remarkable similarity to the 1991 Rose Run at the Test Well, for Ca, TDS and phenol, as well as (as expected) for Na, Cl and Br, supports the original assumption that 1991 Rose Run fluids are a good analog for original Copper Ridge groundwater. The computed presence of acetone in back-calculated original Copper Ridge, again suggests that injectate acetone concentrations may have exceed the average value assumed in the mixing calculations.

3.7 1989 Rose Run Groundwaters from Mixing of Injectate with Original Copper Ridge Groundwaters

The mixing calculations discussed in Section 3.6 suggest a fourth possible origin of contamination in 1989 Rose Run fluids, involving the mixing of injectate with original (computed) Copper Ridge groundwaters. Results of such a mixing calculation are given in Table 8. The average $R_v = 0.29 \pm 0.15 (\pm 52\%)$ corresponds to the following mixture:

89′ Rose Run = 22% (injectate) + 78% (original Copper Ridge)

The large scatter of R_v values for Na, Cl and Br, cast further doubt on this mixing origin for 1989 Rose Run fluids. Back-

Table 8

Mixing calculations to test whether 1989 Rose Run Groundwaters could have formed by mixing of average injectate with original Copper Ridge groundwaters (91′ Copper Ridge less injectate; see text and Table 7). The resultant average R_V based on the values for Na, Cl and Br, is 0.29±0.15(±52%).

Species	R_V	Rose Run 89′ Conc.	Average Conc. if R_V = 0.29
Na	0.13	45,600±1340	41,000
Cl	0.33	165,000±7070	170,000
Br	0.42	1630	1690
TDS	0.07	279,000±12,000	235,000
Acetone	0.21	141±98	184
Phenol	0.10	460±85	1150

calculation indicates that acetone and phenol concentrations in 1989 Rose Run fluids are 23% and 60% lower than would be predicted from such a mixture. However, such attenuation would seem possible. In summary, given that the composition of the original Copper Ridge has itself been estimated, drawing conclusions from this mixing result is obviously rather tenuous.

In spite of the large uncertainties in results of three of the four mixing approaches considered to form 1989 Rose Run fluids, the four approaches lead to a similar conclusion: 1989 Rose Run fluids are comprise of a mixture of 14-22% injectate with an original formation groundwater. (See Table 9 in the text). The lower uncertainty (±24%) associated with the injectate plus 68′ Mt. Simon origin for the 89′ Rose Run suggests that this origin is the most likely of the four

WI-68 BOX 58
002640

INTER-OFFICE MEMORANDUM

To Mr. John Fitzpatrick
USS Chemicals

Date June 15, 1968

From W. J. Turner

Subject Haverhill Drilling Report No. 9

June 2 Coring Mt. Simon sand. Drilled top of Mt. Simon at 5528. Commenced coring at 5532.

June 3 Core No. 6: 5532 to 5562 recovered 30 feet. Twenty-seven feet clean white hard sandstone; 3 feet shaly, fine grain hard silty sandstone.

Core No. 7: 5563 to 5573 recovered 10 feet of fine grained, tight silty sandstone, very hard and dense, poor permeability, bleeding salt water.

June 4 Reamed core hole and drilled from 5573 to 5595. Probable top of Granite wash zone at 5589 indicated by increased penetration rate and granite material in cuttings. Preparing to run drill stem test No. 4 in Mt. Simon sand.

June 5 DST No. 4 - 5520 to 5565, Mt. Simon sand. Open one hour, recovered 1895 feet (978 gallons) of salt water, specific gravity 1.215. Average flow rate 16.3 gpm. Pressures as follows:

	Hydrostatic	Flowing	Shut-in
Initial	2667	130 to 714	2533
Final	2623	736 to 1072	2545

June 6 Core No. 8: 5595 to 5617 recovered 22 feet of granite, no apparent porosity. DST No. 5 - 5575 to 5617 (granite zone) open one hour, recovered two feet of drilling mud; pressures as follows:

	Hydrostatic	Flowing	Shut-in
Initial	2699	30 to 30	2347
Final	2677	30 to 30	2210

Results indicate permeability too low in granite to be practical for disposal. Schlumberger checked resistivity of water samples recovered from DST's as follows:

DST No.	Zone	Depth	Sample Temp °F	R_W Ohm-meters
2	Newburg	1795-1835	71	.051
3	Rose Run	4220-4265	71	.072
4	Mt. Simon	5520-5565	73	.076

June 7 Completed running Schlumberger electric logs at 2:00 a.m. Waiting on delivery of casing hanger.

June 8 Waiting on casing hanger part of well head.

June 9 Still waiting.

June 10 Still waiting. Ran drill pipe in hole to circulate and condition mud in preparation for laying down drill pipe and running casing.

June 11 Laid down drill pipe. Casing hanger arrived on location at noon. Ran 5603.47 feet of 7-inch casing landed at 5600 feet below kelly bushing. Used Baker guide shoe on bottom and Baker insert float valve one joint above bottom. Ran sand coated joints of casing opposite Mt. Simon sand and Rose Run sand. Installed Halliburton DV stage cementing packer collar below Rose Run sand.

Attempted first stage cement job at 11:50 p.m. with 200 sacks of cement. First stage cementing plug failed to seat properly. Continued pumping water after plug until 650 barrels were pumped and tanks were empty. Cement circulated out of hole. Ran wire line measure in hole and found plug at 5325 feet, indicating it had passed through DV collar ok but had failed to seat at bottom. Continuity of circulation indicated possibility that either plug had torn up or casing had a hole in it at about 5325. After circulation was shut down, reverse flow from casing indicated that Baker insert float valve was not functioning.

Cementing attempt was witnessed by State Inspector Harry Smith. After failure of cement job, Inspector Smith was informed that casing would be pulled to investigate cause of failure and that an estimated 36 hours would be required to pull casing, correct the malfunction, re-run it and be ready to cement again.

June 12 Pulled casing to investigate cause of failure. Found two-inch hose adapter nipple with union flange in casing on top of insert float valve. This nipple prevented cementing plug from seating properly. It had accidentally come loose from the end of a two-inch hose which had been used for filling the casing in lieu of the automatic fill-up tube. Pulling the casing destroyed the Baker metal petal basket and also the packer rubber on the Halliburton DV stage cementing packer. Casing was re-run using a Halliburton guide shoe and float collar to replace the Baker equipment which had malfunctioned. It was decided to re-cement in one stage since the packer rubber of the stage collar had been destroyed.

June 13 Completed re-running casing and started pumping single stage cement at 8:25 a.m. Total time lost 32-1/2 hours as a result of foreign object in casing. Cementing completed with 1350 sacks of cement at 9:30 a.m. Cement did not circulate to surface.

Ran total of 5607.38 feet of casing landed at 5605 feet, K.B. Float collar at 5570 or ten feet below bottom of Mt. Simon sand. Hung entire weight of casing on well head casing hanger with internal pressure released. Released rotary rig and waiting on cement to set.

June 14 Ran Schlumberger Temperature Log 13 hours after cementing. Results showed top of cement behind 7-inch casing at 1935 feet, K.B. Cooling anomaly at 1833 to 1838 indicates probable source of salt water and gas flow coming up between 7-inch casing and 10-3/4 inch surface casing. This is the Newburg dolomite zone which was cored and tested.

Failure of primary cement job to circulate to surface was probably caused by excess hole cavings during waiting time for casing hanger and pulling and re-running casing. Cement volume had been calculated on the basis of caliper log run prior to these events. It will be necessary to repair cement job by squeeze cementing after cable tool completion rig moves on.

No rig time was charged to USS Chemicals after June 11 since contractor assumed responsibility for failure of first attempt to cement casing.

WJT bw
cc - Mr. H. L. Hosmer
Mr. J. P. Gravenstreter

INTER-OFFICE MEMORANDUM

To Mr. John Fitzpatrick
USS Chemicals

Date July 1, 1968

From W. J. Turner

Subject Haverhill Drilling Report No. 10

June 17	Earl Schilling and Son, Contractor excavating cellar and welding 10-3/4" casing head.
June 18	Laid reinforcing bars in 12" lattice and poured 8 inches of 5000 psi concrete for cellar floor.
June 19	Setting forms and 12" reinforcing lattice for cellar walls.
June 20	Finished wall forms and reinforcing. Poured 8" of 5000 psi concrete.
June 21	Removed forms and backfilled around walls.
June 22	Waiting for concrete to cure.
June 23	Moving in Carter Well Service rig.
June 24	Rigged up Carter Well Service and ran 5571 feet of 2-3/8" EUE tubing with 6-1/8" bit and drilled cement plug to 5561 G.L. = 5572 K.B. After reaching desired depth, circulating pump malfunctioned, bit plugged and tubing stuck. Operator pulled too hard on tubing and collapsed mast of Carter's single pole well service unit.
June 25	Moved in Halliburton to circulate well. Broke circulation with 4000 psi pump pressure. Circulated hole clean. Released Carter well service rig.
June 26	Moved in Eastern Well Service rig and pulled 2-3/8" tubing. Ran McCullough Correlation Gamma Ray Log and Cement Bond Log. Bond Log good up to top of cement at 1962 feet K.B.
June 27	Finished logging and perforated Mt. Simon sand with 36 - 80 gram jet shots from 5541 to 5559 K.B. with 2 shots per foot. Swabbed hole down. Fluid rose in casing at rate of approximately 300 to 400 feet per hour. Rate not accurate because of drive chain on rig breaking frequently during swabbing. Swabbed hole down in preparation for 25,000 gallon fracture treatment. Halliburton dumped 1000 gallons of Mod 202 acid on bottom and loaded hole with water. Shut down because of darkness for safety reasons.

June 28 Air trapped in casing escaped overnight allowing fluid level in well to fall. Halliburton finished loading hole and began pumping water at 8:50 a.m. to break down formation with acid. After loading hole, pumped 1620 gallons between 8:54 a.m. and 10:26 a.m. at average rate of 17.7 gpm. Pressure at start was 4000 psi. Gradually increased pressure to 7000 psi. Failed to get breakdown of formation. Perforated additional holes from 5517 to 5541 K.B. with 3 - 80 gram jet shots per foot. Total of 72 shots in 24 feet. Perforations now open extend from 5517 to 5559. Halliburton pressured up on casing again in effort to break down formation. Began pumping at 7:55 p.m. at average rate 23 gpm at 6700 psi. Raised pressure to 7000 psi at 8:10 p.m. and 3" side valve connection on 10-3/4" x 7" spool blew off. Released Halliburton.

June 29 Removed christmas tree to re-weld broken part. Swabbed hole to clean up and test productivity. Recovered substantial quantity of unspent acid from casing. No gauge of productivity because of difficulty in swabbing. Swab rubbers were damaged by tight spot or obstruction in casing at approximate depth of 4100 feet. Ran McCullough collar locater log and Caliper to evaluate possible casing damage. Logs indicated no apparent severe damage. Collar log indicated all perforations to be at correct location and no other holes in casing were detected. Caliper indicated I.D. of casing to be correct within tolerance. Concluded that obstruction may be a piece of perforating carrier strip caught in a collar. Fourteen feet of sheet metal carrier strip was lost in hole on last perforating job.

June 30 Sunday, shut down.

WJT bw
cc - Mr. H. L. Hosmer
Mr. J. P. Gravenstreter

INTER-OFFICE MEMORANDUM

To Mr. John Fitzpatrick
USS Chemicals

Date July 9, 1968

m W. J. Turner

Subject Haverhill Drilling Report No. 11

July 1 Re-installed casing head after repair and swabbed from bottom recovering salt water and some sand and perforating debris. Fill-up rate estimated at approximately 50 feet per hour. Shut down at 7:30 p.m.

July 2 Had approximately 600 feet of fill-up in casing overnight (12 hours). Swabbed hole to bottom then swabbed and bailed 18.72 bbl in 3-1/2 hours. Ran tubing with Halliburton Hydro-Jet notching tool on bottom. Tool rigged with four jets 90° apart in horizontal plane.

July 3 Cut notches at 5545, 5541, and 5538 pumping sand and water mixture at rate of 6 to 10 bbl per minute with 5000 psi pump pressure. Circulated hole clean to plug depth of 5566. Pulled tubing to remove notching tool.

July 4 Re-ran 2-3/8" tubing with Halliburton RTTS packer with 3 joints of tail pipe below packer. Spotted 500 gallons of 6% HF acid and 9% HCl over perforations and notches. Set packer and pressured up to 4500 psi and formation broke down. Pumped at average rate of 334 gpm at 3000 to 4500 psi after break down. Instantaneous pressure after shut down was 1200 psi indicating 1800 to 3300 psi friction pressure in tubing. Lower friction pressure was with gel mixed in water and higher friction pressure was with water only. Pulled tubing and installed christmas tree. At 7:30 p.m. well was flowing back fresh water at 3.8 gpm = 132 bpd. At 8:30 p.m. shut well in and measured 100 psi shut-in pressure.

At 9:35 p.m. began fracture treatment by pumping 500 gallons of 6% HF and 9% HCl acid ahead of treatment. Pumped 25,000 gallons of gelled water and 30,000 lbs of 20-40 mesh Ottawa sand at rates up to 43 bbl/min (1810 gpm) average treating pressure 2000 psi. Tailed in with 200 lbs 12-20 mesh UCAR props (Union Carbide glass beads). Treatment complete at 9:58 p.m. Instantaneous shut-in pressure 1350 psi. Pressure declined as follows:

	Time	Pressure
July 4	9:58 pm	1350
	11:30 pm	700
July 5	12:30 am	600
	1:00 am	585
	9:30 am	340
	10:30 am	330

July 5 Ran injection test pumping 15 minutes at each rate as follows:

Injection Rate		Pressure,
Bbl/Min	Gal/Min	psi
0.5	21	389
1.0	42	430
1.5	63	490
2.0	84	540
2.5	105	590
3.0	126	635
3.5	147	690
4.0	168	750
4.5	189	800
5.0	210	880
5.5	231	930
6.0	252	990

Above rates and pressures were measured at the end of the respective 15 minute injection periods. Recorded pressure fall-off after injection test as follows:

Time After Shut-in, Min	Well Head Pressure, psi
0	990
5	640
6	610
15	605
20	600
25	590
30	585
35	580
40	570
45	565
50	560
55	555
60	550

Released remaining pressure by flowing well to pit for approximately 2-1/2 hours. Removed christmas tree and McCullough set Baker wire line model N cast iron bridge plug in casing at 1975 feet, K.B. Perforated with four 0.63 inch holes from 1946 to 1952 feet, K.B. State inspector Gilbert Archer witnessed setting of bridge plug and perforating.

July 6 Ran 2-3/8" tubing with Halliburton RTTS packer set at 1800 feet, K.B. Mixed and pumped 500 sacks of regular cement into perforations at 1946 to 1952. Added 2% $CaCl_2$ to last 25 sacks of cement. Had good circulation returns until about half of cement in the returns ceased. Cleared packer and perforations with water. Cementing witnessed by State inspector Gilbert Archer.

Waited 12 hours for cement to set. For second stage cementing of perforations 1946 to 1952, mixed and pumped 225 sacks of light cement with Flocele flakes and 15 lbs of Gilsonite added per sack. Final pressure reached was 450 psi but pressure did not hold. Cleared perforations with water. Second stage squeeze witnessed by State inspector David Edgar.

July 7 Third stage squeeze of perforations 1946 to 1952 started at 10:30 a.m. twelve hours after second stage. During third stage squeezed 85 sacks of light cement with Flocele and Gilsonite added. Used 2% $CaCl_2$ in last 25 sacks. Cleared packer and repeated squeeze pressures for two hours until attaining 3500 psi which held constant. Left 57 feet of cement in casing above perforations. Third stage cement squeeze witnessed by State inspector David Edgar.

July 8 Waiting for cement to set.

July 9 McCullough ran Cement Bond Log from 720 to 1886 feet, K.B. Top of cement indicated at 852. Perforated two 0.63-inch holes at 846. Halliburton pumped 310 sacks of cement down casing with same mixture as on previous squeeze jobs. Followed cement with rubber cementing plug. Pumped plug down to 746 feet leaving approximately 80 feet of cement and 20 feet of water in casing between plug and perforations. Plug down at 8:00 p.m. Waiting on cement to set. Had good circulation return all during job and circulated good cement to surface. Cementing witnessed by State inspector David Edgar.

WJT bw
cc - Mr. H. L. Hosmer
Mr. J. P. Gravenstreter

P4-91

Barcode 002639

Box 37

APPENDIX S-1

IN-SITU STRESS MEASUREMENTS:
PROTOCOL AND IN-SITU STRESS MEASUREMENTS AT THE ARISTECH CHEMICAL CORPORATION HAVERHILL FACILITY: RESULTS
(PREPARED BY RESEARCH AND ENGINEERING CONSULTANTS, 1991)

PROTOCOL

In-Situ Stress Measurements at the Aristech Chemicals Haverhill Facility

Prepared by
Research & Engineering Consultants, Inc.
Englewood, Colorado

January 9, 1991

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Attachments

Results

In-Situ Stress Measurements at the Aristech Chemical Corporation Haverhill Facility

1991

July 17, 1991

REC

Research & Engineering Consultants, Inc.
5445 DTC Parkway, Suite 640
Englewood, Colorado 80111 (303) 741-5900

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ROSE RUN/ COPPER RIDGE REPORT

Barcode
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Box 35

Volume I

Sections III & IV

August 15, 1991

ARISTECH

Prepared for:
Aristech Chemical Corporation

Under direction of:
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Assembled and edited by:
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Alexandria, Virginia

ATK1/1757/Vol Icj

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Appendices

Appendices (Cont'd)

Appendices (Cont'd)

Appendices (Cont'd)

X - Industrial Facilities (Associated with Phenols) and Underground Injection Wells within 50 Miles of Haverhill, Ohio (Prepared by Environmental Resources Management, Inc., 1989)
Y - Select Annular Pressure Data, WDW No. 1 and WDW No. 2
Z - Corrosion and Precipitation Within Piping at Haverhill (Aristech Internal General Correspondence: 1972, 1980, 1981)

AA - Analysis of DST Data from Aristech Wells, 1989 (Memo from REC Aristech)
BB - Summary of Studies Performed and Methodologies:
  - Organic and Inorganic Geochemistry
  - Organic Chemical "Fingerprinting"
  - Geophysical Information and Well Construction Assessments
  - Data Validation, QA/QC
  - Additional Site Studies
CC - True Vertical Depth Log, WDW No. 3
DD - Marathon Oil Report Re: Work on WDW No. 2, 1984, and Discussion Letter (Prepared by Envirocorp Services, Inc., 1991)

run which showed the interior liner to be in sound condition. The well was then reassembled, and a successful annular pressure test was performed. In September 1989, an annular pressure increase was noted. The pressure rise was discovered to be caused by a faulty packer seal (rather than any well problem that would allow injectate to enter adjoining rock formations). This problem was corrected with the installation of a new packer. A complete summary of WDW No. 1 history is included in Appendix G1.

C.1.4 Formation Fluid Sampling

Fluid from a number of formations was sampled during drilling of WDW No. 1. Sampled and cored intervals are summarized in Table 2.

C.2 WDW No. 2

C.2.1 Well Construction

WDW No. 2 was directionally drilled to a measured depth of 6024 feet (which is equivalent to a vertical depth of 5568 feet) and was completed in August of 1978. The bottom hole location is 2087 feet west of the surface location. This well has a slightly different well construction than WDW No. 1: a 16-inch outer diameter conductor pipe was cemented in place from ground surface to 85 feet, while the surface casing was set from ground surface to 504 feet. The 7-inch protective casing was set to 6024 feet, and the Mt. Simon was perforated through this casing from 5930 to 5972 feet. Three and one-half inch injection tubing was installed from ground surface to the packer at 5862 feet, and 27 feet of injection tubing extends below the packer.

C.2.2 Well Stimulation

Well No. 2 was perforated between 5930 feet to 5972 feet below ground surface and hydraulically stimulated with 2000 gallons of 15 percent hydrochloric acid to enhance the

Table 2

Formation Fluid Sample Collection and Core for WDW No. 1

Interval	Test Type*	Recovered Fluid**
712-733 ft. Berea	DST	30 ft. drilling fluid (6.2 gallons)
1795-1835 ft. Newburg	DST	1410 ft. formation fluid (607.6 gallons)
4220-4265 ft. Rose Run	DST	660 ft. formation fluid (159.7 gallons)
5520-5565 ft. Mt. Simon	DST	1895 ft. formation fluid (897.3 gallons)
5575-5617 ft. Lower Mt. Simon and Precambrian Granite	DST	2 ft. drilling fluid (.4 gallons)

Cored Intervals

710-733 ft:	Berea
1895-1834.5 ft:	Newburg (plug)
1805-1833 ft:	Newburg (full core)
3979-4007 ft:	St. Peter (Beekmantown)***
4242-4246.5 ft:	Rose Run[1]
4250-4261.8 ft:	Rose Run[1]
5532-5561 ft:	Mt. Simon
5563-5573 ft:	Mt. Simon
5595-5617 ft:	Precambrian Gneiss

---

* See Appendix I for description of sample collection (test) methods.

** Calculated fluid recovery (in gallons) assumes that the drill string consists of 600 feet, 6 1/4 inch O.D.; 2 1/4 inch I.D. drill collars; and the rest of the well is lined with 4 1/2 inch, 16.6 lb/ft. drill pipe.

*** Formation correlation based on Table 6.3-11 in the UIC Repermit Application (Appendix A1).

[1] Core actually collected approximately 10 feet higher than indicated log depth.

C.2.4 Formation Fluid Sampling

No formation fluid sampling was conducted at WDW No. 2.

C.3 WDW No. 3

C.3.1 Well Construction

WDW No. 3 was completed in December of 1989 (Appendix G2), and was directionally drilled to a measured depth of 6091 (equivalent to a vertical depth of 5614 feet). The bottom hole location is approximately 2000 feet northeast of the surface location. A 16-inch outer diameter conductor pipe was set and cemented to 77 feet below ground surface. A 10-3/4-inch outer diameter surface casing was set and cemented to 879 feet below ground surface, and a 7-inch protective casing was set and cemented from ground surface to 5978 feet. The hole is open from 5978 to 6091 (within the Mt. Simon Formation).

C.3.2 Well Stimulation

WDW No. 3 has not been artificially hydraulically stimulated.

C.3.3 Well History

WDW No. 3 has not been placed in service. A bridge plug is installed in the well at a depth of 5934 feet. The injection tubing and packer have not been installed. WDW No. 3 was re-entered late in 1989 for interference testing among the three Aristech wells. Subsequent to the interference test, a step rate test was performed, a RAT was run, and an OAL was performed. Neither the RAT or the OAL gave any indication of fluid movement behind the casing or out of the injection interval.

During March 1991, the well was re-entered to perform additional step rate testing on the Mt. Simon injection interval. Three step rate tests were performed. The results from the third test are considered to be the best since the first two tests had operational problems (Appendix G4).

C.3.4 Formation Fluid Sampling

A number of formation fluid samples and formation core samples were taken from WDW No. 3 while it was being drilled (Table 3a). The DSTs are listed in the order that they were conducted. The Berea, first Rose Run, Rome/Conasauga, and Mt. Simon DSTs were performed as the well was being drilled. Other DSTs were "straddle-packer"-type tests wherein samples were collected in the uphole formations after the well had been drilled to the Rome/Conasauga.

C.4 Test/Monitoring Well

C.4.1 Well Construction

The Test/Monitoring Well was approved for installation in early January and spudded on January 17, 1991 (Appendix G3). Seven-inch casing was set to 101.5 feet below ground surface and cemented in place to ground surface. A 4-inch core hole was then drilled to 2170 feet below surface. During this initial coring operation, representative formation fluid samples were obtained from the Logan, Berea, and Lockport Formations. The hole was reamed to a diameter of 6-1/2 inches to a depth of 2105 feet, followed by the setting of a 4-1/2-inch O.D. (outer diameter) casing.

Coring proceeded following setting of the casing. Representative fluid samples were collected from the Beekmantown (identified as Upper Knox when sampling), Rose Run, and Copper Ridge (identified as Lower Knox Formation during sampling). The well was then cored to a total depth of 5434 feet as determined by WLM (wire line measurement). After

Table 3a

Formation Fluid Sample Collection and Core for WDW No. 3 Presented in Order of Sample Collection

Interval**	Test Type*	Recovered Fluid
195 and 214 ft. Logan (195 and 214 ft.)	***	no data
701-751 ft. Berea (701-751 ft.)	DST	no fluid recovery***
4503-4588 ft. Rose Run (4234-4267 ft.)	DST	420 gallons
5598-5733 ft. Rome/Conasauga (5150-5273 ft.)	DST	2 gallons from sample chamber
4491-4591 ft. Rose Run (4183-4271 ft.)	Swab Test	7896 gallons
4171-4232 ft. St. Peter (3910-3962 ft.) (Beekmantown through Wells Creek)****	Swab Test	no formation fluid recovery
1788-1858 ft. Newburg (1773-1834 ft.)	Swab Test	3935.4 gallons
1500-1570 ft. Niagaran (1497-1567 ft.)	Swab Test	3666.6 gallons
5963-6109 ft. Mt. Simon (5481-5614 ft.)	DST	misrun, no test
5978-6109 ft. Mt. Simon (5495-5614 ft.)	DST and Swab	5334 gallons

Table 3a (Con't)

Formation Fluid Sample Collection and Core for WDW No. 3 Presented in Order of Sample Collection

Cored Intervals**

5600-5654 (5151-5200):	Conasauga/Rome
5654-5695 (5200-5237):	Conasauga/Rome
5695-5733 (5237-5272):	Rome
5915-5978 (5432-5495):	Rome
5982-6027 (5499-5540):	Mt. Simon/Rome
6027-6073 (5581-5603):	Mt. Simon
6073-6097 (5603-5614):	Mt. Simon; Gneiss
Basement at 6079	
6097-6109 (5603-5614):	Gneiss Basement

* See Appendix I for description of sample collection (test) methods.

** Measured depths; true vertical depth in parenthesis.

*** Sampled using Repeat Formation Tester, as described in Appendix I.

**** Formation correlation based on Table 6.3-11 in the UIC Repermit Application (Appendix A1).

total depth was achieved, 28 in-situ stress tests were performed. The well was then plugged back to a depth of 4303 feet and a 2-3/8 inch monitoring well casing was installed. The monitoring well casing was then cemented to the surface.

The casing was perforated in the Rose Run from 4186 feet to 4222 feet. A Cement Bond Log/Variable Density Log (CBL/VDL) was run, which confirmed proper cementing of the casing from bottomhole to surface. A pressure monitor was installed on June 27, 1991 to complete the well.

C.4.2 Well Stimulation and Well History

The well was not hydraulically fractured because it will be used for monitoring, not injection. The Test/Monitoring Well has only recently been completed, and has no well performance history.

C.4.3 Formation Fluid Sampling

As stated above, six formations were sampled during drilling of the Test/Monitoring Well. The Logan, Berea, Lockport/Newburg, Beekmantown (Upper Knox), Rose Run, and Copper Ridge (Lower Knox) Formations were sampled, as shown in Table 3b.

C.5 Summary: Mechanical Integrity Test (MIT) Results for WDW No. 1, WDW No. 2, and WDW No. 3

Envirocorp Services & Technology has reviewed the available MIT data and operating histories for WDW Nos. 1 and 2 at the Haverhill facility (Appendix H) and MIT data for WDW No. 3 subsequent to step-rate tests completed in 1991.

Based on a review of the data, the following conclusions were reached:

Table 3b

Formation Fluid Sample Collection for Test/Monitoring Well

Interval	Test Type*	Recovered Fluid
164.2-261.5 Logan	DST/Swab	619 gallons
679.2-734.0 Berea	DST/Swab	231 gallons**
1757.4-1790.7 Lockport/Newburg	DST/Swab	905 gallons
4006.7-4035 Upper Knox/Beekmantown	DST/Swab	1426 gallons
4181-4225 Rose Run	DST/Swab	3389 gallons
4446.7-4480 Lower Knox/Copper Ridge	DST/Swab	5834 gallons

* See Appendix I for description of sample collection (test) methods.

** Total fluid from 2nd swab event only.

a pressure limitation of 1711 psi. In 1986, this was increased to 1739 psi by OEPA after a review of injection data and modeling results.

C.7 Historic Deep-Well Waste Disposal by Other Operators in the Haverhill Area

Harrison/Kroll Environmental Service Inc., was contracted in 1989 to identify chemical production facilities in the Haverhill area and to determine processes and waste disposal practices of these facilities from the 1950s to the 1970s (Appendix K). Harrison/Kroll was also asked to assemble information concerning wells drilled into the Rose Run in the Haverhill area and to interview former employees of local manufacturing facilities. Local residents were also interviewed.

Harrison/Kroll identified six facilities that operated in the past, or continue to operate, which produce waste streams with phenol-related constituents in the Haverhill area: Allied Chemical, Ironton; Dow Chemical, Ironton; Hooker Chemical, Ironton; Allied Chemical, Ashland, Kentucky; Ashland Oil, Catlettsburg, Kentucky; and Allied Chemical, South Point, Ohio. Documentation gathered from government offices does not indicate that waste disposal by deep well injection was conducted at any of the facilities. Interviews with local residents/former employees indicate that injection of wastes may have taken place, but there is no direct evidence of this activity.

D. Fluid Chemistry

The chemical nature of the injectate, the Mt. Simon, Copper Ridge, and Rose Run Formation fluid, and the fluid from overlying formations are summarized below. This discussion also includes the results of studies concerning the chemical nature of the injectate, both historical and present, as well as formation brine characteristics before and after injection began. Additionally, the chemical characteristics of mixtures such as Mt. Simon + injectate, Rose Run + injectate, Copper Ridge + injectate, and Mt. Simon + Rose Run fluids are also briefly summarized. Chemistry data are presented in Appendix L, while a detailed discussion of mixing calculations is presented in Appendix M.

D.1 Injectate

Injection of liquid wastes into the Mt. Simon Formation at the Haverhill site has been conducted for over 20 years. Both historic and current injectate have been comprised principally of phenol-related waste waters, although products other than phenol have also been made at Haverhill and waste waters from these processes could have entered the injectate waste stream. A discussion concerning historic production/waste waters is therefore warranted.

D.1.1 Manufacturing History of the Haverhill Facility and Origin of Injectate

As stated earlier in this report, the first manufacturing facility at the Haverhill site was constructed in 1962, by an Amoco and Pittsburgh Coke and Chemical joint venture. The two companies built an alcohol plant in which heptene and nonene were used to produce isooctyl and isodecyl alcohols. Wastes such as caustic wash waters were produced and organic heavy end wastes were either burned for energy recovery in the plant boilers or directed to the Alcohol Wastewater Treatment Lagoons, depending upon the specific waste type. USX bought the plant in 1965 and continued alcohol production until 1982. There are no records indicating that alcohol wastes were placed in the disposal wells.

USX constructed the Phenol No. 1 manufacturing plant in 1969. Wastewater from the phenol production was disposed in WDW No. 1. USX manufactured polystyrene from 1971 to 1981, but personal interviews with facility representatives indicate that no polystyrene wastes were injected in either WDW No. 1 or WDW No. 2. BPA production began in 1979. Wastes from production of this compound were initially directed to a wastewater disposal facility(ies), but were added to wastes placed into the injection wells in late 1979.

Table 4a (Cont'd)

Typical Constituents in 1989 Injectate

Units - ppm	Injectate Sampled 6/14/89	Injectate Sampled 11/20/89	Injectate Sampled 4/12/90	Range (ug/l)
2-Methylbenzofuran	1.2	NI	NI	NI-1.2
2,3-Dimethylphenol	2.2	NI	NI	22
2-(1-Methylethyl)phenol	1.2	NI	NI	1.2
4-(1-Methyl-1-phenylethyl) phenol (cumyl phenol)	26	NI	10	10-26
2-[1-(4-Hydroxyphenyl) 1-methylethyl] phenol (o,p-BPA)	13	NI	NI	13
Bisphenol A (BPA)	NA	NA	NA	NA
Cumene	22 (TIC)	NA	17 (TIC)	17-22
Formic Acid (as Formate)	NA	NA	NA	NA
Aluminum	0.8	0.3	0.273	.273-0.8
Barium	ND	ND	0.0164	ND-0.0164
Calcium	21	38	164	21-164
Chromium	0.06*	0.05	0.0948	.05-0948
Iron	0.41	ND	ND	ND-0.41
Lead	ND	ND	ND	ND
Magnesium	0.14	ND	0.279	ND-0.279
Manganese	ND	ND	ND	ND
Potassium	17.1	10	169	10-169
Sodium	5080	11000	7410	5080-11000
pH	12.4	11.56	NA	11.56-12.4
Specific Gravity	1.01	NA	NA	1.01

NA - not analyzed (for)
NI - not identified, TIC
ND - analyzed for, but not detected
TIC - tentatively identified compound
* - concentration has been determined to be biased low
Complete list of chemical data qualifiers included in Appendix B

Table 4a (Cont'd)

Typical Constituents in 1989 Injectate

Units - ppm	Injectate Sampled 6/14/89	Injectate Sampled 11/20/89	Injectate Sampled 4/12/90	Range (ug/l)
Ammonia (as Nitrogen)	NA	NA	328	328
Ammonia	NA	560	NA	560
Bromide	ND	NA	ND	ND
Chloride	2790	1900	1590	1590-2790
Nitrate (as Nitrogen)	NA	NA	NA	NA
Sulfate	1790	14000	8440	1790-14000
$CaCO_3$ Alkalinity	NA	NA	2790	2790
Silica	NA	NA	9	9
Turbidity	NA	NA	NA	NA
Iodide	NA	NA	NA	NA
TDS	NA	NA	22100	22100
Resistivity (77°F)	NA	NA	NA	NA
Carbon Dioxide	NA	NA	NA	NA

NA - not analyzed (for)
NI - not identified, TIC
ND - analyzed for, but not detected
TIC - tentatively identified compound
* - concentration has been determined to be biased low
Complete list of chemical data qualifiers included in Appendix B

Table 4b (Cont'd)

Typical Constituents in November 1990 Injectate

Units - ppm	Injectate Sampled 11/19/90[1]
4,4'-Methylenebisphenol	NA
2-Methylbenzofuran	NA
2,3-Dimethylphenol	NA
2-(1-Methylethyl)phenol	NA
4-(1-Methyl-1-phenylethyl) phenol (cumyl phenol)	NA
2-[1-(4-Hydroxyphenyl) 1-methylethyl] phenol (o,p-BPA)	NA
Bisphenol A (BPA)	NA
Cumene hydroperoxide	2.6
Cumene	NA
Formic Acid (as Formate)	1300
Aluminum	NA
Barium	NA
Calcium	13
Chromium	ND/0.02[16]
Iron	NA
Lead	NA
Magnesium	NA
Manganese	NA
Potassium	NA
Sodium	NA

NA = not analyzed (for)
ND = analyzed for, but not detected
16 = total/hexavalent
1 = analyses performed for select group of constituents; no TIC or raw data for validation available

Complete list of chemical data qualifiers included in Appendix B

Table 4b (Cont'd)

Typical Constituents in November 1990 Injectate

Units - ppm	Injectate Sampled 11/19/90[1]
pH	11.1
Specific Gravity	NA
Ammonia (as Nitrogen)	NA
Ammonia	1020
Bromide	NA
Chloride	NA
Nitrate (as Nitrogen)	NA
Sulfate	NA
Diphenylamine	.07
Specific Conductance	42895 umho
$CaCO_3$ Alkalinity	NA
Silica	NA
Turbidity	NA
Iodide	NA
Resistivity (77°F)	NA
Carbon Dioxide	NA
Total Dissolved Solids	5.3%
Temperature	37°C
Total Suspended Solids	ND

NA = not analyzed (for)
ND = analyzed for, but not detected
18 = total/hexavalent
1 = analyses performed for select group of constituents; no TIC or raw data for validation available

Complete list of chemical data qualifiers included in Appendix B

As shown in Table 4a, typical organic constituents present in 1989 injectate include phenol, acetone, acetophenone, cumyl phenol, dimethylbenzyl alcohol (DMBA), aniline, cumene, and toluene. Wastewater from BPA production is also part of the injection waste stream, although analyses of the 1989 injectate did not include BPA, (one analysis did show the presence of the isomeric o,p-BPA, however). Current injectate (based on one November, 1990 sample) contains relatively lower concentrations of phenol, acetophenone, DMBA, and toluene, although aniline and acetone exhibit relatively higher concentrations in this specific sample. Cumene and cumyl phenol were not analyzed in the November, 1990 sample. It must be emphasized that the concentrations presented in both Tables 4a and 4b are representative of individual samples collected on a specific day, and constituent concentrations likely vary from day to day. Comprehensive chemical data lists and plots are presented in Appendices L and O.

Various inorganic constituents are also present in current and 1989 injectate, including potassium, calcium, magnesium, sulfates, and chloride. Although some of these inorganic constituents are also present in formation fluids, injectate concentrations are much different than in area formation waters. According to facility representatives, Ohio River water has always been the process water for injectate. This water is fresh and has contained a range of concentrations from zero to relatively low levels of inorganic and organic constituents such as chloride, sulfate, ammonia, phenol, lead, arsenic, dichloromethane, carbon tetrachloride, 1,2-dichloroethane, and tetrachloroethane. Methylene chloride and chloroform can be present in Ohio River water in excess of the 10^{-6} cancer risk level. A more thorough discussion of the Ohio River chemistry is presented in Appendix P.

Limited detailed historical analytical data are available on injectate chemistry. Most of such data are for the period after 1974 for phenol and after 1981 for several other organic and inorganic species. Monthly phenol concentrations in the injectate are presented as concentration plots that are included in Appendix O and complete injectate analyses are presented in Appendix L. The concentration plots show that the average yearly phenol concentrations varied from 1371 ppm to 8607 ppm with average phenol concentration decreasing during recent years. The concentration data for phenol in the injectate is further generalized in Figure 5, which is a plot of available average annual phenol concentrations and their standard deviations from 1974 to 1989. Most notable are the relatively high and variable phenol concentrations evident between 1978 and 1984. Based on the plotted data, the mean phenol concentration in the injectate for this period is 5800±1900 ppm. For the entire period of this record, 1974 to 1989, the mean phenol injectate concentration is 5100±2100 ppm. This latter value is used in calculations involving hypothetical mixtures of groundwater and injectate (Appendix M).

The more general composition of injectate through time is given in Tables 5a and 5b. Data for several organic and inorganic species are available beginning in 1981. Because of the relatively high phenol concentrations in injectate from 1981 to 1984 and the much lower (declining) phenol concentrations in post-1984 injectate, the data in Tables 5a and 5b have been analyzed in two ways: the 1981 to 1984 data means are presented in Table 5a, while the overall data means for 1981 to 1990 are listed in Table 5b.

Mean concentrations in the injectate based on the data in Table 5a and 5b are summarized in Table 6. Only a few values are available for certain species such as Na, Cl, SO_4, and formic acid.

The variability of existing data as evident from its standard deviation (SD), which is usually quite large, bringing into question the value of using mean concentrations in data evaluations. However, tentative generalizations can be drawn. Total dissolved solids (TDS), and Na, Ca, and SO_4 are relatively constant between 1981 and 1989. The data for Cl suggest that values may have increased through time; however, given that only four analyses are available, such a conclusion cannot be stated with confidence. Although data variability is wide, the data for phenol presented in Table 6 suggest that phenol concentrations decreased after 1984, which is consistent with the plot in Figure 5. Because the number of phenol analyses used to derive the mean values plotted in Figure 5 greatly exceed the

Table 6

Mean Concentrations of Species in the Injectate, in ppm.

1981-1984				1981-1989			
Species	No. of Analyses	Mean	SD	No. of Analyses	Mean	SD	Remarks
Na	2	9500	707	4	8770	2590	Inorganics probably relatively constant '81-89
Ca	2	21	11	12	25	11	
Cl	2	905	375	4	1625	933	"
SO_4	2	9680	813	4	8790	5100	"
TDS	6	18800	3870	14	21500	5850	"
Acetone	9	577	281	20	818	641	Increase '84-89
Acetophenone	8	344	337	18	216	249	Decrease '84-89
Aniline	7	123	126	16	90	90	Decrease '84-89
Formic Acid	3	1010	79	7	1430	1190	Slight increase after 1984
Phenol*	8	3930	1410	19	2580	1755	Decrease '84-89

SD denotes one standard deviation of the mean. Mean injectate concentrations were computed from all available data for the period 1981-1989. Mean concentrations of species in the injectate samples obtained during the period 1981-1984 are also shown separately because of the relatively higher phenol concentrations during this period.

*Based on the information presented in Figure 5, the average phenol concentration from 1978-1984 was 5800±1900 ppm, and from 1974-1984 was 5100±2100 ppm. The latter value has been used in all mixing calculations (Appendix M).

number in Table 6, mean phenol concentrations based on Figure 5 data are considered the more representative. An average value of 5100±2100 ppm for phenol in the injectate is assumed in the mixing calculations (presented in Appendix M), although results of mixing studies using a phenol mean with such a high standard deviation are tentative at best.

An extensive data validation effort was undertaken to determine the validity of the chemical information used in this study. However, data records for the historic phenol data were not sufficient to allow for any data validation.

D.2 Formation Fluid Chemistry

Very limited information is available regarding the natural composition of formation fluid underlying the Haverhill area prior to the start of injection in 1968. Available data are from DSTs conducted in WDW No. 1 in 1968, from which samples from several formations were collected, including the Mt. Simon and Rose Run. However, 1968 data are suspect because they were collected prior to implementation of QA/QC procedures, and cannot be validated.

D.2.1 Mt. Simon Formation Fluid Chemistry

Samples of Mt. Simon Formation fluids were collected from WDW No. 1 in 1968 before injection began into the formation at Haverhill. Analyses for inorganic constituents were conducted on the 1968 samples and the results are presented in Table 7a. These data indicate that the Mt. Simon fluid originally contained high concentrations of inorganic constituents such as chloride and was considered a brine. No data are available concerning the organic constituents that may have been present within formation waters in 1968.

Samples of formation fluid extracted from the Mt. Simon during drilling of WDW No. 3 (Table 7a) show that some of the same organic compounds found in injectate are also present in the Mt. Simon waters. However, concentrations of these compounds within the Mt. Simon are dilute compared to injectate concentrations. For example, phenol is present

Table 7a (Cont'd)

Mt. Simon Formation Fluid Analyses

Units - ppm	WDW No. 1 Mt. Simon Fluid Sampled 1968	WDW No. 3 Mt. Simon Fluid Sampled 9/22/89
Benzoic acid	NA	21
Bis(2-ethylhexyl) phthalate	NA	ND
2,2'-Methylenebisphenol	NA	35 (TIC)
4,4'-Methylenebisphenol	NA	36 (TIC)
2-Methylbenzofuran	NA	NI
2,3-Dimethylphenol	NA	NI
2-(1-Methylethyl)phenol	NA	NI
4-(1-Methyl-1-phenylethyl) phenol (cumyl phenol)	NA	NI
2-[1-(4-Hydroxyphenyl) 1-methylethyl] phenol (o,p-BPA)	NA	NI
Bisphenol A (BPA)	NA	NI
Cumene	NA	4.6 (TIC)
Formic Acid (as Formate)	NA	1370
Aluminum	0.5 (NV)	2
Barium	ND (NV)	ND
Calcium	50600 (NV)	2850
Chromium	NA	ND
Iron	39 (NV)	15.7
Lead	NA	0.03

J - estimated value
NA - not analyzed (for)
ND - analyzed for, but not detected
NI - not identified, TIC
NV - unable to validate
TIC - tentatively identified compound
* - concentration has been determined to be biased low

Complete list of chemical data qualifiers included in Appendix B

Table 7a (Cont'd)

Mt. Simon Formation Fluid Analyses

Units - ppm	WDW No. 1 Mt. Simon Fluid Sampled 1968	WDW No. 3 Mt. Simon Fluid Sampled 9/22/89
Magnesium	7080 (NV)	424
Manganese	NA	0.4*
Potassium	NA	421
Sodium	58300 (NV)	14000
pH	5.5 (NV)	NA
Specific Gravity	1.225 (NV)	1.05
Ammonia (as Nitrogen)	NA	409
Ammonia	NA	NA
Bromide	2160 (NV)	200
Chloride	200000 (NV)	21200
Nitrate (as Nitrogen)	NA	ND
Sulfate	140 (NV)	2490
$CaCO_3$ Alkalinity	28 (NV)	NA
Silica	2 (NV)	NA
Turbidity (TSS)	>150 (NV)	NA
Iodide	1.3 (NV)	NA
TDS	316000 (NV)	48400
Resistivity (77°F)	.047 Ohm-m (NV)	NA
Carbon Dioxide	240 (NV)	NA

J - estimated value
NA - not analyzed (for)
ND - analyzed for, but not detected
NI - not identified, TIC
NV - unable to validate
TIC - tentatively identified compound
* - concentration has been determined to be biased low

Complete list of chemical data qualifiers included in Appendix B

at approximately 940 ppm in the Mt. Simon at WDW No. 3, which is approximately 360 ppm less that the 1989 injectate concentration, and is less than approximately 10 percent of the average historic injectate phenol concentration. The acetophenone concentration within WDW No. 3 Mt. Simon brine is less than 50 percent of 1989 acetophenone injectate concentration. In contrast, in 1968, chloride in the Mt. Simon exceeded 200,000 ppm, but was 21,200 ppm in the 1989 analyses.

Available data indicate that inorganic constituents originally found in the Mt. Simon 1968 analyses still occur in 1989 waters, but at much lower concentrations due to mixing with injectate. Complete Mt. Simon analyses are presented in Appendix L.

D.2.2 Copper Ridge Fluid Chemistry

A formation fluid sample was extracted from the Copper Ridge Formation in the Test/Monitoring Well approximately 250 feet below the Rose Run Formation (Tables 7b and 7c). Analytical results show that this sample of the Copper Ridge contained phenol, BPA, DMBA, acetophenone, benzoic acid, and acetone. Concentrations of some inorganic constituents including sodium, potassium, calcium, magnesium, and ammonium in the Test/Monitoring Well-Copper Ridge sample are practically identical to concentrations of these constituents within the WDW No. 3 Rose Run sample. However, other constituents such as nitrate nitrogen, iron, lead, and manganese are quite different from WDW No. 3 Rose Run sample concentrations.

D.2.3 Rose Run Formation Fluid Chemistry

As with the Mt. Simon, the Rose Run Formation fluid (Table 8a) was also sampled and analyzed from WDW No. 1 in 1968 and was found to contain relatively high concentrations of inorganics such as chloride. No data are available concerning organic compound occurrences in the formation at the time this well was drilled.

Table 7b (Cont'd)

Copper Ridge (Lower Knox) Formation Fluid Analyses, 1991

Units - ppm	Test/Monitoring Well Copper Ridge Fluid Sampled 5/9/91
Bis(2-ethylhexyl) phthalate	0.031[4]
2,2'-Methylenebisphenol	0.130 (TIC)
4,4'-Methylenebisphenol	2.90 (TIC)
2-Methylbenzofuran	NI
2,3-Dimethylphenol	NI
2-(1-Methylethyl)phenol	NI
4-(1-Methyl-1-phenylethyl) phenol (cumyl phenol)	NI
2-[1-(4-Hydroxyphenyl) 1-methylethyl] phenol (o,p-BPA)	NI
Bisphenol A (BPA)	0.840
Cumene	ND
Formic Acid (as Formate)	ND
Aluminum	1.330[3]
Barium	3.810
Calcium	35000
Chromium	ND*
Iron	409
Lead	0.581
Magnesium	6190
Manganese	6.410

J - estimated value
NA - not analyzed (for)
ND - analyzed for, but not detected
NI - not identified, TIC
NV - unable to validate
TIC - tentatively identified compound
* - concentration was determined to be biased low
[2] - biased high quantitative estimate
[3] - matrix interference, result invalid
[4] - value invalid due to presence of compound in field blanks and associated method

Complete list of chemical data qualifiers included in Appendix B

Table 7b (Cont'd)

Copper Ridge (Lower Knox) Formation Fluid Analyses, 1991

Units - ppm	Test/Monitoring Well Copper Ridge Fluid Sampled 5/9/91
Potassium	3610
Sodium	48200
pH	NA
Specific Gravity	1.2 (NV)
Ammonia (as Nitrogen)	73.1
Ammonia	NA
Bromide	2090
Chloride	208000
Nitrate (as Nitrogen)	ND
Sulfate	229
$CaCO_3$ Alkalinity	56.0
Silica	10.803
Turbidity (TSS)	1680
Iodide	NA
TDS	293000
Resistivity as Specific Conductance (77°F)	439 mmhos
Carbon Dioxide	NA

J	-	estimated value
NA	-	not analyzed (for)
ND	-	analyzed for, but not detected
NI	-	not identified, TIC
NV	-	unable to validate
TIC	-	tentatively identified compound
*	-	concentration was determined to be biased low
2	-	biased high quantitative estimate
3	-	matrix interference, result invalid
4	-	value invalid due to presence of compound in field blanks and associated method

Complete list of chemical data qualifiers included in Appendix B

Table 7c (Cont'd)

Comparison of Formation Fluid, Drilling Mud, Potable Water, and Blank Analyses for Copper Ridge Test/Monitoring Well

Units - ppm	Formation Fluid	Mud Sample	Potable Water	Method Blank
Benzoic acid	4.0	ND	ND	ND
2,2'-Methylenebisphenol	0.130	NI	NI	NI
4,4'-Methylenebisphenol	2.90	NI	NI	NI
2-Methylbenzofuran	NI	NI	NI	NI
2,3-Dimethylphenol	NI	NI	NI	NI
2-(1-Methylethyl)phenol	NI	NI	NI	NI
4-(1-Methyl-1-phenylethyl) phenol (cumyl phenol)	NI	NI	NI	NI
2-[1-(4-Hydroxyphenyl) 1-methylethyl] phenol (o, p, BPA)	NI	NI	NI	NI
Bisphenol A (BPA)	0.840	ND	ND	ND
Cumene	ND	ND	ND	ND
Formic Acid (as Formate)	ND	NA	NA	ND
Aluminum	1.330	NA	NA	ND
Barium	3.810	NA	NA	ND
Calcium	35000	NA	NA	ND
Chromium	ND	NA	NA	ND
Iron	409	NA	NA	ND
Lead	0.581	NA	NA	ND
Magnesium	6190	NA	NA	ND

NA - not analyzed (for)
ND - not detected
NI - not identified, TIC
TIC - tentatively identified compound

Complete list of chemical data qualifiers included in Appendix B

Table 7c (Cont'd)

Comparison of Formation Fluid, Drilling Mud, Potable Water, and Blank Analyses for Copper Ridge Test/Monitoring Well

Units - ppm	Formation Fluid	Mud Sample	Potable Water	Method Blank
Manganese	6.410	NA	NA	ND
Potassium	3610	NA	NA	ND
Sodium	48200	NA	NA	ND
pH	NA	NA	NA	NA
Specific Gravity	1.200	NA	NA	NA
Ammonia (as Nitrogen)	73.10	NA	NA	ND
Ammonia	NA	NA	NA	NA
Bromide	2090	NA	NA	ND
Chloride	208000	NA	NA	ND
Nitrate (as Nitrogen)	ND	NA	NA	ND
Sulfate	229	NA	NA	ND
$CaCO_3$ Alkalinity	56.0	NA	NA	ND
Silica	10.80	NA	NA	ND
TSS	1680	NA	NA	NA
Iodide	NA	NA	NA	NA
TDS	293000	NA	NA	NA
Resistivity as specific conductance (77°F)	439 mmhos	NA	NA	NA
(Specific Conductance)				
Carbon Dioxide	NA	NA	NA	NA

NA - not analyzed (for)
ND - not detected
NI - not identified, TIC
TIC - tentatively identified compound

Complete list of chemical data qualifiers included in Appendix B

Table 8a (Cont'd)

Rose Run Formation Fluid Analyses

Units - ppm	WDW No. 1 Rose Run Fluid Sampled 1968	WDW No. 3 Rose Run Fluid Sampled 6/14/89	Test/Monitoring Well Rose Run Fluid Sampled 4/25/91
2-[1-(4-Hydroxyphenyl) 1-methylethyl] phenol (o,p-BPA)	NA	NI	NA
Bisphenol A (BPA)	NA	NA	ND
Cumene	NA	ND	ND
Formic Acid (as Formate)	NA	168	ND
Aluminum	0.5 (NV)	ND	ND
Barium	ND	1.8	4.71[7]
Calcium	39800 (NV)	38500	37000
Chromium	NA	ND*	ND*
Iron	35 (NV)	60.8	171
Lead	NA	ND	0.028 J
Magnesium	7610 (NV)	6070	7010
Manganese	NA	2.35	3.22
Potassium	NA	3330	3810
Sodium	54100 (NV)	44600	25500

J = estimated value
NA = not analyzed (for)
NI = not identified, TIC
ND = analyzed for, but not detected
NV = unable to validate
TIC = tentatively identified compound
* = concentration has been determined to be biased low
3 = matrix interference, result invalid
4 = value invalid due to presence of compound in field blanks and associated method
5 = volatile non-detects rejected due to presence of natural gas in formation
6 = semi-volatile concentrations considered biased low quantitative estimates due to presence of natural gas in formation
7 = matrix interference, result considered biased low quantitative estimate

Complete list of chemical data qualifiers included in Appendix B

Table 8a (Cont'd)

Rose Run Formation Fluid Analyses

Units - ppm	WDW No. 1 Rose Run Fluid Sampled 1968	WDW No. 3 Rose Run Fluid Sampled 6/14/89	Test/Monitoring Well Rose Run Fluid Sampled 4/25/91
pH	6.7	5.76	NA
Specific Gravity	1.199	1.19	1.215 (NV)
Ammonia (as Nitrogen)	NA	80.5	70.0
Ammonia	NA	NA	NA
Bromide	1950	1630	2200
Chloride	176000	170000	218000
Nitrate (as Nitrogen)	NA	220	0.04
Sulfate	74	330	ND
$CaCO_3$ Alkalinity	60	NA	100
Silica	2 (NV)	NA	7.29[3] (TSS)
Turbidity	>150	NA	1770
Iodide	1.3	NA	NA
TDS	278000	287000	309000
Resistivity (77°F)	.046 ohm-m	NA	495 mmohs
Carbon Dioxide	350	NA	NA

J = estimated value
NA = not analyzed (for)
NI = not identified, TIC
ND = analyzed for, but not detected
NV = unable to validate
TIC = tentatively identified compound
* = concentration has been determined to be biased low
3 = matrix interference, result invalid
4 = value invalid due to presence of compound in field blanks and associated method
5 = volatile non-detects rejected due to presence of natural gas in formation
6 = semi-volatile concentrations considered biased low quantitative estimates due to presence of natural gas in formation
7 = matrix interference, result considered biased low quantitative estimate

Complete list of chemical data qualifiers included in Appendix B

Table 8b (Cont'd)

Comparison of Formation Fluid, Drilling Mud, Potable Water, and Blank Analyses for the Rose Run, Test/Monitoring Well

Units = ppm	Rose Run Samples			
	Formation Fluid	Mud Sample	Potable Water	Method Blank
Methylene Chloride	0.014	0.016	0.015	0.016
4-(1-Methyl-1-phenylethyl) phenol (cumyl phenol)	NI	NI	NI	NI
2-[1-(4-Hydroxphenyl) 1-methylethyl] phenol (o,p BPA)	NI	NI	NI	NI
Bisphenol A (BPA)	ND	ND	ND	ND
Cumene	ND	ND	ND	ND
Formic Acid (as Formate)	ND	NA	ND	ND
Aluminum	ND	NA	0.316	ND
Barium	4.710	NA	0.0386	ND
Calcium	37000	NA	30.90	ND
Chromium	ND	NA	ND	ND
Iron	171	NA	0.291	ND
Lead	0.028	NA	0.0005	ND
Magnesium	7010	NA	7.700	ND
Manganese	3.22	NA	0.0806	ND
Potassium	3810	NA	2.22	ND
Sodium	25500	NA	10.80	ND
pH	NA	NA	NA	NA
Specific Gravity	1.215	NA	1.001	NA
Ammonia (as Nitrogen)	70	NA	0.07	ND
Ammonia	NA	NA	NA	NA
Bromide	2200	NA	ND	ND
Chloride	218000	NA	14.6	ND
Nitrate (as Nitrogen)	0.04	NA	0.49	ND
Sulfate	ND	NA	69.5	ND
Alkalinity (bicarbonate)	122	NA	45	ND

NA = not analyzed (for)
ND = not detected
NI = not identified, TIC
TIC = tentatively identified compound

Complete list of chemical data qualifiers included in Appendix B

Table 8b (Cont'd)

Comparison of Formation Fluid, Drilling Mud, Potable Water, and Blank Analyses for the Rose Run, Test/Monitoring Well

Units = ppm	Rose Run Samples			
	Formation Fluid	Mud Sample	Potable Water	Method Blank
Methylene Chloride	0.014	0.016	0.015	0.016
Silica	7.29	NA	5.48	ND
TSS	1770	NA	ND	NA
Iodide	NA	NA	NA	NA
TDS	309000	NA	180	NA
Resistivity as specific conductance (mmhos)	495	NA	0.291	NA
Carbon Dioxide	NA	NA	NA	NA

NA = not analyzed (for)
ND = not detected
NI = not identified, TIC
TIC = tentatively identified compound

Complete list of chemical data qualifiers included in Appendix B

Test/Monitoring Well-Rose Run concentrations either higher or lower than both the WDW Nos. 1 and 3 concentrations.

Langmuir has indicated (Appendix M) that the chemical similarity of inorganic constituents in the Mt. Simon and Rose Run from WDW No. 1, (which span a total vertical depth ranging from about 4800 to 5600 feet) indicates that fluids from these two rock units at this location are either interconnected or have similar histories of evolution. However, hydrogeologic data suggest that vertical interconnection of the Mt. Simon and Rose Run is unlikely given the presence of several low permeability shale horizons separating these formations in the stratigraphic column. Langmuir has also indicated that calculated 1968 (or "clean" 1991, Appendix M), Copper Ridge Test/Monitoring Well fluids are quite similar to 1991 Test/Monitoring Well Rose Run Formation fluid chemistries. This implies either interconnection or similar evolutionary history at this location, but more likely share a similar evolutionary history.

D.2.4 Formation Fluid Chemistry Above the Rose Run

Analytical chemistry data are included in Appendix L for formation fluid samples from rock units above the Rose Run, collected from WDW Nos. 1 and 3 and the Test/Monitoring Well between 1968 and 1991. Test/Monitoring Well Formation fluid (1991) analyses for samples collected from formations above the Rose Run are presented in Table 8c, and analyses for WDW No. 3 (1989) are presented in Table 8d. No formation fluid samples were collected from WDW No. 2 (1978).

D.2.4.1 Data Quality

Analyses of formation fluids collected from WDW No. 1 and WDW No. 3 are suspect. As previously stated, all 1968 fluid samples were collected and analyzed prior to implementation of currently approved data QA/QC practices and therefore cannot be validated. Also, fluid samples collected from low permeability formations in WDW No. 1 and WDW No. 3 using

Table 8c (Con't)

Test/Monitoring Well Formation Fluid Analyses Above Rose Run Formation

Units - ppm	Beekmantown Sampled 4/18/91	Newburg Sampled 2/7/91	Berea Sampled 1/29/91	Logan Sampled 1/22/91
Bisphenol A (BPA)	ND	NA	NA	NA
Cumene	ND	ND	ND	ND
Formic Acid (as Formate)	ND	ND	ND	NA
Aluminum	2.230	0.193	0.186	10.60
Barium	3.05*	0.865^{11}	141^7	40.70*
Calcium	38500	33540	9790	2670
Chromium	0.291*	0.0217^{11}	0.0248*	0.0471*
Iron	999	90.40^{11}	188^7	52.50*
Lead	0.022 J	0.330^2	0.719^{10}	0.976^{10}
Magnesium	7430	7875	2960	648
Manganese	13.80	0.881^{11}	2.540*	0.926*
Potassium	3750	1243	260	89.70
Sodium	34300	ND	32900	9330
pH (field)	NA	NA	NA	NA
Specific gravity	1.218(NV)	1.193(NV)	1.095(NV)	1.035(NV)

J = estimated value
NA = not analyzed or TIC data not yet available (for formation fluid analyses)
ND = not detected; below reporting limit or detection limit
NI = not identified, TIC
NV = unable to validate
pH = is a field measurement; # of samples given in circle
* = concentration was determined to be biased low
2 = biased on high quantitative estimate
3 = matrix interference, result invalid
4 = calibration standards responses below QC limits, results rejected
7 = matrix interferences, result considered biased low quantitative estimate
9 = calibration standards responses below QC limits, results rejected
10 = matrix spike analyses recoveries far outside QC limits, results rejected
11 = ICP serial dilution analysis QC criteria greatly exceeded, results rejected
14 = CRQL is considered estimate

Complete list of chemical data qualifiers included in Appendix B

Table 8c (Con't)

Test/Monitoring Well Formation Fluid Analyses Above Rose Run Formation

<u>Units - ppm</u>	Beekmantown Sampled <u>4/18/91</u>	Newburg Sampled <u>2/7/91</u>	Berea Sampled <u>1/29/91</u>	Logan Sampled <u>1/22/91</u>
Ammonia (as Nitrogen)	56.6	105	150	30.8
Ammonia	NA	NA	NA	NA
Bromide	2260	1680	564	150
Chloride	251000	164000	82500	26200
Nitrate (as Nitrogen)	ND	0.11	ND	0.12
Sulfate	51.8	64.3	ND	4.95
$CaCO_3$ Alkalinity	268	0	8	138
Silica	17.30[3]	1.570[11]	5.2[10]	36.80[10]
Turbidity (TSS)	7460	5900	2680	NA
Iodide	NA	NA	NA	NA
TDS	313000	290000	135000	42500
Resistivity (77°F) as specific conductance (mmohs)	393	430	192	NA
Carbon Dioxide	NA	NA	NA	NA

J = estimated value
NA = not analyzed <u>or</u> TIC data not yet available (for formation fluid analyses)
ND = not detected; below reporting limit or detection limit
NI = not identified, TIC
NV = unable to validate
pH = is a field measurement; # of samples given in circle
* = concentration was determined to be biased low
2 = biased on high quantitative estimate
3 = matrix interference, result invalid
4 = calibration standards responses below QC limits, results rejected
7 = matrix interferences, result considered biased low quantitative estimate
9 = calibration standards responses below QC limits, results rejected
10 = matrix spike analyses recoveries far outside QC limits, results rejected
11 = ICP serial dilution analysis QC criteria greatly exceeded, results rejected
14 = CRQL is considered estimate

Complete list of chemical data qualifiers included in Appendix B

Table 8d (Cont'd)

WDW No. 3 Formation Analyses Above the Rose Run Formation

Units = ppm	Niagaran Sampled 7/18/89	Newburg Sampled 7/15/89	Berea Sampled 4/14/89
Bis(2-ethylhexyl) phthalate	0.053	0.02	NA
2,2-Methylenebisphenol	NI	NI	NA
4,4-Methylenebisphenol	NI	NI	NA
2-Methybenzofuran	NI	NI	NA
2,3-Dimethylphenol	NI	NI	NA
2-(1-Methylethyl) phenol	NI	NI	NA
4-(1-Methylethyl) phenol (cumyl phenol)	NI	NI	NA
2-[(1-methy-1-pheyl) 1-methyl ethyl]phenol (o,p BPA)	NA	NI	NA
Bisphenol A (BPA)	NA	NA	NA
Cumene	NI	NA	NA
Formic Acid (as Formate)	ND	NA	1100 (NVM)
Aluminum	12.9	5.4	NA
Barium	1.1*	1*	9.2 (T,NV)
Calcium	36400	38700	3000 (T,NV)
Chromium	0.25	0.15	ND (T,NV)
Iron	122	64	2.7 (T,NV)
Lead	ND*	0.2*	ND (T,NV)
Magnesium	8970	9150	730 (T,NV)

NA - not analyzed (for)
ND - analyzed for, but not detected
NI - not identified, TIC
NV - unable to validate
NVM - method not validated
T - total metals analysis
TIC - tentatively identified compound
* - concentration has been determined to be biased low
13 - value below CRQL, result is quantitative estimate

Complete list of chemical data qualifiers included in Appendix B

Table 8d (Cont'd)

WDW No. 3 Formation Analyses Above the Rose Run Formation

Units - ppm	Niagaran Sampled 7/18/89	Newburg Sampled 7/15/89	Berea Sampled 4/14/89
Manganese	2.3	2.9*	0.5 (T,NV)
Potassium	1210	1430*	96 (T,NV)
Sodium	42500	42700	9900 (T,NV)
pH	NA	NA	NA
Specific Gravity	1.17	1.2	NA
Ammonia (as Nitrogen)	133	129	NA
Ammonia	NA	NA	NA
Bromide	NA	NA	NA
Chloride	139000	179000	29000 (NV)
Nitrate (as Nitrogen)	ND	ND	NA
Sulfate	180	130	82 (NV)
$CaCO_3$ Alkalinity	NA	NA	ND (NV)
Silica	NA	NA	NA
Turbidity	NA	NA	NA
Iodide	NA	NA	NA
TDS	277000	327000	54000 (NV)
Resistivity (@ 77°F)	NA	NA	NA
Carbon Dioxide	NA	NA	NA

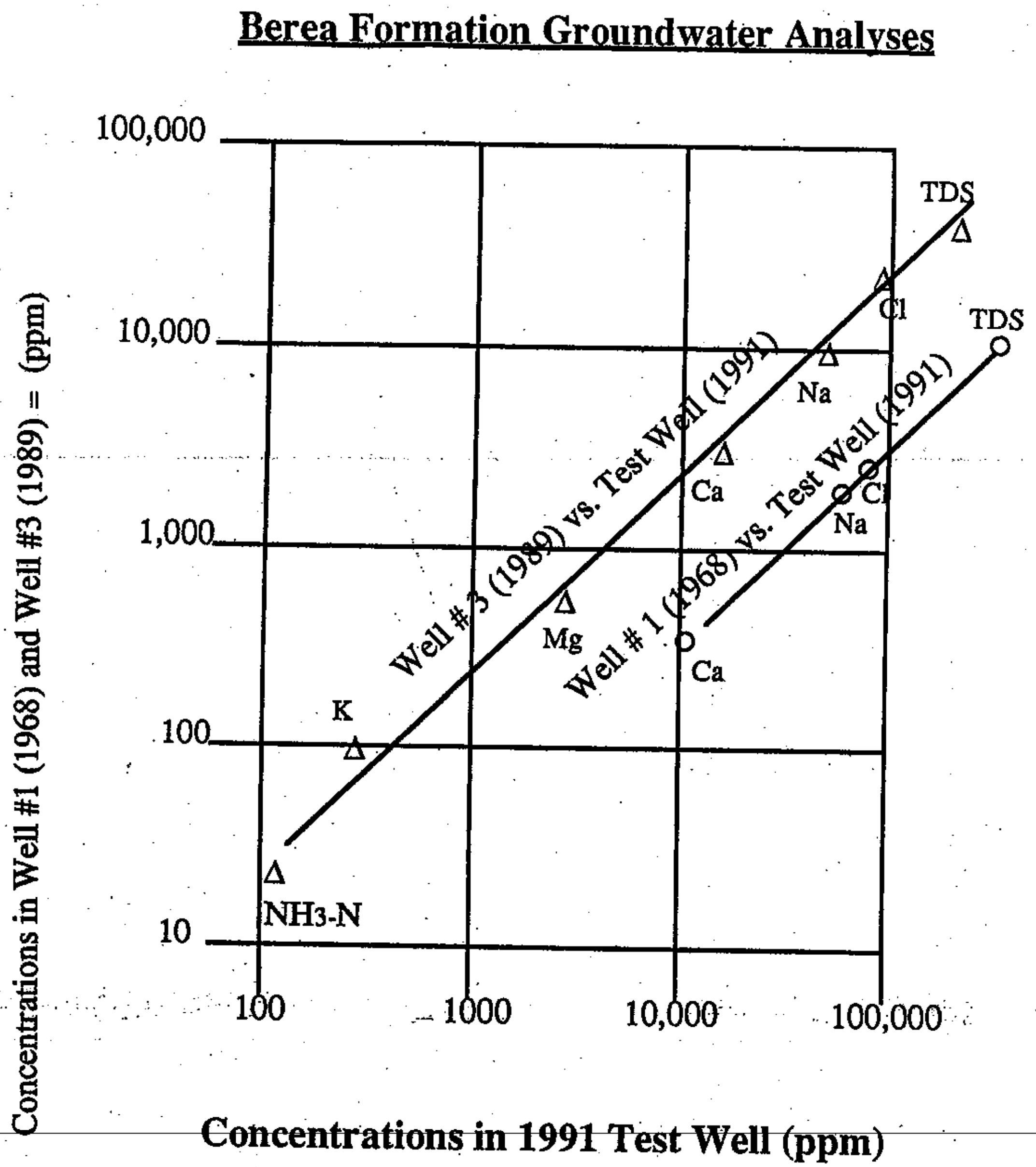
NA - not analyzed (for)
ND - analyzed for, but not detected
NI - not identified, TIC
NV - unable to validate
NVM - method not validated
T - total metals analysis
TIC - tentatively identified compound
* - concentration has been determined to be biased low
13 - value below CRQL, result is quantitative estimate
Complete list of chemical data qualifiers included in Appendix B

DSTs or Repeat Formation Testers (RFTs) often contained drilling fluid (with little formation fluid) rather than "pure" formation fluid. For example, the Berea Formation fluid analyses reported from WDW No. 1, WDW No. 3, and the Test/Monitoring Well show very different analyte concentrations, which can be attributed to the admix of drilling fluid with extracted formation fluids in WDW No. 1 and WDW No. 3. This is best shown by comparing the concentrations of relatively unreactive major inorganic species or parameters (i.e., sodium, potassium, calcium, magnesium, chloride, nitrate, and TDS) in the WDW No. 1 (1968), WDW No. 3 (1989), and Test/Monitoring Well formation fluids (Figure 6). Assuming that the 1991 Berea Formation fluids were not diluted by drilling mud (which is supported by sample collection procedures), Figure 6 shows that the inorganic constituents in the 1968 Berea analyses have been diluted 22-fold on average relative to their concentrations in 1991 fluids. Inorganic species in 1989 Berea fluids have been diluted 2.7 fold on average relative to their concentrations in the 1991 fluids. Thus, chemistry data indicate that reported concentration differences between 1968, 1989, and 1991 Berea samples are due to admix of drilling mud in 1968 and 1989 samples.

The majority of formations above the Rose Run contain small quantities of organic constituents. These include compounds that can occur naturally (i.e., benzene), and also include typical anthropogenic compounds such as phenol and methylene chloride. Test Well analyses for the Beekmantown, Newburg, Berea, and Logan that compare formation fluid, mud, potable water, and method blank analyses (Tables 8e and 8f) show that organic constituent occurrence in these formations can be attributed to secondary contamination or naturally-occurring hydrocarbons. A more detailed discussion of this, including observed chemistries in WDW No. 3 fluids, is presented below.

D.2.4.2 Formation Fluid Analyses

Beekmantown, Newburg (Lockport), Berea, and Logan Formation fluids were collected and analyzed in the Test/Monitoring Well (Table 8c); the Berea and Newburg were sampled in WDW No.1 and Berea, St.Peter (Beekmantown-Wells Creek), Niagaran, and Newburg



Berea Formation Groundwater Analyses

Plot shows that when 1989 vs. 1991 and 1968 vs. 1991 constituent concentrations are plotted against one another, straight-line relationships are achieved indicating similar dilution of all constituents by drilling mud.

Figure 6. Comparison of Berea Formation Fluid Analyses for Select Inorganic Species for 1968, 1989 (WDW No. 3) and 1991 (Test/Monitoring Well) Samples

Table 8e (Cont'd)

Comparison of Logan and Berea Formation Fluid, Drilling Mud, Potable Water, and Blank Analyses

Units = ppm	Logan Samples				Berea Samples			
	Formation Fluid	Mud Sample	Potable Water	Method Blank	Formation Fluid	Mud Sample	Potable Water	Method Blank
Acetophenone	ND	NA	ND	ND	NA	NA	NA	ND
a,a-Dimethyl benzyl alcohol	ND	NA	ND	ND	NA	NA	NA	NA
Benzoic acid	ND	NA	ND	ND	ND	NA	ND	ND
2,2'-Methylenebisphenol	NI	NA	NI	NI	NI	NA	NI	NI
4,4'-Methylenebisphenol	NI	NA	NI	NI	NI	NA	NI	NI
2-Methylbenzofuran	NI	NA	NI	NI	NI	NA	NI	NI
2,3-Dimethylphenol	NI	NA	NI	NI	NI	NA	NI	NI
2-(1-Methylethyl)phenol	NI	NA	NI	NI	NI	NA	NI	NI
4-(1-Methyl-1-phenylethyl) phenol (cumyl phenol)	NI	NA	NI	NI	NI	NA	NI	NI
Bisphenol A	NA	NA	NA	NA	NA	NA	NA	ND
2-[1-methyl-1-phenyl) 1-methylethyl phenol] o,p-Bisphenol A	NI	NA	NI	NI	NI	NA	NI	NI
Cumene	ND	NA	ND	ND	NA	NA	NA	ND
Formic Acid	ND	NA	NA	ND	ND	NA	NA	ND
Aluminum	10.60	NA	0.24	ND	0.186	NA	NA	ND
Barium	40.70	NA	0.0347	ND	141	NA	NA	ND
Calcium	2670	NA	29.30	ND	9790	NA	NA	ND

NA = not analyzed (for)
ND = not detected
NI = not identified, TIC
TIC = tentatively identified compound

Complete list of chemical data qualifiers included in Appendix B

Table 8e (Cont'd)

Comparison of Logan and Berea Formation Fluid, Drilling Mud, Potable Water, and Blank Analyses

Units = ppm	Logan Samples				Berea Samples			
	Formation Fluid	Mud Sample	Potable Water	Method Blank	Formation Fluid	Mud Sample	Potable Water	Method Blank
Chromium	0.0471	NA	ND	ND	0.0248	NA	NA	ND
Iron	52.50	NA	9.660	ND	188	NA	NA	ND
Lead	0.976	NA	0.0007	ND	0.719	NA	NA	ND
Magnesium	648	NA	6.340	ND	2960	NA	NA	ND
Manganese	0.926	NA	0.484	ND	2.540	NA	NA	ND
Potassium	89.70	NA	2.010	ND	260	NA	NA	ND
Sodium	9330	NA	9.270	ND	32900	NA	NA	ND
pH	NA	NA	NA	NA	NA	NA	NA	NA
Specific Gravity	1.035	NA	NA	NA	1.095	NA	NA	NA
Ammonia (as nitrogen)	30.8	NA	NA	ND	150	NA	NA	ND
Ammonia	NA	NA	NA	NA	NA	NA	NA	NA
Bromide	150	NA	NA	ND	564	NA	NA	ND
Chloride	26200	NA	NA	ND	82500	NA	NA	ND
Nitrate (as nitrogen)	0.12	NA	NA	ND	ND	NA	NA	ND
Sulfate	4.95	NA	NA	ND	ND	NA	NA	ND
Alkalinity (bicarbonate)	138	NA	NA	ND	10	NA	NA	ND
Silica	36.80	NA	4.420	ND	5.20	NA	NA	ND

NA = not analyzed (for)
ND = not detected
NI = not identified, TIC
TIC = tentatively identified compound

Complete list of chemical data qualifiers included in Appendix B

Table 8e (Cont'd)

Comparison of Logan and Berea Formation Fluid, Drilling Mud, Potable Water, and Blank Analyses

Units = ppm	Logan Samples				Berea Samples			
	Formation Fluid	Mud Sample	Potable Water	Method Blank	Formation Fluid	Mud Sample	Potable Water	Method Blank
TSS	2780	NA	NA	NA	2680	NA	NA	NA
Iodide	NA	NA	NA	NA	NA	NA	NA	NA
TDS	42500	NA	NA	NA	135000	NA	NA	NA
Resistivity (m-mhos) (specific Conductance)	69	NA	NA	NA	192	NA	NA	NA
Carbon Dioxide	NA	NA	NA	NA	NA	NA	NA	NA

NA = not analyzed (for)
ND = not detected
NI = not identified, TIC
TIC = tentatively identified compound

Complete list of chemical data qualifiers included in Appendix B

Table 8f (Cont'd)

Comparison of Newburg and Beekmantown Formation Fluid, Drilling Mud, Potable Water, and Blank Analyses

Units = ppm	Newburg Samples				Beekmantown Samples			
	Formation Fluid	Mud Sample	Potable Water	Method Blank	Formation Fluid	Mud Sample	Potable Water	Method Blank
Aluminum	0.193	NA	NA	ND	2.230	NA	NA	ND
Barium	0.865	NA	NA	ND	3.05	NA	NA	ND
Calcium	33540	NA	NA	ND	38500	NA	NA	ND
Chromium	0.217	NA	NA	ND	0.291	NA	NA	ND
Iron	90.40	NA	NA	ND	999	NA	NA	ND
Lead	0.330	NA	NA	ND	0.022	NA	NA	ND
Magnesium	7875	NA	NA	ND	7430	NA	NA	ND
Manganese	0.881	NA	NA	ND	13.80	NA	NA	ND
Potassium	1243	NA	NA	ND	3750	NA	NA	ND
Sodium	ND	NA	NA	ND	34300	NA	NA	ND
pH	NA	NA	NA	NA	NA	NA	NA	NA
Specific Gravity	1.193	NA	NA	NA	1.218	NA	NA	NA
Ammonia (as nitrogen)	105	NA	NA	ND	56.6	NA	NA	ND
Ammonia	NA	NA	NA	NA	NA	NA	NA	ND
Bromide	1680	NA	NA	ND	2260	NA	NA	ND
Chloride	164000	NA	NA	ND	251000	NA	NA	ND

NA = not analyzed (for)
ND = not detected
NI = not identified, TIC
TIC = tentatively identified compound

Complete list of chemical data qualifiers included in Appendix B

Table 8f (Cont'd)

Comparison of Newburg and Beekmantown Formation Fluid, Drilling Mud, Potable Water, and Blank Analyses

Units = ppm	Newburg Samples				Beekmantown Samples			
	Formation Fluid	Mud Sample	Potable Water	Method Blank	Formation Fluid	Mud Sample	Potable Water	Method Blank
Nitrate (as nitrogen)	0.11	NA	NA	ND	ND	NA	NA	ND
Sulfate	64.3	NA	NA	ND	51.8	NA	NA	ND
Alkalinity (bicarbonate)	29	NA	NA	ND	327	NA	NA	ND
Silica	1.570	NA	NA	ND	17.30	NA	NA	ND
TSS	5900	NA	NA	NA	7460	NA	NA	NA
Iodide	NA	NA	NA	NA	NA	NA	NA	NA
TDS	290000	NA	NA	NA	313000	NA	NA	NA
Resistivity as specific conductance (mmhos)	430	NA	NA	NA	393	NA	NA	NA
Carbon Dioxide	NA	NA	NA	NA	NA	NA	NA	NA

NA = not analyzed (for)
ND = not detected
NI = not identified, TIC
TIC = tentatively identified compound

Complete list of chemical data qualifiers included in Appendix B

Formations were sampled and analyzed from WDW No. 3 (Table 8d). A plot of major chemical species concentration variations with depth for Test/Monitoring Well samples is presented in Figure 7. (Also plotted, for comparison purposes at the bottom of the graph in Figure 7 are constituent concentrations in formations above and below the Rose Run.) The plot shows a general increase in TDS concentration from 42,500 ppm in the Logan Formation at the 164- to 262-foot depth, to 313,000 ppm in the Beekmantown at the 4010 to 4036-foot depth. Reversals in concentrations of sodium and magnesium below the Berea and Newburg down to the Beekmantown and Rose Run probably reflect natural differences in formation fluid chemistry. The reversal in constituent concentration in the Copper Ridge is likely due to the admix of injectate.

Comparisons of analyses presented in Tables 8c and 8d indicate that samples from formations above the Rose Run contained very little or no man-made organics such as phenol, acetone, and methylene chloride (i.e., Test/Monitoring Well samples). The concentration of these constituents is very low and contamination of the fluid samples from outside sources such as drilling mud and laboratories can be demonstrated (Table 8e). The Newburg and Niagaran samples from WDW No. 3 were collected from tests after the Rose Run was encountered, and Rose Run fluids (containing phenol) were allowed to circulate through the borehole for a number of weeks prior to the sampling of these overlying formations. Therefore, the occurrence of phenol in WDW No. 3 fluids collected from formations overlying the Rose Run can be attributed to contamination by Rose Run Formation fluid. The Berea in WDW No. 3 was sampled before drilling proceeded to underlying formations and therefore did not encounter circulating Rose Run fluids prior to sampling. However, this formation at WDW No. 3 shows low concentrations of acetone and phenol, as well as formic acid (Table 8d). Acetone and phenol may be due to lab/drilling mud contamination, but the occurrence of formic acid is anomalous. The value cannot be validated for a number of reasons such as incorrect reporting of analytical methods (see Appendix L for more complete discussion). However, because formic acid was not present in formation fluids from underlying strata at WDW No. 3, and was not detected in any of

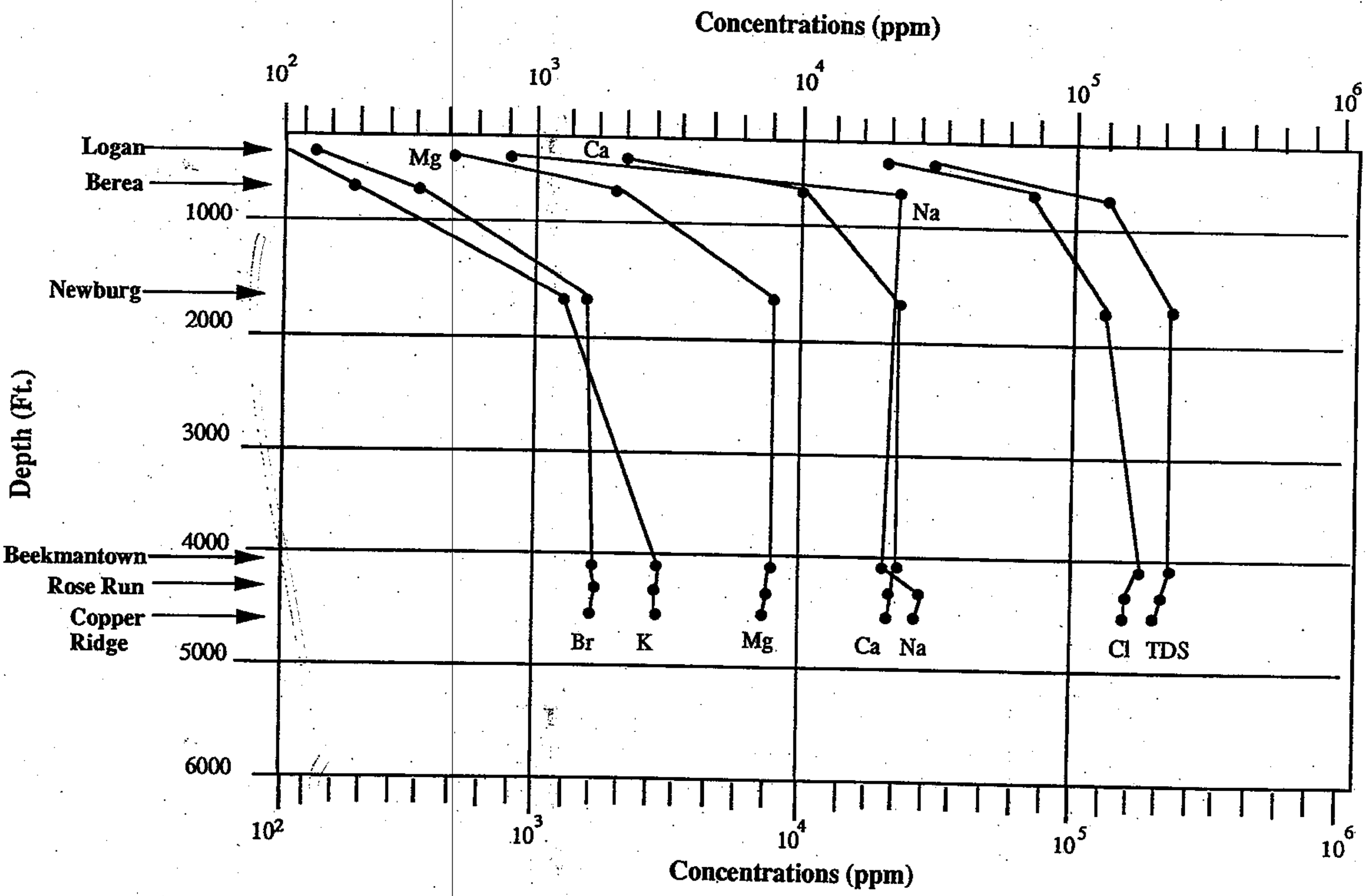


Figure 7. Formation Fluid Inorganic Constituent Concentration vs. Depth, Test/Monitoring Well

the test/monitoring samples, it is likely that the occurrence is unrelated to fluid migration and was somehow anonymously introduced.

Many of the formations sampled above the Rose Run contain benzene, toluene, and xylene (BTX) constituents as well as various alkenes and alkanes (Tables 8c and 8d). Additionally, many of the samples were described as having an "oily sheen" (i.e., Berea, Test/Monitoring Well). BTX constituents as well as other hydrocarbons are typical constituents of natural oil and gas, and are often found in drilling mud and potable water (Tables 8e and 8f) but do not occur in significant quantities in Aristech injectate (Table 4a). Therefore, the occurrence of these constituents in formations above the Rose Run can be attributed to natural hydrocarbons, drilling mud, or potable water.

D.2.4.3 Formation Fluid Chemistry Relative to the USDW

The deepest underground source of drinking water (USDW) in the Haverhill area is no deeper than the alluvium, which is approximately 80-90 feet below ground surface. This determination is based on analytical data collected from the Test/Monitoring Well which indicate that all bedrock units underlying Haverhill, including the Logan, exhibit TDS >10,000 ppm (Appendix L).

Through informal conversations with representatives from the ODNR, it has been determined that there are very little geochemical data for Logan Formation fluids, most of which are of questionable quality. Geophysical log calculations were therefore performed (Appendix A1) to estimate the calculated sodium chloride (NaCl) salinities for the Logan at WDW Nos. 1, 2, and 3. The calculated salinities were 25,000 ppm in WDW No. 1, 27,000 ppm in WDW No. 2, and 25,000 in WDW No. 3. This demonstrates that calculated salinities of the Logan have remained relatively consistent between 1968 and 1989. These values are not direct indicators of TDS, but it is likely that 1968, 1978, and 1989 TDS Logan values were higher than calculated salinities because NaCl salinity is part of (and therefore less than or equal to) the total TDS.

It is not possible to compare the calculated Logan salinities at WDW Nos. 1, 2, and 3 with a calculated Logan salinity in the Test/Monitoring Well because the log curves required to perform these calculations are not available in the Test/Monitoring Well. However, formation fluid analyses for the Logan at the Test/Monitoring Well showed a chloride content of 26,200 ppm, and sodium content of 9330 ppm, resulting in a sodium chloride salinity of 35,530, which is similar to the calculated log salinities for the Logan in the other wells.

In conclusion, available data support the Test/Monitoring Well analytical data which indicates that the USDW in the Haverhill area is above the Logan Formation.

D.2.5 Naturally-Occurring Organic Compounds in Formation Fluid

Natural oil and gas occur within rock units in southern Ohio, including rocks of Paleozoic age. The composition of oil and gas is highly variable and depends on such factors as source rock and thermal history of the region. However, several general families of compounds may comprise oil and gas, the most common being paraffins (both normal and branched), naphthenes (cyclopentanes and cyclohexanes) and aromatics (i.e., toluene, benzene, ethylbenzene). According to Sweeney, 1950 (Appendix A), sulfide compounds may also be present including open chain (i.e., hydrogen sulfide, aliphatic mercaptans/sulfides/disulfides and polysulfides) and ring (cyclic sulfides) structures as well as aromatic thiols/sulfides/disulfides and thiophene, thiopyrans, thionaphthene, thianthrene, and dibenzothiophene. Nitrogen-bearing compounds (such as pyridines, and quinolines) and metals such as vanadium, nickel, lead, cobalt, aluminum, and iron may also be present, although usually in low (0-.1 percent) concentrations.

Sweeney (Appendix L) states that "oxygen compounds appear to be one of the least important classes of chemicals in crude oil, on the basis of the reported work. Of the possible oxygen compounds in crude oil, naphthenic acids and phenols have been identified." Analyses for specific oxygen-bearing compounds that could be present in trace quantities in

Ohio crude oil/gas were not available in the literature examined. According to information acquired during drilling of WDW No. 3, "shows" (i.e., fluorescence, streaming cut) of natural hydrocarbons were present in the rocks below the Cuyahoga and above the Cincinnati Group. Also, relatively minor "gas effects" were detected on well logs in Cambrian rock, such as the Rose Run and Mt. Simon. No economic oil and gas reserves have been found in the Haverhill area, according to publicly available maps.

D.2.6 Effect of Natural Formation Gas on Formation Fluids

Natural formation gas (methane) was encountered during sampling of the Rose Run in the Test/Monitoring Well. In order to address the possibility that natural formation gas could extract phenol, Aristech's research laboratory simulated this process (Appendix L).

Lacking a sample of the actual well water, a synthetic brine containing approximately 100 ppm phenol and saturated with NaCl was prepared, and cylinder methane was used to saturate the brine at 1800 psig. Analyses for phenol in the brine before and after pressurization/depressurization showed that, at most, only seven percent of the phenol was lost after three cycles. Phenol analyses were confirmed by several techniques (GC, LC, and 4-AAP-colormetric). While awaiting delivery of the methane cylinder, sparging tests were conducted at ambient pressure with brine and natural gas. The volume of purge gas was at least 2.5 times that expected to be dissolved in water at the pressure and temperature specified. In this case, at most, 12 percent of the phenol was lost. Both the pressurized cylinder and sparging tests showed that only a small fraction of phenol could have been lost during sampling of the Rose Run in the Test/Monitoring Well.

SRI supports the opinion that complete loss of phenol or other semi-volatile organics is highly unlikely via volatization or extraction by methane (Appendix L). Phenol has a low vapor pressure (.53 torr at 20°C) and high water solubility (93 g/L). The resultant Henry's constant (0.5 torr/molar terms) indicates that phenol should have remained in the fluid and not been vaporized by natural gas. SRI concluded, based on these data and the results of

Aristech's experiment, that the Test/Monitoring Well-Rose Run sample does not appear to have contained phenol or other semi-volatile constituents characteristic of Aristech Haverhill injectate.

D.2.7 Isotope Analyses

Oxygen (18), deuterium, and direct tritium isotope analyses were performed on Beekmantown, Rose Run, and Copper Ridge Formation fluid samples from the Test/Monitoring Well (Appendix L). Analysis of the del-oxygen/deuterium data suggests that original fluids in the Beekmantown, Rose Run, and Copper Ridge were formed under the similar environments of deposition and formed either by evaporative concentration of a water similar to surface waters now present in the Haverhill area, or by the mixing of such a water with ancient sea water. No tritium was detected in the analyzed samples, indicating that the formation fluid samples contained below detection limit concentrations of post-1950 waters. Enriched tritium analyses is being performed for these samples, which has an order of magnitude lower detection limit. Results of these analyses will be available in September.

D.2.8 Summary: Formation Fluid Chemistry

Chemical analyses to determine the presence of dissolved organic species in the formation fluids were not performed on the samples collected in 1968 (WDW No. 1). Consequently, it is unknown whether man-made organic substances were present in these formations prior to injection. However, natural hydrocarbons, albeit in non-economic concentrations, are present in rocks within the area as evidenced by trace oil and gas "shows." Man-made organic compounds were found in the 1989 Rose Run and Mt. Simon Formation fluids from WDW No. 3, as well as the Copper Ridge Formation fluid in the Test/Monitoring Well in 1991.

Organic constituents are present in formation fluids collected from units above the Rose Run. These constituents are attributed to secondary contamination by factors including drilling mud, potable water, or laboratory contamination. The presence of naturally-occurring hydrocarbons (i.e., Berea, Test/Monitoring Well) in formations above the Rose Run can account for the occurrence of BTX constituents in these formation fluids.

D.3 Mixing of Fluids

Chemical data indicate that the Copper Ridge at the Test/Monitoring Well, and the Rose Run at WDW No. 3 contain man-made compounds that are also found in Haverhill injectate. Calculated hypothetical mixtures of various Mt. Simon - Rose Run - Copper Ridge - injectate combinations have been used to determine theoretical concentrations that could be achieved by mixing these fluids. The data, assumptions, calculations, and conclusions for this task are included in Appendix M and are summarized below.

Inorganic constituents were used for mixing calculations because some of these are practically inert (unreactive) and should be conserved (unattenuated) when mixed. However, it must be emphasized that the significance of mixing calculations results depends upon the accuracy of the chemical analytical data used in the calculations. The 1968 WDW No. 1 analyses are questionable due to lack of supporting QA/QC documentation. The "average" injectate composition is also an assumption, based on limited data, and therefore has a wide error range (± approximately 2100 ppm for phenol, as shown in Figure 5). Additionally, analyses often exhibit poor charge balances (cations do not equal anions), bringing into question the results of the analyses. In light of these major uncertainties, the results of the mixing calculations should be considered semiquantitative at best.

The least reactive inorganic species (which, in these fluids, are sodium, chloride, and bromide) were used in calculations to compute the volume proportions involved in mixing. The mixing proportions are based on the following equation:

$$C_mV_m = C_1V8_1 + C_2V_2$$

where $C =$ concentration
$V =$ volume

The subscript "m" refers to the resultant mixtures, while subscripts "1" and "2" are the two fluids combined to produce the mixture "m".

The assumption can be made that $V_m = V_1 + V_2$, and $V_m = 1$. Given algebraic manipulation of this assumed relationship and the above equation, a second equation can be developed:

$$R_v = \frac{V_1}{V_2} = \frac{C_2 - C_m}{C_m - C_1}$$

where R_v is the ratio of the volume of fluid 1, when mixed with fluid 2, that will produce "C_m", the observed concentration in the mixture. R_vs have been calculated for sodium, chloride, and bromide for various mixtures of average injectate, Mt. Simon fluids (1989 and 1968), Copper Ridge fluids (calculated 1968, and 1991), and Rose Run fluids (1968, 1989, and 1991). Results are presented in Table 9. In this table, the average R_v calculated for each mixture is presented, followed by the standard deviation of that average, and the percentage of the R_v value that the standard deviation represents.

In general, the most realistic mixtures are those with the lowest standard deviations as a percentage of their R_v values. For example, in Table 9 it is apparent in equation No. 1 that 1989 Mt. Simon is probably the result of mixing injectate and 1968 Mt. Simon fluids because of the low percentage standard deviation value of ± 9 percent. However, the large uncertainties associated with 1968 analyses do not necessarily rule out the possibility of other mixtures. For example, in Table 9 a high percentage standard deviation is associated with mixing 1968 Rose Run fluids with average injectate to produce 1989 Rose Run fluids (± 53 percent, equation No. 2, Table 9). This high percentage is because the chloride R_v (which

E.1 Biodegradation of Organic Constituents

The possibility of biodegradation under halophilic/anoxic conditions such as those in the Mt. Simon and Rose Run Formations is questionable. Data indicate that formation fluids are saline in the Rose Run at both WDW No. 3 and the Test/Monitoring Well, with chloride contents in excess of 170,000 ppm and 218,000 ppm, respectively. The Mt. Simon was originally saline with 200,000 ppm chloride, although mixing with injectate (discussed in a later section and in Appendix M) has lowered the chloride content to 21,200 ppm at WDW No. 3. The occurrence of reducing ions (ammonia, methane) in the WDW No. 3 Rose Run, Mt. Simon, and Copper Ridge indicates that subsurface conditions are anoxic. The presence of unaltered pyrite in the subsurface rocks also indicates that anoxic conditions are present.

Battelle Columbus conducted an extensive computer-based literature search to find studies concerning biodegradation at depths under these chemical conditions (Appendix Q). No articles, books, or any other publications were identified by Battelle or other team members. This indicates that biodegradation potential under both halophilic and anoxic conditions is poorly understood.

The existence of biodegradation was also assessed by Dr. C.H. Ward of Rice University (Appendix R). In terms of biological activity, Dr. Ward concluded that some data could be interpreted as possibly indicating the occurrence of biological anaerobic processes in the subsurface at Haverhill. For example, methylene chloride (dichloromethane) and 2-methylphenol (o-cresol) have been shown to be intermediates in anaerobic processes, and these compounds are present in the Rose Run at WDW No. 3 and in the Copper Ridge at the Test/Monitoring Well. Additionally, o-cresol can be an intermediate of anaerobic toluene degradation (toluene was detected in the Mt. Simon WDW No. 3 samples and in injectate, but not in the WDW No. 3 Rose Run or Test/Monitoring Well-Copper Ridge samples). If trace levels of oxygen were present, it is conceivable that o-cresol could also be the product of a toluene monooxygenase system; however, most of these systems are reported to produce p-cresol.

Dr. Ward also indicated that dichloromethane (which is present in the WDW No. 3 Rose Run Formation fluids that were sampled) has been shown to be a product of the reductive dechlorination of carbon tetrachloride and chloroform (Egli et al., 1988; Galli and McCarty, 1989). The work of Egli et al, shows this process occurring under sulfate-reducing conditions, which Dr. Ward deemed interesting considering the high sulfate concentration in the Rose Run at WDW No. 3. Neither of the parent compounds, however, were detected in the Aristech injectate. Dr. Ward indicated that several other compounds seen in samples from Mt. Simon at WDW No. 3 and in 1989 injectate (benzoic acid, phenol, acetone, aniline, toluene, and ethylbenzene) can degrade under anaerobic conditions, but there is not enough information to predict their fate in the subsurface at Haverhill. Dr. Ward also indicated that "although the physical/chemical parameters (salinity, pH-injectate, temperature, and pressure) tend to make this an inhospitable environment, all values (of environmental parameters for biological activity) are well within known limits....As new environments are explored, such as the deep sea hydrothermal vents where bacterial growth is known to occur at 250°C and 265 atm....(the) hypothesis that life can exist wherever there is liquid water appears more and more reasonable." In summary, Dr. Ward concluded that although biodegradation could conceivably occur, it is neither probable nor pervasive because the expected environment would greatly inhibit the process.

E.2 Other Transformation/Attenuation and Transport Processes

Transformation, attenuation, and transport processes such as sorption, hydrolysis, oxidation, volatilization, and dissolution/mineral precipitation and adsorption could occur at ground surface, and may also occur in the subsurface. While some of these processes certainly occur, the extent to which they influence constituent distributions is also dependent upon subsurface conditions, as discussed below.

E.2.1 Sorption of Organic Compounds

Preferential sorption of compounds as they migrate laterally and vertically could influence the contaminant distribution in the subsurface. For example, preferential adsorption of compounds within rock layers could occur, but is dependent upon the partitioning behavior of the compound (Table 10). Data indicate that the extensive sorption of constituents in Aristech injectate will not occur, the reasoning for which is discussed below.

Sorption is a general term for the removal of a chemical constituent from the water phase into or onto a solid phase (material). In this case, there are three kinds of sorption processes: non-specific adsorption to mineral surfaces, specific partitioning between the water and any organic material on the rock (K_{oc}), and ion exchange onto cationic sites in clays. Non-specific sorption is the least likely to affect these compounds because of their high to moderate solubilities. The log K_{ow} (octanol-water partition coefficient) and log K_{oc} (organic carbon partition coefficient) both describe or allude to an organic material's propensity to partition to organic material within the system. The relationship between K_{ow} and K_{oc} is described by:

$$\text{Log } K_{oc} = 0.63\ K_{ow}$$
$$\text{Log } K_{oc} = \text{Log } K_{ow} - .21$$
$$\text{Log } K_{ow} - .21 = 0.63\ K_{ow}$$

Thus, values of K_{oc} are about half of those for K_{ow}. Sorption slows or retards the movement of the organics relative to water and inorganic species such as sodium and chloride ions. The retardation factor, R, (Table 10) describes retention of a compound with 1 = no retention. R has been calculated using the following relationship:

$$R = 1 + \frac{\rho b}{n} K_{oc}\, OC \qquad \text{where:}$$

Table 10

Physical Properties of Selected Chemicals (20-25°C)

Compound	Water Solubility mg/L	Vapor Pressure Torr	log K_{ow}	log K_{oc}[g]	$R_{0.1\%}$[i]	H_c[j] torr/M
Acetone	1 X 10^{6}[k]	228[d]	-0.24[e]	-0.15	1.01	13
Acetophenone	5100[h]	0.3[f]	1.83[g]	1.15	1.14	7.0
Aniline	36,600[a]	0.6[d]	0.84[d]	0.53	1.03	1.5
Benzene	1780[a]	95[d]	2.12[c]	1.34	1.22	4200
Benzoic Acid	2700[c]	<1[f]	1.87[c]	1.18	1.15	<45
a,a-Dimethylbenzyl Alcohol	5000[h]	1[f]	1.88[e]	1.18	1.15	30
2,3-Dimethylphenol	1200[h]	0.26[d]	2.36	1.49	1.31	25
Ethylbenzene	152[b]	10[d]	3.15[e]	1.98	1.95	7000
Formic Acid	5 X 10^{6}[k]	40[d]	-0.54[e]	-0.34	1.00	~2
Phenol	82,000[a]	0.5[d]	1.46[e]	0.92	1.08	0.50
alpha-Picoline	~1 X 10^{6}[k]	10[f]	1.06[e]	0.67	1.05	~2
Toluene	1500	25[d]	2.69[c]	1.69	1.49	1500

[a] Kenaga, E.E., Ecotox. & Envi. Safety, 4:26-38 (1980).

[b] Thibodeaux, L.J., "Chemodynamics," John Wiley, New York (1979).

[c] Chiou, et al., Envi. Sci. and Tech., 11;425-478 (1977).

[d] Stull, D.R. Ind. Eng. Chem. 39:517-550 (1947)

[e] Leo, A.C. Hansch, and D. Elkins, Chem. Reviews, 71:525-616 (1971).

[f] Handbook of Chemistry and Physics, CRC Publishing, Boca Raton, FL, 5th Ed. (1976).

[g] Calculated from $K_{oc} = 0.63K_{ow}$. Karckhoff, S.W., D.S. Brown, and T.A. Scott, Water Research 13:241-248 (1979).

[h] Calculated from $\log (1/S) = 1.214 \log K_{ow} - 0.850$, Lyman, N.J., Riehl, W.F., and D.H. Rosenblatt, "Handbook of Chemical Property Estimation Methods," McGraw-Hill, 1982, pp. 2-15.

[i] Estimation of maximum retention for 0.1% organic carbon.

[j] Values calculated from $H_c = P(\text{torr})/\text{Solubility (Moles/L)}$.

[k] Estimated from $S = 1/8\ 0.018L\ Mol^{-1}$, See McKay, D., and W.Y. Shiu, J. Phys. Chem. Ref. Data 10:1175-1205 (1981).

ρb = bulk density (assumed - 2 g/ml)
n = porosity (assume n = .2)
Koc = organic carbon partition coefficient
OC = fraction of organic carbon in formation

Using the above equation, retardation factors were calculated and are presented in Table 10. An organic carbon content of 0.1 percent has been assumed. This calculation assumes that aqueous organics are in equilibrium with the natural organic matter in the mineral, a reasonable assumption given the slow rate of movement of the aquifer waters. However, enhanced migration caused by cosolvent effects (e.g., acetone which would lead to R ± 1.00), have not been included here. Any cosolvent effect would be important only for toluene and ethylbenzene which have R values much greater than 1.

Evaluation of these data indicate that, for the most part, compounds present within the injectate, Mt. Simon, Rose Run at WDW No. 3, and Copper Ridge will usually exhibit low K_{oc} values. Also, geologic information indicates that there is little naturally occurring organic material within the rock column, particularly between the Mt. Simon and Rose Run. Therefore, major sorptive attenuation of compounds such as acetone, phenol, and benzene due to this mechanism will not occur, although attenuation of some compounds, such as phenol, may occur relative to other compounds with a lower K_{oc}, such as acetone.

Ion exchange as a sorptive mechanism has also been assessed. Geologic data indicate that clays are present in many of the rock units, including the Mt. Simon. Ion exchange of cations to clays such as illites could be an important attenuation process for amines such as picoline; aniline is less susceptible to ion exchange, but could be affected to a minor degree by this process. Inorganics such as ammonium, however, could be sorbed to clays by this process. In summary, data indicate that extensive sorption of organics will likely not occur, although sorption of constituents such as ammonia may occur due to ion exchange.

E.2.2 Hydrolysis and Oxidation

Both hydrolysis and oxidation can significantly alter compounds. However, none of the major compounds found in these formation fluids are susceptible to hydrolysis under conditions present in the formations. Moreover, natural subsurface conditions are most likely anoxic. Therefore, oxidation is not considered a significant transformation mechanism.

E.2.3 Vapor Phase Transport

Not only can organic compounds exist in the dissolved phase in liquids, a certain amount can also exist as a vapor phase (in equilibrium with the liquid phase). This is significant because a separate movement of compounds in the vapor phase can occur independent from the dissolved phase.

The volatility of compounds listed in Table 9 is proportional to their Henry's Law Constants, H_c, listed in the last column. Benzene, toluene, and ethylbenzene are by far the most volatile compounds listed in Table 10 and are most likely to partition to the vapor phase as well as to any organic matter. Dr. Mason Tomson, Rice University, has indicated that a mechanism which would allow for this phase transfer through 1000 feet of fluid-filled rock was not present in any of the evaluated scenarios.

In summary, while vapor phase transport of the particular organic compounds of interest in the Aristech situation could possibly occur to a limited extent, it probably could not transport large quantities of organic materials.

E.2.4 Dissolution/Precipitation of Inorganic Constituents

Fresh water from the Ohio River with relatively low inorganic constituent concentrations (Appendix P) was used as make-up water for the injectate, which resulted in low inorganic concentrations in both the 1989 and current injectate (i.e., chloride). WDW No. 3 Mt.

Simon waters also have low TDS concentrations, indicating that substantial admix of formation and injectate water has occurred. If injectate entered the Rose Run or Copper Ridge, reduction of inorganic constituent concentrations would therefore also be expected. However, the inorganic chemistry of the Rose Run Formation at WDW No. 3 and Copper Ridge at the Test/Monitoring Well indicates that these waters are still quite saline/inorganic constituent-rich and that little admix with fresher water has occurred. It is possible that this is because surrounding rock has added cations and ions to formation fluids (through rock dissolution), essentially "masking" any dilution of inorganic constituent concentrations due to injectate.

Although rocks below Haverhill contain calcium and magnesium, (which are present in the Rose Run in relatively large quantities), acidic waters would be required to dissolve limestones and dolomites, and release calcium, magnesium, and carbonate. Since injectate is not alkaline, dissolution of subsurface rocks by injectate is unlikely. The addition of enough chloride to increase salinity of fresh water to the over 170,000 ppm chloride content in many subsurface formation fluids would require that fluids encounter a salt-bearing interval from which salts could be dissolved. Nowhere in the geologic history or core record is there any indication that salt beds are present that could provide the necessary inorganic constituents. Therefore, major dissolution of rock units by injectate has probably not occurred, and in fact, mineral precipitation upon mixing of injectate and natural formation fluids is more likely.

Computer calculations show that both 1968 (pre-injectate) and 1989 (post-injectate) Mt. Simon and Rose Run formation fluids are at saturation with calcite and gypsum/anhydrite (Appendix M). Mixing of 10 percent 1968 Mt. Simon fluids with 90 percent injectate likely created 1989 Mt. Simon fluids (Table 9); calculations indicate that this mixing has probably not caused significant calcite precipitation, but could have precipitated 10.3 grams of gypsum or 8.2 grams anhydrite from every liter of injectate-Mt. Simon mixture (Appendix M). The precipitation of gypsum or anhydrite in the subsurface due to injectate-formation fluid mixing could lead to minor plugging of smaller pore spaces.

F. Subsurface Formation Pressures

As stated in previous sections, many formations were sampled during installation of WDW Nos. 1, 2, 3 and the Test/Monitoring Well. Along with extraction of formation fluid samples, tests were performed which revealed the in-situ formation pressures that were used to interpret relative fluid flow in Section IV. Formation pressure data are summarized below.

F.1 Historic Sampling/Testing and Calculation Methodologies

Pressure measurements have been taken in many of the formations penetrated by Aristech deep wells, from the drilling and completion of WDW No. 1 in 1968 to the recent drilling of the Test/Monitoring Well completed in 1991. Generally, the data from the 1968 testing are of a more limited nature and are subject to some accuracy limitations. This is because technology that is now over 20 years old was used to collect 1968 pressure data, and the 1968 data were collected under much less stringent QA/QC procedures when compared to the more critically designed/reviewed testing conducted in 1989 and 1991.

Calculations made using the data are based on hydrostatics; pressure values taken at differing locations and depths were compared by correcting the values to the same elevation or datum depth. This correction was made by adding or subtracting the hydrostatic pressure of a column of fluid, which is equivalent to the difference between the depth at which a pressure was measured and the desired datum depth. Inferences regarding pressure changes can be made by comparing corrected pressure values from the 1968 tests to the newer corrected pressure values from the more recent 1989 and 1991 tests.

F.1.1 WDW No. 1

During the drilling and completion of WDW No. 1 in 1968, five DSTs were conducted. The formations tested were the Berea, Newburg, Rose Run, Mt. Simon, and Lower Mt. Simon (Table 2). The Berea test did not obtain a representative pressure because drilling mud plugged the sampling tool. The first Mt. Simon test provided good data, but the lower Mt. Simon test was not useful due to very low formation permeability. Test data are summarized in Table 11.

F.1.2 WDW No. 2

No DST data were collected during the drilling and completion of WDW No. 2.

F.1.3 WDW No. 3

Five DSTs were conducted during the drilling and completion of WDW No. 3 in 1989. The formations tested were the Berea, Niagaran, Newburg, Rose Run, and Mt. Simon (Table 3a). The Berea test did not obtain an accurate pressure due to plugging of the tool and low formation permeability. Plugging also affected the data collected in the Niagaran and Newburg. Rose Run testing was successful, as was the first Mt. Simon test. Test data are summarized in Table 11.

F.1.4 Test/Monitoring Well

Six DSTs were conducted during the drilling and completion of the Test/Monitoring Well in 1991. The formations were the Logan, Berea, Newburg, Beekmantown, Rose Run, and Copper Ridge; all tests were successful (Table 3b). Test data are summarized in Table 11.

Table 12 summarizes the pressures and apparent pressure rises observed at the Aristech wells in the Rose Run and Copper Ridge. Pressure differences between the Rose Run and Copper Ridge at the Test/Monitoring Well and the same formations at the other wells is relatively small when compared to the pressure rises evident in the Mt. Simon injection interval between WDW Nos. 1 and 3.

Table 11

Summary of Formation Pressure Data

Formation	Well	Date	Interval (ft KB)	Gauge Depth (ft KB)	P* (psi)	Note	Brine density (g/cm^3)
Logan	Test	1/21/91	164.2-261.5	157.7	63.7	-	1.033
Berea	Test No. 3 No. 1	1/29/91 4/13/89 5/14/68	679.2-734 701-751 712-733	672.7 710 -	324 333.3[1]	- Low Perm/Plugged Plugged	1,095 1.03 1.005[1]
Niagaran	No. 3	-	-	-	-	-	1.17
Newburg	Test No. 3 No. 1	3/91 - 5/16/68	1757.4-1790.7 - 1795-1835	1750.9 - 1805	837.7 - 859	- - Not P*, Plugging	1.097 1.2 1.193
Beekmantown (Upper Knox)	Test	4/20/91	4009.5-4035.5	3995.5	1805.7	-	1.218
Rose Run (Knox)	Test No. 3 No. 1	4/25/91 5/15/89 5/26/68	4181-4225 4503-4588 4220-4265	4170.0 4572.0[3] 4230.0	1912.2 1968.8 1895.6[1]	- Deviated Well -	1.214 1.19 1.199
Copper Ridge (Lower Knox)	Test	5/8/91	4446.7-4480	4440.2	2078.2	-	1.20
Mt. Simon	No. 3 No. 1	9/25/89 6/5/91	5978-6109 5520-5565	5965[3] 5545	2645.9 2633	Deviated Well -	1.05[2] 1.225
Lower Mt. Simon	No. 1	6/6/91	5575-5617	5613	-	No Perm.	-

[1] = not representative value; insufficient sample/shut-in time
[2] = fluid sample primarily injectate
*P = extrapolated reservoir pressure
[3] = values reported as measured depths

Table 12

Copper Ridge and Rose Run Formation Pressures

Formation	Well	Date	KB	TVD Depth (ft) RKB	BSL	P* (psi)	P* at Datum (psi)	Apparent ΔP (psi)
Rose Run	Test	4/25/91	545	4170	-3625	1912.8	1937.1	2.7
	No. 3	5/15/89	560	4266[1]	-3706	1968.8	1951.7	17.3
	No. 1	5/26/68	557	4230	-3673	1934.4	1937.4	0
Copper Ridge	Test	5/8/91	545	4440.2	-3895.2	2078.2	2078.2	15-28
	Estimated Original	-	-	-	-3895.2	-	2050-2063	0

*P = extrapolated reservoir pressure
TVD = True vertical depth
[1] = TVD based on data from TVD log (Appendix CC)

F.1.5 In-Situ Stress Testing

During the period May 30, 1991 through June 5, 1991, 28 in-situ stress tests were conducted from the Rome Formation [approximately 5390' below ground surface (BGL)] upsection to the Black River Formation (approximately 3550 feet BGL) in the Test/Monitoring Well (Table 13). As discussed in the Protocol for this testing issued January 9, 1991, (Appendix S1), the purpose of these measurements was to determine the capability of the geologic column overlying the Mt. Simon and Rose Run Formations to contain fractures potentially induced by injection fluid pressure and well stimulations.

In-situ stress measurements are controlled injection tests in which an isolated portion of a formation is hydraulically fractured. The process is often referred to as a "mini-frac" test because of the relatively short test duration and the small volumes of fluid typically used. A straddle packer assembly and a down-hole shut-in tool are used with high resolution pressure gauges to collect data to determine formation fracture initiation pressures, fracture extension pressures, fracture opening pressures, fracture closure pressures, and estimates of formation pore pressures.

G. Fluid Flow Modeling

REC maintains a model called "Injection Forecast" to assess fluid movement within deep-well disposal systems. This program is a set of mathematical models specifically created to predict injectate/fluid transport in subsurface disposal formations throughout the country and is an analytical (rather than numerical) simulator. The REC model is an accepted standard model within the injection well industry.

Although this model places some limits on the configurations that can be used to model physical injection systems, the advantages inherent in analytical solutions (such as the accurate treatment of large rock property contrasts and a lack of sensitivity to numerical solution methods) made this simulator an appropriate tool for this assessment. Appendix

TABLE 13
Aristech Chemical Corporation
Test/Monitoring Well
IN-SITU STRESS TEST INTERVALS

Date	Test No.	Tool Spacing	Depth to M.P.P.*	Formation	Pump-in Rate, GPM	Packer Inflation Pressure
5/31/91	1	4	5388	Rome	2.1 - 4+	1000
5/31/91	2	4	5375	Rome	2.3	850
5/31/91	3	4	5362	Rome	2.3	750
5/31/91	4	4	5317	Rome	2.3	500
6/1/91	5	4	5243	Rome	2.3	650
6/1/91	6	4	5200	Rome	2.4	900
6/1/91	7	4	5176	Conasauga	2.4	775
6/1/91	8	4	5119	Conasauga	2.3	650
6/1/91	9	4	5070	Conasauga	2.5	850
6/1/91	10	4	4977	Beekmantown	2.4	750
6/2/91	11	4	4823	Beekmantown	2.4	520
6/2/91	12	4	4474	Beekmantown	2.4	700
6/2/91	13	4	4257	Beekmantown	2.3	745
6/2/91	14	4	4212	Rose Run	2.3	400
6/3/91	15	4	4196	Rose Run	2.3	675
6/3/91	16	4	4188	Rose Run	2.4	640
6/3/91	17	4	4176	Copper Ridge	2.4	675
6/3/91	18	4	4162	Copper Ridge	2.3	660
6/3/91	19	4	4142	Copper Ridge	2.5	520
6/3/91	20	4	4123	Copper Ridge	2.5	670
6/3/91	21	4	3972	Copper Ridge	2.5	520
6/3/91	22	4	3902	Wells Creek	2.4	670
6/3/91	23	4	3782	Black River	2.5	520
6/3/91	24	4	3550	Black River	2.4	465
6/4/91	25	4	5381	Rome	2.3	595
6/4/91	26	10	5147	Conasauga	7.0	630
6/4/91	27	10	4628	Beekmantown	6.9	580
6/4/91	28	10	4055	Copper Ridge	7.0	680

* Mid Point Packers

S2 includes a more comprehensive discussion of the mathematics and approach involved in the modeling system that was utilized to calculate fluid transport and pressures in these investigations.

Prior to using the Injection Forecast model for the investigation of fluid movement at the Haverhill area, site-specific parameters (input variables) that describe the Mt. Simon and Rose Run rock conditions at Haverhill were assigned from various tests and available records. This input was then used with the appropriate sub-models (chosen using site-specific criteria) to develop predictions for several different fluid movement scenarios, which are discussed in Section IV of this report. Effective parameters used in modeling the Rose Run Formation were:

Rose Run:

$k = 22.7$ md
$\phi = 0.112$
$h = 15$ feet
$\mu = 0.69$ cp
$c_T = 5.5 \times 10^{-6} \text{psi}^{-1}$

As previously stated, approximately 1120 million gallons of injectate were added to the Mt. Simon from 1968 until 1989 through WDW Nos. 1 and 2. REC has modeled the lateral movement of the 50 percent concentration injectate front which has resulted from injection into WDW Nos. 1 and 2 to estimate the lateral movement of injectate in the Mt. Simon through time (Figure 8). This front is defined as the location of the 50 percent injectate-50 percent formation water mixture boundary. REC calculates that the 50 percent concentration front for 1968 injectate has migrated over 5000 feet outward from WDW No. 1, and reached the portion of the Mt. Simon that occurs below the WDW No. 3 Rose Run intercept sometime in the mid-1970s.

Fluid transport and pressure rise modeling was also conducted to investigate scenarios which involve injectate entering the Copper Ridge Formation. Parameters used in this modeling included:

MT. SIMON INJECTATE FRONT PROJECTIONS
Aristech Chemical Corporation
Haverhill, Ohio

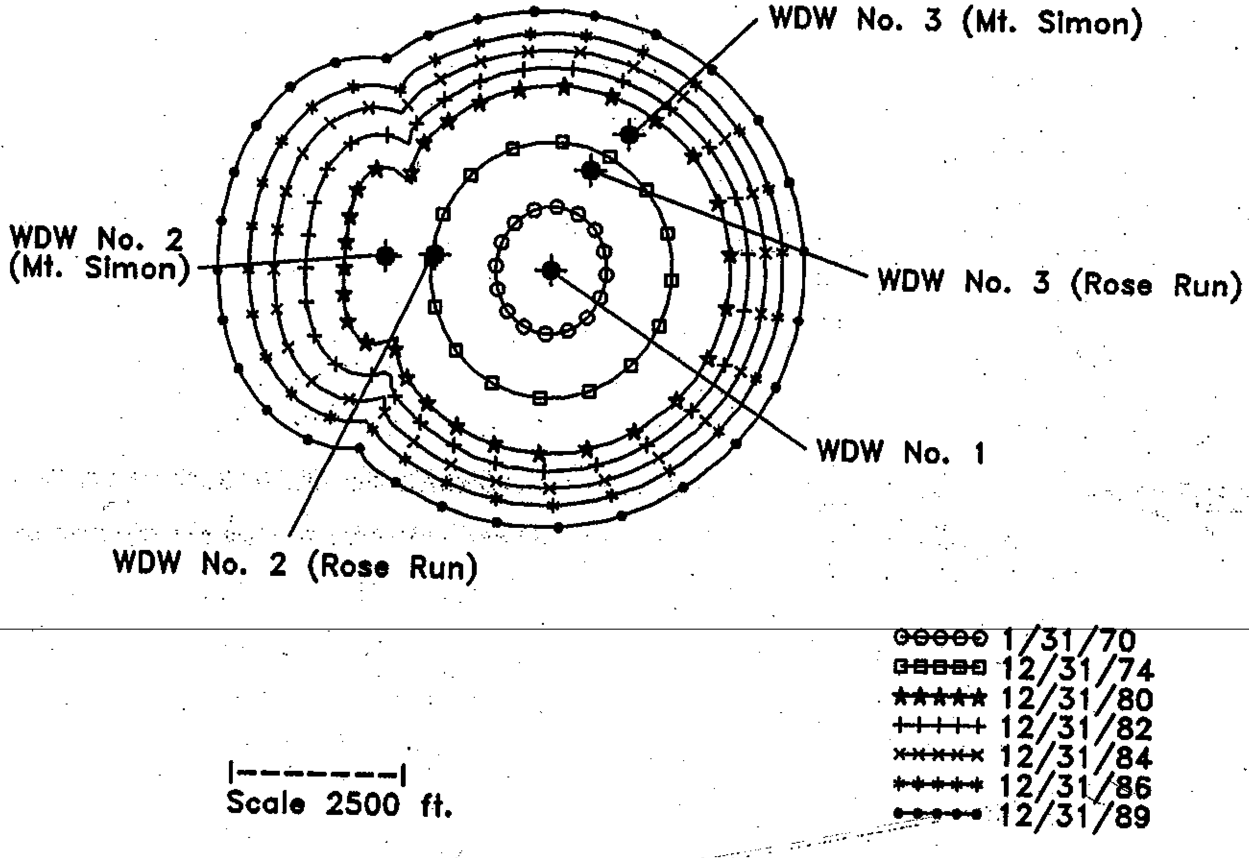


Figure 8. Location of the 50 Percent Injectate Front Movement Through Time in the Mt. Simon Formation.

$k = 135$ md
$\phi = 2$ to 5%
$h = 2$ to 40 feet
$\mu = 0.75$ md
$c_T = 5 \times 10^{-6} \text{psi}^{-1}$

These Copper Ridge data are based on log analysis, core analysis, DST data, and standard correlations (for compressibility and viscosity).

However, exceptionally high leak rates are generally required for this to occur, as well as over 20 percent of the injectate exiting the borehole through the casing hole or breach. If a lower leak rate is assumed, then the required pressure rise at the WDW No. 3 intercept is much higher than the observed pressure change.

The pressure build-up in the Rose Run Test/Monitoring Well is approximately 3 psi (compared to 17.5 ± 17 psi in the Rose Run at WDW No. 3). However, the Test/Monitoring Well-Rose Run intercept is approximately 960 feet from WDW No. 1, while the WDW No. 3 intercept is approximately 1340 feet from WDW No. 1. This pressure relationship is opposite of that expected even for a highly anisotropic system because higher pressure buildup would occur nearer the leak source at the Test/Monitoring Well, rather than at or near WDW No. 3 (assuming the leak source is at or near WDW Nos. 1 or 2).

In summary, modeling of pressure and fluid transport based on data collected from the cores, logs, and DSTs indicates that fluid could reach WDW No. 3 through a casing breach in WDW No. 1 or 2, but only under unrealistic leak rates and dispersivities, and unsupported assumptions about Rose Run heterogeneity.

C.1.3 Geologic and Hydrogeologic Investigation Results

For Scenario 1 to be realistic, not only would injectate have to enter the Rose Run through a casing breach at a very specific location, but the Rose Run would also have to be extensively compartmentalized so that fluid and pressure effects would specifically reach WDW No. 3, bypassing the Test/Monitoring Well. Geologic information does not support compartmentalization of the Rose Run to such a degree that this would occur.

Well log and core analyses indicate that the Rose Run is a near shore to peritidal sandstone, which has been identified as tidal channel deposits (Appendix A2). Development of overlapping sand packages may occur as channels migrate laterally or as sands are reworked along a shoreline. Geophysical logs indicate that sand packages in WDW No. 1 directly correlate with sandstone intervals at the Test/Monitoring Well, with no indication that a major facies change occurred between the two locations. This indicates that there is not such a major lithological change between WDW No. 1 and the Test/Monitoring Well that complete hydrologic isolation of the two locations would occur. Available cores indicate that the Rose Run is comprised almost exclusively of siliciclastic (quartz and feldspar) sand, with varying degrees of cementation and packing (see Appendix A2 for complete discussion). Core data also indicate that above this sandstone interval within the Rose Run, a silicified carbonate clastic unit is present. While this unit is significantly different than the underlying sandstone in terms of depositional environment, secondary alteration, and rock characteristics, the unit is not laterally or vertically pervasive enough to impact the "interconnectedness" of the Rose Run sandstones, particularly between WDW No. 1 and the Test/Monitoring Well.

In summary, although some lithologic and depositional differences occur within the Rose Run, these differences are not pronounced enough to result in complete compartmentalization of the Rose Run to such a degree that injectate would flow from WDW No. 1 or 2 to WDW No. 3, but completely bypass the Test/Monitoring Well. It must be pointed out that the Test/Monitoring Well is located between WDW No. 1 and WDW No. 3, and WDW No. 1 is approximately 350 feet closer to the Test/Monitoring Well than it is to WDW No. 3 (Figure 2).

It is also possible that one large short-term leak could have taken place with no continued leakage.. However, hydrogeologic information does not indicate that natural flow gradients could naturally more a slug of fluid in the Rose Run from WDW No. 1 or 2 to the WDW No. 3 location (Figure 2) within the appropriate timeframe. The natural (non-injection related) groundwater flow velocity is probably less than two feet/year and the possible flow direction is to the north or west. Therefore, it would require 700 years to move fluid approximately 1400 feet from WDW No. 1 to WDW No. 3. Additionally, if the natural gradient is similar to that of the Mt. Simon, fluid would flow away from WDW No. 3, rather than toward WDW No. 3, from WDW Nos. 1 or 2. Without an induced pressure gradient, it is highly unlikely that fluid could naturally migrate to WDW No. 3 over the lifetime of these wells.

C.1.4 Process Chemistry and Formation Fluid Chemistry Study Results

As stated above, injectate contains constituents such as phenol, which can be corrosive and could have led to a tubing leak. Also, injectate chemistry was substantially altered in the early 1980s with the addition of aniline and BPA and reduction of acetone in the injectate (due to addition of the stripper). The injection wells began to plug (Appendix N) with calcium sulfate, calcium carbonate, and organic materials at this time, which was temporarily remedied through nitrogen jetting. Therefore, it is possible that if a casing breach occurred prior to the process chemistry change, the alteration of injectate chemistry during the early 1980s and resulting precipitation of material downhole could have sealed a hole(s) or casing breach. However, it is highly unlikely that constituent precipitation could have been rapid or pervasive enough to plug an ongoing leak, particularly of the rate/ volume required to make this scenario plausible. Therefore, although data indicate that the process chemistry changes required to plug leaks occurred, it is unlikely that plugging could be effective enough to seal an ongoing leak, particularly a leak of the requisite rates as indicated by modeling.

C.1.5 Implications of Fluid Mixing Calculations

Mixing calculations indicate that 1989 WDW No. 3 Rose Run chemistry could be the result of mixing 15 percent injectate with 85 percent original Rose Run fluid (Table 9). Mixing calculations, therefore, support this scenario. However, assuming relative homogeneity (non-compartmentalization) of the Rose Run, a relatively large volume of fluid--likely tens of millions of gallons--is required to create WDW No. 3 Rose Run conditions from a direct leak at WDW No. 1 and/or WDW No. 2. Also, chemical mixing data suggest that this appropriate injectate/Rose Run mix requires unrealistic assumptions of dispersivity and leak rate to create the conditions at WDW No. 3.

C.1.6 Conclusion

In summary, Scenario No. 1 is generally not supported by available information. The bulk of the available historic well construction/operation and modeling information discussed above does not indicate that a breach in the outer casing has occurred, although a minor leak in the tubing could have occurred in WDW No. 1 or WDW No. 2 prior to the 1983-1984 workovers. Healing of unrecognizable casing failures by precipitation of material is supported by process chemistry information, although unrealistic assumptions concerning leak rate, dispersivity, volume, etc., would be required to explain observed pressures and to have contaminants migrate to WDW No. 3.

Geologic data do not support the compartmentalization of Rose Run sandstones to the degree that would be required to have contaminants flow to WDW No. 3, but not to the Test/Monitoring Well location. Mixing calculations indicate that the WDW No. 3 Rose Run fluid could have been the result of mixing 1968 Rose Run fluid with average injectate. However, Rose Run-injectate mixing calculations and modeling results also imply that a large volume (tens of millions of gallons) would have to have been added to the Rose Run to even approach the concentrations of organic constituents present at WDW No. 3. Modeling calculations also indicate that a significant pressure increase at WDW No. 3 would be evident from movement of contaminants to the WDW No. 3 Rose Run location, which is not the case. Therefore, the relatively large volume of injectate required to make this scenario possible from a chemical perspective is not consistent with known pressure data and modeling results.

C.2 Scenario 2: Vertical Conduit Near WDW Nos. 1 and 2

Scenario 2 deals with the addition of injectate-bearing fluid into the Rose Run from a location immediately adjacent to WDW Nos. 1 and/or 2, with flow in a significantly compartmentalized Rose Run Formation to the WDW No. 3 intercept, bypassing the Test/

Monitoring Well (Figure 11). In order for this to occur, it must be assumed that one or more of the following has taken place:

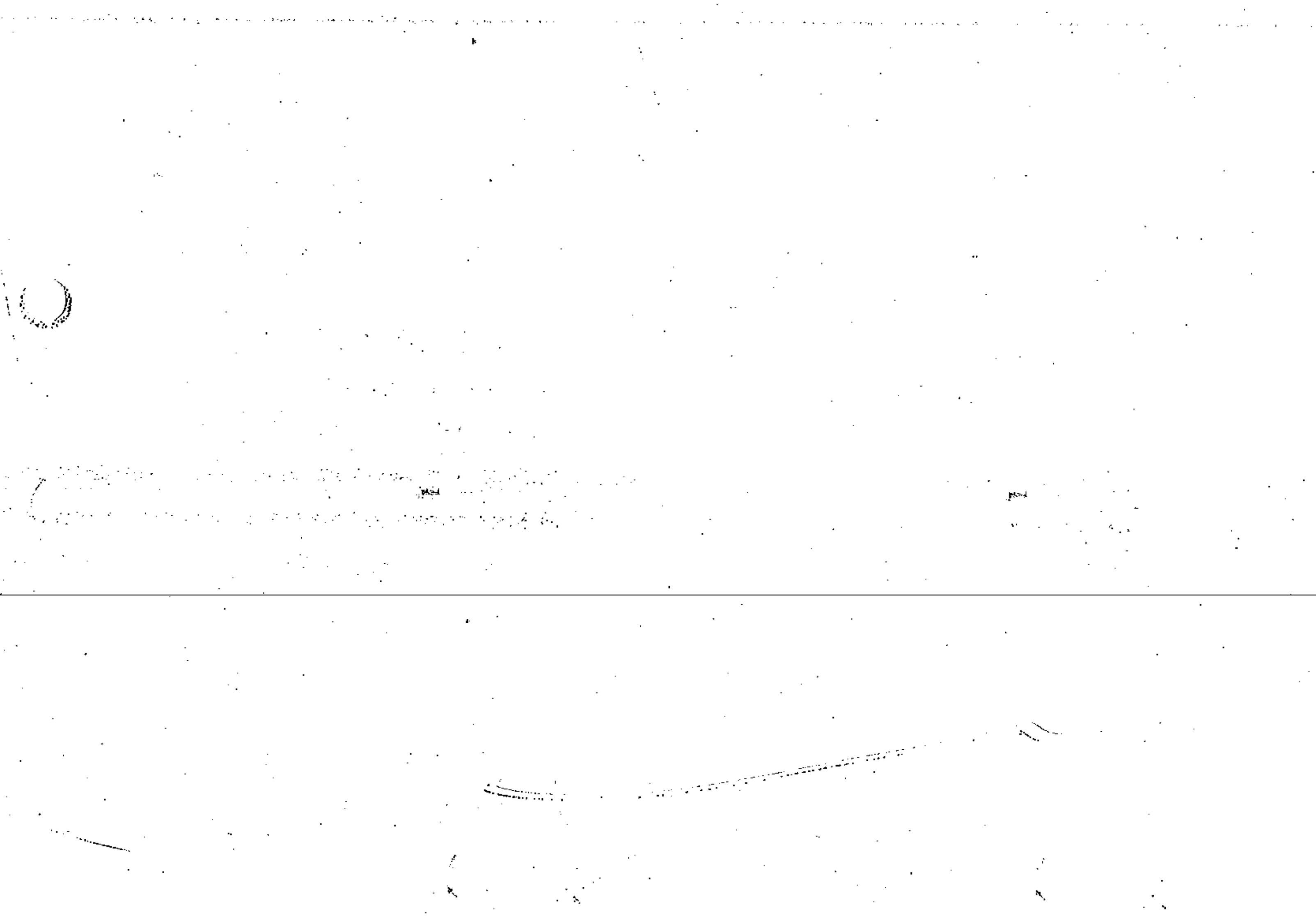
- Migration up the annulus between the outer casing and the borehole wall from the Copper Ridge to Rose Run;
- Migration upward through a vertical micro fracture system (i.e., caused by the induced fracturing near boreholes) between the Copper Ridge and Rose Run; and
- Migration up through an abandoned borehole or major, continuous fault from the Mt. Simon or Copper Ridge to the Rose Run.

It is also assumed that fluid added to the Rose Run at or near WDW Nos. 1 and/or 2 due to direct interconnection with the Mt. Simon from a fault or borehole is a mixture of injectate or 1989 Mt. Simon with 1968 Rose Run fluids. This is because the direct pathway allows for instantaneous interconnection of the Mt. Simon and Rose Run with no mixing with intervening formation fluids. If a conduit is assumed between the Copper Ridge and Rose Run only, then a mixture or displacement of Copper Ridge and 1968 Rose Run fluid is assumed. In all cases, compartmentalization of the Rose Run is required to move the migrating fluids to the WDW No. 3 location without encountering the Test/Monitoring Well-Rose Run. The possibility for this scenario rests upon well integrity, fluid flow modeling results, site geologic/hydrogeologic conditions, and fluid chemistry, which are discussed below.

C.2.1 Well Integrity

Failure of the cement seal between the casing and borehole wall could have created a pathway from the Copper Ridge to the Rose Run, allowing injectate to enter the Rose Run at WDW Nos. 1 and 2 (Figure 11). However, MITs indicate that wells were sound when the tests were conducted in 1984, and the wells have demonstrated integrity in all tests since that time. Moreover, as discussed in Section B.1., the annular pressure fluctuations have

Figure 11



probably been the result of possible tubing problems coupled with temperature effects, which are solely internal to the well, rather than leakage of fluid outside of the casing along the borehole wall. Cement bond logs (CBLs) for WDW No. 1 (conducted in 1968, 1983 and 1985) and WDW No. 2 (conducted in 1984 and 1990) indicate that the outer casing-formation cement seal was intact when logged.

It is possible that a casing-formation cement bond failure occurred prior to 1984 and that injectate leaked up to the Rose Run from the Copper Ridge along the outside of the casing, with subsequent healing of the leak area due to precipitation of organic or inorganic plugging material. Injectate chemistry data indicate that plugging of the wells occurred in conjunction with process chemistry changes during the early 1980s, and resultant sealing of an open annulus could have taken place. Data indicate that relatively low quantities of calcite and gypsum would likely precipitate (Section III) with the majority of plugging due to precipitation of organics. However, unless calcite and gypsum <u>only</u> were precipitated, signal attenuation due to "low velocity" organics would likely have been apparent on CBL logs. This indicates that the CBL log would have detected the plug since it would be likely comprised predominantly of organics, but no such plug was observed in recent CBLs.

C.2.2 Fluid Transport and Pressure Rise Modeling Results

Analysis of the in-situ stress tests and modeling of pressure rise based on available DST data indicate that the induced fracture systems near the active injection wells are arrested within the Copper Ridge. Therefore, the occurrence of an injection-induced microfracture system adjacent to the WDW No. 1 or 2 location between the Copper Ridge and Rose Run is not supported by available data. If a localized microfracture network which is either naturally occurring or caused by injection (which would be contrary to the known data derived from Test/Monitoring Well in-situ stress test measurements), were present and transmissive, it is possible that pressurization of the Rose Run could be nominal, assuming the injectate slowly migrates upward through the microfractures. However, for fluid to have moved from the WDW No. 1 vicinity to the WDW No. 3 Rose Run intercept, a large volume of fluid would have to have been emplaced in the Rose Run requiring unrealistic pressure rises, dispersivities, leak rates, and other constraints similar to those discussed under Scenario 1 (Table 15). This large volume of fluid would also result in a pressure rise in the Rose Run at the Test/Monitoring Well location that is significantly in excess of the observed 3 psi pressure rise. Therefore, the dispersivity and leak rate constraints which limit Scenario 1 also apply to Scenario 2.

Pressure data also do not indicate that an ongoing annular leak, borehole or open fracture is present near WDW No. 1 or No. 2, since this requires that a large pressure rise (in excess of 70 psi) currently be present in the Rose Run at WDW No. 3 (Table 15), and a pressure rise significantly in excess of the observed 3 psi be present at the Test/Monitoring Well. Because this large pressure rise has not been observed in the Rose Run, the occurrence of an ongoing leak into the Rose Run near the active injection wells (through boreholes, fracture systems, or annular leak) is not supported by the pressure data.

C.2.3 Geophysical and Other Studies to Locate Potential Boreholes

In support of the UIC Repermit Application for WDW No. 1 and 2, Envirocorp performed extensive search within a 6.1 mile radius of the Haverhill facility for artificial penetrations (wellbores) to the Rose Run. Records from numerous state agencies were reviewed, including maps from ODNR and records from the Kentucky Geological Survey. Also, a foot search for deep wells within a ten mile radius of Haverhill was performed by Harrison/Kroll. Two wells were found of the appropriate depth within the six mile radius, although no wells were confirmed within 3-4 miles of the Haverhill facility.

As stated above, the Harrison/Kroll and ERM studies did not identify any boreholes to the Rose Run, Copper Ridge, or Mt. Simon within a three-to-four mile radius around the facility. However, historic aerial photographs of the Haverhill area taken by the USDA from 1951-1988 indicate that an area of ground scarring was present in the plant area prior to construction of the facility in 1965. A magnetometer survey was conducted over a 1000-foot area at 25-foot grid spacing, with 5-foot spacings in a more detailed area where severe ground scarring was noted (see report in Appendix V). In addition to the magnetometer survey, a gradient analysis was performed to assess the "orientation" of any anomalies detected in the survey, with particular emphasis in locating anomalies that could be vertical well bore casings. The survey indicated that a small magnetic anomaly was present in the suspect area, but the magnitude, size, and dimension of the anomaly indicated that it was probably not a vertical casing that could be associated with a heretofore unidentified wellbore. It must be pointed out that casing can be removed from borings prior to abandonment, and therefore, the absence of metal casing does not necessarily indicate that no boreholes are present. Similarly, surface scarring is not always associated with drilling activity. Norfolk/Southern, who owned the Haverhill property prior to 1965, had no record of any drilling activity in the area at or before this time.

C.2.4 Geologic, Hydrogeologic, and Seismic Study Results

From a geologic perspective, it is unlikely that a conductive, continually open fracture (analogous to an open borehole) is present near WDW No. 1 or WDW No. 2 that would directly connect the Mt. Simon or Copper Ridge and Rose Run and allow for "instantaneous" interconnection of formation fluid. Also, geological and geophysical data show that no large-scale faulting is present within the seismic grid area. Recent reinterpretation of seismic data, originally acquired by Apex Geophysical, was performed by Envirocorp (Appendix D) and Ms. Sally Zinke (Appendix E), and included reprocessing of portions of line KD-6 in response to requests by OEPA. Both the Envirocorp reassessment and that performed by Ms. Zinke indicate that some faults are present at the Precambrian within a 16-mile radius of the Haverhill facility, but none are present within an approximately one-mile radius of the plant itself. The two reports recognized the presence of an apparent structure beneath the Aristech Haverhill facility along line KD-6 approximately between shotpoints 180 and 290; a break in seismic reflection continuity at the Rose Run level is also apparent on the same line below these shotpoints. However, the experts indicate that there are a number of factors that could have influenced this apparent structure, including noise, data skips, and changes in the thickness of the overlying lower velocity material. After extensive data refinement and re-interpretation, both Ms. Zinke and Envirocorp believe that no true structural turnover or structural high is present in this area, and that the observed seismic response was likely a result of the above interferences. The break in seismic reflection near shotpoint 180 is attributed to noise because of "the lack of diffraction patterns associated with these breaks, along with their spatial relationship to continuous reflectors above and/or below [the Rose Run]" (Envirocorp, 1990, Appendix D).

A lineament trend study was conducted by Envirocorp to locate linear features evident at ground surface (Appendix F) using satellite imagery and aerial photographs. In this study, linear features were identified, and the location where these features intersected seismic lines were distinguished. The purpose of the study was to determine whether any faults identified through seismic study correspond with surface features, implying the occurrence of large-scale faults. Based on satellite imagery, the study concluded that "no linear trends are interpreted to pass through or very near the Haverhill site." The location of surface lineaments was then compared with the occurrence of subsurface faults identified in an earlier Apex geophysical study of the seismic lines to determine whether there was any association between surface lineaments and subsurface faults. The study drew no conclusions concerning the correspondence of surface features with subsurface faults because the early Apex study did not identify any faults with displacements greater than 30 feet within a 12-mile radius of the facility.

However, the seismic data have since been reprocessed and new reports interpreting the reprocessed lines were prepared by both Envirocorp (Appendix D) and Ms. Zinke (Appendix E). A comparison of the location of lineaments that occur on both the satellite imagery and aerial photograph lineament maps against seismic anomalies identified in the recent reinterpretations has been performed. This assessment shows that, in some instances, features such as faults or rollovers identified via seismic interpretation correspond to surface linear features, although this correspondence is neither common nor pervasive. The closest surface linear feature to the Haverhill facility that was identified on both the aerial photograph and satellite imagery lineament maps occurs over 1.5 miles east of the plant, and does not correspond to a subsurface feature as evidenced by the seismic data. In conclusion, seismic data do not indicate that either a structural "roll-over" or fault is present in the immediate area of the Aristech Haverhill plant. The seismic data has a resolution of approximately 30 feet, and therefore, features smaller than this would not be detected.

If a pressure-induced fluid rise from the Mt. Simon/Copper Ridge near WDW No. 1 or No. 2 to the Rose Run at WDW No. 3 somehow occurred, extreme heterogeneity (compartmentalization) of the Rose Run is required for injectate to reach WDW No. 3 without any flow to the Test/Monitoring Well location. As presented in Section IV-C.1., this is not realistic, given known site geologic conditions. Also, if fluid somehow naturally rose from the Copper Ridge or Mt. Simon to the Rose Run near WDW Nos. 1 or 2 with little pressurized flow, it is not possible that natural lateral (not pressure-induced) migration of fluid in the Rose Run would move fluid to the WDW No. 3 location because of both the probable low groundwater flow velocity and the southwest groundwater flow direction of the Rose Run.

C.2.5 Fluid Chemistry

Based on mixing calculations, it is most likely that 1989 Rose Run fluid was formed by mixing approximately 22 percent injectate and approximately 78 percent original (1968) Mt. Simon fluid, which displaced rather than mixed with 1968 Rose Run fluids (Table 9, Equation 4). Although less likely, 1989 Rose Run could also be formed by mixing approximately 15 percent injectate and 85 percent of original (1968) Rose Run fluid. It is also possible that 1989 Rose Run chemistry could be the result of a 1968 Copper Ridge (78%) and injectate (22%) fluid mixture that displaced rather than mixed with Rose Run fluid.

Mixing calculations show that formation of the 1989 WDW No. 3 Rose Run by mixing 1989 Mt. Simon and original (1968) Rose Run fluids is unlikely based on chemical evidence

(Table 9). Mixing data also show that fluid recovered from the Rose Run at WDW No. 3 cannot be formed by mixing 1991 Copper Ridge (at the Test/Monitoring Well) and 1968 Rose Run (Appendix M) because concentrations of major species are greater in both 1991 Copper Ridge and Rose Run fluids than they are in 1989 Rose Run fluid. Mixing calculations also show that 1991 Rose Run and the calculated 1968 Copper Ridge fluid chemistries at the Test/Monitoring Well are very similar (Appendix M). This implies either some sort of interconnection between the formations, or a similar history and evolution of these waters; there is no geologic evidence in support of natural formation interconnection.

As stated in previous sections, mixing calculations are based on questionable data, and results are tenuous, at best. Calculations show relative likelihood of various fluid mixtures, but actual percentages probably vary from those presented above because of questionable fluid chemistries.

Although mixing calculations show that a number of fluid mixtures could have created WDW No. 3 Rose Run fluid chemistry, the constraints that limit the plausibility of Scenario 1 also apply to Scenario 2. For example, if almost pure injectate migrated upward from the Mt. Simon to the Lower Knox and then into the Rose Run near WDW No. 1 or 2, large volumes of injectate would have to have been added to the Rose Run to produce the Rose Run-injectate mixing conditions at the WDW No. 3 location. It is unlikely that such a large volume leak could have occurred without direct indication of this leak which is not apparent from the available data. In all cases, large volumes of fluid are required to create conditions at WDW No. 3.

C.2.6 Conclusion

Based on the modeling, geologic, well construction/well integrity, and hydrologic data, Scenario 2 is an unlikely explanation for organic constituent occurrence in the Rose Run Formation near the WDW No. 3 location. From a chemical mixing perspective, it is possible to derive fluid of similar composition to those at the WDW No. 3 location and there is some indication that natural Rose Run-Copper Ridge fluid flow may have occurred based on calculated Copper Ridge chemistries. However, in view of the available geologic information, fluid transport modeling and pressure build-up that could occur in such a system, Scenario 2 is not likely.

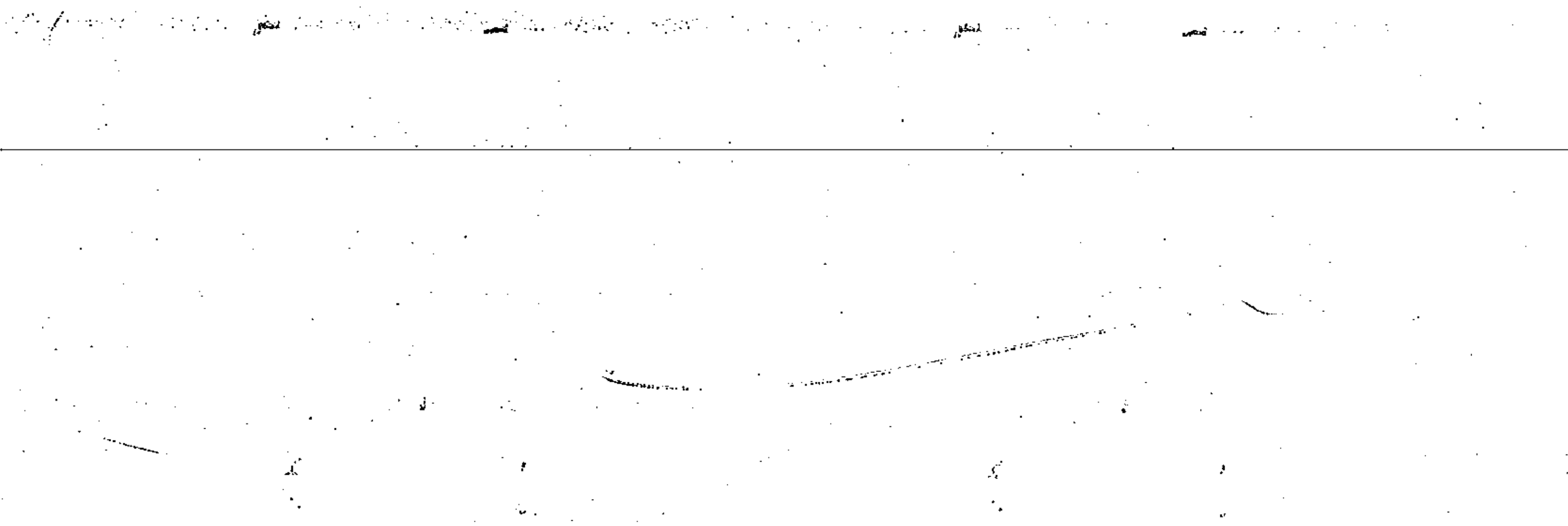
C.3 Scenario 3: Vertical Conduit Near WDW No. 3

Upward migration of fluid from the Mt. Simon to the Rose Run through a vertical fracture or open borehole localized near the bottomhole location of WDW No. 3 that allows for instantaneous interconnection between the Mt. Simon or Copper Ridge and Rose Run was also considered (Figure 12). However, this Scenario is slightly different from that presented in the Rose Run Interim Document (1990) because it also includes the consideration of a permeable zone (i.e., vugular intervals or localized microfracture system) that acts as a conduit between the Copper Ridge and Rose Run near WDW No. 3. This conduit has been hypothesized to have sufficient vertical permeability to allow for slower upward migration of fluids from the Copper Ridge to the Rose Run. Under this scenario, therefore, instantaneous interconnection between the Rose Run and Mt. Simon or Copper Ridge through a single fracture or borehole was considered, as well as a relatively slow leak from the Copper Ridge to the Rose Run (near WDW No. 3). Fluid transport and pressure modeling results, hydrogeologic conditions, hydrologic studies, and fluid chemistry were evaluated.

C.3.1 Fluid Transport and Pressure Rise Modeling Results

Simulation studies show that flow through a large, single open fracture or borehole directly connecting either the Mt. Simon and Rose Run or Copper Ridge and Rose Run near WDW No. 3 could occur with a nominal pressure rise in the Rose Run at WDW No. 3 and an even smaller pressure rise in the Rose Run at the Test/Monitoring Well. Therefore, fluid flow modeling cannot be used to rule out the occurrence of such a localized pathway existing near the WDW No. 3 location based on the available pressure and chemistry data.

Figure 12



If a leak from the Copper Ridge to the Rose Run is occurring close to the WDW No. 3 location, pressure at the leak entry into the Rose Run would be only marginally higher than that found at the WDW No. 3 intercept. However, it is important to note that neither this pressure rise nor the maximum pressure which can be present in the Copper Ridge (and be consistent with available data) is great enough to open or propagate fractures in the same manner as within the Copper Ridge at the WDW No. 1 or 2 wellbores. This would happen only if these pressures could overcome the minimum horizontal in-situ stresses measured at WDW No. 3, which are likely very similar to those determined by in-situ stress tests at the Test/Monitoring Well (600 psi). It is unlikely that the in-situ stresses at the WDW No. 3 intercept are significantly lower than those measured at the Test/Monitoring Well (approximately 1000' Southwest), since there is no direct evidence of significant structure (i.e., major structural flexure) or other geologic perturbations to account for such significant lateral variations in stress. It is also probable that any such localized vertical pathway would need to be relatively permeable (> 1 md) for the small pressure differentials between the Rose Run and Copper Ridge (less than 30 psi) to cause significant vertical fluid movement.

C.3.2 Geologic, Hydrogeologic, Borehole Identification Study Results

Geologic information shows that there is little likelihood for open fracture "plumbing systems" to be maintained that would allow immediate upward movement of fluid and "instantaneous" interconnection of the Mt. Simon and Rose Run or of the Copper Ridge and Rose Run near WDW No. 3. Although core analyses indicate that relatively discontinuous microfractures (both healed and unhealed) can occur, as stated in Scenario 2, there is no geologic evidence to suggest the presence of a large open fracture(s) that directly connects these formations. Seismic data support the contention that a large fault is not present within the assessed grid in the Haverhill area. Because it is assumed that the hypothetical fracture is close to WDW No. 3, the low natural fluid flow rate would not be a constraint in that fluids would not be required to move a great distance to the WDW No. 3 Rose Run location.

As stated under Scenario 2 discussions, the Harrison/Kroll investigation did not identify any boreholes within three to four miles of the Aristech Haverhill area. The magnetometer study performed at the Aristech Haverhill plant did not identify the presence of cased boreholes within the area of investigation. The exhaustive Area of Review exercise discussed under Scenario 2 also revealed no boreholes to the Rose Run within a four-mile radius of the Aristech Haverhill Plant.

Log and core analyses show that the interval between the Rose Run and this uppermost Copper Ridge porous bleed-off zone is comprised of shaley microcrystalline dolomites with little vugular development, and that it has a particularly low porosity above the uppermost Copper Ridge porous bleed-off zone (Figure 12, Appendix A-2). Log analyses for all wells at Haverhill confirm that this interval has relatively low porosity throughout the site (except near the Rose Run-Copper Ridge conformable contact), and likely has a low vertical permeability. Lateral facies variation to a more porous dolomite can occur in this interval beyond the general area of the injection wells, but it is not possible to determine where this hypothetical porous zone might develop based on log analyses. It is also possible that a small microfracture system completely restricted to this upper Copper Ridge-Rose Run interval is present somewhere near Haverhill, because these do occur in other natural settings. If such a system is present within the given interval, it is not evident in either the log or core analyses, and it is probably outside the area of the injection wells. To summarize, geologic data do not support the occurrence of large-scale open faults/fractures in the area, and there is no direct evidence that a localized permeable/porous zone is present between the Copper Ridge and Rose Run at WDW No. 3.

C.3.3 Fluid Chemistry

Under this scenario and assuming flow from the Mt. Simon to Rose Run, it is possible either that (1) 1989 Mt. Simon fluid entered the Rose Run and mixed with Rose Run fluid, or (2) that an average injectate/1968 Mt. Simon fluid mix entered the Rose Run and displaced (rather than mixed with) Rose Run fluid. Of these possibilities, the second is the more probable, based on the organic and inorganic chemistry (Table 9). This is supported by fluid chemistry composition, since the 1989 Rose Run does not contain all of the constituents present in 1989 Mt. Simon fluid, such as aniline.

The scenario also considers Copper Ridge-Rose Run interconnection. Calculations indicate that a mixture of 1991 Copper Ridge and 1968 Rose Run fluids could not create the 1989 WDW No. 3 Rose Run composition, but the 1989 Rose Run composition could be formed if a 1968 Copper Ridge injectate mixture displaced rather than mixed with the Rose Run. However, modeling studies and chemistry data indicate that relatively low volumes of injectate have entered the Copper Ridge. This implies that although it is possible to create 1989 Rose Run Chemistry through displacement by a 1968 (calculated) Copper Ridge fluid (Appendix M), it is not known whether the appropriate injectate volume would be present at WDW No. 3 in the Copper Ridge to create such a displacement mixture.

Calculated 1968 Copper Ridge chemistry at the Test/Monitoring Well is quite similar to 1991 Test/Monitoring Well-Rose Run chemistry, implying either similar evolutionary histories or natural interconnection between the two formations at this location (Appendix M). This potential interconnection at the Test/Monitoring Well therefore raises questions concerning the possibility of natural interconnection in other locations, such as the WDW No. 3 location.

To summarize, mixing data indicate that it is possible to create 1989 Rose Run fluid through displacement of the Rose Run fluid by a 1968 Copper Ridge/injectate mixture or a 1968 Mt. Simon fluid and injectate mixture. It is also possible that natural interconnection of the Rose Run and Copper Ridge occurs near the Test/Monitoring Well location, based on mixing calculations, and this relationship could also apply to the WDW No. 3 location. However, it is also quite possible that the apparent chemical similarities of the 1968 (calculated) Copper Ridge and 1968 and 1991 Rose Run chemistries are due to similar depositional/ evolutionary histories of the two formations, which is generally supported by geologic data (Appendices M and A2).

C.3.4 Conclusion

Scenario 3 cannot be ruled out based on available data. Fluid transport and pressure rise modeling cannot rule out this scenario, because the observed pressure rises are consistent with a localized interconnection near WDW No. 3, but these data can also be consistent if no interconnection occurs in the area. Interconnection of the Mt. Simon or Copper Ridge and Rose Run by a major fault or fracture system is not supported by geologic data. Although geologic data indicate that a Copper Ridge to Rose Run interconnection at WDW No. 3 is not likely, these data cannot confirm or deny the presence of such an interconnection outside of the immediate injection well area. No boreholes were found in the Haverhill area that could connect the Mt. Simon/Copper Ridge and Rose Run. Chemical mixing data indicate it is possible to produce 1989 Rose Run WDW No. 3 chemistry by mixing injectate and 1968 Rose Run waters, or by displacing the original Rose Run fluids with either a 1968 Mt. Simon and injectate mixture, or calculated 1968 Copper Ridge and injectate mixture. Mixing data also indicate that the calculated 1968 Copper Ridge at the Test/Monitoring Well and the 1991 Rose Run at the Test/Monitoring Well are quite similar, implying similar evolutionary histories or localized interconnection at this location (which could occur at other locations as well).

C.4 Scenario 4: Contamination by Drilling Fluids

Invasion of drilling fluid into surrounding formations can result in contamination of formation waters (Figure 13). However, chemical data indicate that drilling fluid used during installation of WDW No. 3 could not have caused the organic contamination apparent in WDW No. 3 Rose Run brines.

A variety of drilling additives were used during installation of WDW No. 3, including alpha-tetralone, glutaraldehyde, xanthan gum, modified starch, clay, ethyl cellulose, Poly-Plus™, Spersene™, Quick-Seal™, cottonseed hulls, and drilling paper. Small quantities of phenolic compounds may be present in these substances, but none contain free phenol. Analyses of

Figure 13

drilling muds used in WDW No. 3 indicate that the maximum phenol content never exceeded 10 ppm (total phenolic compound concentrations were higher; 16 ppm phenolics was reported in one WDW No. 3 mud sample). Furthermore, drilling fluid manufacturers indicate that the amount of free phenol within these additives is low (4 to 5 ppm). This information indicates that there is not enough phenol in drilling fluid to create the concentrations present in the WDW No. 3 Rose Run Formation waters. Also, the drilling fluids used in the drilling of WDW No. 3 do not contain the full range of constituents found in the 1989 Rose Run. Therefore, Scenario 4 is not a plausible explanation for organics in the Rose Run at WDW No. 3.

Drilling fluid likely affected formation fluid analyses in samples collected above the Rose Run (Appendix L). As discussed in Section III-D.2, formation fluid samples collected from WDW Nos. 1 and 3 in formations above the Rose Run were likely contaminated by drilling mud and/or potable water used during drilling, causing dilution of formation brines by adding fresh water and adding organics (i.e., phenol, BTX) to formation fluid samples. For example, a DST in the Berea was unsuccessful because of the low formation permeability, and formation fluid samples were then collected using a Repeat Formation Testing (RFT) tool. This tool collects a small volume of fluid from relatively close to the borehole, which was likely infiltrated by drilling fluid, and did not provide a sample of fluid from deeper portions of the formation (which would be more representative of actual formation fluid chemistry). As discussed in Section III, it is highly probable that the wide range of inorganic and organic species concentrations reported in chemical analyses of Berea fluids sampled in 1968 at WDW No. 1, in 1989 and WDW No. 3, and in 1991 at the Test/Monitoring Well, was caused either by secondary contamination (i.e., drilling fluid or laboratory artifact), or by naturally occurring substances. Considerable care was taken to avoid dilution of Berea formation fluid with drilling mud in the 1991 Test/Monitoring Well, and this Berea sample is likely very representative of Berea fluid with no drilling mud admix. The Berea in the Test/Monitoring Well had a TDS of 135,000 ppm. Figure 6 shows that based on TDS and other species concentrations, the 1968 and 1989 Berea samples have been contaminated by drilling fluid, and also shows that simple dilution of the 1991 Berea fluid could create the earlier Berea formation fluid sample chemistries.

C.5 Scenario 5: Third-Party Source

Injection of material into the Rose Run by a third party (Figure 14) is also a scenario that has been examined. This scenario was first posed because although the Rose Run fluids at WDW No. 3, Mt. Simon fluids, and injectate have some organic compounds in common, other compounds are unique to individual fluids (Table 16). The possibility of a third-party source has been investigated based on known disposal/manufacturing activities in the area, hydrogeologic study results, modeling of fluid transport and pressure, and injectate/formation fluid chemistries.

C.5.1 Possible Third-Party Sources: Harrison/Kroll Investigation

Compounds characteristic of phenol manufacturing processes have been found in both 1989 Rose Run and 1989 Mt. Simon waters samples collected from WDW No. 3. A number of processes other than the Aristech cumene/phenol/acetone process can be used to create phenol, some of which have been conducted at Ohio, West Virginia, and Kentucky facilities near the Aristech Haverhill facility (Appendix X). Harrison/Kroll (Appendix K) identified the presence of a number of wells in the general Haverhill area, with two of the wells drilled into Cambrian-age Rocks approximately four miles northeast of the Haverhill plant. Evidence gathered by Harrison/Kroll indicates that Dow Chemical may have drilled wells in the area to acquire and/or dispose of brines. One interviewee indicated that she thought wastes were disposed of in one of the wells, and that the well was only recently plugged. One well is referred to as the Albert Rase Well, approximately four miles from the Haverhill site, and apparently penetrated the Rose Run Formation. Interviews and other documentation indicate that the well remained open only one to two months, but liquid waste may have been hauled to the site while the well was open.

Figure 14

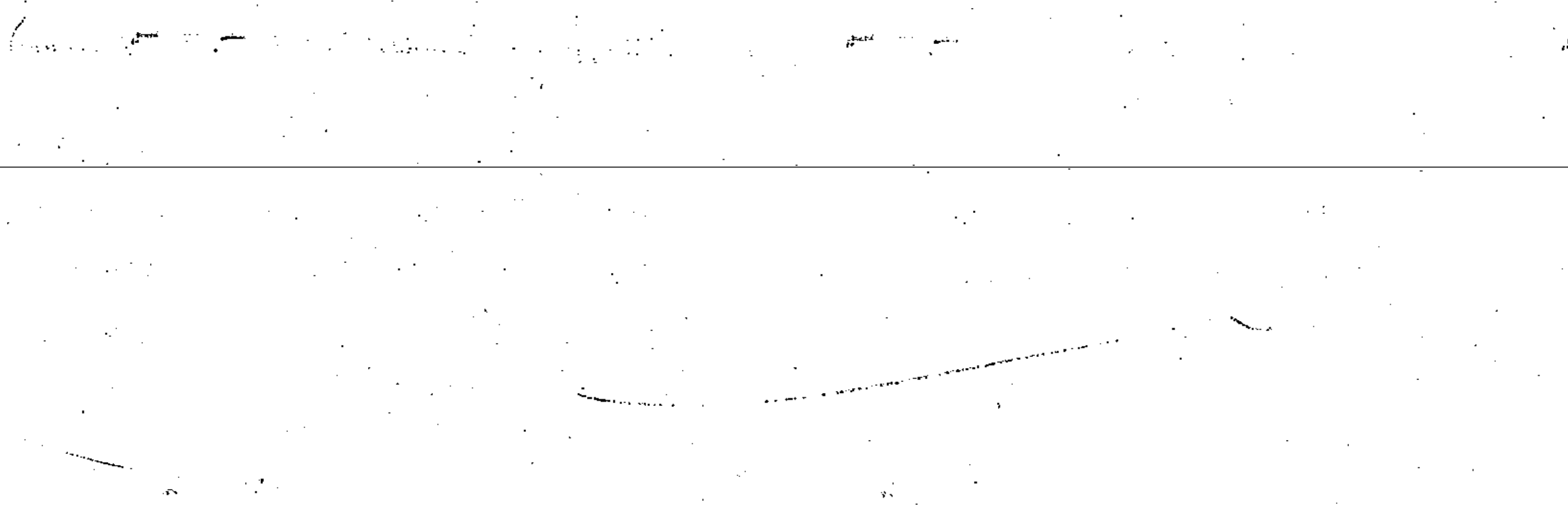


Table 16

Comparison of Constituents in 1989 WDW No. 3, and 1990 Test/Monitoring Well Samples

Units - ppm	Injectate Sampled 6/14/89	Injectate Sampled 11/20/89	WDW No. 3 Mt. Simon Fluid Sampled 9/22/89	WDW No. 3 Rose Run Fluid Sampled 6/14/89	Test/ Monitoring Well Copper Ridge Fluid Sampled 5/9/91	Test/ Monitoring Well Rose Run Fluid Sampled 4/25/91
Methylene Chloride	NA	ND	ND	1.7	15[4]	0.014[4]
Acetone	NA	600	1200	210	110[4]	0.034[4]
2-Butanone	NA	ND	5.4	3	ND	ND[5]
Benzene	NA	7.5	0.64	ND	ND	0.022*
4-Methyl-2-pentanone	NA	ND	0.37	ND	ND	ND[5]
2-Hexanone	NA	ND	0.27	ND	ND	ND[5]
Toluene	NA	16	10	ND	ND	0.006*
Ethylbenzene	1.1 (TIC)	ND	0.33	ND	ND	ND[5]
2-Propanol	NA	NI	0.18(TIC)	NI	NI	NI
3-Methyl-2-butanone	NA	NI	0.19(TIC)	NI	NI	NI
Methoxybenzene	NA	NI	0.21(TIC)	NI	NI	NI
alpha-Picoline	28	NI	13 J	ND	ND	ND
Aniline	18.8	NA	3.1 J	ND	ND	ND
Phenol	1300	250	940	400	240[2]	ND[6]

J - estimated value
NA - not analyzed (for)
NI - not identified, TIC
ND - analyzed for, but not detected
TIC - tentatively identified compound
* - concentration has been determined to be biased low
[1] - semi-volatile holding time exceeded by three days
[2] - biased high quantitative estimate
[4] - value invalid due to presence of compound in field blanks and associated method
[5] - volatile non-detects rejected due to presence of natural gas in formation
[6] - semi-volatile concentrations considered biased low quantitative estimates due to presence of natural gas in formation

Complete list of chemical data qualifiers included in Appendix B

Table 16 (Cont'd)

Comparison of Constituents in 1989 WDW No. 3, and 1990 Test/Monitoring Well Samples

Units - ppm	Injectate Sampled 6/14/89	Injectate Sampled 11/20/89	WDW No. 3 Mt. Simon Fluid Sampled 9/22/89	WDW No. 3 Rose Run Fluid Sampled 6/14/89	Test/ Monitoring Well Copper Ridge Fluid Sampled 5/9/91	Test/ Monitoring Well Rose Run Fluid Sampled 4/25/91
1,4-Dichlorobenzene	ND	4.2	ND	ND	ND	ND[6]
2-Methylphenol (o-cresol)	ND	ND	ND	0.22	0.160	ND[6]
4-Methylphenol (p-cresol)	ND	ND	ND	ND	0.065	ND[6]
Acetophenone	93.7	NA	35	6	2.70	ND
a,a-Dimethylbenzyl alcohol	270	NA	130	44	9.60	ND
Benzoic acid	8.6	ND	21	1.7	4.0 J	ND[6]
Bis(2-ethyl hexyl) phthalate	ND	ND	ND	ND	0.031[4]	ND[6]
2,2'-Methylene bisphenol	NI	NI	35(TIC)	7.2(TIC)	0.130(TIC)	NI
4,4'-Methylene bisphenol	NI	NI	36(TIC)	4.8(TIC)	2.90(TIC)	NI
2-Methylbenzofuran	1.2	NI	NI	NI	NI	NI

J - estimated value
NA - not analyzed (for)
NI - not identified, TIC
ND - analyzed for, but not detected
TIC - tentatively identified compound
* - concentration has been determined to be biased low
[1] - semi-volatile holding time exceeded by three days
[2] - biased high quantitative estimate
[4] - value invalid due to presence of compound in field blanks and associated method
[5] - volatile non-detects rejected due to presence of natural gas in formation
[6] - semi-volatile concentrations considered biased low quantitative estimates due to presence of natural gas in formation

Complete list of chemical data qualifiers included in Appendix B

Table 16 (Cont'd)

Comparison of Constituents in 1989 WDW No. 3, and 1990 Test/Monitoring Well Samples

Units - ppm	Injectate Sampled 6/14/89	Injectate Sampled 11/20/89	WDW No. 3 Mt. Simon Fluid Sampled 9/22/89	WDW No. 3 Rose Run Fluid Sampled 6/14/89	Test/ Monitoring Well Copper Ridge Fluid Sampled 5/9/91	Test/ Monitoring Well Rose Run Fluid Sampled 4/25/91
2,3-Dimethylphenol	2.2	NI	NI	NI	NI	NI
2-(1-Methylethyl) phenol	1.2	NI	NI	NI	NI	NI
4-(1-Methyl-1-phenylethyl) phenol (cumyl phenol)	26	NI	NI	NI	NI	NI
2-[1-(4-Hydroxyphenyl) 1-methyl-ethyl] phenol (o,p-BPA)	13	NI	NI	NI	NI	ND
Bisphenol A	NA	NA	NI	NA	0.840	ND
Cumene	22 (TIC)	NA	4.6 (TIC)	ND	ND	ND
Formic Acid (as Formate)	NA	NA	1370	168	ND	ND
Aluminum	0.8	0.3	2	ND	1.330[3]	ND
Barium	ND	ND	ND	1.8	3.810	4.71[7]
Calcium	21	38	2850	38500	35000	37000

J - estimated value
NA - not analyzed (for)
NI - not identified, TIC
ND - analyzed for, but not detected
TIC - tentatively identified compound
* - concentration has been determined to be biased low
[1] - semi-volatile holding time exceeded by three days
[2] - biased high quantitative estimate
[4] - value invalid due to presence of compound in field blanks and associated method
[5] - volatile non-detects rejected due to presence of natural gas in formation
[6] - semi-volatile concentrations considered biased low quantitative estimates due to presence of natural gas in formation

Complete list of chemical data qualifiers included in Appendix B

Table 16 (Cont'd)

Comparison of Constituents in 1989 WDW No. 3, and 1990 Test/Monitoring Well Samples

Units - ppm	Injectate Sampled 6/14/89	Injectate Sampled 11/20/89	WDW No. 3 Mt. Simon Fluid Sampled 9/22/89	WDW No. 3 Rose Run Fluid Sampled 6/14/89	Test/ Monitoring Well Copper Ridge Fluid Sampled 5/9/91	Test/ Monitoring Well Rose Run Fluid Sampled 4/25/91
Chromium	0.06*	0.05	ND	ND*	ND*	ND*
Iron	0.41	ND	15.7	60.8	409	171
Lead	ND	ND	0.03	ND	0.581	0.028 J
Magnesium	0.14	ND	424	6070	6190	7010
Manganese	ND	ND	0.4*	2.35	6.410	3.22
Potassium	17.1	10	421	3330	3610	3810
Sodium	5080	11000	14000	44600	48200	25500
pH	12.4	11.56	NA	5.76	NA	NA
Specific Gravity	1.01	NA	1.05	1.19	1.2 (NV)	1.215 (NV)
Ammonia (as Nitrogen)	NA	NA	409	80.5	73.1	70.0
Ammonia	NA	560	NA	NA	NA	NA
Bromide	ND	NA	200	1630	2090	2200
Chloride	2790	1900	21200	170000	208000	218000
Nitrate (as Nitrogen)	NA	NA	ND	220	ND	0.04

J - estimated value
NA - not analyzed (for)
NI - not identified, TIC
ND - analyzed for, but not detected
TIC - tentatively identified compound
* - concentration has been determined to be biased low
[1] - semi-volatile holding time exceeded by three days
[2] - biased high quantitative estimate
[4] - value invalid due to presence of compound in field blanks and associated method
[5] - volatile non-detects rejected due to presence of natural gas in formation
[6] - semi-volatile concentrations considered biased low quantitative estimates due to presence of natural gas in formation

Complete list of chemical data qualifiers included in Appendix B

Table 16 (Cont'd)

Comparison of Constituents in 1989 WDW No. 3, and 1990 Test/Monitoring Well Samples

Units - ppm	Injectate Sampled 6/14/89	Injectate Sampled 11/20/89	WDW No. 3 Mt. Simon Fluid Sampled 9/22/89	WDW No. 3 Rose Run Fluid Sampled 6/14/89	Test/ Monitoring Well Copper Ridge Fluid Sampled 5/9/91	Test/ Monitoring Well Rose Run Fluid Sampled 4/25/91
Sulfate	1790	14000	2490	330	229	ND
$CaCo_3$ Alkalinity	NA	NA	NA	NA	56.0	100
Silica	NA	NA	NA	NA	10.803	7.29^3
TSS	NA	NA	NA	NA	1680	1770
Iodide	NA	NA	NA	NA	NA	NA
TDS	NA	NA	48400	287000	293000	309000
Resistivity (or specific conductance) (77°F)	NA	NA	NA	NA	439 mmohs	495 mmohs
Carbon Dioxide	NA	NA	NA	NA	NA	NA

J - estimated value
NA - not analyzed (for)
NI - not identified, TIC
ND - analyzed for, but not detected
TIC - tentatively identified compound
* - concentration has been determined to be biased low
[1] - semi-volatile holding time exceeded by three days
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[4] - value invalid due to presence of compound in field blanks and associated method
[5] - volatile non-detects rejected due to presence of natural gas in formation
[6] - semi-volatile concentrations considered biased low quantitative estimates due to presence of natural gas in formation

Complete list of chemical data qualifiers included in Appendix B

However, the bulk of the data gathered by Harrison/Kroll indicate that other identified manufacturers in the Haverhill area did not use deep-well injection to dispose of wastes. Harrison/Kroll concluded that, despite the possible prior use of wells for injection of waste into the Rose Run in other locations as early as 35 years ago and the existence of phenol/ phenolic-based manufacturing facilities in the area, there is no confirmation that a third party injected any phenol/phenolic chemicals into the Rose Run or Mt. Simon Formations in the area around the Aristech facility. In fact, the closest wells of the appropriate depth are over four miles away from the Haverhill facility, and there is no conclusive information that these wells were used for waste disposal purposes.

C.5.2 Hydrogeologic Study and Fluid Transport Modeling Results

Current hydrogeologic conditions and fluid modeling do not support a third-party origin because: 1) even if an injection well is present and wastes were clandestinely dumped (or pumped for a limited time) down a borehole, it is highly unlikely that natural subsurface groundwater flow velocity is sufficient to have moved the relatively small plume of anthropogenic materials which could have been emplaced in the Rose Run from an unidentified borehole more than two miles away; 2) fluid transport modeling shows that in order for this scenario to be plausible a relatively high volume injection well in the Rose Run within two miles of the Haverhill facility must have been present--no such well has yet been found; and 3) enhanced fluid transport velocity due to phase separation, etc., would not be sufficient to support a third-party origin.

C.5.3 Fluid Chemistry

The concentration of inorganic constituents within the 1989 WDW No. 3 Rose Run fluid has remained relatively consistent since 1968, except for minor variations in most inorganic constituent concentrations. Mt. Simon fluids, however, have shown major reductions in the concentrations of most inorganic constituents between 1968 and 1989 due to mixing with injectate. Both Mt. Simon and Rose Run fluids contain anthropogenic organic compounds such as phenol, acetone, and acetophenone. However, analyses of Rose Run and Mt. Simon fluids have also detected aromatic ring compounds that could conceivably have originated from two different phenol processes. Compounds such as phenol, which is most commonly generated by the cleavage of cumene hydroperoxide, are characteristic of Aristech waste. Other compounds present in analyses of Rose Run fluid samples, such as 2,2- and 4,4-methylenebisphenols, are created by phenol formaldehyde processes and are not characteristic of wastes produced by processes at Haverhill.

Given the distinct organic and inorganic chemistries of WDW No. 3 Rose Run and Mt. Simon fluids, and the possibility that other manufacturing processes could create the same organic wastes, a "chemical profile" of a hypothetical waste can be created to account for the chemistries of WDW No. 3 Rose Run fluids. This hypothetical waste would have to have a relatively concentrated organic constituent content, acidic pH, high sulfate concentration, and essentially no capacity to dilute the natural Rose Run formation water. By adding a waste such as this to the Rose Run, it would be possible to create the observed conditions in the Rose Run at WDW No. 3 wherein pH is relatively neutral, organic constituents are present in relatively high concentrations, and the inorganic chemistry remains similar to 1968 Rose Run concentrations.

Although one can "build" an appropriate third-party case, the bulk of the chemical data indicate that the material in the WDW No. 3 Rose Run fluid was derived from Aristech injectate. For example, upon first comparison, it appears that the occurrence of 2,2- and 4,4-methylenebisphenols in the Mt. Simon and Rose Run, but not in the injectate, could be attributable to third-party influence. As stated in Section III, the likelihood that these compounds could be created via biodegradation is low. However, facility representatives indicate that formaldehyde has been present as an intermediate in the process and/or wastestream, and because of the presence of this compound in facility operations, it is possible that phenol-formaldehyde reactions creating these compounds occurred at the plant some time during the past.

Upon initial examination, it also appears that inorganic constituent concentrations within the Rose Run have not changed since 1968, but careful observation indicates that this is not the case. 1989 Rose Run fluids show minor alteration or dilution of inorganic constituent concentration relative to 1968 values, negating the necessity of a third-party source that would add organics without altering inorganic constituent concentration.

The variability in injectate concentration and minor constituent composition through time relative to organic and inorganic constituents adds uncertainty to any conclusions drawn from "known" injectate chemistry. Additionally, as discussed in previous sections and presented in Appendix M, mixing calculations indicate that the 1989 Rose Run Formation fluid chemistry at the WDW No. 3 intercept could be the result of a number of mixing combinations; hence, there is no reason to believe that a third party created the observed WDW No. 3 Rose Run fluid chemistries.

C.5.4 Conclusion

In summary, a third party source for constituents in the Copper Ridge and Rose Run is highly improbable. Although it is possible to construct a third-party source for some of the constituents within the Rose Run and Mt. Simon, the bulk of the evidence does not support this scenario. Numerous manufacturers that could have created some of the materials of interest were operational near the Aristech area during the relevant time period, and local residents and workers indicate that well disposal of wastes may have occurred in the area. However, no confirmation of local subsurface injection of these materials by a third party has been found. Hydrogeologic and fluid flow modeling indicate a low probability for this scenario, and chemistry mixing data indicate that fluids within the Rose Run at WDW No. 3 are most likely from Aristech injectate.

C.6 Scenario 6: Microfracture System

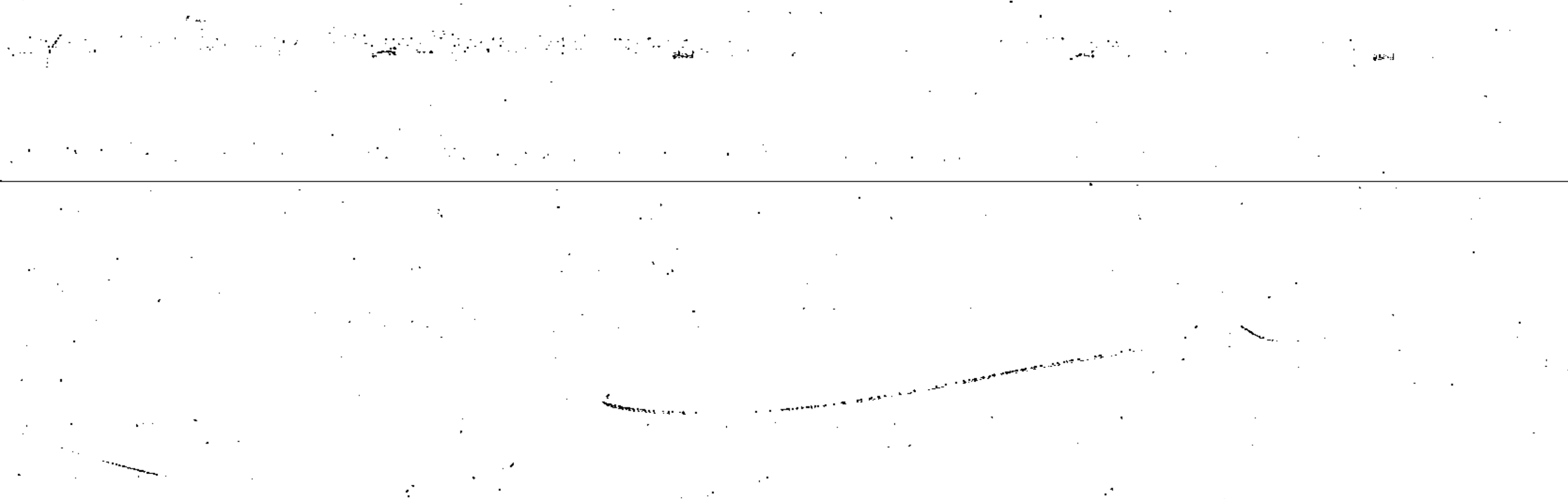
Although direct interconnection of the Rose Run, Copper Ridge, and Mt. Simon through a continuous open fracture(s)/fault has been ruled out, the possibility of relatively slower leakage of fluids upward through an extensive network of microfractures must be examined (Figure 15). This scenario is different from Scenario 3 because it assumes that instantaneous interconnection of fluids has not occurred, but instead slower migration in a microfracture system from the Mt. Simon to the Rose Run has taken place, allowing for fluid-rock interaction. It also assumes that this microfracture system locally extends from the Mt. Simon to the Rose Run near the WDW No. 3 intercept (Figure 15), hence explaining the lack of contamination at the Rose Run Test/Monitoring Well location.

C.6.1 Fluid Transport and Pressure Rise Modeling

If a naturally transmissive microfracture system is present, modeling results alone cannot be used to rule out the possibility of slow upward fluid movement through such a system of microfractures that is close to the downhole Rose Run location of WDW No. 3. As with Scenario 3, modeling indicates that only a low pressure rise would be evident in WDW No. 3 Rose Run if fluid moved slowly upward, and such pressure rise is apparent in WDW No. 3 Rose Run upon comparison of 1968, 1989, and 1991 pressure data.

Even if extensive microfractures are present, many formations throughout the country have naturally-occurring microfractures that normally exist in a totally closed configuration due to lithostatic or naturally occurring stresses. Modeling and core data indicate it is highly probable that the Mt. Simon and Lower Rome are naturally fractured at WDW No. 3 (injection-induced fractures do not extend to this location), and these fractures are closed, even during injection. The natural microfractures at WDW No. 3 can begin to open when the threshold pressure between 3200 psi and 3400 psi is reached (at a depth of 5416 feet below ground level [BGL]), which corresponds to a fracture opening pressure gradient between 0.59 psi/foot and 0.63 psi/foot. This gradient has been confirmed through step-rate

Figure 15



testing performed in March 1991 (Appendix G4). (The step rate test data collected at WDW 3 indicates fracture opening at a gradient of ≈0.59-0.63 psi/foot, which is consistent with data observed in the Mt. Simon at WDW Nos. 1 and 2 and implies that stresses in the Mt. Simon in all three wells are similar.) Above this gradient range, pre-existing natural fractures will open in the Mt. Simon.

Based on these data, pressure rise in the Mt. Simon at WDW No. 3 has not reached the requisite 600 psi above original formation pressure that is required to open such fractures in the Mt. Simon. Furthermore, a pressure rise of at least 800 to 900 psi would be required to open fractures in the overlying Rome Formation. Data, therefore, indicate that the natural fractures in the Mt. Simon at WDW No. 3 are currently closed, even with ongoing injection.

This microfracture network is not apparent in WDW No. 3 core above the Lower Rome, but even if a microfracture network occurs in the vicinity of WDW No. 3 from the Rome to the Rose Run, it is highly likely that native horizontal in-situ stresses present in the subsurface at WDW No. 3 would be sufficient to close the fractures. Even if it is assumed that an extensive microfracture system is present and open (particularly near WDW No. 3), the rock column would have to be under stress conditions that are significantly different from those measured in the Test/Monitoring Well, and there is no evidence to suggest that in-situ stresses in the formation are significantly different from the Test/Monitoring Well to WDW No. 3. Therefore, unless major differences in formation stress characteristics are present between the Test/Monitoring Well and WDW No. 3 due to features such as previously unidentified flexure or fold, it is unlikely that a hypothetical microfracture system is present in an open configuration that could provide a transmissive pathway from the Mt. Simon to the Rose Run.

C.6.2 Geological and Geophysical Evidence

Geological and geophysical data show that no large-scale faulting is present in the Aristech area. Comparison of seismic and surface lineament data indicate that there is no direct correspondence between surface lineaments and identified subsurface faults at or immediately near the Haverhill plant. Envirocorp (Appendix F) concluded that a general lineament trend to the north-northwest was apparent in the Haverhill area, and stated "the surface evidence of common, non-random linear trends suggests the presence of fractures in the sedimentary section." However, it is probable that many surface lineaments do not necessarily indicate microfracturing in the subsurface, but instead correspond to bedrock outcrop, etc. Seismic data has a vertical resolution of approximately 30 feet, and therefore may not detect microfracture zones. Based on the above evidence, the occurrence of microfractures in the general Haverhill area cannot be ruled out based on seismic and lineament evidence, although seismic data confirmed the laterally continuous nature of beds within the area and did not identify any major disruptions.

Core data from the Test/Monitoring Well indicate that some healed fractures are present in the subsurface. However, almost all of the cored intervals in the Test/Monitoring Well were relatively unfractured, even to within approximately 70 feet of the Mt. Simon formation. Core examined at WDW No. 1 indicate that extensive microfractures were not naturally present in the Rose Run, Rome, and Mt. Simon Formations at this specific location, although fracture records are ambiguous concerning the possibility of fractures in the general vicinity of WDW No. 1. The Mt. Simon and Lower Rome were fractured at WDW No. 3, as evidenced by core data from these intervals, but the Upper Rome at WDW No. 3 was not extensively fractured. Geophysical log analyses tend to confirm core data, although the resolution of geophysical logs relative to microfracture detection is limited and based on the type of log. Therefore, the core data provide strong evidence that the rock column at Haverhill is not extensively and universally fractured above the Mt. Simon such that fluids could everywhere exit the Mt. Simon and flow upward toward the Rose Run Formation.

If a microfracture system was present that allowed upward migration of liquids, the fluid migration rates would be relatively slow (when compared to some aspects of Scenarios 2 and 3), allowing for fluid-rock interaction. Also, the microfracture pathway must also be in relatively close proximity to the WDW No. 3 Rose Run intercept, because natural groundwater flow velocities within the Rose Run are likely so slow that lateral migration of fluids due to natural groundwater movement in the Rose Run would likely be minimal.

In conclusion, core data do not support this scenario, although WDW No. 3 core in the Mt. Simon and Lower Rome was naturally fractured. However, for this scenario to be plausible the microfracture system would <u>not</u> be present near the Test/Monitoring Well, which is confirmed by core data and inferred by Rose Run Formation fluid sample analyses.

C.6.3 Fluid Chemistry and Fluid Mixing

Mixing calculations indicate that fluid present at the WDW No. 3 Rose Run intercept could not be the result of mixing of 1989 Mt. Simon fluids with 1968 Rose Run fluids. However, mixing calculations (based on comparison of a limited number of constituents) indicate that if a mixture of an average injectate/1968 Mt. Simon fluids moved up a microfracture system and displaced rather than mixed with 1968 Rose Run fluids, this could also produce the observed WDW No. 3 Rose Run fluid chemistry. Displacement or mixing of Copper Ridge injectate combinations were not considered under this scenario.

1989 Rose Run fluids did not contain aniline, which was added to injectate in 1981. Because this constituent is not present in 1989 Rose Run fluid this can be used in support of slow upward-migration of fluids through a microfracture system. However, dilution and injectate compositional variations could account for this discrepancy, and therefore fluid composition does not confirm or refute this scenario.

C.6.4 Conclusion

Geologic core data indicate that only WDW No. 3 Mt. Simon was fractured at the time of drilling, and formations above the Mt. Simon at WDW Nos. 1, and 3, and the Test/Monitoring Well do not show development of pervasive microfracture systems. Geophysical data indicate that strata in the area are continuous with no major disruptions visible within the resolution of the seismic data, but can neither confirm nor refute the occurrence of microfracture systems that may be undetectable because of the 30-foot resolution limit of the seismic data.

Stress test data indicate the regional horizontal stresses are sufficient to close natural microfractures, particularly near WDW No. 3. Also, there is no evidence that sufficient injection-related pressure rise has occurred in a regional perspective to open fractures, especially near WDW No. 3. Modeling of pressure rise and flow transport data can neither confirm nor deny the scenario if a naturally transmissive pervasive microfracture system is assumed to exist (contrary to stress test and geologic evidence). Chemistry data indicate that Rose Run Chemistry could be the result of displacement of Rose Run fluids by Mt. Simon-injectate mixtures.

No data absolutely confirm that this scenario is possible, and other recently acquired Test/Monitoring Well data indicate that the scenario is unlikely. Therefore, because of the new Test/Monitoring Well data relative to site geology, the scenario is unlikely.

C.7 Scenario 7: Incorrect Sampling of the Rose Run Formation at WDW No. 3

The formation fluid chemistries in the Rose Run at WDW No. 3 and the Copper Ridge at the Test/Monitoring Well indicate that both formations contain injectate in various percentages. The question then arises whether the sampled interval in WDW No. 3 at the Rose Run horizon was correct (Figure 16).

Figure 16

The Rose Run was sampled twice during drilling of WDW No. 3: once during the drilling process before the Copper Ridge was drilled into, and once (via straddle pack test) after the Copper Ridge was encountered. If an error was made concerning drilling depth when the first Rose Run sample was collected, it is possible that this sample could have been taken from a deeper formation, such as the Copper Ridge. Available data indicate that the sampled interval was correct, and that the Copper Ridge was not sampled at WDW No. 3. Daily drilling records and personnel on-site during drilling of WDW No. 3 indicate that no errors were made (i.e., during pipe tally) to such a degree that an interval approximately 200 feet below the Rose Run was accidentally sampled.

Scenario 7 is not plausible because available data indicate that the Rose Run, not Copper Ridge, was sampled in WDW No. 3.

P1-91
002636
Box 34
CITED

DGS CORE # 3248

APPENDIX 6.3-L

TERRATEK PETROGRAPHIC STUDY OF THE CORED INTERVAL

5915 FEET - 6109 FEET

PETROGRAPHIC ANALYSIS OF THE MOUNT SIMON FORMATION FROM

ARISTECH CHEMICAL CORPORATION'S

WASTE DISPOSAL WELL, #3
SCIOTO COUNTY, OHIO

PREPARED FOR

ENVIROCORP SERVICE & TECHNOLOGY, INC.
7020 PORT WEST DRIVE, SUITE 100
HOUSTON, TEXAS 77024

PREPARED BY:

PETROGRAPHIC SERVICES GROUP
TERRA TEK GEOSCIENCE SERVICES
360 WAKARA WAY
SALT LAKE CITY, UTAH 84108

FEBRUARY 1990
TTGS FILE NO. 5398

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SUMMARY

Petrographic analysis and a lithologic description were performed on core material from the Cambrian Mount Simon Formation and the underlying granitic basement from Aristech Chemical Corporation's Waste Disposal Well #3, Scioto County, Ohio. Petrographic analysis consisting of thin section microscopy, X-ray diffraction, and scanning electron microscopy was performed on 23 samples. The cored interval between 5915' - 6109' can be divided into three lithofacies: (1) a dolomite facies from 5915' to 6010', (2) a sandstone facies from 6010' to 6079', and (3) granitic rocks from 6079' to 6109'. Ten samples were analyzed from the sandstone and dolomite facies and three specimens were selected from the granitic basement.

The dolomite facies is dominated by sandy dolomite but also includes dolomitized oolitic and stromatolite lithologies. Matrix porosity within the dolomite facies is generally poorly developed. Individual dissolution pores are scattered and appear isolated. Late stage dolomite and anhydrite infill or line many pores. Isolated dissolution porosity within potassium feldspars is present in sandy dolomite samples. Naturally occurring fractures are present throughout most of this facies (see lithologic description for fracture distribution). Some natural fractures are mineralized or partially mineralized, but significant porosity and <u>permeability</u> are associated with fractures. Routine analysis of full diameter samples indicated fracture permeabilities of up to 600 md, whereas matrix permeability is generally less than 0.2 md.

The sandstone facies is characterized by fine to medium grained arkose and subarkose. Median grain size ranges from 1.32 to 3.27 phi, and grain size generally decreases with depth. Composition is also related to grain size; the two coarser grained samples plot in the subarkose field of a Folk (1974) classification diagram. Grains are typically rounded to subangular with finer grains, which are commonly potassium feldspar, showing the greatest angularity. Sorting ranges from well sorted to moderately sorted. Several samples exhibit a bimodal grain size distribution which

tends to decrease sorting. The effects of compaction are variable, even within an individual sample.

Grain coating/pore-lining clays are dominated by chlorite and mixed-layer chlorite-smectite. SEM analysis suggests that grain coating chlorite precipitated early and has partially inhibited the precipitation of authigenic silica and potassium feldspar overgrowths.

A variety of different cements is present within these sandstones. These cements include: silica, potassium feldspar, anhydrite, and dolomite. Minor amounts of calcite were also observed. The abundance of dissolution porosity suggests that pore-filling and grain replacing calcite was once much more widespread, but has since been dissolved.

Porosity and permeability are best developed in a zone from 6021' to 6043'. Porosity here reflects a combination of secondary intergranular and intragranular porosity. Many of the potassium feldspars show severe dissolution. Large holes within grains are common as are "moldic" pores formed by complete grain dissolution. Matrix permeability is in the 1 to 10 md range. At least two different generations of fractures are present: an early gouge filled set, and a later partially mineralized fracture set. The latter fracture set will provide significant fracture permeability.

The three granitic samples 6081, 6090, and 6103, are medium- to coarsely-crystalline perthite granites anhedral-crystalline-textured aggregated dominated by perthite but also composed of quartz, orthoclase albite or oligoclase, various mafic minerals, and trace to minor amounts off magnetite/ilmenite, apatite, and zircon. The samples are texturally similar, but two (6081 and 6090) are intensely altered, veined, and perhaps weathered such that all original mafic minerals and most primary plagioclase have been converted to secondary phases. The relatively fresh sample, 6103, contains both primary clinopyroxene and hornblende. Chlorite and mixed-layer chlorite/smectite (identified by XRD) are the principal alteration phases in all three granite samples.

None of the three granites is particularly porous (maxium est. 0.7%)--in the case of 6103 because of its relatively pristine condition, and in the case of 6081 and 6090 because of intense alteration and veining which sealed most fracture porosity. In all three rocks however, minor porosity occurs as: (1) intercrystalline vugs, most commonly in association with diseminated magnetite/ilmenite grains and grain aggregates; (2) open, late-stage microfractures which both follow and cross-cut older veinlets; these conceivably could have been induced by the drilling process; (3) irregularly distributed microporosity in chlorite-chlorite/smectite aggregates as well as within most microveinlets.

INTRODUCTION

Petrographic analysis consisting of thin section microscopy, X-ray diffraction, and scanning electron microscopy was performed on twenty-three samples of the Mount Simon Formation and of the underlying Precambrian Granite from Aristech Chemical Corporation's waste disposal well #3, Scioto County, Ohio. A lithologic description was also performed on the 158 ft. of core recovered from this well. Petrographic sample depths and the specific analyses performed on each sample are listed in Table 1.

Table 1

Sample Analyzed

Depth	Thin Section	Bulk XRD	Clay XRD	SEM
5920	X	X		
5928	X	X		X
5933	X	X		X
5935	X	X	X	
5976	X	X		X
5988	X	X		X
5997	X	X		X
6001	X	X	X	X
6007	X	X		
6013	X	X	X	X
6019	X	X	X	X
6025	X	X	X	X
6029	X	X	X	X
6034	X	X	X	X
6039	X	X	X	X
6044	X	X	X	X
6051	X	X	X	X
6060	X	X	X	
6069	X	X	X	X
6074	X	X		
6081	X	X		
6090	X	X		
6103	X	X		

Terratek, 1990, well #3

Diagenesis

The following diagenetic sequence is envisioned for the Sandstone Facies.

1. Deposition of sand and minor clay in a shallow marine setting.
2. Bioturbation, especially in clay rich laminae.
3. Precipitation of grain-coating chlorite.
4. Compaction.
5. Precipitation of silica and potassium feldspar cement on framework grains.
6. Precipitation of pore-filling calcite cement along with calcite replacement of potassium feldspars.
7. Continued physical and chemical compaction resulting in stylolite formation.
8. Formation of gouge filled fractures.
9. Dissolution of calcite resulting in varying amounts of secondary porosity.
10. Dolomitization of remaining calcite and dolomite replacement of clastic grains.
11. Second fracturing event.
12. Precipitation of mixed-layer chlorite-smectite.
13. Precipitation of pore-filling ankerite.
14. Precipitation of minor fracture-filling calcite and dolomite.
15. Precipitation of pyrite.
16. Precipitation of pore-filling anhydrite.
17. Precipitation of other minor fracture filling chlorite.

Terratek, 1990, well #3

Diagenesis

The following generalized diagenetic sequence is envisioned for the dolomite facies:

1. Deposition of carbonate and clastic grains along with varying amounts of lime mud in a shallow marine setting.
2. Compaction.
3. Precipitation of pore-filling calcite cement.
4. Dolomitization.
5. Dissolution and the formation of secondary porosity.
6. Fracturing and stylolite formation (mineralized fracture set).
7. Precipitation of pore/fracture filling dolomite.
8. Precipitation of pore/fracture filling ankerite.
9. Pyrite precipitation.
10. Precipitation of pore/fracture filling anhydrite.
11. Fracturing (partially open fracture set).
12. Precipitation of minor pore-lining clays.

APPENDIX 7
Kentucky Workgroup for Legal Issues Of Carbon Sequestration

Smith Management Group

SMG

Sustainability
Safety/Industrial Hygiene
.formation Technology
Environmental Management

January 8, 2010

Dr. Len Peters
Secretary
Energy and Environment Cabinet
12th Floor, Capital Plaza Tower

Frankfort, KY

Re: Legal Issues of Carbon Sequestration

Dear Secretary Peters:

I am please to present to you the report of the Workgroup that has examined Legal Issues of Carbon Sequestration during the past fifteen months. This report represents hundreds of hours of research, discussion, negotiation, writing and review by the more than ninety participants in the Workgroup, listed in an attachment to the report. This large group also represents a wide range of stakeholders in the developing issues, including without limitation, regulatory personnel, utilities, scientists, natural resource developers and environmentalists. We are providing this report to you in the hopes you will share it with Governor Beshear and the Kentucky Legislature, as appropriate

The Workgroup was conceived during the Governor's Conference on the Environment in September 2008 through an open discussion about the importance of reaching a consensus on the path Kentucky should take in addressing the legal issues inherent in the storage of carbon dioxide. During the following year, the group met officially four times to review and discuss information, research and developments in other states and countries. In addition to the group meetings, many of the Workgroup participants continued the conversation among themselves. This report represents the consensus of the Workgroup, as documented by the meeting minutes included with the report.

The report has been reviewed thoroughly by a number of Workgroup participants and every member of the Workgroup has been asked to review and comment on the report. The report reflects comments received through this date.

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I believe this report provides challenges to our leaders and describes avenues available to Kentucky to move forward to prepare for the constraints on the use of fossil fuels that we believe are imminent.

I appreciate the strong support and assistance your Cabinet has provided in this process. I believe I speak for each of the members of the Workgroup when I offer our continuing assistance in solving the difficult problems that lie in front of us.

Please let me know how I can help move these issues forward.

Respectfully,

Sara G. Smith
President
SMITH MANAGEMENT GROUP
Saras@smithmanage.com
859-231-8936 ext. 105

enclosure

EXECUTIVE SUMMARY

EXECUTIVE SUMMARY

In October 2008, an *ad hoc* group interested in studying the legal issues inherent in geologic storage of carbon dioxide formed during a session at the Governor's Conference on the Environment. Over the next twelve months, the group met a total of four times, moving through discussions of property rights, competing interests and developments in the science of carbon dioxide storage. The group monitored the changing legal scene as states began to wrestle with these legal issues and trends began to take shape on both the national and international stage.

It was decided, early in the process, that the work group could not address all questions effectively. Specific issues were identified for focus:

- What is "pore space" in Kentucky and where does ownership of pore space lie?
- Where should the liability (short-, mid- and long-term) lie for carbon dioxide storage?
- What agency or entity should regulate the storage of carbon dioxide?

Numerous other questions were discussed, some corollary to these central issues. Over the period of the four meetings, the work group reached consensus on the findings and recommendations presented in this report.

In summary, the Work Group for Legal Issues of Carbon Storage reached the following conclusions by consensus:

- The regulation of the capture, transportation and geologic storage of carbon dioxide should be housed in the Kentucky Division of Oil & Gas Conservation as it has the most experience with the physical aspects of the process. Oversight of the development and use of the injection well(s) should be coordinated under the Safe Drinking Water Act Underground Injection Control Program with either EPA Region IV or within the agency in the event that the state receives approval for a state UIC program for Class VI wells.

- The pore space is that space within the strata in which the carbon dioxide will be stored. As such, ownership of the pore space will depend on existing ownership of the real property. If the property is owned in fee, the surface owner is the owner of the pore space. If the mineral estate has been severed by a lease or deed, the language of the instrument and rules of instrument construction will determine the issue.

- Geologic storage will, of necessity, rely on the ability to use the storage strata in a significant area of adjoining properties. Kentucky may provide for access to the pore space in several ways. The first would be by operation of an existing public utility, regulated by the Public Service Commission, with the right of eminent domain. Second, pooling or unitization rules should be developed to allow a private entity to operate a storage site through leasing analogous to present day natural gas development. Finally, when the options above are not feasible, the right of eminent domain for the purpose of carbon dioxide storage should be available, similar to the rights granted to common carrier pipelines. Alternatively, the possibility of creating a new class of utility to provide carbon dioxide storage, to be regulated by the Public Service Commission, should be explored.

- Liability for the storage should remain with the operator of the storage facility during storage and the initial period after closure. Long-term liability should transfer to the state or federal government following that closure period under conditions sufficient to assure that the cost of the long-term monitoring and remedial actions are adequately funded by the generators of the CO_2.

- In order to manage the long-term liability and monitoring, a non-profit quasi-governmental entity should be formed. The entity would be funded by a fee per ton stored. The funding for this entity would not be subject to attachment or transfer to the General Fund.

INTRODUCTION

Comprehensive climate-change legislation remains viable within the United States Congress. H.R. 2454 (“Waxman-Markey”) passed the House of Representatives in June. In September 2009, S. 1733 (“Boxer-Kerry”) was introduced. Following committee discussion, it was reported out of the Environment and Public Works Committee on November 5, 2009.

Both bills rely upon a “cap and trade” mechanism to restrain carbon dioxide (CO_2 or “carbon”) output in future years. The concept is to place a “cap” upon the upper limit of carbon emissions within the United States. S. 1733 - the more ambitious proposal - envisions a 20 percent reduction in carbon emissions by 2020 and an 80 percent reduction from 2005 levels by 2050. With established limits, carbon emitters will then have the opportunity to “trade” carbon allowances. For example, where it is not feasible for a facility or company to meet their targeted carbon reductions, they will be able to purchase emission credits from others that have reduced their carbon output below target. The goal is to reduce total carbon emissions within the United States while creating a quasi-market mechanism to sort out how to get there.

Hanging over the congressional debate is the Environmental Protection Agency’s stated intention to proceed with developing greenhouse gas emission regulations, whether authorized by Congress or not. The agency is basing its authority to move ahead upon a United States Supreme Court decision[1] that ruled greenhouse gas emissions are pollutants that fall within the EPA’s authority under the Clean Air Act. In April 2009, the EPA initialized the process by issuing a proposed rule (an “endangerment finding”) that could ultimately result in agency regulation of carbon dioxide and other greenhouse gases.[2] The proposed endangerment finding was sent to the White House on November 6, 2009 and on December 7, 2009, EPA Administrator announced the final endangerment finding.

The recent final rule for inventory and reporting of greenhouse gas emissions and the proposed rule to regulate greenhouse gases are intended to target only “large facilities” – those that emit more than 25,000 tons of greenhouse gases a year. The EPA has stated that this rule would “cover nearly 70 percent of the national GHG emissions that come from stationary sources, including those from the nation’s largest emitters—including power plants, refineries, and cement production facilities.”[3]

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[1] Massachusetts et al. v. EPA. Case No. 05-1120. April 2007.

[2] 40 CFR Chapter 1 – “Proposed Endangerment Finding and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act; Proposed Rule.” *Federal Register – April 24, 2009*.

[3] “Fact Sheet –Proposed Rule: Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule.” U.S. Environmental Protection Agency. www.epa.gov

The legislative and regulatory proposals are not free from controversy. Opponents of climate-change legislation maintain that the cap-and-trade policy will impose significant costs upon the American consumer and industry. An analysis conducted by the United States Treasury concluded that "economic costs (of cap and trade) will likely be on the order of 1% of GDP, making them equal in scale to all existing environmental regulation."[4] News reports of this Treasury study translated those findings as "a cap and trade law would cost American taxpayers up to $200 billion a year, the equivalent of hiking personal income taxes by about 15 percent."[5]

Proponents of climate-change legislation argue that a significant portion of the allowances are directed toward ensuring that costs borne by consumers are mitigated[6] and that the costs of inaction far exceed the cost of the anticipated policy prescriptions.

A 2007 United Nation's study concluded that the global cost of adapting to climate change would range from $47-117 billion annually by 2030.[7] A recent study concluded that the costs anticipated by the 2007 UN study may have been underestimated by nearly 2-3 times.[8]

Notwithstanding the different points of view, action on climate change in the United States Congress is a possibility, action by EPA is occurring and litigation by numerous parties is a certainty. When legislation and/or regulations are enacted, there will be wide-ranging implications for the Commonwealth of Kentucky.

In preparation for the potential legislative and regulatory action, a workgroup was formed to examine the legal aspects of one potential mitigation approach: carbon capture and geologic storage (CCS). The work group was initiated during a session at the 2008 Governor's Conference on the Environment, during which an overview of legal questions associated with carbon storage was presented All interested parties were invited to participate in ongoing discussions to examine issues, potential solutions and develop recommendations on the path Kentucky should take in addressing CCS. Four meetings[9] were held throughout 2008 and 2009 and included stakeholders from legal, utility, coal, oil & gas, regulatory, environmental and scientific communities. Minutes from those meetings and lists of participants are found in the Appendices to this report. This report addresses the findings of that workgroup, and provides

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[4] United States Department of Treasury. Response to FOIA No. 2009-04-09.

[5] CBS News – Declan McCullagh – Taking Liberties Blog Post. 9/15/2009.

[6] "Analysis of H.R. 2454, the American Clean Energy and Security Act." National Resources Defense Council

[7] United Nations Framework Convention on Climate Change.

[8] "Assessing the Costs of Adaptation to Climate Change." Grantham Institute for Climate Change – Imperial College, London England. Aug. 2009.

[9] Governor's Conference on the Environment October 7, 2008; December 1, 2008, KGS Core Barn; February 13, 2009, Capitol Annex; July 20, 2009, KHEAA Building

consensus recommendations for steps Kentucky can take to prepare for implementation of carbon constraints.

Numerous reports and studies that have been helpful to the deliberations of the work group have been appended to or referenced within this report.

Impact on Kentucky

In a recent statement, Governor Beshear said, "Obviously we all agree on the goals of trying to approach this climate-change issue -- that's cleaning up our air and holding down greenhouse-gas emissions. The issues that we're wrestling with are in the details of how we do that, the cost of doing it and how those costs are distributed."[10]

Climate change legislation presents serious challenges for states that significantly utilize coal-fired generation for electricity, and those that have significant manufacturing and large agricultural sectors. Kentucky has all three – though efforts are being made in the climate legislation to mitigate the impact on small manufacturers, and to employ the agricultural sector as a partial solution to greenhouse gas emissions by creating carbon offsets for sale.

According to the Energy Information Administration[11], in 2007 coal provided the energy source for 93.1 percent of Kentucky's electricity generation. This compared with a national average of 48.5 percent. Hydroelectric and natural gas combined for a total of 3.5 percent. Biomass and wood derived fuels combined for less than 0.5 percent.

In 2007, Kentucky's average price for electricity (measured in "cents per kilowatt hour") remained very favorable when compared to the national average and our surrounding states.

West Virginia	5.34¢
Kentucky	5.84¢
Indiana	6.50¢
Missouri	6.56¢
Tennessee	7.07¢
Virginia	7.12¢
Ohio	7.91¢
Illinois	8.46¢

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[10] Richmond Times-Dispatch. August 23, 2009.

[11] Energy Information Administration. *State Historical Tables for 2007.* Jan. 29, 2009.

United States Avg. 9.13¢

Kentucky's industrial price for electricity remains one of our key competitive advantages in economic development – coming in at 4.47 cents per kilowatt hour as compared to the national average of 6.39 cents per kilowatt hour.

Low electricity rates are likely a strong contributing factor to the fact that Kentucky's economy retains a large manufacturing sector relative to the national average[12]. In 2008, manufacturing made up 11 percent of United States economic output. In Kentucky, that figure was 18.4 percent. Manufacturing contributed $15.8 billion to Kentucky employee compensation in 2008, 17.8 percent of the state's total.

As might be expected, the National Association of Manufacturers (NAM), an industry trade association, is opposed to the current climate change legislation before Congress. A recent study[13] by NAM concluded that Waxman-Markey would result in a loss of 25,000–35,000 jobs in Kentucky by 2030 if Waxman-Markey becomes law.

It is reasonable to expect that as energy prices increase significantly, as they are projected to do with carbon constraints, much of Kentucky's industry or potential industry will locate elsewhere. Kentucky is the country's leading primary aluminum smelter, measured by the value of shipments, and is home to 16% of active smelter capacity in the U.S.[14] Kentucky ranks in the top group of the country's steel production, with 54 manufacturing facilities.[15] Kentucky is also home to significant petroleum refining capacity and, in 2008, Kentucky's auto industry related employment was third highest in the nation[16]. Following any significant increases in electrical power cost we can expect that some of the existing industry will relocate, and expansions will be located elsewhere.

Proponents of climate legislation counter that federal policies will stimulate the growth of "green collar" jobs. According to the Pew Charitable Trusts, in 2007 Kentucky had 9,300 "clean jobs" representing a growth rate of 10 percent since 1998.[17] The Pew Report defines "clean jobs" as those in the following five sectors, not all of which are related to energy issues:

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[12] Source: Bureau of Economic Analysis. www.bea.gov

[13] "Economic Impact of the Waxman-Markey American Clean Energy and Security Act." American Council for Capital Formation & the National Association of Manufactures. Aug. 12, 2009.

[14] "Profile of Kentucky's Aluminum Industry", October 2009, Kentucky Cabinet for Economic Development

[15] "Profile of Kentucky's Steel Industry", August 2009, Kentucky Cabinet for Economic Development

[16] "The Automobile Industry in Kentucky", October 2009, Kentucky Cabinet for Economic Development

[17] "The Clean Energy Economy – Repowering Jobs, Business and Investments Across America." Pew Charitable Trusts. June 2009.

(1) Clean Energy, (2) Energy Efficiency, (3) Environmentally Friendly Production, (4) Conservation and Pollution Mitigation, and (5) Training and Support.

One final consideration on the jobs issue, in 2006 coal mining directly employed over 17,600 Kentuckians. The average weekly wage for those jobs was $1,126.[18] A recent evaluation[19] by the National Mining Association proposed that Waxman-Markey, if enacted, would lead to the loss of a minimum of 14,700 coal jobs nationwide by 2020. The study further suggested that at least 2,900 coal jobs would be lost in the Illinois basin (which includes western Kentucky) and 3,100 in the central Appalachian region (which includes eastern Kentucky) by 2020 if Waxman-Markey becomes law. Based on an economic study published by the Kentucky Cabinet for Economic Development[20], the regional impact of these job losses will be in excess of $1.770 billion.

There are costs which will be realized by inaction. The United States Climate Action Partnership, a group of businesses and environmental organizations, in its Call to Action stated:

> *Each year we delay action to control emissions increases the risk of unavoidable consequences that could necessitate even steeper reductions in the future, at potentially greater economic cost and social disruption. Action sooner rather than later preserves valuable response options, narrows the uncertainties associated with changes to the climate, and should lower the costs of mitigation and adaptation.*[21]

Carbon Capture and Storage: An Overview

If carbon emissions become regulated and if it can be reasonably assumed that Kentucky will continue to rely at least in part upon coal-fired generation for electricity and remains committed to retaining a vibrant manufacturing sector, a question before policymakers and the public is how to manage carbon released during the process of conversion of solid fossil fuels into heat energy? Though that answer has not yet been settled, one approach currently employed is to stimulate production of oil and gas using injected CO_2, is carbon capture and storage (CCS).

In a recent letter to the world energy ministers, Steven Chu –the current Secretary of the United States Department of Energy - wrote that the goal must be “to advance carbon

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[18] “Kentucky Coal Facts 2007-08.” Kentucky Office of Energy Policy – Division of Fossil Fuels and Utility Services & the Kentucky Coal Association.

[19] “Analysis of Waxman-Markey” Prepared for the National Mining Association by CRA International. www.nma.org

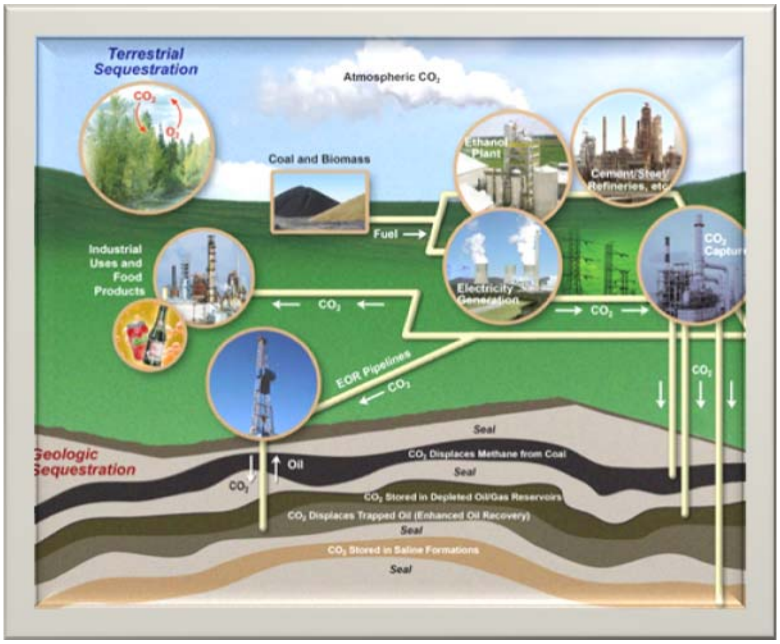
[20] “Economic Impact of Gaining or Losing 100 Jobs: 2006”, Kentucky Cabinet for Economic Development

[21] Call To Action, United States Climate Action Partnership, Page 2, http://us-cap.org/USCAPCallForAction.pdf

capture and storage technology to the point where widespread, affordable deployment can begin in 8 to 10 years.”[22] His letter continued:

> *Can this aggressive timeline be met? Having examined the technology and consulted with leading scientists, researchers and industry experts over the past few months…the answer is yes. Without question, there are many hurdles to the broad deployment of this technology, but none appear to be insurmountable.*

In 2009 (as part of the federal stimulus package) the federal Department of Energy (DOE) announced over $2.4 billion available for carbon capture and storage projects. On top of this funding is a commitment of over $1 billion to the FutureGen project in Mattoon, Illinois. Additionally, DOE has committed $100 million in CCS research and development – intended to capture 90 percent of the plant’s CO_2 output - to the Antelope Valley Station in Beulah, North Dakota and $308 million to Hydrogen Energy LLC, which intends to construct and operate an IGCC plant in California. The plant will be capable of capturing and using 2,000,000 tons of CO_2 annually for EOR.



Kentucky’s energy strategy is aligned with these goals. It states that “by 2025, Kentucky will have evaluated and deployed technologies for carbon management, with use in 50 percent of our coal-based energy applications.”[23]

This image presents a simplified explanation of CCS. CCS is the process by which carbon dioxide (CO_2) is isolated from the emissions stream, compressed, and transported to an injection site where it is stored underground permanently. Before CO_2 gas can be sequestered from power plants and other point sources, it must be captured as a relatively pure gas. Existing capture technologies, however, are not cost-effective when considered in the context

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[22] Secretary Steven Chu – U.S. Department of Energy. Oct. 12, 2009. www.fossil.energy.gov

[23] “Intelligent Energy Choices for Kentucky’s Future.” Nov. 2008.

of retrofitting existing fossil-fuel power plants to enable the pre- or post-combustion scrubbing of CO_2. Most power plants and other large point sources use air-fired combustors, a process that emits flue gas containing CO_2 diluted with nitrogen. Flue gas from coal-fired power plants contains 10-12 percent CO_2 by volume, while flue gas from natural gas combined cycle plants contains only 3-6 percent CO_2.

For effective carbon storage, the CO_2 in these exhaust gases must be separated and concentrated. CO_2 is currently recovered from combustion exhaust by using amine absorbers, solvents and cryogenic coolers. The cost of CO_2 capture using current technology, however, is on the order of $150 per ton of carbon - much too high for carbon emissions reduction applications. Analysis performed by SFA Pacific, Inc. indicates that adding existing technologies for CO_2 capture to an electricity generation process could increase the cost of electricity between 2.5 cents to 4 cents/kWh depending on the type of process.[24] A draft NETL study indicated that retrofitting an existing pulverized coal-fired power plant with scrubbing capability would double the cost of electricity from that plant and require 25% more coal in order to power the scrubbing process.

Costs associated with carbon capture from coal gasification technologies are substantially less burdensome than in post-combustion applications. Because the CO_2 liberated in the gasification process is present at much higher concentrations in syngas than in post-combustion flue gas, CO_2 capture should be less expensive for pre-combustion capture than for post-combustion capture. Currently, however, there are but few gasification plants in full-scale operation, and the capital costs are significantly higher than for conventional pulverized coal plants. Analysis conducted at the National Energy Technology Laboratory (NETL) shows that CO_2 capture and compression using Selexol, a solvent that takes advantage of pressure swing adsorption, raises the cost of electricity from a newly built IGCC power plant by 30 percent.[25] The cost of actual storage has not been addressed in this section but it is expected to be substantial and will include both fees for the present cost of storage as well as fees to address long-term monitoring and potential liability.

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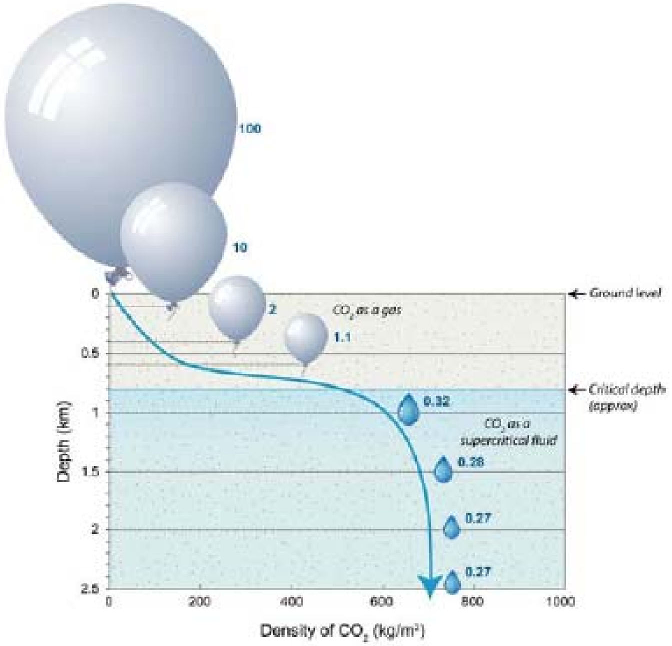
[24] NOTE: The source for this paragraph is the “Carbon Capture and Storage R&D Overview” at the U.S. Department of Energy’s website. Given their thorough, yet easy-to-understand discussion of the complex issue, their description of CCS and associated costs was copied verbatim for this report. Additionally, the image’s source is also the U.S. Department of Energy.

[25] Note: The source for this paragraph is the Carbon Capture overview at the U.S. Department of Energy’s National Energy Technology Laboratory (NETL) website http://www.netl.doe.gov/technologies/carbon_seq/core_rd/co2capture.html. Given their thorough, yet easy-to-understand discussion of the complex issue, their description of CCS and associated costs was copied verbatim for this report.



CO_2 will be injected at depths below 0.8 km (2600 feet). CO_2 increases in density with depth and becomes a supercritical fluid below 0.8 km. Supercritical fluids take up much less space than gases, as shown in this figure, and diffuse better than either gases or ordinary liquids through the tiny pore spaces in storage rocks. The blue numbers in this figure show the volume of CO_2 at each depth compared to a volume of 100 at the surface.

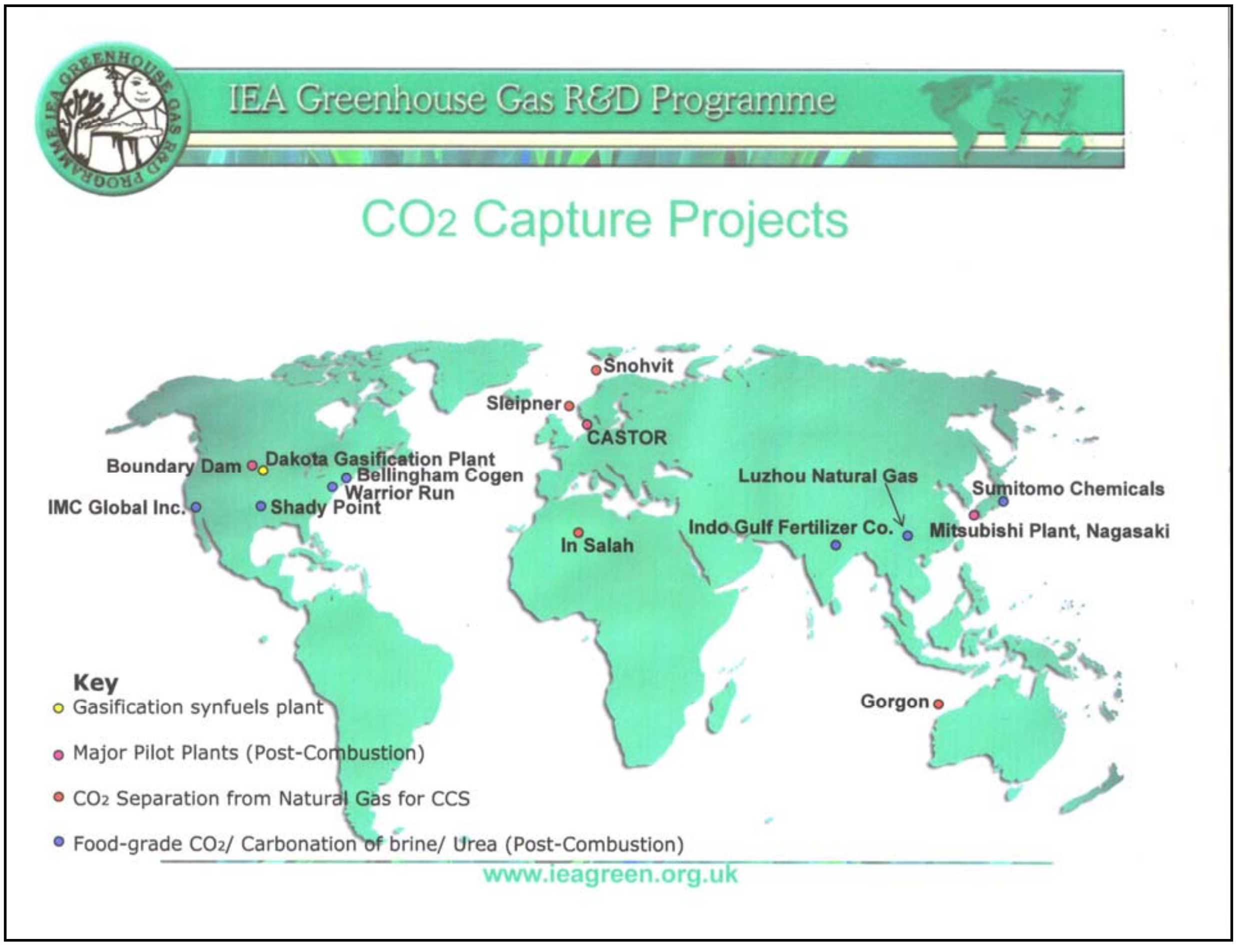
Image Source: CO2CRC

Geologic storage involves pressurizing the captured CO_2 and pumping it deep below the ground surface into a competent rock layer with sufficient porosity and permeability to accept the CO_2 and hold it in the formation indefinitely. Based on the known geothermal gradient and lithostatic pressure of rocks, CO_2 which is pressurized to supercritical phase in preparation for injection can be maintained as a super critical liquid when it is stored below approximately 2,500 feet in depth. The storage areas are selected both for their potential capacity to accept CO_2 and for the impermeable sealing strata located between the storage site and the ground surface.

Underground storage of CO_2 in geological formations has taken place for many years as a consequence of injecting CO_2 into oil fields to enhance recovery. While this technique does not result in 100% retention of the CO_2, a substantial portion remains within the subsurface. The oil industry in Texas has benefited for years from this technique. Interestingly, the CO2 sources for the Texas and Gulf Coast EOR projects are natural underground CO2 sources (Jackson Dome, Bravo Dome, McElmo Dome) that have reliably stored CO2 for millions of years.

There are also currently a number of large geological storage projects underway around the world e.g. Sleipner (North Sea, Norway), Weyburn (North Dakota), In Salah (Algeria), and several new projects in development e.g. Snohvit, Gorgon.

In order to encourage and speed the development of CCS, the United States and international community has invested (and plans to continue investing) significant resources in research and development of the technology. By one count, there are currently between 170 to 180 active CCS projects underway worldwide.



The remainder of this section will discuss some of the most relevant to Kentucky.

- **Midwest Regional Carbon Sequestration Partnership:** The Midwest Regional Carbon Sequestration Partnership (MRCSP) is comprised of universities, state geological surveys, non-profit organizations and private companies from Indiana, Kentucky, Maryland, Michigan, New York, New Jersey, Ohio, Pennsylvania and West Virginia. In 2008, MRCSP was awarded $61 million from the U.S. Department of Energy (DOE) for Phase III activities. MRCSP partners committed an additional $32 million to Phase III, bringing the total resource commitment to $93 million. Recently, the MRCSP and DOE announced that the consortium had successfully injected 1,000 metric tons of CO_2 into the Mt. Simon sandstone, a deep saline formation that is widespread across much of the Midwest. The injection site was at Duke Energy's East Bend Generating Station in Boone County, Kentucky.[26]

- **Midwest Geological Sequestration Consortium:** The Midwest Geological Sequestration Consortium (MGSC) is comprised of the state geological surveys from Illinois, Indiana and Kentucky as well as a number of private corporations and industry associations, including ConocoPhillips, Duke Energy, the Kentucky Oil and Gas Association, LG&E, the Natural Resources and Defense Council and Peabody Energy.[27]

- **Western Kentucky Carbon Storage Foundation:** In 2008, the Western Kentucky Carbon Storage Foundation was formed to partner with the Kentucky Geologic Survey (KGS) in carrying out a significant CCS research project in western Kentucky. The Foundation is a non-profit entity organized primarily by ConocoPhillips, LG&E and Peabody Energy. Other contributors and participants include the University of Kentucky, the U.S. Department of Energy National Energy Technology Laboratory, TVA, the Illinois Department of Commerce and Economic Opportunity, Schlumberger, Sandia Technologies, Geo Consultants, LLC, Wyatt Tarrant & Combs and Smith Management Group.[28] The research project was managed by the Kentucky Geological Survey using funds provided by the Foundation and the Kentucky Legislature after passage of HB 1 by a special session of the Kentucky General Assembly in 2007.[29] In April 2009, the Foundation announced that it was drilling a test-well in Hancock County, Kentucky. By August 2009, KGS had

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[26] Fossil Energy Techline – Oct. 21, 2009. www.fossil.energy.gov

[27] See. www.sequestration.org

[28] See www.uky.edu/KGS/kyccs/partners/index.htm

[29] See www.uky.edu/KGS

successfully injected 323 tons of CO_2 into an 8,126 foot deep well.[30] KGS was awarded nearly $1.1 million in September 2009 to proceed with a second phase of research during the spring and summer of 2010.

- **Southeast Regional Carbon Sequestration Partnership: M**embers of the Southeast Regional Carbon Sequestration Partnership include KGS, Duke Energy, American Electric Power, the Southern States Energy Board, Equitable Resources, Consol Energy and the Tennessee Valley Authority. In May 2009, the Southern Company, a partner, announced plans for a CCS demonstration project in Alabama, with the goal of capturing between 100,000 to 150,000 tons of CO_2 per year beginning in 2011. The National Energy Technology Laboratory has stated its intention to build a 10 to 13 mile pipeline to transport the CO_2 as part of the project.[31]

- **FutureGen – Mattoon, Illinois:** After significant uncertainty over the past several years, the FutureGen project seems to be back on track. DOE announced in June 2009 that it will provide $1.073 billion to the project from the American Reinvestment and Recovery Act and other previously approved appropriations. In July 2009, DOE released its "record of decision" that determined that the FutureGen site meets the necessary environmental compliance to proceed. FutureGen is anticipated to produce 275 megawatts of electricity with a goal of capturing 90 percent of its carbon emissions and storing over 1 million tons annually within deep geological formations. Operated as a non-profit, public/private partnership, the FutureGen Alliance members include Alpha Natural Resources, Consol Energy, E.ON U.S. and Peabody Energy. Additionally, the Alliance includes a number of international members representing Australia, China and the United Kingdom. Construction on the project is intended to commence in 2010.[32]

- **Mountaineer Plant – New Haven, West Virginia:** September 2009, American Electric Power (AEP) announced that it would begin small-scale CCS testing at its Mountaineer Plant. The initial project will capture up to 90 percent of the carbon dioxide from a slipstream of flue gas equivalent to 20 megawatts of generating capacity. The captured carbon dioxide, more than 100,000 tons a year, will be compressed and injected into suitable geologic formations for permanent storage approximately 1.5 miles below the surface. Further, AEP is seeking $334 million, about half the estimated cost of installing a system that will use a chilled ammonia process to capture at least 90 percent of the carbon dioxide from 235 megawatts of the plant's 1,300 megawatts of capacity. The

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[30] See www.uky.edu/KGS/kyccs/wkydeep.html

[31] Source: http://www.secarbon.org

[32] See www.futuregenalliance.org

captured carbon dioxide, approximately 1.5 million metric tons per year, will be treated and compressed, then injected into suitable geologic formations for permanent storage approximately 1.5 miles below the surface. The system will begin commercial operation in 2015.[33]

- **Archer Daniels Midland Company – Decatur, Illinois:** Archer Daniels Midland Company, a member of DOE's Midwest Geological Sequestration Consortium, is planning to demonstrate the Dow/Alstom's advanced amine process to capture CO_2 from industrial flue gases and sequester the CO_2 in the Mt. Simon Sandstone reservoir. DOE has committed $1.4 million to the project as part of its larger commitment of $1.4 billion allocation for industrial CCS projects.[34]

- **Center for Applied Energy Research – University of Kentucky:** CAER received $2 million from HB1 and has formed the Carbon Management Research Group (CMRG) to advance carbon capture research. In 2006, the University of Kentucky announced the receipt of a $1.5 million research grant from E.ON U.S to the Center for Applied Energy Research (CAER) for carbon-capture research. CAER is also actively pursuing the development of an algae based system for CO_2 mitigation from coal-fired plants. That project seeks to investigate and demonstrate the potential of using waste CO_2 and heat from a coal-fired power plant to cultivate algae, which could then be processed into value added products.[35]

- **International Projects:** A short sample of international efforts to demonstrate and commercialize carbon capture and storage:

  ZeroGen (Australia): 530 megawatt power plant. 90 percent carbon capture and storage. Planned deployment date: late 2015.
  Project Pioneer (Canada): Retrofit of existing coal-fired plants to capture and sequester one-million tons annually of CO_2 beginning in 2015. The Canadian national government is contributing $343 million towards the project.
  Regional Opportunities for CCS in China (China): International partnership determined that China has over 1,620 large CO_2 point sources producing 3.8 billon tons of CO_2 annually. Further determined that China has an estimated 2.3 gigatons of potential storage capacity for CO_2 storage.

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[33] Source: www.aep.com/newsroom
[34] Fossil Energy Techline. Oct. 2, 2009. www.fossil.energy.gov
[35] Source: http://www.caer.uky.edu/greenhouse/home.shtml

Sleipner Field (Norway): In operation since 1996, the Sleipner project injects and sequesters 1 million tons of CO_2 annually into the Utsira Formation -- a 250m thick massive sandstone formation located at a depth of 800-1000m beneath the ocean floor.

SUMMARY OF WORKGROUP MEETINGS

Minutes of the four meetings held by the workgroup are included in the appendices. The majority of meeting attendees remained the same throughout the process and represented a wide range of stakeholders. As with any ongoing process, some attendees were not able to be at each meeting and the group grew and changed with time.

The workgroup has recognized that it is not productive and not pertinent to this discussion, to apply a blanket characterization to carbon dioxide as a waste or a commodity. We recognize that the Interstate Oil and Gas Compact Commission (IOGCC) has suggested that treatment as a waste is not appropriate while the World Resources report has suggested the opposite (see attached reports). We also recognize that there are beneficial and valuable uses for carbon dioxide and circumstances that indicate that stored carbon dioxide is not likely to be retrieved.

Following is a brief summary of the issues discussed and conclusions reached by the members.

October 8, 2008 -

In order to frame the discussion, the first session held at the Governor's Conference on the Environment on October 8, 2008 included presentations on the technology of carbon storage and the then-planned research project in Hancock County. A review of the regulatory framework and common law which may pertain to this new issue was then presented, followed by a brief summary of potential issues and actions taken by other states on the identified issues. Discussion among the session attendees included:

- A review of the questions surrounding ownership of the pore space, concluding that a definition of pore space should be developed, watching to be sure it does not impact caves and caverns, and taking into account the differing estates.
- It was agreed that this matter is pressing, that we do not have a decade to develop our thoughts and approaches.
- It was assumed by those in attendance that defining CO_2 as a waste is too limiting as there are now and will be in the future valuable uses for the material. The limited market available for use of CO_2 as an agent for EOR means that the lion's share of the emitted CO_2 will have to be permanently stored.
- The path Kentucky takes must not ignore the impact of carbon constraints on those living on fixed incomes or below the poverty line, as they will be significantly affected

- The importance of addressing both ownership and liability was discussed as participants are reluctant to move forward until some manageable framework is established.

The session ended with an agreement to invite a greater participation in continuing discussions.

December 1, 2008 –

This meeting began with a review of some basic assumptions that would frame the discussion. The assumptions agreed upon were:

- There will be national regulations on CO_2 emission limitations (cap / trade or others).
- To meet electrical demands, (40% more demand in Kentucky by 2025) we will be required to sequester carbon.
- Deep geologic storage will have to be one of those means, including enhanced oil / gas recovery (EOR & EGR).
- We agreed for purposes of this discussion that geologic carbon storage can be done safely / efficiently.
- Urgency requires that this project move more quickly than other similar-sized projects.
- Remaining huge coal reserves in Illinois Basin and their use requires their development.
- CO_2 storage is a policy that is in the public interest.
- Stored CO_2 has potential later uses.

Following agreement on the assumptions, a discussion of storage through EGR was conducted. If an additional 20% recovery could be obtained through EGR the gas industry would benefit greatly.

It was agreed that use of CO_2 in EGR and EOR would be subject to existing laws and structures within the oil and gas industry that are well established. The difficulty arises when storage is the only activity. Discussion included the differences between underground storage of gas that is currently being done in about 25 locations in Kentucky, and the permanent storage of CO_2.

Discussion of permitting under the proposed Class VI underground injection well permit currently under review included acknowledgement that at this time there is not sufficient staff or experience within the Oil & Gas agency to achieve primacy in management of either the Class II or Class IV UIC program. Kentucky should seek primacy for the UIC program only if the program is funded, staffed and managed appropriately.

Discussion then turned to rights of access for storage. It was agreed that while there is developed law on the right to access mineral, there is little case law developed on the right to inject something back into the ground. It was agreed that we do not have the years needed for case law to develop on this issue.

The point was made that the General Assembly cannot legislate property rights and neither the state nor the entity storing the CO_2 will likely be able to afford to purchase the storage space. This turned the discussion to the potential for eminent domain and the value of property taken for the public good. It was pointed out that the state should carefully examine the potential for storage under public lands.

Issues arising out of pipelines, effect on ratepayers, long-term liability and the importance of educating the public and the legislature were discussed.

February 13, 2009 –

Review of prior meeting discussions and an update on the pending Hancock County project was given. The subject of eminent domain was raised with the explanation that the principle of eminent domain is used when the government takes a property interest from an individual for a public purpose and the government must compensate the owner. It is important to adequately define "the public good" and address the potential involvement of a commercial entity.

Sub-groups were formed to gather information on technical aspects and development, other state and federal action, and legal background for the issues. Finally, a group was designated to draft a report describing the findings and recommendations of the workgroup.

July 20, 2009 –

The fourth meeting was delayed due to a proposal in the legislature to formalize the workgroup which eventually stalled. The sub-groups gathered to review information developed during the hiatus and a final session with all participants convened in the afternoon with reports from the subgroups.

Following a brief review of the technology, it was agreed that liability exists in the near-, mid- and long-term of each storage project. Near-term liability is found with traditional drilling and construction projects and can likely be addressed with appropriate practices and conventional insurance products. Mid-term liability covers the immediate post-closure and monitoring timeframe. This period will continue to be regulated and subject to best practices.

Long-term liability arises years after the closure of the well and requires continued monitoring and the ability to take corrective measures if needed.

The discussion concluded that:

- “Pore space” in Kentucky is the geologic formation where the storage capacity or the “pores” are located.
- Kentucky needs primacy over the Class VI underground injection control program, and to achieve that there must be adequate funding of the program. To achieve primacy over the Class VI program, Kentucky must first adequately manage the Class II UIC program.
- Long-term liability must have long-term funding. If the state (or federal government) is to assume this liability, funding generated from storage fees must be protected from use for other purposes.
- A regulatory forced pooling or eminent domain structure will be required. Compensation for the “taking” must be defined carefully, taking into account the diminished value of the property, if any. Use of the property by a commercial venture can complicate this as there would be gain to the storage operator through use of private property rights.
- In general, it was agreed that there is no economic value to the geologic strata where storage is likely to take place.
- The country appears to be making a determination that CO_2 storage is in the public interest and runs to the benefit of all.
- Interstate compacts will be required to address cross jurisdiction migration.

WHAT ARE THE LEGAL ISSUES PRESENTED BY GEOLOGIC CARBON STORAGE?

Legal issues associated with the process of CCS are found in every aspect of the technology. Following is a brief discussion of those issues identified by the Workgroup. These issues address how CCS may be regulated, ownership of the storage space into which the CO_2 is stored, access to the storage space, liability for storage during active operations and in subsequent years.

Most of these issues are new questions. While we draw our interpretations from existing case law or regulatory structures, the subject is new and may result in different outcomes.

How should CO_2 storage be regulated?

EPA has finalized its proposed endangerment finding, declaring that Green House Gases, including CO_2, (GHG) are hazardous to human health and the environment,[36] making GHG subject to the Clean Air Act provisions. Facilities that emit 25,000 tons per year of GHG are now subject to a requirement to monitor and report GHG emissions beginning in 2010[37]. EPA is currently considering a “Tailoring Rule” intended to raise the threshold for Prevention of Significant Deterioration (PSD) authority to 25,000 tons per year for CO_2 equivalents and include GHG as a permitted emission.[38] It appears imminent that facilities with these emissions will soon be severely affected. In addition, EPA has issued a draft rule for CCS injection wells which continues to gather public comment and deliberation.[39]

These developments on the national stage indicate that CCS will become necessary as emission limits are established and the construction and installation of storage wells will be regulated through EPA’s Clean Water Act injection well authority. Certain states have achieved primacy for injection well programs and can be expected to do so for this new class of permit. Kentucky does not have primacy for injection wells and does not appear, at this time, to have the resources to achieve that. Therefore, currently, Kentucky CCS wells will be regulated under EPA’s rule.

The crux of the discussion of how CO_2 storage should be regulated is whether the CO_2 is a waste or a product that has economic value. In fact, it is probably both. CO_2 does not fit under the definition of a hazardous waste, although we may yet see a determination to that

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[36] EPA Docket ID No. EPA-HQ-OAR-2009-0171, effective 12/7/2009

[37] EPA Docket ID No. EPA-HQ-OAR-2008-0508-2278, effective 12/29/2009

[38] Federal Register: October 27, 2009 (Volume 74, Number 206) Proposed Rules, Page 55291-55365

[39] Federal Register, Volume 73, Number 144, July 25, 2008, Proposed Rules, Page 43491-43541; August 31, 2009, Volume 74, Number 167, Page 44802-44813

effect, given the recent endangerment finding. CO_2 is essential to life and is a necessary part of numerous products and consumer goods.

Generally, one expects waste to be regulated by the Department for Environmental Protection, Division of Waste Management. One expects the storage of a material to be under the purview of an agency with control over the storage space or the material. When stored permanently in deep saline storage, the CO_2 is not expected to be removed. When used for enhanced oil recovery (EOR) and potentially enhanced gas recovery (EGR), CO_2 is part of an extraction process with storage a co-benefit of the increased flow of oil or gas.

This model has been followed in several states[40] and the role of CO_2 in EOR has been recognized even in the federal bills under consideration. Uniformly, use of CO_2 for EOR has been exempted from proposed rules for CCS.[41] Similarly, in states which have passed legislation specifically addressing CCS, EOR and the potential withdrawal of CO_2 for commercial purposes have been relegated to the jurisdiction of the Oil and Gas authority, while permanent storage usually falls to the Environmental Protection authority[42]. This can lead to a result of EOR projects being regulated by the oil and gas authority and if converted to permanent storage, then having to transfer regulatory responsibility to the environmental protection agency. Logic and efficiency suggest that the permitting of wells, for injection or otherwise, can be adequately managed by the oil and gas agency which has the most experience with issues arising from this activity.

Two model frameworks for regulation of the capture, compression, transmission, injection, disposal, and monitoring of Co2 have been developed – one by the IOGCC, and the other by the World Resources Institute. They are attached.

Who owns the pore space?

This question has engendered more discussion than most. Pore space ownership can determine who will control where the CO_2 can be stored. While regulatory permitting of a storage facility may be subject to federal law and direction, the question of ownership falls to state law. States control their own property law and the interpretation of that law. The answer to the question depends on where you are and where you are trying to store the CO_2.

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[40] e.g., Oklahoma (SB 610)

[41] e.g., North Dakota (SB 2095; Oklahoma (SN 610); Utah (SB 202 Substitute); West Virginia (HB 2860)

[42] e.g., Wyoming (HB 90); However, Montana (SB 498) places regulatory responsibility on the Board of Oil & Gas Conservation

A review of case law in Kentucky indicates that the answer is unclear. Potentially analogous case law arises from disputes over the storage of natural gas in depleted reservoirs.[43] As the pore space is a part of a geologic strata, whether it is found in un-mineable coal, within shale or in a sandstone with a saline aquifer. The ownership should therefore be determined by the ownership of the mineral estate, and by the definition of "mineral" in any transferring document. For example, if the property in question is owned in fee, the surface owner has all rights to all strata. If a general conveyance of "mineral" has been made, it is likely that the mineral owner will have title to the pore space. If a limited conveyance of mineral has been made, i.e. natural gas or coal resources, the ownership of the pore space should follow ownership of the particular strata.

Several states have attempted to identify the owner of the pore space by legislative measures[44], generally declaring the surface owner to be the owner unless specifically severed.

In Kentucky, we have many ways in which aspects of one piece of property are separated. Quite often the mineral estate has been severed from the surface estate, and in some cases by several conveyances or leases, dividing coal from oil and gas, from hard rock. In Kentucky, there is also precedent for the pore space, if associated with mineral strata, belonging to – or under the control of – the mineral owner until the mineral is completely depleted[45]. One must question whether mineral is ever completely depleted. If the storage is to occur within strata interpreted as being "mineral" separated from the surface estate, it would follow that it would belong to the mineral estate.

A further question arises as to how to address the fact that the stored CO_2 will migrate across property boundaries and even state or national boundaries. One solution is to use a methodology analogous to unitization or forced pooling used in oil and gas extraction. Using this method, all potentially affected property owners can be addressed, although potentially at a substantial cost. However, due to the likely migration across state or national boundaries, multi-state or multi-national treaties may be required.

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[43] *Central Kentucky Natural Gas v. Smallwood*, 252 S.W.2nd 866 (Ky. Ct. App 1952) rentals from a gas storage space must be paid to the mineral owner. The Court cited the English Rule (minority position in U.S.; law in Canada and Great Britain) which holds that the mineral owner has the exclusive right of production and right to the storage space left after production has ceased. *Smallwood* was overturned on other grounds by *Tex. Am. Energy Corp v Citizens Fid. Bank & Trust Co.,* 736 S.W.2nd 25 (Ky. 1987)

[44] Wyoming (HB89) pore space belongs to the surface owner unless specifically transferred or excluded; West Virginia (HB2860) pore space is an attribute of the surface estate and does not convey unless specified; North Dakota (SB 2139) title to pore space vests in the surface owner and may not be conveyed separately. Interestingly, in the same legislation, West Virginia established a workgroup charged with study and recommendations of numerous issues, including recommendations on the treatment of pore space.

[45] *Central Kentucky Natural Gas v. Smallwood*, 252 S.W.2nd 866 (Ky. Ct. App 1952)

If the CO_2 migrates across property boundaries, we must question if this constitutes a trespass, giving rise to a claim in tort. To constitute trespass, there must be a physical incursion and, in some interpretations, a harm to the affected property owner's enjoyment of his estate.[46] The potential for harm is not yet established. There has been speculation about numerous possibilities such as impact to drinking water, impact of seismic stability due to increased pressures within the storage strata, etc. Research simply has not yet been able to quantify this aspect, although the risk is generally perceived as low.

How can we access the storage space?

We are fortunate in Kentucky to have a significant body of case law addressing the competing interests associated with a property and its viable mineral extraction. These cases, as well as statutory and regulatory developments have given us examples we can apply to the competing interests on a property. For example, in Kentucky, we have established a statutory means to address the ongoing production of mineral or petroleum when faced with coal bed methane or coal and oil development in the same area.

Access to storage for CO_2 can follow these models. The surface owner at the injection point must grant the right to construct the injection point and all mineral interests must be respected and protected by appropriate construction and compensation for mineral that becomes unmineable or locked in by the presence of the injection project.

How can we address stored CO_2 that crosses jurisdictional boundaries?

In Kentucky, we can all but guarantee storage of CO_2 into fields near our state boundaries will cross state lines. Of necessity, our coal-fired power plants are located along significant waterways. These facilities or their replacements will be a primary source of CO_2 requiring storage. As such, unless advances are made to lessen or eliminate the use of water in power generation and cooling, it is probable that the new generation of plants will likewise site near major waterways, and that injection will occur in as close proximity to the production point as possible in order to lessen the cost and process of siting, constructing and maintaining guarantee that pipelines to transport the CO_2 away from the source. Therefore, the injection points will, in many cases be located near the rivers which form the majority of our state boundaries: the Ohio, the Mississippi and the Big Sandy Rivers.

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[46] Restatement (2nd) of Torts, section 329. Tresspass "protects the interest in the exclusive possession of the land." Tresspass requires interference and intent or negligence. In cases of pollution or neighbor trespass, damage is also required. Nuisance protects the quiet enjoyment of land and requires both damages and a showing that the invasion was unreasonable.

The deep subsurface plume of CO_2 could well migrate beyond our state lines. Conversely, we are just as likely to be the recipients of migrating CO_2 from neighboring states. This situation highlights the need to engage with our neighboring states to reach agreement on how we will treat such migration. The potential for migration brings into focus the shared responsibility and impact that coal producing and using states will face.

Who holds the liability for stored CO_2?

Liability for stored CO_2 can fall in one of three pots: liability for regulatory violations, for lost carbon credits or tort liability. Similarly, liability can arise at different point in the timeline of a storage facility: during active storage, during the near-term post closure period, or during the long-term of storage reaching into the future.

- The act of storing carbon dioxide will be regulated under EPA's injection well rule or by states with primacy over that program. Violations of those regulations and the permits issued under those regulations will result in fines and clean-up responsibilities for the permitted entity.

- Carbon storage will likely be subject to credits or the avoidance of cost, while also being subject to the cost of storage. Should the stored carbon escape, all those who received the credit or benefit of storage may be subject to repay that amount, together with penalties or other assessments.

- An accident while constructing the well or injecting the carbon could result in tort liability, arising from personal injury or injury to property. Although it appears unlikely, a catastrophic failure of a system would also result in tort liability.

Failure of a system could result in all three types of liability attaching from the same event. For example, if the stored CO_2 migrates into the drinking water strata, making the water unusable, a cause of action in tort may arise, in addition to violations of the Clean Water Act and permit conditions. At the same time, the entity which was credited with storage may have to address the loss of that credit due to atmospheric release of the sequestered carbon.

It appears that certain of these liabilities can be addressed through normal insurance products and bonding requirements, as they have for years for normal well drilling and permitting actions. Storage of CO_2 as a gas bears similarities to the geologic in-formation storage of natural gas by regulated utilities. It is the long-term responsibility for keeping the CO_2 stored that is less likely to be adequately addressed with traditional indemnity products. If we require the CO_2 to be stored for a substantially long time, or permanently returned to the earth, who will be responsible years after the storage well is closed and properly abandoned? Entities that may seem the logical carriers of this responsibility are likely to disappear, go out of business. Where then can we look for the long-term monitoring and responsibility for corrective action if an issue ever arises?

Several states have begun to address this question through legislative action.[47] Their action reflects suggestions made in numerous reports published by study groups.[48] Further, the European Union has issued a directive which must be implemented by member countries by Spring 2011 that suggests that responsibility for the long-term storage and monitoring can be transferred to the state at 20 years following closure or greater.[49] Australia, in the Offshore Petroleum Amendment (Greenhouse Gas Storage) Bill 2008, allows transfer of liability to the state after 20 years monitoring of a closed storage facility.

Long-term monitoring and responsibility must be funded. Those jurisdictions that have acted, and those studies that have suggested the eventual transfer of liability to the public through its government, have uniformly suggested that a trust be established to fund these activities. The funds would come from a per-ton fee assessed on storage, paid by the facility generating the CO_2 and requiring storage services.

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[47] Louisiana (HB 661); Montana (SB 498); North Dakota (SB 2095). Pennsylvania has determined that the state will own the CO2 stored within its CCS network (HB 80).

[48] e.g., “Storage of Carbon Dioxide in Geologic Structures, A Legal and Regulatory Guide for States and Provinces”, IOGCC, September 25, 2007

[49] EU Directive 2009/31/EU

CCS POLICY FRAMEWORKS: FEDERAL & STATE

The imperative to prepare for a carbon-constrained world is motivating the consideration of public policy frameworks for carbon capture and storage at the state and federal level. This section will review a number of the policy proposals and developments that are unfolding.

- **FEDERAL**

HR 2454 (Waxman-Markey): The House version of climate change legislation contains several sections related to CCS. It requires:

- A national strategy within one-year of enactment that identifies legal and regulatory barriers to the deployment of CCS and recommendations for rulemaking.
- The EPA to issue regulations within 2 years of enactment to "protect human health and the environment by minimizing the risk of escape to the atmosphere of carbon dioxide injected for purposes of geological storage."
- The establishment of a national task force to study existing state and federal statutory frameworks governing carbon storage. The task force is to report back to Congress no later than 18 months after the enactment of the law.
- The establishment of the Carbon Storage Research Corporation to "establish and administer a program to accelerate the commercial availability of carbon dioxide capture and storage." Authorizes the Corporation to place fees upon fossil based generation to fund operations and grant programs.
- Promulgation of regulations providing for the distribution of emission allowances to support the deployment of carbon capture and storage technologies by the EPA no later than two years after enactment.
- Requires that any coal-fired power plant that obtains a clean air permit between 2009 and 2020 must reduce its CO_2 emissions by 50% four years after the EPA has determined that there is a specified amount of "commercial operation" of carbon capture and storage.
- Requires that any coal-fired power plant that obtains a clean air permit after 2020 reduce its CO_2 emissions by 65%.

S. 1733 (Kerry-Boxer): Within the Senate version of climate-change legislations, the provisions for CCS are similar to Waxman-Markey with some differences. Significant differences include:

- A requirement that the Carbon Storage and Research corporation to raise $1 billion annually through assessments "on distribution utilities for all fossil-based

electricity delivered directly to retail-consumers" to fund their program to accelerate the deployment of CCS.
- No mention of the distribution of emission allowances to support the deployment of carbon capture and storage.

S. 1502 (Casey-Enzi): Proposes the establishment of a program by the Department of Energy "to ensure the prompt and orderly management of the liability issues surrounding carbon capture and storage. Its provisions include:

- Requiring private liability assurance during the active period of a project.
- Establishing a program to certify the closure of carbon storage facilities.
- Providing for the transfer of long-term stewardship to the federal government for carbon-dioxide storage facilities on the issuance of a certificate of closure.
- Ensuring the prompt and orderly payment for any damages related to carbon storage.
- Authorizing the program to establish and levy fees as a means of funding.
- Allowing states to gain primacy over long-term stewardship over carbon dioxide facilities located within their state.

- **STATES (ENACTED)**

Illinois (HB 3854 – Introduced & Passed 2009): Created a Carbon Capture and Sequestration Legislation Commission to report on all issues related to carbon capture and sequestration, including but not limited to: ownership of the CO_2, liability for release of CO_2, acquisition and ownership of pore space, procedures and safeguards for the transportation and sequestration of CO_2, methodology to establish any necessary fees, potential use of CO_2, construction of pipelines and coordination with federal authorities and agencies. The commission is to expire after the report is issued.

Louisiana (SB 10 – Introduced and Passed 2009): Excluded the sale of anthropogenic carbon from the state and local sales and use tax. Granted a 50 percent reduction in severance tax within a carbon dioxide tertiary recovery project.

Montana (S.B. 498 – Introduced and Passed 2009): Granted ownership of pore space to surface owners unless it could be determined from existing deeds or severance documents to be otherwise. Established a fee on CO_2 storage to fund the state's monitoring of storage sites and program administration. Liability for CO_2 remains with the storage operator until a certificate of closure is issued by the state, at which time title is transferred to the state.

North Dakota (S. 2221 – Introduced and Passed 2009): Granted a 20% tax reduction against the state coal conversion tax for those electricity generating plants and coal conversion facilities that reduce CO_2 output by twenty percent. Higher tax abatements were allowable if CO_2 reductions exceeded twenty percent, with the maximum allowable amount reaching 50% for an eighty percent reduction in CO_2 output.

North Dakota (S. 2095 – Introduced and Passed 2009): Placed authority over carbon capture and storage activities under the North Dakota Industrial Commission. Authorized the commission to collect a fee from storage operators on a per-ton basis. Title and liability for the sequestered carbon remain with the storage operator while site is active. A certificate of closure can be issued by the Commission no earlier than 10 years after carbon injections have ended. Once certificate of closure is issued, the state gains title and responsibility for the storage facility.

North Dakota (S. 2139 – Introduced and Passed 2009): Vested ownership of pore space with the surface owners. Prohibited the severance of pore space ownership from surface ownership.

Texas (SB 1387 – Introduced and Passed 2009): Granted jurisdiction over the geological storage and injection of carbon dioxide to the Texas Railroad Commission and giving permitting power to the Commission to approve projects. Defined the owner of the sequestered carbon dioxide as the “storage owner” and not the surface or mineral estate. Created the Anthropogenic Carbon Dioxide Storage Trust Fund to resource the Railroad Commissions authority to inspect, monitor, remediate and/or repair carbon dioxide injection wells. Required the Railroad Commission to establish rules about the extraction of sequestered carbon for commercial or industrial purposes.

Utah (S.B. 202 – Introduced and Passed 2008): Directed a variety of state agencies to develop and recommend rules for carbon capture and storage. Specifically stated that the proposed rules would not apply to the “injection of fluids…for the purpose of enhanced hydrocarbon recovery.”

West Virginia (HB 2860 – Introduced and Passed 2009): Established the statutory authority for the West Virginia Department of Environmental Protection to issue permits for carbon storage. Established a working group to study issues pertaining to carbon dioxide sequestration including, but not limited to, scientific, technical, legal and regulatory issues, and issues regarding ownership and other rights and interest in subsurface space that can be used as storage space for carbon dioxide and other associated constituents, or other substances, commonly referred to as "pore space," and shall report to the secretary and the Legislature its recommendations with respect to the development, regulation and control of carbon dioxide sequestration and related technologies.

Wyoming (HB 89 and HB 90 – Introduced and Passed 2008): These companion bills conferred ownership of pore space to the surface owner and legislated that the conveyance of surface ownership also included ownership over pore space, unless specifically severed. Directed the Wyoming Department of Environmental Quality to institute a program for issuing permits for and regulating long-term geological carbon sequestration.

Wyoming (HB 80 – Introduced and Passed 2009): Adopted a new procedure for "unitizing" geologic sequestration sites used for the sequestration of carbon dioxide. Unitization provides a means for all pore space owners to participate in a sequestration project and assures that all such owners will share in the economic benefits of a sequestration project.

- **STATES (PROPOSED)**

Indiana (HB 1412 – Introduced 2009): Proposed incentives for alternative energy purchases. Provides that purchases of energy, capacity, or renewable energy credits from alternative energy sources are eligible for the financial incentives available for clean coal and energy projects. Specifies that "clean coal and energy projects" include projects at new or existing energy facilities that involve carbon dioxide capture, storage, and sequestration. Requires the utility regulatory commission (IURC) to allow an energy utility that purchases alternative energy to recover any costs arising under the purchase contract through rate adjustments.

Kentucky (HB 285 – Introduced 2009): Proposed that the Kentucky Economic Development Finance Authority to grant financial incentives to a pilot project with a minimum $100 million capital investment that is utilizing advanced carbon capture and storage and received federal funding as a clean energy initiative. It allowed for the project to be a modification of an existing coal-fired generating station with at least 300 MW of rated capacity.

Kentucky (HB 351 – Introduced 2009): Proposed that the Commonwealth of Kentucky would “accept and receive all rights, title and interests in sequestered (carbon) including any current or future environmental benefits, marketing claims, tradable credits, emission allocations or offsets (voluntary or compliance based).”

Kentucky (HB 537 – Introduced 2009): Proposed the creation of a carbon management legal issues study group “to identify and analyze legal issues that may hinder development of solutions of carbon dioxide in Kentucky.”

New York (A05836 – Introduced 2009): Proposed that the ownership of “all pore space in all strata below the surface lands and waters…to the several owners of the surface above the strata." Proposed a process by which a carbon capture and storage pilot project would be permitted and authorized.

Oklahoma (SB 492 – Introduced 2009): Proposed that the Oklahoma Department of Environmental Quality to issue "temporary, time-limited permits for pilot-scale testing of technologies for geological sequestration." The utilization of CO_2 in enhanced oil recovery was exempted unless the oil and gas well was converted to geological sequestration.

Texas (SJR 39 – Introduced 2009): Proposed a constitutional amendment authorizing the issuance of general obligation bonds by the State of Texas to provide and guarantee loans for clean energy projects. In order to qualify, an energy project needed to capture and sequester not less than 50 percent of its carbon emissions.

Texas (SB 2111 / HB 2811 – Introduced 2009): Companion bills introduced to enact SJR 39. Exempted components of tangible personal property used in connection with geological sequestration and enhanced oil recovery from tangible personal property taxes. Required that a permit for a clean energy project be rejected or denied within nine months (with a possible three month extension) after the application was deemed technically complete. Granted jurisdiction over the geological storage and injection of carbon dioxide to the Texas Railroad Commission.

Wyoming (HB 56 – Introduced 2009): Proposed that no pore space containing recoverable hydrocarbons be used for carbon sequestration without the written consent of the owner of the oil and gas lease.

Wyoming (DRAFT LEGISLATION – Currently being discussed in Interim Committee): Proposes to create a Wyoming Special Revenue Account within the Wyoming treasury to fund measurement, monitoring and verification costs during long term stewardship by the state. Additionally, a Long-term Care, Stewardship and Compensation Trust Fund may be needed to maintain funds adequate to address potential liability coverage. Further, it proposes to amend the process by which sequestration sites are permitted to include the requirement that the applicant has obtained public liability insurance policy in force for the sequestration site or has met state or federal self-insurance requirements.

RECOMMENDATIONS: A PATH AHEAD FOR KENTUCKY

The effect of potential carbon constraints on Kentucky may be severe. Therefore, Kentucky needs to position itself as a favorable location for business even in a carbon managed environment. By thoughtful action, Kentucky can remove the barriers and uncertainty that are paralyzing other states, and continue to allow Kentucky to maintain competitive electric rates in the nation. To achieve this goal Kentucky can proactively address those legal issues that will arise in the event that carbon capture and geologic storage becomes economically viable for existing generation sources or is utilized by new power sources relying on carbon-based fuels. By clearly defining the path forward with regard to storage liability, permitting and pore space, Kentucky will be better able to respond to advances in Carbon Capture and Storage technology and economics.

The workgroup discussions led to several consensus recommendations which are outlined below. In general, these recommendations address the regulatory structure, pore space and access and long-term liability issues. Following a brief discussion, specific recommended actions are identified.

Regulatory Structure

Clearly, Kentucky should establish the **regulatory structure** necessary to properly permit and oversee this new industry.

- As part of that development, Kentucky must determine if it will achieve primacy of the underground injection program and if so, dedicate appropriate funding to that program. The sense of the Workgroup is that if Kentucky intends to obtain primacy it must seriously address the funding and staffing of the Division for Oil & Gas Conservation in order to accomplish that goal.
- It appears to the Workgroup that permitting of injection wells should be a function of the oil & gas authority as the agency with the most knowledge and experience with the types of structures and risks inherent in the activity.
- Corollary to the development of storage wells is the development of the pipelines necessary to transport the gas.

A number of states have already enacted a regulatory framework for permitting CCS sites. Common requirements contained within the statutory frameworks enabling CCS site permitting and the permitting process include:

- Required public hearing before permit is issued, with specific notification to each mineral lessee, mineral owner and pore space owner within the storage reservoir and within a certain proximity to the storage reservoir's boundaries.
- Description of the general geology of the area affected by the injection.
- Proof that the proposed injection wells are designed to meet acceptable construction standards
- A plan for periodic mechanical integrity testing of all wells and of the integrity of the storage zone.
- A monitoring plan to assess the migration of the injected carbon dioxide and to ensure the retention of the carbon dioxide in the storage site
- Plans and procedures for environmental surveillance and excursion detection, prevention and control programs.
- Requirement that the proposed storage facility will not adversely affect surface water or formations containing water that can be put to beneficial use.
- Proof of bonding or financial assurance to ensure that carbon dioxide storage sites and facilities will be constructed, operated and closed in accordance with the regulatory framework.
- A detailed plan for post-closure monitoring, verification, accounting, maintenance and mitigation.

Recommendation:

✓ Legislatively enact a regulatory framework for CCS site permitting and closure within the Department of Natural Resources, Division of Oil & Gas. Evaluate enacted and proposed state legislation and EPA proposed rules to determine which permitting requirements fit well with promoting the viability of CCS, protecting the interests of property owners and ensuring the public safety within the Commonwealth of Kentucky.

✓ Adequately fund the program if the General Assembly determines that Kentucky should seek and obtain primacy of the Underground Injection Control Program for Class II and Class VI (CCS) wells.

✓ As needed and appropriate, adopt enabling regulations for pipeline construction.

Pore Space Ownership and Access

- A quick solution to this question would be for the state to declare that all pore space belongs to the state which it can then lease as appropriate. Of course this option will likely require a constitutional amendment and would likely engender challenges as a "taking" of physical property. Absent this option, the Workgroup believes that **pore space ownership** is not a subject appropriate for legislative determination because it is a property right. However, it was agreed that "pore space" means the strata into which storage will occur. As such, it appears to be associated with ownership of the strata and should be analyzed accordingly. For example, if the property is a fee estate, the ownership of the pore space lies with the fee owner. If the mineral estate has been severed by a lease or deed, the language of the instrument and rules of instrument construction will determine the issue.

This interpretation then suggests the potential for several paths to accessing the pore space and addressing compensation to pore space owners for the use of their property.

- First, the storage activity may be conducted by public utilities which would operate and manage the permitting, injection and monitoring of a storage facility, subject to the jurisdiction and control of the Public Service Commission (PSC) as part of their primary function of providing services to the public. This entity would have the power of eminent domain to obtain access to the pore space. Owners would be compensated under existing rules for their lost estate. However, this approach only addresses electric generating utilities, which represent only a portion of the regulated industries.

- Entities wishing to act as storage facilities but not subject to the PSC would have to gain access to pore space. Access to pore space may be through conventional leasing, and could utilize a pooling or unitization rule similar to that which is currently in place for aggregating the interests of entities in oil and gas extraction. Owners of the pore space would be compensated by the storage facility subject to those agreements.

- Similar to common carrier pipelines, when unitization is not possible, the storage entity should have the power of eminent domain to obtain access to the storage space, subject to a requirement of nondiscriminatory service under published tariffs determined to be fair, just and reasonable. The pore space owners would be compensated for the lost value of their estate.

- Finally, the possibility of creating a new kind of public utility should be examined. As the storage of carbon dioxide is in the public interest, these entities are certainly providing a service to the public. Regulation by the PSC could enable the establishment of service areas, much like the areas designated for service by our electric providers. Status as a public utility would also allow the storage entities to obtain access to storage space through the power of eminent domain.

- All entities storing carbon dioxide would be subject to appropriate permitting and reporting under applicable regulation.

Recommendation:

✓ Legislatively create a new type of public utility, under the jurisdiction of the PSC, for geologic storage of carbon dioxide. Provide appropriate powers for the expected activities and appropriate oversight to protect the public interest.

✓ Legislatively provide the ability to unitize a geologic storage area generally based on the principles now used in the oil and gas industry. This statutory solution may have to address substantially larger areas than are generally applied in the natural gas or oil industry.

✓ Provide for the power of eminent domain for storage of carbon dioxide where appropriate, consistent with Kentucky's constitutional and legislative restrictions on the exercise of the power requiring that there be a public use served, not merely a public purpose.

Long-Term Liability

Following the closure and monitoring of a storage facility, the Workgroup believes that the long-term responsibility for monitoring, corrective action and liability should generally be funded by the generator of the CO_2 and transferred to the state or federal government. The Workgroup recognizes that carbon constraints are being enacted as a matter of public policy and, as such, the collective public should shoulder the long-term aspects of its actions. Therefore, the Workgroup recommends that a means be established by which the liability and responsibility can be transferred to the state, or to the federal government should that become a possibility.

A consensus is emerging from other state and international frameworks that title and liability for the sequestered carbon remain with the storage operator while site is active and for a specified period of time (10-20 years) after a closure permit has been issued. After closure, states (and other nations) are planning to assume long-term liability and monitoring responsibility.

- In order to adequately accept the **long-term storage monitoring and liability**, the state must have both authority and funds. Both paths (identified above) to access the pore space and store carbon dioxide should be subject to a fee per ton of CO_2 injected, which will be actuarially set and periodically adjusted to capture the cost of long-term monitoring and possible remedial action necessary, which will be transferred to a trust or other entity to fund the associated long-term responsibility. The entity holding the funds generated from this fee must be able to ensure that the funds will remain available to serve their intended purpose and will not be eligible for transfer to the General Fund at any time in the future.

- However, because we cannot foresee what demands will be made on the allocated funds, we also cannot envision whether there may come a time that the funds are deemed to be too much or too little for the purpose. Therefore, the state or designated entity must have the ability to increase the fee charged when actuarial projections indicate too little funding will be available. Conversely, if in the future, the sequestered funds are substantially more than expected expenditures, a means by which excess funds can be expended should exist. Preferably, those excess funds would be used for a related research purpose.

To meet these objectives, a legislatively created CCS non-profit organization – possibly modeled along the lines of the Kentucky Employers Mutual Insurance (KEMI) Authority – should be given serious consideration. The CCS non-profit would have two primary functions. After closure of a CCS site, the non-profit would 1) assume the liability for the long-term storage of CO_2 and 2) assume the responsibility for the ongoing monitoring and maintenance of the CCS sites. A fee per ton of CO_2 would create a viable and ongoing revenue stream to ensure that adequate resources are available to shoulder these responsibilities. Given this revenue stream, it is anticipated that no state appropriations will be required for the Authority, outside of the need for an initial appropriation sufficient to allow the organization to be created and staffed. The revenue stream should ensure stability and operational viability so long as the revenues generated and potentially accumulated are not subject to transfer back to the state's general fund.

The Workgroup also agreed that in the event that there is a future commercial use of the stored carbon, the non-profit organization, having taken on liability and responsibility of the stored carbon, should utilize any future revenues to ensure organizational viability and, if possible, develop programs to further secure Kentucky's energy future (e.g. ongoing university CCS research, clean-coal combustion research, energy efficiency initiatives, etc).

Recommendation:

✓ Establish a statutory framework that delineates between private sector and public responsibility for title and liability of sequestered carbon based upon the emerging consensus that CCS site operators hold title and liability during active site operation and for a specified period (10-20 years) after closure, at which time the state or a designated entity assumes title, liability and responsibility for long-term monitoring, with costs prepaid by the generators using a fee per ton of CO_2 sequestered, actuarially set to assure funding of all present and future liabilities and responsibilities.

✓ Create and provide initial funding for a statutorily authorized CCS non-profit to assume title, long-term liability and monitoring responsibility for CCS sites after closure. Authorize the CCS non-profit to levy appropriate fees to enable organizational viability.

Finally, in addition to the specific recommendations described above, the Workgroup recognizes the need to immediately engage with surrounding states, and with states which will be hard hit by the pending carbon constraints to develop a unified and coordinated approach to the issues we will commonly face. This effort should include development of a coordinated approach with surrounding states as to migration of CO_2 and its treatment as trespass.

WORKGROUP MEMBERSHIP

Legal Issues – CO_2 Workgroup

Andrew McNeill
Barry Mayfield
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Bill Sharp
Bob Ehrler
Brandon C Nuttall
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Jerry Purvis
Jim Fallin
Jim Lamb
Jimmy Keeton
John Buckner
John Cooper
John Horne
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Judge Jack B McCaslin
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Karen Thompson
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Mike Haines
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Talina Mathews
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Timothy C Mosher
Tom Dorman
Tom Fitzgerald
Tom Lane
Valerie Hudson
Van Needham

10/7/2008

Discussion from "Carbon Management for Greener Energy" Session, 32nd Governor's Conference on the Environment
Lexington, KY October 7, 2008

Presentations were made by

- Dave Harris, KGS, and Karen Thompson, SMG on geologic sequestration,
- Karen Greenwell, Wyatt Tarrant & Combs and Michael Healy, UK College of Law, on legal aspects of sequestration, and
- Sara Smith, SMG, on legislative actions taken by other jurisdictions.

Following the presentations, a general discussion with questions and comments from the audience and presenters ensued. The presentations can be accessed through the Energy and Environment Cabinet's website, www.energy.ky.gov.

Opening comments:

Secretary Len Peters, Energy and Environment Cabinet, and Dean Louise Graham from the University of Kentucky College of Law joined the panel to comment and respond to questions.

In response to a question about the capacity of Kentucky's geologic strata for carbon sequestration, Secretary Peters, with assistance from Brandon Nuttall, KGS, was able to state that Kentucky should have enough geologic carbon storage capacity for up to 300 years of emissions, based on the current amount of electricity generation in Kentucky.

Secretary Peters stressed that we need to keep our approach to carbon management **as simple as possible – but no simpler (quoting Einstein)**, while engaging the legal community and educating the general public.

Louise Graham, dean, UK College of Law, stated that UK Law plans to put some students in Sec. Peter's office to work on these topics. The Law School will also facilitate additional **round table** discussions on the topic with the next discussion to be scheduled in November, most likely to be held at the KGS Core Barn in Lexington.

Sara Smith, SMG, read portions of a letter from Tom FitzGerald, Kentucky Resources Council, who could not attend. The letter has been included with the minutes of the meeting.

Questions and discussion:

Pore space: How is the Kentucky Consortium on Carbon Storage (KYCCS) addressing the potential issues of trespass and pore space ownership in its test projects? Dave Harris of KGS answered that only a small volume of CO_2 is being injected in the current projects, and it can't migrate far. There are also agreements with both the surface and mineral owners, so it's not an issue for these test projects.

We should approach the **pore-space access issue** incrementally. Start with the handling of the pore space. But this involves the different "estate" owners with different rights (surface rights, mineral rights, water rights, etc). Eminent domain may be necessary but should be used carefully and sparingly.

The definition of pore space needs to be established (i.e., does it mean with or without the gas stored in it?). Dave Harris pointed out that in determining what pore space is and who owns pore space, we must be cautious not to inadvertently impact rights pertaining to **caves and caverns**.

A structure should be created to allow projects to go forward while such ownership issues are worked out. Waiting for such legal determinations shouldn't hold up important projects or developments in this arena.

State Representative Rocky Adkins, Sandy Hook: We've worked together to get to where we are, and we're being seen as a **national model** in our approach to adopting a policy for the state on a broad range of energy issues: renewables, energy efficiency, etc. The real vision here was consideration of our opportunity to expand research and development, backed up with state money, which we'll continue to do. We also expected entities like KGS and UK Center for Applied Energy Research (CAER) to find a match for the state funding, whether in carbon capture, carbon storage, or gasification research. The hope is that Kentucky will be seen as the **place to be for both R & D and placement of new-technology energy industries**, creating a new economy for the state and the nation.

He noted that energy industries have requested over a billion dollars in economic incentives from the provisions of House Bill 1, passed in 2007. If all of them were built, it would mean over $15 billion in capital construction investment.

Sec. Peters: Don't be lulled into thinking there's not much urgency in addressing the legal issues of carbon storage. Texas, for instance, has been sequestering CO_2 for many years. We'll need the legal framework in place for affected companies to be prepared to do it. We don't have a decade to work on reducing Kentucky's carbon footprint and managing carbon emissions.

Sara Smith: A recent Government Accountability Office (GAO) report has indicated that the liability and ownership issues <u>must</u> be addressed. Property issues are handled at the state level.

General Discussion:

Property owners need to understand the pore space issues as they relate **to contracts for the use of their land and subsurface rights**. They need to know what provisions are included in leases, deeds etc., such as contracts regarding the right to inject gas deep underground and the rights to pore spaces.

It was noted that the comment period on the EPA's proposed Class VI injection well regulations is open through November. States, businesses and individuals need to file any comments they have.

The classification of carbon dioxide will be an evolving issue. With technology breakthroughs, the gas could go from being seen as a waste product to a resource. This is what Dow Chemical and 3-M have typically done: Continuous examination of transforming waste products into useful resources. **Defining carbon dioxide as a waste is too narrow a view.**

Leadership in this arena is an issue: **Who will set the pace** on this discussion, at the national and state level? It was noted that the U.S. became excited about coal liquefaction once before, then it faded away. Some leadership entity needs to set time frames and **goals** on the issues being discussed here.

In the next few years, there will likely be a **carbon tax**, which will impact what is paid by utility users. With **40% of Kentucky living below the poverty line**, these people will be at risk, making it imperative that policy decisions be made. Additionally, there appears to be a consensus that funds from a carbon tax should be **actively applied to the solution.** If a **carbon tax** is a given, the **revenue should not be diverted** from the task of resolving the issues being discussed here. This seems to be what happened when a similar levy was made on the nuclear power industry to create methods of disposal of nuclear waste. The state should be trying to influence the way that any funds from a national carbon tax are to be used.

Sec. Peters: We have not taken a position on a tax vs. a cap and trade system. I believe a cap and trade system is more likely, though I don't necessarily prefer it. Utilities will want **regulatory certainty** on the use of the funds from a carbon tax. The issue of **pass through** costs resulting from CO_2 constraints will be important.

Rodney Andrews of CAER: Industries won't continue to provide matching funds for research projects as they have with KGS and CAER if these topics aren't addressed. **Regulatory and liability certainty** are required to continue research, development and commercial application. **Liability and uncertainty limit research**.

The state's prohibition on nuclear power plants for energy may have to be modified if the state is to reduce its "carbon footprint."

How will the state balance its concern for reducing its carbon footprint while also dealing with the issue of carbon credits and carbon dioxide as a resource? The overall equation of reducing the state's carbon footprint must include consideration for how to handle the carbon emissions created by the new technologies, such as gasification.

Sec. Peters: Kentucky seems to be limiting itself too much to geologic sequestration. **What about biologic sequestration?** DOE has indicated it is focusing its greatest attention on geologic sequestration. I think we need to look at other storage strategies, and **states should take some leadership** on this. We're working with CAER on some alternative sequestration strategies.

A fund should be created for up-front state monitoring as well as activities in perpetuity. This raises the question of where the long-term liability will lie and what that liability may be.

Suggestion for next year's Conference on the Environment: How to determine the monetary value of CO_2. We need to know what kind of accounting standards need to be developed to determine how to compare the costs of one course of action to another. Is it an asset or a liability (similar to whether it's a waste or a resource), and how will it be valued as such.

Action Items:

- Presentations will be available through the www.energy.ky.gov web site.
- Minutes describing the discussions will also be made available.
- Additional conversations will be held and facilitated by the Department for Energy Development and Independence and the UK College of Law. The next round table conversation will be held in November and will be announced at www.energy.ky.com.
- Efforts to identify and include stakeholders will be a focus.
- Values to be applied to all options and issues will be agreed upon.

Notes from Meeting of Organizers
October 14, 2008

Attending: Karen Greenwell
Karen Wilson
Brad Stone
Sara Smith
Louise Graham
Michael Healy

- A date for the next conversation was established as November 12 and it was agreed that a 3-4 hour session would be adequate. *Note: This has been amended to December 1, 9AM to 1PM*
- The KGS core barn in Lexington appears to be a convenient place to meet with no or low cost. *Note: KGS has agreed, has the venue scheduled and will provide coffee and pastries.*
- Discussion about who should be there included Tom FitzGerald and other members of the environmental community, representatives of the oil and gas industry and coal industry, in addition to KGS, state legislators, utilities, executive branch policy makers and all others who have expressed an interest. *Note: List at the bottom indicates who has been invited or notified.*
- The general discussion regarding access and control included the issue of condemnation with the suggestion that we need a system that is certain, perhaps looking to the FERC model, with a process that allows progress. In order to have condemnation or eminent domain, there must be a public purpose established and agreed upon. We questioned whether the state condemnation code will work as it. The measure of damages in the state system is the difference in value before and after the taking. The value diminution CANNOT include fear. Additionally, minerals are not valued separately. This may leave the question of access in doubt. Condemnation for pipelines and gas storage fields may provide the closest analogy. Regardless, all interests must be joined in a manner that allows the project to proceed. Can the state assert a fee interest in strata below a certain depth?
- The general discussion of responsibility raised the question of who owns the CO2 when injected, and much later? The best analogy is probably the storage of natural gas which does not change ownership when injected. The IOGCC model contemplates a trust fund created by injection fees. In Kentucky, how would you protect the trust fund from the legislature? Long term liability may be subject to bonding over a period of time, similar to surface mining. Question then becomes, when is the bond released?

Parties contacted:
Tom Fitzgerald (confirmed he will attend Dec 1)
Rusty Ashcraft (will attend)
CAER – Greg Copley
EMLF – Sharon Daniels (confirmed)
NGAS – Bill Barr and Rick Bender
Rocky Adkins
Tania Pullin
Western Ky Sequestration Project Partners

12/1/2008

Next Meeting – 12/1/2008
9AM – 1PM
KGS Core Barn

Organizers include: UK College of Law
Energy & Environment Cabinet

Follow up to Carbon Sequestration session at the Governor's Conference

Session will review basic assumptions: (30 minutes)

- Some sort of regulation will require, through tax or cap & trade, that carbon dioxide emissions be limited
- In order to meet current electrical demands and supply the increased demand, we will be required to sequester carbon, among other activities to reduce CO2 emissions
- The available means of storage will include geologic sequestration which will include EOR and storage in deep saline aquifers
- We will assume this can be done safely and maintained effectively
- We assume there is an urgency requiring that this new activity must mature more quickly than a similar large project
- We assume that geologic storage is in the public good
- We assume that there is a potential for later use of the stored carbon

The discussion will begin with a brief summary of the earlier session and an explanation of the assumptions.

The discussion will then center on two aspects:

- The legal implications of how we will access and control the storage site (1:30 hours), and
- Who will be responsible for the CO2 during different period of the project from capture onwards through long term storage. Responsible includes both the physical control and the legal liability. (1:30 hours)

Wrap-up, Action Items, Next Meeting (20 minutes)

December 1, 2008 Meeting
CCS Legal Issues Discussion Group

Attending:
Karen Thompson, SMG
Rick Bertelsen, PSC
Michael Healy, UK Law
Sara Smith, SMG
Taylor Moore, LRC
Brad Stone, KY DEDI
Mike Lynch, KGS
Dave Harris, KGS
David Samford, PSC
Lee Colten, KY DEDI
Karen Greenwell, Wyatt
John Horne, KY DEP
P.A. Moss, MXI Technologies
Craig Stratton, MXI Technologies
Len Peters, KY EEC
Mike Haines, KY EEC
Rodney Andrews, UK CAER
Kim Collings, KY Div Oil and Gas
Bill Barr, NGAS
David Williams, KGS
Brandon Nuttall, KGS
Greg Copley, UK CAER
Karen Wilson, KY EEC
Scott Smith, SMG
Rick Bender, NGAS
Todd Littlefield, LRC

Sara Smith moderated the discussion. Sara Smith opened the meeting with a recap of the last session at the Governor's Conference on the Environment. Topics reviewed: common law, science of CCS, urgency of issue, need for simplicity ("keep it as simple as possible, but no simpler"). Property rights are like a "layer cake" (surface rights, mineral rights, voids for CO2 injection). This is a significant public policy issue; uncertainty is hindering R&D; need an expedited approach.

Items for today's meeting:

Assumptions
Access and control of storage site
Responsibility for CO2

Jim Cobb: Regionally, all state geological surveys are engaged in CCS research, which is rare. Legislation should be coming in 1-2 years. Recently attended a conference in IL and IN on this same issue of legal concerns.

ASSUMPTIONS

There will be some sort of national requirement that CO2 emissions will be regulated/limited.
CO2 sequestration will be required.
Enhanced oil recovery and deep storage will be included.
We will do CCS safely, effectively, and efficiently.
The size of our coal reserves demands development (Cobb); these resources will not be left in the ground.
Urgency
Geologic storage is in the public good.
There is potential for later use of the stored CO2.
CO2 occurs naturally in deep subsurface.

Dave Williams: most utilities are on the Ohio River; thus, interstate issues emerge with CCS; and hence a role for federal intervention.

Scott Smith: First target should be storage volumes in your state. Going interstate in past experiences was done with EOR in mind.

Dave Williams: There are three strata being looked at in KY: Mt. Simon, Knox Dolomite, St Peter sandstone. KGS will test all three, but Knox is most promising. Depth of 2,500 feet is minimum necessary to achieve supercritical phase. 5% porosity (10% is likely); 10-20 millidarcies viscosity (low).

In Kentucky, property is owned “in fee.” KGS contracted with surface owner and mineral owner and leasor.

Cobb: The Knox extends nearly throughout the entire state of Kentucky.

Nuttall: CO2 can be stored in coals, displacing methane in the process. Nuttall's research is focused on determining if this can be done with shale (including enhanced gas recovery).

Bill Barr: Increasing recoverability factor by 5% in natural gas extraction is a no-brainer, but the CO2 must be removed, processed, and re-injected into the void. However, these areas may not be suitable for permanent storage. These factors determine the overall economic feasibility.

Common law gives each mineral owner the right to access their minerals including through EGR provided you preserve the rights of those above you (coal vs. gas vs. oil).

Economic issues are affected by improper casing of disposal wells; most coal issues can be worked around.

Rick Bender: Example: Arbuckle formation in (WV?) they are using horizontal drilling; allow one well instead of several across a field.

Bill Barr: KRS 353 – Division of Oil and Gas has obligation to permit oil/gas drilling through coal. At 5% porosity, you need a lot of storage volume. Legislature needs to establish some rights between competing interests. [condemnation question].

Len Peters: Some percent of CO2 injected will sequester in coals or shales, so it's the "how much" that can affect overall feasibility. "Native sequestration" could lead to a preference for shales.

Barr: There are thousands of Devonian shale gas wells that are still viable.

Nuttall: Seems the model of natural gas storage is a logical parallel to CO2 storage.

Barr: We use depleted reservoirs because they exist; and we know more about them. There are ~25 natural gas storage fields in KY.

Cobb and Harris: Defining the boundaries in a CO2 storage reservoir is a lot more challenging.

Harris: Like "oil on top of vinegar in salad dressing" the CO2 can migrate somewhat with added water over time "up-dip." CO2 will be injected in Hancock County without traps.

Barr: Abandoned wells, poor construction, means oil/gas reservoirs are not a realistic option for permanent sequestrations. Deep saline or shales seem more likely.

Peters: Regarding the question of UIC primacy: Yes, we're looking at it; we've had discussions with EPA R4; they want KY to take it over; need to work through budget constraints of hiring staff to implement.

Harris: Ky could assume primacy over class 6 UIC only as a first step.

Barr: Rulemaking comment period for federal regs has been extended to Dec. 25. Class 6 would need to be adopted at state level.

Bender: statutory change is also necessary.

After Break Topics:

Pipelines
PSC Role
CCS is not equal to access to minerals
Eminent domain

Sara Smith: Should we equate CCS with "accessing my minerals?"

Nuttall: Is porosity not a mineral commodity?

Barr: There are some southern cases dealing with access through aquifers. But legislature can assign ownership without a "takings" issue.

Karen Greenwell: FERC condemnation process is somewhat established. Issues over area of plume and access around wellhead; assessing value of impacts of access is another unknown.

Barr: Coal will be more than happy to have their coal condemned un-mined. Who will pay for this? Probably the ratepayers.

Karen Greenwell: Difference is deep saline injection (a valueless formation) vs. EGR void which has value. (Smallwood case).

UIC permits must demonstrate the injection target doesn't have hydrocarbons present.

Harris: in the Future Gen proposal, KGS identified a 50-ft zone in Knox, plume volume assuming 9% porosity, at 1 M tons/yr for 30 years would require 50 square miles.

Barr: Class 1 haz waste injection has no concern for property rights, assuming no migration is detected.

Greenwell: oil/gas owner doesn't necessarily own the void space left behind after extraction.

Copely: sequester in public land to avoid ownership issues?

Samford: Natural gas pipelines largely regulated by FERC (wholesale distrib.) Water lines are PSC domain (retail distrib.); CO2 seems more akin to the natural gas (intuitively speaking), though there is a connection to PSC if CCS affects utility rates.

Scott Smith: CO2 is now included in definition of a gas for the purposes of the pipeline authority. What context does that imply?

Barr: Pipeline authority is merely a financing conduit for construction. No real impact unless it's to finance (via bonds) a pipeline. There is a nebulous rarely-used statute for intra state pipeline construction. Oddly, none for liquids and crude oil.

Option: Move CO2 under FERC for pipeline right-of-ways.

Bertelsen: Interstate compact concept (IL, OH interested).

PHYSICAL CONTROL / RESPONSIBILITY

Need to examine IOGCC model legislation. States charge fee per ton sequestered. After 10 years of monitoring, the trust fund is tapped for state long-term liability.

Haines: Maxey Flats has a separate statute and federal involvement, which is key for all of this.

Concerns regarding capture, transport, injection, storage, long-term storage. Concerns are not health related (except maybe around the surface), but economic liability is the key issue.

Barr: Proposed EPA regs look at 50 years of monitoring. Need to resolve CO2 as a waste vs. a commodity.

Peters: Plausibility of future utilization of stored CO2 is 1 in a million.

Barr: Does it really matter? Eventually costs will roll to either taxpayers or ratepayers (who are obviously the same people).

Sara Smith: this brings to mind concerns about higher rates and their impacts on indigent populations, and energy-intensive industries.

Peters: Funds from carbon taxes could be set-aside to assist low-income people, in addition to R&D.

Rodney Andrews: Coops are capped on funds they can devote to liability in relation to financing construction. Also, how do we handle TVA?

Bertelsen: We have very little leverage with TVA beyond their own federal statutes and regs.

Barr: Statute of limitations in federal program could be 15 years, but what are the real liabilities? Presumably de minimus.

Peters: If Congress adopts a waste-oriented approach as they did with nuclear waste, it could be very long term liability.

Secretary Peters thanked the group for participating with this legally and technically complex issue. This is an issue that is very important to the Commonwealth. There are several state in the same boat as we are. It's encouraging to have the law school's involvement as a means to educate ourselves and the legislature. Key stakeholders are not here, but we will work to bring them into the discussion. UK Law students will be joining EEC to work on issues such as this.

Sara Smith: Tort-type claims are likely to only come from well-drilling and abandonment. What is "long-term?"

Stakeholders not present: Tom FitzGerald, utilities, Schlumberger, coal industry, primary metals, cement, refineries, fertilizer manufacturers.

Barr: federal tax could roll all the way back to the coal operator. CCS can sterilize coal.

Scott Smith: need to be aware of where the U.S. House Energy committee is headed now that Rep. Waxman is chair; see white papers.

Next discussion items:

Class 6 permit regs / primacy
RCRA mode vs some other regulatory scheme

Recurring themes:

Education
Natural gas storage as regulatory model
Personnel for UIC permitting
Statutory change to allow class 6 reg development, perhaps in the form of a resolution; need a legislator to lead the charge
Outcomes from NGA meeting in DC on 12/16/08

Sara will contact stakeholders
Scott will contact legislators to determine if there is any pending legislation that might affect this issue.
Need to develop a study group thru EEC and/or the law school.
Next meeting will be in January on a Monday or Friday.

West KY KGS test will inject 300-1000 tons during a 3-week period at 1,200 psi.

Sara Smith

From: Bertelson, Rick (PSC) [Rick.Bertelson@ky.gov]
Sent: Friday, February 13, 2009 3:50 PM
To: FitzKRC@aol.com; Sara Smith
Subject: RE: Meeting Announcement for Carbon Sequestration Workgroup
Attachments: 12-1-08 KGS attendance sheet.pdf

Sara,

As we discussed this afternoon, below is my summary e-mail regarding the December 1, 2008 meeting.

Fitz,

Since you asked for any minutes and an attendance sheet, here you go as well.

-Rick

Richard W. Bertelson, III
Kentucky Public Service Commission
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On Monday, David and I attended a meeting at the Kentucky Geological Survey in Lexington regarding the urgent need for Kentucky policy makers to start making decisions about how we are going to handle carbon capture and sequestration from both a legal and regulatory standpoint.

Among those present at the meeting were Secretary Peters, Karen Wilson of his staff, Brad Stone from Energy, Professors Janet Graham and Mike Healy of the UK Law School, Mike Haynes and John Horne of the Cabinet's environmental legal staff, Rodney Andrews from the Center for Applied Energy Research, Jim Cobb the State Geologist (KGS), Sara Smith of Smith Management, Scott Smith (Chair of the Environmental Quality Commission), Bill Barr of the Natural Gas Assoc., Karen Greenwell of Wyatt Tarrant & Combs, and Taylor Moore with LRC. There was another fellow from LRC, but he came late and he didn't give his name or sign the sign-in sheet. there were a number of other attendees as well. See attached attendance sheet.

Those present at the meeting agreed that, from a legal standpoint, there is a need to establish who has rights over the porous rock layers under the earth where most of the carbon emissions that would be captured under a carbon control regime will likely be stored. Some states, such as Montana and Wyoming, have already passed such legislation. So, we would not have to start from scratch.

From a regulatory standpoint, there is a need to have a permitting program in place to govern how such carbon storage is undertaken. Most likely, such regulations will follow along the same general framework as existing regulations for the underground storage of natural gas.

However, there will be some differences, as the underground storage is not for reuse--at least in the short term--and these storage areas may underlie a lot of other underground minerals and drinking water supplies that could be affected by the carbon.

There was also an accompanying discussion of Kentucky's potential for geological storage and the research projects currently being undertaken by the KGS in both western and eastern Kentucky. Some of the research in eastern Kentucky is going to be looking at injecting into shale formations to both store CO2 and to drive off methane entrapped in the shale, for commercial recovery and use. The technology has been shown to be feasible when CO2 is injected into coal beds. So, KGS believes the same should be true for shale.

The main takeaway from the Carbon Sequestration meeting was that the Energy and Environment Cabinet should push to get funding back to take primacy over permitting for Class II injection wells. Class II wells inject fluids associated with oil and natural gas production: http://www.epa.gov/ogwdw/uic/wells_class2.html#what_is. Apparently, the Cabinet had the funding and two employees in place for a Class II permitting program in either 2006 or 2007, but the money was redirected and the employees were let go before their probationary periods ran. So, the program has not gone forward since then.

It was suggested at the meeting that if the Cabinet can get the Class II permitting program re-established, then it will be much easier to eventually get EPA approval for primacy over permitting Class VI wells (for underground carbon injection). The group agreed that will be necessary if Kentucky wants to have a successful carbon capture and sequestration program. Note that the regulations establishing such wells are still pending. You may recall that we filed comments on those EPA regs in November. There would also have to be legislation passed to give the Cabinet the authority to take primacy over permitting Class VI wells, as there is apparently a statute on the books that prohibits taking primacy over any injection well permitting other than Class II (I have looked for that statute but have not found it yet).

There will be continuing meetings of this group, which may develop into a study group to draft model legislation. Secretary Peters had to leave before the end of the meeting. So, Karen Wilson said she would discuss with him how he wants the group to be organized and run. Scott Smith is going to start contacting legislators to discuss these issues with them and see if anyone would be able to help getting funding back for the Class II well program and to see who might be interested in sponsoring legislation in the 2010 session to get authority for the Cabinet to take primacy over permitting for Class VI wells. Sara Smith is going to contact other stakeholders who were not present at Monday's meeting (utility companies, environmentalists, coal companies, low income groups) to see if they will engage in this discussion. And UK Law School will be providing some research work.

The next meeting of this group will be sometime after the holidays, in the early part of January 2009.

-Rick

From: FitzKRC@aol.com [mailto:FitzKRC@aol.com]
Sent: Friday, February 06, 2009 9:58 AM
Subject: Re: Meeting Announcement for Carbon Sequestration Workgroup

Sara:
I will be able to attend the February 13 meeting. Your note indicates that there are certain assumptions that were "agreed upon." Could you provide those assumptions, and a list of who was in attendance at the meeting

where the assumptions were agreed upon, and any minutes from the meeting?

Fitz

In a message dated 2/6/2009 8:54:12 A.M. Eastern Standard Time, Sara@smithmanage.com writes:

> **Conversation on Carbon Sequestration**
>
> You are invited to participate in an important ongoing discussion about the legal issues and impacts in Kentucky of carbon sequestration.
>
> As a follow-up to a session at the Governor's Conference, and a further meeting and discussion held in early December, the next conversation on carbon sequestration has been scheduled for **Friday, February 13, from 10:00AM - 2:00 PM** in **Room 111 of the Capital Annex** building in Frankfort.
>
> Numerous groups and individuals are engaged in this discussion and your participation, as a stakeholder in this issue, is important. To date, we have significant involvement from the University of Kentucky College of Law, the Kentucky Geologic Survey, The Center for Applied Energy Research, the Department for Energy Development and Independence as well as oil & gas interests, the legal community, the environmental community, coal interests and utilities.
>
> All businesses, groups and individuals interested in the impact of projected carbon constraints and the effect on power generation and costs should participate in this discussion of one potential means of reducing carbon dioxide emissions.
>
> During the last meeting, certain assumptions were discussed and agreed upon as a basis for discussion. An extensive discussion about access to potential sequestration targets was conducted and we began discussions the potential liability of this technology and where responsibility would lie during all phases of a project.
>
> Please let us know if you or your representative will be able to attend by contacting Christy Morris at Christy.morris@ky.gov or 502-564-3350.
>
> Please call with any questions you have about this meeting.
>
> Sara G. Smith
> President
> **SMITH MANAGEMENT GROUP**
> 859-231-8936 ext. 105
> **Saras@smithmanage.com**

"History is a compass for the future - we look back and then we go forward and if we're lucky, we journey together in wisdom and in faith and perhaps even love." Al Smith's Farewell, Comment on Kentucky.

AME	EMAIL
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Michael Healy	healym@uky.edu
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David Samford	DavidS.Samford@ky.gov.
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John Horne	john.horne@ky.gov
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Kim Collings	Kim.Collings@ky.gov
Bill BARR	~~NGAS RES.~~ bbarr@NGAS.com

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Greg Copley	gccop12@uky.edu
Karen Wilson	KarenL.Wilson@ky.gov
Scott Smith	Scott.r.Smith@smithmanage.com
Rick Bender	rbender@ngas.com
D. TODD LITTLEFIELD	TODD.LITTLEFIELD@LRC.KY.GOV

2/13/2009

Sara Smith

From: Sara Smith

Sent: Friday, February 06, 2009 8:54 AM

To: '(Karen.Armstrong-Cummings@lrc.ky.gov)'; 'Barry Mayfield'; 'Bill Barr'; 'Bob Leeper'; 'Bob M. DeWeese'; 'Brandon C Nuttall'; 'Brent Yonts'; 'D. Todd Littlefield'; 'Dale Honn'; 'David B. Meece (dbmeece@tecocoal.com)'; 'David E. Boswell'; 'David Freibert'; 'David Osborne'; 'David Samford'; 'Don Newell'; 'Dwight D. Butler'; 'Ed Stephens'; 'Eddie Ballard'; 'Edman, Sarah A.'; 'FitzKRC@aol.com'; 'Fred Nesler'; 'Gary Tapp'; 'George Siemens'; 'glenn.sundheimer@eon-us.com'; 'Graham, M L'; 'Greenwell, Karen'; 'Greg Copley'; 'Harris, David C'; 'James C Cobb'; 'Jim Fallin'; 'Jim Gooch'; 'Jimmy Keeton'; 'John Buckner (John.Buckner@lrc.ky.gov)'; 'John Cooper'; 'John Horne'; 'John Talbert'; 'Judge Jack B. McCaslin'; 'Karen Thompson'; 'Karen Wilson'; 'Katie.allison@ky.gov'; 'Kelly Blevins (Kelly.Blevins@lrc.ky.gov)'; 'Kim Collings'; 'Larry Clark'; 'Lee Coulton'; 'Leonard Peters'; 'Leslie Combs'; 'Lillian F Deprimo'; 'Lonnie Napier'; 'Michael Healy'; 'Mike Gribler'; 'Mike Haines'; 'Mike Lynch'; 'Myron Dossett'; 'Nancy Mitchell'; 'Nick Brake'; 'Rebecca Brooker (Rebecca.Brooker@lrc.ky.gov)'; 'Rick Bender'; 'Rick Bertelson'; 'Rick G. Nelson'; 'Robert Stivers'; 'Robin L. Webb'; 'Rodney Andrews'; 'Roger Medina'; 'Ron Weston'; 'Rusty Ashcraft'; 'Sannie Overly'; Sara Smith; 'Schetzel, Doug'; 'Scott Rennie'; Scott Smith; 'Shannon Graves'; 'Sharon Dodson'; 'Spoonamore, Susan (LRC)'; 'Stefan Kasacavage (stefan.kasacavage@lrc.ky.gov)'; 'Stone, Brad (EEC)'; 'Suzanne Fisher'; 'Tanya Monsanto (Tanya.Monsanto@lrc.ky.gov)'; 'Taylor Moore'; 'Thomas Kerr'; 'Tim Moore'; 'Timothy C. Mosher'; 'Tom McKee'; 'Tom Riner'; 'Van Needham'; 'Williams, David A'

Subject: Meeting Announcement for Carbon Sequestration Workgroup

Conversation on Carbon Sequestration

You are invited to participate in an important ongoing discussion about the legal issues and impacts in Kentucky of carbon sequestration.

As a follow-up to a session at the Governor's Conference, and a further meeting and discussion held in early December, the next conversation on carbon sequestration has been scheduled for **Friday, February 13, from 10:00AM - 2:00 PM in Room 111 of the Capital Annex** building in Frankfort.

Numerous groups and individuals are engaged in this discussion and your participation, as a stakeholder in this issue, is important. To date, we have significant involvement from the University of Kentucky College of Law, the Kentucky Geologic Survey, The Center for Applied Energy Research, the Department for Energy Development and Independence as well as oil & gas interests, the legal community, the environmental community, coal interests and utilities.

All businesses, groups and individuals interested in the impact of projected carbon constraints and the effect on power generation and costs should participate in this discussion of one potential means of reducing carbon dioxide emissions.

During the last meeting, certain assumptions were discussed and agreed upon as a basis for discussion. An extensive discussion about access to potential sequestration targets was conducted and we began discussions the potential liability of this technology and where responsibility would lie during all phases of a project.

Please let us know if you or your representative will be able to attend by contacting Christy Morris at Christy.morris@ky.gov or 502-564-3350.

Please call with any questions you have about this meeting.

Sara G. Smith
President
SMITH MANAGEMENT GROUP
859-231-8936 ext. 105
Saras@smithmanage.com

Attendees List
Friday, February 13, 2009
Capitol Annex Room 111
CO2 Legislation Meeting

Name	Organization	Email Address
Sara Smith	SMG	
Scott Smith	SMG	
Karen Thompson	SMG	karent@smithmanage.com
Dan Zaluski	SMG	danielz@smithmanage.com
Brandon Nuttall	KGS	
Bob Ehrler	Eon	
Rick Bender	Daughterty Petroleum	
Scott Kreutzer	TECO Coal	
Rick Bertelson	PSC	
Karen Greenwell	WTC	
Mike Lynch	KGS	
Brad Stone	EEC	
Len Peters	EEC	
Karen L. Wilson	EEC	
Taylor Moore	LRC	
Stefan Kasaravage	LRC	
Sharon Dodson	Eon	
Mike Haines	EEC	
Jason Bentley	MML&K	
Jimmy Keeton	AEP	
David Freibert	EON	david.freibert@eon-us.com
Tim Mosher	AEP	
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David Samford	PSC	
Dave Harris	KGS	
D. Todd Littlefield	LRC	todd.littlefield@lrc.ky.gov
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David B Meece	TECO Coal	
Brooke Parker	EEC	
Kate Shanks	EEC	
Nancy Mitchell	TVA	
Tom Fitzgerald	KRC	
Liz Edwardson	KRC	
Hank List	EEC	
Jerry Purvis	EKPC	
Rodney Andrews	CAER	
Mark Brewer	EKPC	
Michael Healy	UK Law	
John Talbert	Big Rivers	
Sabrina Watkins	ConocoPhillips	

Sara Smith

From: Sara Smith

Sent: Tuesday, February 24, 2009 10:12 AM

To: '(glenn.sundheimer@eon-us.com)'; '(Karen.Armstrong-Cummings@lrc.ky.gov)'; 'Barry Mayfield (barry.mayfield@ekpc.coop)'; 'Bill Barr (billbarr@ngas.com)'; 'Bill Caylor (bcaylor@kentuckycoal.com)'; 'bob.ehrler@eon-us.com'; 'Brandon C Nuttall (bnuttall@uky.edu)'; 'Charles R. Dailey'; 'D. Todd Littlefield (Todd.Littlefield@LRC.ky.gov)'; Daniel Zaluski; 'David B. Meece (dbmeece@tecocoal.com)'; 'David Freibert (david.freibert@eon-us.com)'; 'David Samford (DavidS.Samford@ky.gov)'; 'Don Newell (donald.newell@ky.gov)'; 'Eastern Mineral Law Foundation (news@emlf.org)'; 'Ed Stephens (estephens@tva.gov)'; 'Edman, Sarah A.'; 'George Siemens (george.siemens@eon-us.com)'; 'Graham, M L'; 'Greenwell, Karen'; 'Greg Copley (gccopl1@uky.edu)'; 'Hank List (Hank.List@ky.gov)'; 'Harris, David C'; 'James C Cobb (cobb@uky.edu)'; 'Jason Bentley (jbentley@mmlk.com)'; 'Jerry Purvis (jerry.purvis@ekpc.coop)'; 'Jim Fallin'; 'Jim Lamb (jim.lamb@ekpc.coop)'; 'Jimmy Keeton (jekeeton@aep.com)'; 'John Buckner (John.Buckner@lrc.ky.gov)'; 'John Cooper (JPCooper@bellsouth.net)'; 'John Horne (john.horne@ky.gov)'; 'John Talbert (jtalbert@bigrivers.com)'; 'Judge Jack B. McCaslin (jackbmack@bellsouth.net)'; 'Karen Thompson'; 'Karen Wilson (karenl.wilson@ky.gov)'; 'Kate Shanks (kate.shanks@ky.gov)'; 'Katie.allison@ky.gov'; 'Kelly Blevins (Kelly.Blevins@lrc.ky.gov)'; 'Kim Collings (Kim.Collings@ky.gov)'; 'Lee Colten (Lee.colten@ky.gov)'; 'Lillian F Deprimo'; 'Liz Edmondson (liz.d.edmondson@gmail.com)'; 'Mark David Goss (mgoss@fbtlaw.com)'; 'Mark S Brewer (mark.brewer@ekpc.coop)'; 'Michael Healy (healym@uky.edu)'; 'Mike Gribler (mike.gribler@duke-energy.com)'; 'Mike Haines (mike.haines@ky.gov)'; 'Mike Lynch (mike.lynch@uky.edu)'; 'Nancy Mitchell (nkmitchell@tva.gov)'; 'Nick Brake (nbrake@owensboro.com)'; 'Nick Carter (ncarter@wpplp.com)'; 'Patrick Underwood (Patrick.underwood@gallatinsteel.com)'; 'Peters, Len (EEC Cabinet Secretary)'; 'Rebecca Brooker (Rebecca.Brooker@lrc.ky.gov)'; 'Rick Bender (rbender@ngas.com)'; 'Rick Bertelson (rick.bertelson@ky.gov)'; 'Rocco D'Ascenzo (rocco.d'ascenzo@duke-energy.com)'; 'Rodney Andrews (andrews@caer.uky.edu)'; 'Roger Medina (roger.medina@eon-us.com)'; 'Roger Nicholson (rnicholson@intcoal.com)'; 'Ronald R. Van Stockum, Jr.'; 'Roy Palk (thepalks@insightbb.com)'; 'Rusty Ashcraft (rustya@arlp.com)'; 'Sara Smith'; 'Schetzel, Doug'; 'Scott Rennie (scott.b.rennie@conocophillips.com)'; 'Scott Smith'; 'Shannon Graves (shannons.graves@cemex.com)'; 'Sharon L. Dodson (sharon.dodson@eon-us.com)'; 'Spoonamore, Susan (LRC)'; 'Stefan Kasacavage (stefan.kasacavage@lrc.ky.gov)'; 'Stone, Brad (EEC)'; 'Suzanne Fisher'; 'Tanya Monsanto (Tanya.Monsanto@lrc.ky.gov)'; 'Taylor Moore (Taylor.Moore@lrc.ky.gov)'; 'Tickner, Dianna'; 'Timothy C. Mosher (tcmosher@aep.com)'; 'Tom Fitzgerald (FitzKRC@aol.com)'; 'Tom Lane (tlane@bowlesrice.com)'; 'Van Needham (van.needham@duke-energy.com)'; 'Watkins, Sabrina S.'; 'Williams, David A'

Cc: 'Stone, Brad (EEC)'; 'Dorman, Tom (LRC)'; Karen Thompson

Subject: Carbon Sequestration Legal Issues Workgroup

To all,

Thank you for participating in a productive meeting on Friday the 13th. Based on the discussions at the meeting, we have developed sub-workgroups to track issues and information and develop materials for education and potential legislation. The following people have volunteered to chair and organize these groups:

Sara Smith	saras@smithmanage.com	Other State Legislation
Brandon Nuttall	bnuttall@uky.edu	Technology and Research updates
Rick Bender	rbender@ngas.com	Federal Actions

Legal Issues will be organized by:

Karen Greenwell	kgreenwell@wyattfirm.com
Mike Healy	healym@uky.edu
Tom Fitzgerald	FitzKRC@aol.com

Compilation of all work will be organized by:

Scott Smith	scottr.smith@smithmanage.com
Jason Bentley	jbentley@mmlk.com

Note that we will benefit from the legal externship established by the UK College of Law and the Energy and Environment Cabinet and from students at Louisville's Brandeis School of Law as well. **If you would like to participate in any of these groups, please contact the person heading up the activity**. For those not in attendance, the next meeting will be held in late March. We hope to establish that date shortly. We have agreed to meet again in Frankfort with time scheduled for the work groups to meet prior to the general meeting. Each work group will report on its progress.

During our discussions we learned that an energy bill was likely to be filed this week which would include a section addressing the work we have set out to do. House Bill #537 was introduced yesterday http://www.lrc.ky.gov/record/09RS/HB537/bill.doc sponsored by Representative Rocky Adkins. This bill contains a number of interesting issues and I recommend your review.

Until this bill passes, we will proceed as planned. Upon passage, we will adjust to fit within the structure described by the bill and follow it's mandate.

At our meeting, the Department for Energy Development and Independence agreed to look at setting up a web page on which we will be able to post the minutes of our meetings, schedules and developments. We will notify you as soon as that is a reality.

Minutes from our last meeting are being drafted and will be forwarded as soon as they are ready.

Note that Wyoming has passed three bills which address carbon sequestration issues. Please review House Bills 57, 58 and 80

http://legisweb.state.wy.us/2009/Enroll/HB0057.pdf
http://legisweb.state.wy.us/2009/Enroll/HB0058.pdf
http://legisweb.state.wy.us/2009/Enroll/HB0080.pdf

Again, thank you for participating in this effort. Contact me with any questions or suggestions.

Sara G. Smith
President
SMITH MANAGEMENT GROUP
859-231-8936 ext. 105
Saras@smithmanage.com

Meeting on legal issues related to carbon management, Feb. 13, 2009, Room 111, Capital Annex, Frankfort

Sara Smith opened the meeting, citing the significant engagement from EEC, UK College of Law, the legal community (Wyatt Tarrant & Combs in particular); coal and oil & gas industries; PSC, Tom Fitzgerald (Resources Council) and noted that geologic sequestration is just a small portion of the overall energy issue in the U.S.

All present introduced themselves.

Sara asked how many were without power during the ice storm and noted that it showed how much we rely on electricity.

She reviewed the topics of discussions at the Governor's Conference on the Environment 2008 and the December 1 meeting of this group.

There was discussion about what Kentucky needs to do to gain primacy over its environmental permitting, including the proposed EPA Class VI permits. This involves both staffing and other programmatic changes. Sara suggested a task for this group might be to determine what it would take to manage a Class VI permit process.

There was discussion about the limitations of IOGCC and other model legislation in the areas of pore-space ownership, other property rights and liabilities.

Dave Harris of KGS summarized KGS state research projects funded by House Bill 1 funds and DOE-funded regional consortium projects Kentucky is involved in. He also gave some background on carbon storage and how it should be accomplished.

We're more heavily involved in HB 1-funded projects:

- Hancock County deep carbon storage, with major partners (Peabody, ConocoPhillips, E.ON U.S. and others.)
- Hopkins County enhanced oil recovery project in conjunction with Illinois and a DOE partnership, leveraging our HB-1 money. This is an effort to determine possible enhancement of oil recovery AND potential for storage of CO-2.
- KGS is also looking for partners and additional funding for an eastern Kentucky deep storage test as well as enhanced gas recovery test in the organic shales which can absorb carbon dioxide while forcing additional natural gas out.

(Break)

What other states are doing (Suggest Sara's spreadsheet be inserted here):

Sara Smith reviewed what Texas and Illinois had done to attract the FutureGen project: i.e. assuming ownership of carbon dioxide; clean-coal portfolio standards.

Other states which have considered or are considering legislation: Wyoming, Ohio, Idaho, Oklahoma, New Mexico, Washington, Montana, Kansas, Pennsylvania.

She noted the various provisions of House Bill 1in Kentucky: developing strategies for coal-to-liquids and biomass development; tax incentives; KGS and CAER research funding. HB-2: to examine portfolio standards for utilities in renewables and other energy alternatives. She also reminded the group of the Governor's energy strategy which has recently been released for comment.

Discussion of several bills and resolutions currently in the Ky. General Assembly:

HB 285: Incentives for carbon capture and sequestration. This bill appears to be focused on a single, coal-fired electricity-generating plant funded through the national economic stimulus package.

HB 351: Encourages industries to partner with CAER and KGS for essential research and development projects in carbon capture and sequestration. Brandon Nuttall noted the language is not necessarily clear enough to determine if this relates only to short term research projects or long-term commercial ones. Tom Fitzgerald indicated that he believes the sponsors think this is needed when, in fact, it is not. Brandon added that he is concerned about what an "environmental covenant" is and whether it means the land and pore space owner are restricted by eminent domain. The bill also appears to include an unfunded mandate for KGS to monitor, measure, the status of sequestered carbon dioxide gas.

Sara Smith commented that legislation like this demonstrates that we have to look at the whole picture and see how these bills affect a variety of entities and situations.

A participant asked for the definition of "eminent domain."

Karen Greenwell explained that the principle of eminent domain is used when the government takes a property interest from an individual for a public purpose and the government must compensate the owner. For instance, utility lines through property, gas storage fields, and other public interest situations. In the arena of carbon storage, there is the potential that a private, third party will use the property to make money. This becomes problematic when carbon dioxide may spread under adjacent properties. Complications arise about defining "the public good" and possible involvement of a commercial benefit.

Tom Fitzgerald added that there is another wrinkle: How do you deal with trespass (vertical and horizontal) displacing mineral-producing zones and water zones? Is this a private utility disposing of waste? Oil and gas companies also have eminent domain in Kentucky for some pipelines. Other complications: new grids for "green energy" coming from other locations may require eminent domain.

Len Peters noted that there is legislation to formalize this group and require delivery of a final report.

Sara suggested that sub-groups of the main one be formed to track various developments: i.e., technology and research, state legislation, and what's happening at the federal level. She suggested that people or offices already working in each of these areas should step up and do it in sub-groups, eventually reaching the point of identifying options, developing a work group to develop white papers on these topics and a final report.

Tom Fitzgerald offered assistance from students at the Brandeis School of Law (U of L) to help identify issues and research how other states are approaching these issues.

A sign-up sheet was started in the room for people willing to participate in the sub-groups to track issues and developments and to develop a final report.

Tom Fitzgerald said the state is looking at a daunting job of capturing one of the major by-products of coal combustion, not simply a hazardous pollutant, such as SO_2. He asked whether the rate payers or the shareholders should pay for it. Our culture didn't consider this aspect of the problem at the start of the choice to use this form of energy--a choice the rate payers did not actually make.

Len Peters thanked Sara for keeping this effort moving. He called it a daunting task policy-wise, legally and technologically. This is perhaps one of the most complicated and complex issues we face today. He asked those at the meeting to stay involved, helping the state AND the nation find their way through this complex topic.

It was agreed that a "work product" is needed by the end of the summer. The next meeting should be scheduled by the end of April, probably in Frankfort, as it is more centralized.

The people accountable for each work group will receive the list of names on the subgroups.

The Department for Energy Development and Independence offered to host a web site for the group's reports.

7/20/2009

Sara Smith

From: Sara Smith

Sent: Wednesday, July 08, 2009 11:01 AM

To: (glenn.sundheimer@eon-us.com); (Karen.Armstrong-Cummings@lrc.ky.gov); Barry Mayfield (barry.mayfield@ekpc.coop); Bill Barr (billbarr@ngas.com); Bill Caylor (bcaylor@kentuckycoal.com); Bill Sharp; bob.ehrler@eon-us.com; Brandon C Nuttall (bnuttall@uky.edu); Charles R. Dailey; D. Todd Littlefield (Todd.Littlefield@LRC.ky.gov); Dale Honn (DHonn@emseng.com); Daniel Zaluski; David B. Meece (dbmeece@tecocoal.com); David Freibert (david.freibert@eon-us.com); David Samford (DavidS.Samford@ky.gov); Don Newell (donald.newell@ky.gov); Eastern Mineral Law Foundation (news@emlf.org); Ed Stephens (estephens@tva.gov); Edman, Sarah A.; George Siemens (george.siemens@eon-us.com); Graham, M L; Greenwell, Karen; Greg Copley (gccopl1@uky.edu); Hank List (Hank.List@ky.gov); Harris, David C; James C Cobb (cobb@uky.edu); Jason Bentley (jbentley@mmlk.com); Jerry Purvis (jerry.purvis@ekpc.coop); Jim Fallin; Jim Lamb (jim.lamb@ekpc.coop); Jimmy Keeton (jekeeton@aep.com); John Buckner (John.Buckner@lrc.ky.gov); John Cooper (JPCooper@bellsouth.net); John Horne (john.horne@ky.gov); John Talbert (jtalbert@bigrivers.com); Judge Jack B. McCaslin (jackbmack@bellsouth.net); 'Karen Thompson'; Karen Wilson (karenl.wilson@ky.gov); Kate Shanks (kate.shanks@ky.gov); Katie.allison@ky.gov; Kelly Blevins (Kelly.Blevins@lrc.ky.gov); Kim Collings (Kim.Collings@ky.gov); Lee Colten (Lee.colten@ky.gov); Lillian F Deprimo; Liz Edmondson (liz.d.edmondson@gmail.com); Mark David Goss (mgoss@fbtlaw.com); Mark S Brewer (mark.brewer@ekpc.coop); Michael Healy (healym@uky.edu); Mike Gribler (mike.gribler@duke-energy.com); Mike Haines (mike.haines@ky.gov); Mike Lynch (mike.lynch@uky.edu); Nancy Mitchell (nkmitchell@tva.gov); Nick Brake (nbrake@owensboro.com); Nick Carter (ncarter@wpplp.com); Patrick Underwood (Patrick.underwood@gallatinsteel.com); Paul Brooks; Pete Goodmann; Peters, Len (EEC Cabinet Secretary); Rebecca Brooker (Rebecca.Brooker@lrc.ky.gov); Rick Bender (rbender@ngas.com); Rick Bertelson (rick.bertelson@ky.gov); Rick DeCesar; Rocco D'Ascenzo (rocco.d'ascenzo@duke-energy.com); Rodney Andrews (andrews@caer.uky.edu); Roger Medina (roger.medina@eon-us.com); Roger Nicholson (rnicholson@intcoal.com); Ronald R. Van Stockum, Jr.; Roy Palk (thepalks@insightbb.com); Rusty Ashcraft (rustya@arlp.com); Sara Smith; 'Schetzel, Doug'; Scott Rennie (scott.b.rennie@conocophillips.com); Scott Smith; Shannon Graves (shannons.graves@cemex.com); Sharon L. Dodson (sharon.dodson@eon-us.com); Spencer Noe; Spoonamore, Susan (LRC); Stefan Kasacavage (stefan.kasacavage@lrc.ky.gov); Stone, Brad (EEC); Suzanne Fisher; Tanya Monsanto (Tanya.Monsanto@lrc.ky.gov); Taylor Moore (Taylor.Moore@lrc.ky.gov); Tickner, Dianna; Timothy C. Mosher (tcmosher@aep.com); Tom Fitzgerald (FitzKRC@aol.com); Tom Lane (tlane@bowlesrice.com); Valerie Hudson; Van Needham (van.needham@duke-energy.com); Watkins, Sabrina S.; Williams, David A

Subject: Legal Issues of Carbon Sequestration Work Group

Call to Meeting

Legal Issues of Carbon Sequestration Work Group

July 20, 2009 – Monday

Work Group Sessions

Conference Rooms B31 & D16: # 2 Hudson Hollow
And Large Meeting Room: KHEAA Building – 100 Airport Road
Frankfort Kentucky
9:30 – 11:30AM

Lunch on your own

General Session

KHEAA Building - 100 Airport Road
Frankfort Kentucky
1:00PM – 4:30PM

RSVP – Christy.morris@ky.gov

This meeting will focus on a few specific questions. Work groups will meet in the morning to craft their response to the questions. The full group will meet in the afternoon to discuss the questions in light of the work group reports. The Agenda and questions will be provided in a following email.

Workgroups -

Technology & Research
  Brandon Nuttall bnuttall@uky.edu

State & Federal Actions and Developments –
  Sara Smith saras@smithmanage.com
  Rick Bender rbender@ngas.com

Legal
  Karen Greenwell kgreenwell@wyattfirm.com

Sara G. Smith
President
SMITH MANAGEMENT GROUP
859-231-8936 ext. 105
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CCS Legal Issues Meeting
7/20/09

Sara Smith	SMG	8592318936	Saras@Smithmanage.c
Bill Sharp	EKPC	859-745-9551	Bill.Sharp@EKPC.coop
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KAREN THOMPSON	SMG	859-231-8936	karent@smithmanage.com ~~Kthompso~~
Mark Brewer	EKPC	859-745-9672	mark.brewer@EKPC.coop
Mike Lynch	KGS	859 323 0561	mike.lynch@uky.edu
Michael Healy	UK	859-257-3636	healym@email.uky.edu
Bob Ehler	E.ON U.S.	502-627-2305	bob.ehler@eon-us.com
Mike Haines		502-564-2356	Mike.Haines@ky.gov
John Horne	EEC	502-564-2150	John.Horne@ky.gov
~~James~~ Noe	Bowles Rice	8595358384	jnoe@bowlesrice.com
Stefan Kasacavage	LRC	502 564 8100	
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Sara Smith

From: Sara Smith
Sent: Friday, July 17, 2009 2:12 PM
To: Greenwell, Karen; rbender@ngas.com; 'Nuttall, Brandon (EEC)'
Cc: Peters, Len (EEC Cabinet Secretary); 'Wilson, Karen (EEC)'; Karen Thompson
Subject: Important agenda for work group meetings

Monday's meeting is critically important and the information coming from the sub groups will help direct the discussion in the afternoon. As group leader, you will need to keep your group focused on the questions, as they pertain to the sub group's subject matter. We are trying to avoid "Why is there air" discussions and really focus. Therefore, please guide your group to develop answers to the questions for reporting back to the main discussion in the afternoon.

The questions are below, with notes indicating what each group should be trying to develop.

Questions:

1. Pore Space
    a. *What is pore space and who owns it?* - Technical should answer what is pore space, considering the areas currently considered. Legal should feel free to consult with technical. Legal should develop an answer as to the current legal interpretation as to who owns the pore space in Kentucky.
    b. *If the pore space is associated with a marketable mineral, who owns it after the mineral is depleted?* Legal - please answer this one, keeping in mind we are looking at current law in Kentucky. Technical - can you ever actually deplete a mineral?
    c. *What is the likelihood of useable mineral strata being used for sequestration?* Technical - this one is all yours.

2. Liability
    a. *What is the liability we are discussing? (near, mid-, and long term)* Technical - please develop a list of the liability inherent in the physical process of sequestering CO2. Inform us as to other potential liabilities and rate them as to likelihood and severity. Think about the life of the sequestration site. Legal - please evaluate the liabilities with regard to current law.
    b. *Where does the liability need to run?* Legal - this is a subjective question, try to develop an objective answer. Try to develop reasons for suggestions on where the liabilities should run and emphasize what is already established law. State and federal developments will provide a discussion on what has developed in other states, what may influence this question in proposed legislation and what trends we seeing in international legislation.
    c. *Is there a benefit to the state of assuming liability at some time?* This will be discussed by the full group although ideas from each of the discrete groups can be helpful.
    d. *Is there a potential revenue stream to the state in managing CO2 injection vis a vis owning the pore space and assuming the liability of storage?* Discussion in the afternoon with input from the subgroups pertinent to their area of study.

I will be in Frankfort at the meeting site by 9AM. Let's get our heads together then. Let me know if you have questions.

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CARBON DIOXIDE SEQUESTATION LEGAL ISSUES MEETING:

July 20, 2009

KHEAA building, 100 Airport Rd.

Morning committee session

Karen Greenwell requested introductions by all who were attending.

Ms. Greenwell opened the meeting, saying there are two major legal issues relating to carbon sequestration in Kentucky: access issues / injection rights and the liability issues.

Ownership of pore spaces vs. rock formation

There was a discussion about focusing specifically on "pore space" issues. Carbon sequestration involves injecting CO_2 into these microscopic holes in the rock, AND the hope that it stays there forever. That seems to indicate nothing can ever be done with that rock formation at the site again, since it would release the carbon dioxide, thus affecting the ownership of the whole strata.

Should the ownership issue be seen as in two parts? i.e., is the pore space owned separately from the other ownerships?

Currently in Kentucky, after minerals are removed, there is another set of rules relating to ownership of the empty space. But that may not be conceptually analogous to the ownership of pore space in advance of an activity like sequestration. There is no Kentucky jurisprudence on "pore space" as there is in the case of <u>cave</u> spaces. This is not a "hole in the ground."

There was further discussion of whether, if I own the rock, I own the microscopic spaces between the molecules of rock, and how did I get it and how do I keep it? The aspect of the "taking" issue needs to be explored. A Wyoming statute says the pore space stands independent of the mineral owner.

Is this the same as natural gas storage? (i.e., the leasing of pore space by contract.) But one difference is that natural gas is put in and removed multiple times from a storage site.

But isn't the owner giving up all rights to "his rock," because the area cannot be disturbed ever again? It can never be disturbed, due to the need to get the "credits" in a cap and trade system.

The concept of treating pore space separately also is in Pennsylvania law.... It "slices" property rights more finely than we currently do in Kentucky.

But an owner can sell whatever he/she wants to of the land to anyone who wants to buy it. So the pore space probably could be sold separately. It simply hasn't been bought up to this point in Kentucky. So we're left to ask whether we <u>have</u> a concept of pore space. absent its conveyance so far.

Bill Barr noted there is precedent for selling pore space in fee in depleted gas reservoirs for gas storage. A formation that formerly had natural gas or other minerals is being sold for storage.

But the question is comes down to recognizing the pore space separately from the rock itself. The focus for natural gas storage is, indeed, on the pore space, but we don't currently envision the pores and the rock separately.

There was general agreement that porosity doesn't exist separate from the rock in Kentucky.

Issue: If we can sell the pores, we HAVE to sell the rock, because the use of the rock is limited or prohibited while the pore space is being occupied whether by natural gas or carbon dioxide. Each tract's handling will vary, based on the ownership of the various strata. The intervening strata are also important because they provide multiple layers of sealing formations. There was a discussion of the vertical and horizontal seepage, the property issues of such spread and the tracking of the plume of gas.

Discussing the current UIC requirements, it was noted there is no requirement to demonstrate where an injection plume will end up in UIC-permitted operations. It appears that no one thought about adjacent property rights when UIC permits were first used in the 1960's.

The issue of a taking from a mineral owner must also be addressed, because there may be economic resources in the injection formation.

Use of eminent domain and payment of damages

Eminent domain seems to be a possible way to approach properties in carbon sequestration projects.

In that case, the question also becomes "what are the damages?" At the depths of carbon sequestration, the answer may be "none," because we're considering the value before an operation and the value after.

Yet presumably a private entity providing carbon storage services is making money from such operations. So a different concept of damages may be needed for this purpose.

(Most of the test projects now are government sponsored, though there is much private participation. Eventually, they are likely to be private operations when carbon sequestration becomes a required and common practice.)

There was discussion that the state legislature could create a legal structure which says CO_2 sequestration is a public interest issue, so that condemnation / eminent domain will be allowed in the case of infrastructure needed to achieve carbon storage. Right or wrong, the public will see CO_2 as a "waste," and that perception will need to be overcome. There will be new pipelines which will not necessarily be popular.

There was discussion about whether "damages" will have to include attractiveness, fear of what will happen to the injected gas, and other things which are not necessarily currently considered,

so that the damage to sequestration sites, rather than been "nothing," may, in fact, be the entire value of the property, due to perceptions of the value, worth, and usefulness of a property after carbon (a waste) injection has begun.

There was discussion of the "public good" of carbon dioxide generated by non-utility private companies. (i.e., cement plants; coal to liquid plants, etc.) They are still emitting carbon, whose emission and storage will be regulated. They cannot exercise eminent domain now; should they be allowed to use it for purposes of constructing pipelines for storage of their carbon?

The eminent domain which will be needed for the purpose is going to be multi-jurisdictional, thus complicating the process. The multiple issues relating to each piece of property (missing heirs, mortgages, etc.) will seriously complicate the process, absent major state legislation enabling the process legally. Will the legislature create a separate definition of "trespass" for this particular purpose? Will they establish a value for the definition of damages in this kind of project?

Forced pooling:

It is used in oil and gas operations: At least 51 percent of property owners must agree before drilling can go forward, and the 49% owners will get paid royalties for the project. In carbon sequestration projects, it's conceivable that royalties would have to be paid to property owners for having had to allow their property to be used for a purpose that makes money for a private operator.

The liability question:

On the one hand, with sequestration in very deep formations, the carbon dioxide wouldn't make its way to the surface again. But, since there are pipeline issues (for transporting CO_2) as well, and accidents / damages could occur along the pipeline. CO_2 in a liquid form may also be more corrosive. Carbon dioxide can also displace oxygen in the air and pose an asphyxia hazard.

There was discussion of whether this is a strict liability issue or a negligence one.

Because high-pressure carbon dioxide (and other gas) pipelines already exist, Kentucky will not be re-creating the wheel.

The issues relating to liability include: contamination of drinking water; dissolution of rock allowing CO_2 to escape; potential seismic induction via over-pressurization of wells; seeping carbon dioxide could also affect oil, gas and other economic resource production in formations where it might seep.

Migration issue: We have already injected hazardous materials, natural gas, and other materials into the ground. Given the size of the plume, will EPA, which is reluctant to inject water into deep formations, be reluctant to allow CO_2 injection in a region (western Kentucky) which includes the Rough Creek Graben, faulting, and other questionable formations?

Concern was expressed about avoiding pipelines brining carbon dioxide for sequestration from other states, and whether we see that as a public good for Kentucky.

There was general agreement that **eminent domain** or **forced pooling** appear to be the two choices for this process. A new agency or division to oversee this will be needed, and a new definition of certain property rights in these cases. And the issue could end up in the state supreme court as a constitutional issue.

Takings and restrictions of use

There was a discussion of the difference between "takings" and restrictions on use in the carbon sequestration arena. The use of a "taking" will result in a backlash, even if what's taken is 8,000 feet underground.

But we already "take" resources which seep into wells which are legally spaced away from private property for which we don't have an established "right" to take economic resources.

CARBON DIOXIDE SEQUESTATION LEGAL ISSUES MEETING:

July 20, 2009

KHEAA building, 100 Airport Rd.

AFTERNOON GENERAL SESSION:

Reports: **Technology & Research**: Brandon Nuttall

Pore space is defined as the ratio of void volume to total volume of rock. Members of this committee believe the original rock owner owns the pores, as if they are a "storage tank"

Depletion: there are already economic, technical/practical, and legal definitions for depletion.

Stratigraphic / depth cutoffs are likely to be required for permanent storage zones to insure carbon dioxide stays in place.

Sequestration likelihood will be determined by these factors:

Pore volume

As a function of the existing fluids in the pore spaces, since they will have to move

Permeability

Seal integrity

"Swiss cheese" factor; well bores, faults and fractures existing in the region

CO_2 phase, as a result of the depth of storage. At about 2500 feet, it goes supercritical, which causes its volume to be reduced exponentially.

Liability phases:

Near-term injection: during active storage and injection phase. (injury; damages, etc. are the same as in drilling and construction projects)

Mid term: post closure. Best management practices cover this (i.e., hazardous waste—30 years; UIC requirements) Trespass issues (if CO_2intrudes vertically into other strata or horizontally onto other owners' property.) Migration must be monitored. Currently, costs to remediate issues in this phase come from bonds.

Long term: Trespass issues and long-term well integrity are the issues here. (i.e., post closure for landfills; possible state assumption of liability)

KY needs UIC class II primacy. Otherwise, we cannot administer a program for Class IV wells for long-term seq. We must demonstrate the state's ability to administer such a program.

Other programs have long term funding solutions from forfeited bond, EPA funds, etc., specific to plugging wells, and this one will, as well.

Some flexibility is needed in funding, since we're talking very long term (hundreds of years)

It's premature to ask the state to indemnify without money and technology demonstrations, such ones being conducted now. (Hancock County and elsewhere.)

There was discussion on the long term funds and how are they protected from being raided for other purposes. The cognizant state cabinet AND legislators involved must understand the importance of the fund. A quasi-governmental entity may have to administer this, making it more immune from such raiding.

There was discussion of what a "depth cutoff" means. It would need to be a depth and / or a stratigraphic cutoff which differs in different areas due to regional conditions and the depth at which CO_2 becomes supercritical. Brandon Nuttall noted that CO_2 is an acid gas, so its interaction with different formations will differ depending on the formation rock. We need to know more about these interactions, which is why we're doing injection testing in Hancock County and elsewhere.

Other state actions in 2009: Sara Smith

Much has happened in 2009:

Wyoming: Pore spaces defined as belonging to surface owners, but the severed-mineral owners are dominant if they are impacted.

West Virginia: Pore space is an attribute of the surface estate; mineral ownership does not convey pore space ownership unless it is specifically conveyed.

North. Dakota: Pore space vested title is with the surface owner.

Montana: Three legislative proposals. Bottom line: they did not end up addressing pore space

(Two other states)

Liability: Louisiana: after ten years, the state takes responsibility, unless the fund is depleted.

Montana: After ten years, state takes liability.

North Dakota: State takes the responsibility when a certificate of completion is issued.

Penn: will own carbon dioxide (if bill passes) in a CCS network of carbon dioxide generated in Penn.

Texas: In pilot tests, the state is responsible (in one bill). In another bill: Carbon dioxide belongs to storage operator.

Wyoming: one bill: gas presumed owned by entity that injected it, therefore the liability as well.

Europe: Adopted a directive to be implemented by spring of 2011 (as a guideline): Responsibility can be transferred to a state at 20 years or greater.

Australia: adopted a "Greenhosue Gas Act" which transfers long term liability to the government after 20 years.

Sara added that many governments have not addressed the issue at all.

American Clean Energy Act proposal: A task force would be set up for two years to study existing laws, the statutory framework, private sector risk management, sub-surface mineral rights, water rights, and property rights. We should watch this, as many of these rights are currently state rights.

Legal Issues: Karen Greenwell:

An eminent domain or regulatory forced pooling/unitization process would be necessary for the sequestration process. Discussion on the whether the state could legislate the definition of allowable damage levels, even though the activity may be so deep that it is not known to have an economic value. The compensation may be nothing, since my property value is not diminished, but if the value is influenced by how the property is perceived after the injection activity, the damage levels may have to be seen as much larger. The issue of a private enterprise making money on such an activity complicates the "public good" view of the activity, vis a vis the private property rights in an eminent domain situation.

There was a discussion on the "public purpose" issue related to carbon storage. In the case of regulated utilities, whose rates and profits are a matter of state / public good and control, they have been told that, as a public good, they must participate in a carbon capture / sequestration program.

Property access issues:

What does Ky. case law currently say about access? Every piece of property is controlled by the documents. Depending on the documents, there may be ONE owner, or owners of different strata or rights. A rock formation may be under lease, and the entity leasing the formation has the rights to the formation. (The rights to lease property go as deep as the owner owns…essentially no limitations. In some coal cases, the lease may be determined by the coal seams, thus limiting the depths of a lease.)

There was discussion of whether the "context" of a lease may also govern ownership? That is, what the parties were contemplating in the lease. The ownership of the pore space may depend on what the lease was about.

Tom Fitzgerald offered the opinion that, to secure sufficiently large areas to do sequestration, it's not palatable to landowners to bear the burden of even a public good that condemns their property rights. In the case of forced pooling for oil and gas drilling, the "forced" owner still gets some monetary value. In the carbon storage arena, he suggested that ongoing compensation should be provided to landowners whose property is involved and whose activities on their own property are constrained. The compensation could be based on the volume of carbon dioxide that is injected. He suggested forced pooling is more palatable in this situation than condemnation.

Participants discussed whether a lump-sum payment to cover the property owner's rights would be sufficient. Another way of looking at it: The generator of the carbon purchases a carbon credit from the landowner as an item of value. Someone could sell their "storage rights" up front, and the "holdouts" would have to come in under a "forced pool." Perhaps the payment would be, not a royalty, but a payment for damage to property. But it is important that a landowner not pick up liability simply by virtue of being the owner. The royalties or other payments might come from an injection fee or from the value of the credits which are traded in a cap and trade system.

"Forced pooling:"

It is available if an oil and gas drilling operator can get half of the ownership interest or acreage ownership to agree to the lease. Owners of the remaining necessary acreage or remaining joint owners can be required to enter the lease, and they are paid royalties. There may be a similar process to this one in sequestration operations. Condemnation, due to the large amount of acreage carbon sequestration will involve, may be the other option.

Tom Fitzgerald was of the opinion that we're dealing with a different issue in sequestration: Companies are seeking to get rid of a waste product. This is private-sector waste. The idea that we will endow that entity with the right to force a neighbor into a business relationship to get rid of the waste is "a bit of a stretch." The question is whether we socialize the cost or require the generators to shoulder the responsibility. Should we negotiate openly with property owners or keep condemnation as a possibility? He asserted that all of this remains theoretical because it hasn't been proven on a large scale yet. Kentucky is in a different situation from most other states, because 98% of our power comes from fossil fuels, mostly coal, yet we're the 46th poorest state.

There was a discussion of whether carbon sequestration is, in fact, a "public interest" issue.

Before the break, it was agreed that there is a consensus on what pore space is: It's the formation itself where the pores are.

(BREAK)

There was a discussion of how deep sequestration is likely to occur and whether there are economic resources of value that deep. In general, the answer is "No," for the depths of sequestration.

Liability:

Sara began the discussion observing that, in the injection phase, the liabilities are the same as they are now during oil & gas operations. "Mid-term" time frame is during active storage e and the early post-closure time. Long term is after that.

Mid term liabilities include potential loss of pressure in the formation due to faulting, as an example, or some other release (i.e., one that goes into someone else's zone but not o the surface). There was a discussion of whether monitoring networks are good enough to determine if the formation's integrity is uncompromised. It was noted that Norwegian sequestration projects have such a monitoring set-up. Brandon Nuttall noted that a 3-D seismic array is needed for that, and permissions will be needed from landowners for access to their property to maintain such a monitoring network.

There was discussion of who has the liability at this time period and whether they pay into a fund to cover costs of damages. What set-up will provide funds and an efficient system to cover any accidents or incidents (Is this operator liability or state liability?)? Ongoing monitoring, funded adequately, must go on for a long time. But where is the end-point for such monitoring, since the objective is sequester the material permanently?

When the operation is no longer a revenue generator, it becomes a long-term problem of a public nature. And the entity which does the long-term monitoring must be a "durable" one which can exist for the very long term ("in perpetuity").

It was noted that interstate compacts will be needed to insure that adjoining states recognize that projects at their common borders can affect each other.

Discussion: Even with careful, legal projects and monitoring over the long run, catastrophic natural events, such as earthquakes, can cause significant damage or devastation to the project site and possible release of stored carbon dioxide.

Among the long-term questions: How to fund long-term activities? How to protect the funding from being raided for other needs? It was agreed that this is an infant industry and market, and pricing of products, including insurance and bonding, are difficult now. A "sinking fund" would be needed up front, and a quasi-governmental organization would be needed to protect the funds as much as possible from being raided.

Discussion of how a permanent cap and trade system would work and interface with a state and allocate costs and credits per state.

SUMMARY ON LIABILITY ISSUE: Monitoring will be dictated by EPA minimum rules. The majority of the liabilities can be handled by carefully legislated monitoring of operations and setting of time limits and/or benchmarks for when liability is handed over to the next-in-line entity (i.e., from private entity to the state).

Brandon Nuttall of KGS: What we did as we drilled in Hancock County was to monitor loss of fluid, performed a suite of wire line logs, and we will test-inject into the formation. We also use seismic techniques to determine what the plume is doing between wells. All this information is synthesized to determine location and size of permeable formations and whether there are breaches in such zones and where there are sealing formations for the carbon dioxide. Pressure changes can also be detected via "gas sniffers" to determine the type of gas and the rate it reaches the surface, as standard practice to determine the activity deep in a drilled hole. Each well will require a plan for drilling the wells and for monitoring potential leakage and monitoring the plume of gas underground. Monitoring expectations by EPA are large now (as in Hancock County) and are expected to be larger for permanent storage projects.

Can assuming liability benefit the state? Brandon noted that, if companies see that the state will assume liability, they will be more likely to build facilities in the state. Could the state make money if there is a fee for injection and real chances of catastrophic damages is low? This may drive the kind of fees which are charged. The state will have to set up an expensive regulatory structure which will cost money, and a fee / charge system must be able to sustain that.

Len Peters observed that this will be a tax in another form on the ratepayers, and the state must balance its need to regulate carbon emissions (as required by EPA) and maintain its ability to attract industries and jobs.

Sara observed that there are a number or consensuses from today. The information and observations from the four meetings to this point need to be synthesized and turned over to the state General Assembly, whose Special Energy Committee has shown interest in this topic. There was discussion of whether to expect the legislature to act in its next regular session in 2010 or move more deliberately by waiting for federal rules, which will determine the framework for a lot of these issues.

It was agreed to put together an internal draft by Sept. 1 of all discussions, which could become an informative document for legislators.

STATE CCS LEGISLATIVE & REGULATORY DEVELOPMENTS
Prepared and Maintained by Alston & Bird LLP
Last Updated 7/6/09

Active/High-Priority Legislation

State	Legislation	Status	Link to Bill Text/News
Indiana	Introduced on January 13, 2009, HB 1412 provides incentives for "clean coal and energy projects", including project using coal from the Illinois Basin and projects that involve CCS. Incentives include cost recovery, enhanced returns on shareholder equity, and product offtake incentives.	Mar 24th --- pending before the Committee on Commerce, Energy, Technology and Utilities.	http://www.in.gov/legislative/bills/2009/PDF/IN/IN1412.1.pdf
Kansas	Introduced on January 20, 2009, HB 2038 establishes capture requirements for different classes of power generating facilities and directs the Department of Health & Environment to propose CO_2 emission limits for "carbon emitters for which [CCS] technologies are available and cost-effective."	January 21st – referred to Energy & Utilities January 26th -- hearing	http://www.kslegislature.org/bills/2010/2038.pdf
Kentucky	Introduced on February 5, 2009, HB 285 authorizes the Kentucky Economic Development Authority to award incentives to one pilot project that involves the construction of a new IGCC electric generation plant; the construction of a new ultrasupercritical, oxyfuel, or other electric generation plant; or the retrofit of an existing coal-fired power plant. The project must include or allow CCS. Additional limits apply.	Feb 6th – to Appropriations & Revenue Feb 13th – posted in committee Feb 23rd – reported favorably with substitute Feb 24th – to Rules Feb 25th – posted for passage in the regular orders of the day for Feb. 26th Mar 11th – returned to Rules	http://www.lrc.ky.gov/record/09RS/HB285/bill.doc
Kentucky	Introduced on February 9, 2009, HB 351 establishes as State policy the involvement of the Kentucky Geological Survey and Center for Applied Energy Research at the University of Kentucky in CCS demonstration projects; to further	Feb 10th – to Natural Resources & Environment Feb 23rd – posted in committee	http://www.lrc.ky.gov/record/09RS/HB351/bill.doc

State	Legislation	Status	Link to Bill Text/News
	such projects, the State of Kentucky agrees to "accept and receive [] all rights, tight, and interests in the sequestered gas, including any current or future environmental benefits, marketing claims, tradable credits, emission allocations, or offsets (voluntary or compliance-based) …."		
Kentucky	Introduced on February 11, 2009, House Joint Resolution 126 expresses the Legislature's support for the Kentucky Geological Survey's pursuit of federal funding opportunities for CCS under the American Recovery & Reinvestment Act of 2009.	Feb 12th -- to Natural Resources & Environment Feb 23rd -- posted in committee Feb 26th -- reported favorably, 1st reading, to Consent Calendar Feb 27th -- 2nd reading, to Rules; posted for passage in the Consent Orders of the Day for Tuesday, March 3, 2009 Mar 3rd -- 3rd reading, adopted 100-0 Mar 4th -- received in Senate Mar 6th -- to Natural Resources and Energy Mar 9th -- taken from committee; 1st reading; returned to Natural Resources and Energy; reported favorably, to Calendar as a Consent Bill Mar 10th -- 2nd reading, to Rules	http://www.lrc.ky.gov/record/09RS/HJ126/bill.doc
Kentucky	Introduced on February 23, 2009, HB 537 authorizes the creation of a carbon management legal issues study group to investigate and report on CCS policy recommendations by October 31, 2009.	Feb 24th – to Tourism Development & Energy Feb 26th – reported favorably Feb 27th – to Rules	http://www.lrc.ky.gov/record/09RS/HB537/bill.doc

State	Legislation	Status	Link to Bill Text/News
		Mar 2nd – passed House as amended Mar 5th – to Natural Resources & Energy Mar 9th – reported favorably Mar 10th – to Rules Mar 13th – passed Senate as amended Mar 13th – returned to House	
Louisiana	House Bill 661 was introduced on April 16, 2009. The "Louisiana Geologic Sequestration of Carbon Dioxide Act," provides definitions of key terms relating to sequestration. It gives the commissioner of conservation the authority to regulate CO2 storage. States that after 10 years of completion of injection, the state will assume all liability, unless the Carbon Dioxide Geologic Trust Fund has been depleted.	Apr 16th—Introduced. Apr 18th—Referred to Committee on Natural Resources and Environment. Apr 27th—First Reading. May 20th—Engrossed Jun 4th—Passed House Jun 18th—Passed Senate with amendments, returned to House. June 23rd—Passed House as amended. June 25th--Sent to Governor.	http://www.legis.state.la.us/billdata/streamdocument.asp?did=645317
Michigan	Introduced on January 22, 2009, HB 4016 provides a tax credit equal to the cost of "purchasing, leasing, or constructing carbon dioxide capture machinery, equipment, or pipeline infrastructure and the cost of materials used in preparing, maintaining, or capping a carbon dioxide injection well".	Jan 22nd – referred to Committee on Energy & Technology Jan 27th – printed bill filed	http://www.legislature.mi.gov/documents/2009-2010/billintroduced/House/pdf/2009-HIB-4016.pdf
Mississippi	Introduced on January 19, 2009, HB 1459 levies a gross income tax of 1.5% on businesses engaged in the "sale of naturally occurring carbon dioxide and anthropogenic carbon dioxide lawfully injected into the earth	Mar 23rd – Passed the Mississippi Legislature and sent to the Governor for signature Mar 31st– Signed by	http://billstatus.ls.state.ms.us/documents/2009/pdf/HB/1400-1499/HB1459IN.pdf

State	Legislation	Status	Link to Bill Text/News
	for: 1. Use is an enhanced oil recovery project, including, but not limited to, use for cycling, repressuring or lifting of oil; or 2. Permanent sequestration in a geological formation."	Governor.	
Montana	Not yet introduced, draft bill LC0194 would require the Board of Environmental Review to set standards for the capture, transportation and storage of CO_2 at coal-fired electrical generation and synthetic fuels facilities. The bill would require 100% capture and subsequent "permanent storage", although offsets could be used in a limited fashion.	Dec 24, 2008 – draft legislation available This effort appears to be have stalled and been overtaken by events (see SB 66 and HB 502 below)	http://data.opi.mt.gov/bills/2009/billpdf/LC0194.pdf
Montana	Introduced on December 10, 2008, SB 66 authorizes the Board of Environmental Review to issue CCS regulations that broadly follow whatever federal requirements may emerge; specific features of note include: (i) requirement for operator to obtain and hold insurance for 75 years following well closure; (ii) establishment of pore space rights as attribute of surface estate; and (iii) disqualification of CO_2-EOR from being able to do storage under Class II. CO_2-EOR operations can convert to storage, and thus become subject to the storage rules, but cannot do storage and engage in oil production concurrently while remaining subject to regulation by the Board of Oil & Gas Conservation.	Dec 16, 2008 – referred to Energy & Telecommunications Jan 5, 2009 – first reading Jan 15th – hearing Jan 23rd -- tabled	http://data.opi.mt.gov/bills/2009/billpdf/SB0066.pdf
Montana	Introduced on February 9, 2009, HB 502 authorizes the Board of Environmental Review to issue CCS regulations. HB 502 is broadly similar to SB 66 (discussed above) except for the following: (i) pore space is vested in the State of Montana; and (ii) contamination of ground water in a regulated geologic sequestration site is excluded from the definition of "pollution."	Feb 9th -- referred to Natural Resources Committee Feb 18th – hearing Mar 20th – tabled	http://data.opi.mt.gov/bills/2009/billpdf/HB0502.pdf
Montana	Introduced on February 20, 2009, SB 498 authorizes the Board of Oil & Gas to issue CCS regulations. The	Feb 21st – first reading Feb 23rd – referred to	http://data.opi.mt.gov/bills/2009/billpdf/SB0498.pdf

State	Legislation	Status	Link to Bill Text/News
	legislation differs from SB 66 and HB 502, in the following respects: (i) oil & gas, not environmental, regulators are in charge of the CCS regulators (although the Board of Oil is required to consult with the Department of Environmental Quality); (ii) a mechanism exists to transfer liability to the State and the conclusion of the post-closure period (envisioned to be ten years); and (iii) pore space ownership is not addressed.	Energy & Telecommunications Mar 5th – hearing Mar 18th – passed Energy & Telecommunications Mar 24th – passed the House and transmitted to the Senate Mar 24th – referred to Federal Relations, Energy and Telecommunications Apr 8th- Amendments have been offered. One that gives pore space ownership to the surface landowners. The Governor now supports the measure, after previously threatening veto over lack of pore space ownership. Apr 24th—Bill passes Senate as amended, 43-7. Apr 27th—Enrolled. May 6th—Signed by Governor.	
New Mexico	Introduced on February 16, 2009, HB 790 authorizes creation of a regulatory regime for CCS rooted in the Oil Conservation Commission and the Oil Conservation Division of the Energy, Minerals and Natural Resources Department. The legislation: (i) does not envision the storage and EOR may occur concurrently, and (ii) endeavors to clarify pore space ownership rights.	Mar 24th -- pending before the House Energy and Natural Resources Committee Note: We understand that HB 790 has been effectively tabled, with the focus now on SB 208 (discussed below)	http://www.nmlegis.gov/lcs/_session.aspx?chamber=H&legtype=B&legno=%20790&year=09
New Mexico	Introduced on January 22, 2009 and subsequently amended in committee and on the Senate floor, SB 208 establishes pore space ownership rights. Ownership of the pore space is vested in the surface estate, unless	Mar 17th – passed the Senate. Mar 18th – referred to House Business & Industry Committee.	http://www.nmlegis.gov/Sessions/09%20Regular/bills/senate/SB0208COS.pdf

State	Legislation	Status	Link to Bill Text/News
	previously severed. The rights of mineral owners and lessees are recognized, however, in that they have the right to use pore space as necessary to produce native oil, gas or other minerals, including rights to inject fluids for EOR. Injected CO_2 remains the property and responsibility of the person conducting the injection, unless transferred to another person or released from the reservoir by another person.	Apr 1st---Died.	
New York	Introduced on February 20, 2009, A05836: (i) authorizes the Department of Environmental Conservation to permit storage sites; (ii) declares that pore space is owned by the surface estate; and (iii) grants regulated public utilities and municipal electric corporations condemnation rights for pore space.	Mar 20th—referred to Environmental Conservation May 1st—Amend and referred to environmental conservation.	http://assembly.state.ny.us/leg/?bn=A05836&sh=t
New York	Introduced on June 9, 2009, AB 8802 enacts the Carbon Capture and Sequestration Act to authorize the siting and regulation of a CCS demonstration project.	Jun 9th—Referred to Environmental Conservation.	http://assembly.state.ny.us/leg/?bn=A08802&sh=t
North Dakota	Introduced on January 6, 2009, SB 2095 establishes a regulatory framework for CCS. The Industrial Commission is the permitting authority. Permitting requirements are established. Unitization is provided. Stored CO_2 is deemed not to be a pollutant and does not constitute a nuisance. Operators pay per-ton storage fees, which are used to fund a Carbon Dioxide Storage Facility Administrative Fund. The storage operator has title to the CO_2 and is responsible for it, until such time as the Industrial Commission issues a certificate of project completion, as which time title to and responsibility for the CO_2 transfers to the State. With respect to whether CO_2-EOR and storage may occur concurrently (without subject EOR to the full weight of the storage rules), SB 2095 provides that EOR may convert to storage, but also states that the Industrial Commission may tailor or waive specific requirements	Feb 4th – passed the Senate. Mar 11th – passed the House. Apr 8th—Signed by Governor.	http://www.legis.nd.gov/assembly/61-2009/bill-text/JQTA0200.pdf

State	Legislation	Status	Link to Bill Text/News
	on a case-by-case basis.		
North Dakota	Introduced on January 14, 2009, SB 2221 creates a credit against coal conversion privilege taxes for facilities that achieve a required level of carbon dioxide capture.	Feb 18th – passed the Senate Feb 26th – referred to Finance & Taxation Mar 10th – hearing Mar 11th – referred to Appropriations Apr 22nd---Signed by Governor.	http://www.legis.nd.gov/assembly/61-2009/bill-text/JAQD0400.pdf
North Dakota	Introduced on January 6, 2009, SB 2034 creates a permanent exemption from the oil extraction tax for incremental production from a tertiary recovery project that uses carbon dioxide.	Feb 13th – passed the Senate March 2nd – passed the House Mar 4th —Signed by House Speaker Mar 5th – Signed by Senate President Apr 8th —Signed by Governor.	http://www.legis.nd.gov/assembly/61-2009/bill-text/JAIP0300.pdf
North Dakota	Introduced on January 6, 2009, SB 2139 defines pore space and vests title in it to the surface estate.	Feb 4th – passed the Senate Mar 11th – passed the House, as amended Mar 23rd – passed the Senate, as amended Apr 8th—Signed by Governor	http://www.legis.nd.gov/assembly/61-2009/bill-text/JQTB0300.pdf
Oklahoma	Introduced on February 2, 2009, SB 492 authorizes the Department of Environmental Quality to issue CCS permits under certain terms and conditions. CO_2-EOR is not included (unless the operations are converted to storage). The resulting regulations would likely broadly mirror EPA's forthcoming UIC rule.	Feb 3rd – referred to Energy & Environment	http://webserver1.lsb.state.ok.us/WebBillStatus/main.html
Oklahoma	Introduced on February 2, 2009, SB 610 authorizes the Department of Environmental Quality to issue CCS permits under certain terms and	Mar 10th – passed the Senate, as amended Mar 17th – referred to	http://webserver1.lsb.state.ok.us/WebBillStatus/main.html

State	Legislation	Status	Link to Bill Text/News
	conditions. The Corporation Commission is authorized to regulate storage operators and pipelines as public utilities. CO_2-EOR is not subject to the scheme "where the sole purpose" is enhanced oil. Storage and pipeline operators are provided eminent domain rights.	Energy & Utility Regulation Apr 8th –Amended committee substitute Energy and Utility Regulation Committee. Title Restored. Apr 16th—Passed House. Apr 22nd—Senate conference requested. May 5th—Senate conference held, but agreement unable to be reached. Jun 1st—Signed by Governor.	
Oklahoma	Introduced on February 2, 2009, SB 679 extends the life of the Oklahoma Geologic Storage of Carbon Dioxide Task Force until December 1, 2009.	Mar 5th – passed the Senate Mar 18th – referred to Energy & Utility Regulation Apr 2nd—Do pass. Apr 9th –Third reading, ayes 86, nays 3. Referred for engrossment. Apr 13th—Engrossed and Signed, moved to Senate. House amendment's read. May 8th—Signed by Governor.	http://webserver1.lsb.state.ok.us/WebBillStatus/main.html Note: The task force continues to meet and is working through jurisdictional issues
Oregon	Introduced on March 4, 2009, H.J.M. 11 calls on the President and Congress of the U.S. to ensure that revenue resulting from forestry sequestration on federal lands is shared with the states.	Mar 6th – referred to House Committee on Environment and Water. May1st---Public hearing and work session scheduled. May 14—Passed House. Jun 4th—Passed Senate Jun 17th—Signed by	http://www.leg.state.or.us/09reg/measpdf/hjm1.dir/hjm0011.intro.pdf

State	Legislation	Status	Link to Bill Text/News
		House Speaker. Jun 18th—Signed by Senate President.	
Pennsylvania	Introduced on March 19, 2009, SB 92 amends the Alternative Energy Portfolio Standards Act to add "advanced coal combustion with limited carbon emissions" as a type of alternative energy source and providing minimum retail power sales percentages from such facilities over time. "Advanced coal combustion with limited carbon emissions" means the production of electric power from a facility that: (i) is fueled by coal or gas derived from an advanced coal gasification plant; (ii) captures and permanently sequesters increasing percentages of CO_2 over time; and (iii) has been designed to accommodate the required additional processing equipment to produce power with a maximum of 1,000 pounds of CO_2 emissions per megawatt hour. The CCS requirement is relieved if a storage network is not available by June 1, 2015. Retail sales requirements are also relieved if it is determined by December 15, 2015 that "advanced coal combustion [facilities] with limited carbon emissions" have not commenced construction. The Department of Conservation & Natural Resources is directed to develop and operate a "carbon dioxide sequestration network" on State land or land that DCNR has acquired. Only CO_2 generated within Pennsylvania may be stored on such sites. DCNR is authorized to collect fees to operate the CCS network. DCNR can enter into a contract to have a third party run the CCS network. More broadly, DCNR must issue regulations to govern CCS. CO_2-EOR is excluded from and cannot be deemed part of the CCS	**SB 92** Mar 19th – referred to Environmental Resources and Energy **HB 80** Mar 12th – referred to Environmental Resources and Energy Jun 16th—Approved by House Environmental Resources and Energy Committee as amended. Jun 22nd—Referred to Appropriations Committee. July 2nd –Recommitted to environmental resources and energy committee.	SB 92: http://www.legis.state.pa.us/CFDOCS/Legis/PN/Public/btCheck.cfm?txtType=PDF&sessYr=2009&sessInd=0&billBody=S&billTyp=B&billNbr=0092&pn=0683 HB 80: http://www.legis.state.pa.us/CFDOCS/Legis/PN/Public/btCheck.cfm?txtType=PDF&sessYr=2009&sessInd=0&billBody=H&billTyp=B&billNbr=0080&pn=2177

State	Legislation	Status	Link to Bill Text/News
	network. Pennsylvania takes title to and is responsible for all CO_2 stored within the CCS network. The companion bill is HB 80		
South Dakota	Introduced on January 27, 2009, HB 1129 requires the Public Utilities Commission to regulate carbon dioxide pipelines.	Feb 24th – passed the House Mar 3rd – passed the Senate Mar 11th – signed by the Governor	http://legis.state.sd.us/sessions/2009/Bills/HB1129P.pdf
Texas	Introduced on March 13, 2009, SJR 39 proposes a constitutional amendment authorizing the issuance of generation obligation bonds to provide and guarantee loans to encourage "advanced clean energy projects", which in turn must "capture[] not less than 50 percent of any carbon dioxide produced by the combustion of fuel and sequester[] that captured carbon dioxide by geologic storage or other means". "Geologic storage" means the "underground storage of carbon dioxide in a suitable geologic formation, including storage that is accomplished in conjunction with an enhanced oil recovery project." SJR 39 is being implemented via two companion bills: SB 2111 and HB 2811. SB 2111 and HB 2811 also specify that the Railroad Commission retains jurisdiction over CO_2-EOR operations that include both oil production and storage activities	**SJR 39** Mar 13th – introduced and received by the Secretary of the Senate Mar 31st –referred to Finance Committee Apr 23rd—Left pending in Committee. **SB 2111** Mar 13th -- introduced and received by the Secretary of the Senate Apr 27th—Passed House. May 6th—Reported favorably as substituted May 21—Placed on state calendar. **HB 2811** Mar 9th – introduced Mar 17th – referred to Energy Resources Mar 25th – scheduled for public hearing Apr 1st –Public hearing	SJR 39: http://www.legis.state.tx.us/BillLookup/Text.aspx?LegSess=81R&Bill=SJR39 SB 2111: http://www.legis.state.tx.us/BillLookup/Text.aspx?LegSess=81R&Bill=SB2111 HB 2811: http://www.legis.state.tx.us/BillLookup/Text.aspx?LegSess=81R&Bill=HB2811

State	**Legislation**	**Status**	**Link to Bill Text/News**
		held, reported on favorably.	
Texas	Introduced on December 22, 2008, HB 469 provides tax incentives to organizations that participate in R&D activities related to a "clean energy project", defined as a coal-fired power plant that: (i) can generate at least 200MW; (ii) uses IGCC technology; and (iii) is capable of capturing and permanently sequestering at least 60% of the facility CO_2 emissions. A franchise tax credit not to exceed $100M per organization is provided. The tax credits could be assigned to a taxable entity. The Bureau of Economic Geology must monitor measure and verify the sequestered CO_2 for the first three clean energy projects. HB 469 amends the tax code to reduce the oil production tax rate from 4.6% to 1.15% for EOR using CO_2 from a clean energy project. The credit lasts for the later to occur of thirty years or the date upon which EPA determines that CO_2 is a pollutant. The amount sequestered must be certified by the Railroad Commission (in the case of EOR) or TCEQ (in other cases) based upon substantial evidence that the "planned sequestration program will ensure that at least 60 percent of the carbon dioxide sequestered … will remain sequestered for at least 500 years." Finally, SB 483 contains similar provisions but is not a formal companion bill. Because of their overlaps, we are reporting both bills together here.	**HB 469** Feb 19th – referred to Energy Resources Mar 25th – scheduled for public hearing Apr 1st –public hearing held. Substitute considered and amended. Reported favorably as substituted. May 5th—Passed House. Jun 1st—Signed in House, June 3rd Signed in Senate. Jun 19th—Signed by Governor. **SB 483** Mar 13th – referred to Finance Apr 9th --public hearing held. Left pending in committee.	HB 469: http://www.legis.state.tx.us/tlodocs/81R/billtext/pdf/HB00469E.pdf SB 483: http://www.legis.state.tx.us/BillLookup/Text.aspx?LegSess=81R&Bill=SB483
Texas	Introduced on January 29, 2009, SB 16 amends the definition of "advanced clean energy project" in a manner similar (CCS requirement, etc.) to that provided under SB 2111 and HB 2811, discussed above. TCEQ is authorized to provide grants	Feb 10th – referred to Natural Resources Mar 19th – public hearing Apr 8th –amendments heard and voted on. Passed to engrossment	http://www.legis.state.tx.us/tlodocs/81R/billtext/pdf/SB00016I.pdf

State	Legislation	Status	Link to Bill Text/News
	or other financial incentives for eligible projects to offset the incremental cost of emission reductions. Eligible projects include "advanced clean energy projects." Except for projects using Texas natural resources, projects incorporating CCS are not provided a preference.	as amended. Apr 22nd—Moved to House. May 4th—Hearing Scheduled. May 23rd—Placed on state calendar.	
Texas	Introduced on February 25, 2009, HB 1796 requires TCEQ to work with the Bureau of Economic Geology to do a pilot study to identify locations and develop standards and rules for the offshore sequestration of carbon dioxide. Thereafter, TCEQ would use the study results to select a location for an offshore repository; a storage fee mechanism is also envisioned. TCEQ, on behalf of the State of Texas, would take title to injected CO_2.	Mar 4th – referred to Environmental Regulation Mar 25th – hearing held. Left pending in committee. Apr 9th—Reported favorably in Committee. Apr 22nd—Committee report sent to calendars and is now out of committee by vote of 9-0. May 7th—Passed House May 23rd—Hearing held in Senate Natural Resources Committee; reported on favorably. Jun 2nd—Passed Senate, Sent to Governor for Signature. Jun 19th—Signed by Governor.	http://www.legis.state.tx.us/tlodocs/81R/billtext/pdf/HB01796I.pdf
Texas	Introduced on March 5, 2009, SB 1387 provides that TCEQ is responsible for CCS regulation and permitting, except for CO_2-EOR wells, which remain under authority of the Railroad Commission. The Railroad Commission is also given authority to regulate saline formations directly above or below an EOR reservoir. It is envisioned that TCEQ and the Railroad Commission will cooperate on permitting, and to that end, the agencies must enter into a MOU.	**SB 1387** Mar 17th – referred to Natural Resources Mar 26th – hearing held. Left pending in committee. Apr 22nd—Passed Senate by vote of 30-0. Moves to House.	SB 1387: http://www.legis.state.tx.us/tlodocs/81R/billtext/pdf/SB01387I.pdf HB 2669: http://www.legis.state.tx.us/BillLookup/Text.aspx?LegSess=81R&Bill=HB2669

State	Legislation	Status	Link to Bill Text/News
	CCS regulations must be consistent with and not more stringent than whatever rules emerge from EPA. Injected CO_2 is declared to be the personal property of the storage operator. Previously injected CO_2 may be extracted for later commercial or industrial use, with the approval of TCEQ. The companion bill is HB 2669.	May 18th—Passed House. Awaiting Gov. signature. May 27th—Signed by Governor. **HB 2669** Mar 6th – introduced Apr 15th—Reported favorably in committee by vote of 8-0. May 14th—Following a number of postponements to bring it up, it has been laid on table subject to call.	
Texas	SB 1716 and HB 2338 are companion bills. Both bills were introduced in March and provide tax rebates for energy efficient buildings or facilities under the EPA Energy Star program.	**SB 1716** Mar 20th—Referred to Finance Committee. **HB 2338** Apr 20th—Public hearing was held. The bill was left pending in House Ways & Means Committee. May 7th—Committee report sent to calendars.	
Utah	Introduced on January 30, 2009, HJR 12 expresses the Legislature's support for: (i) producing hydrogen from coal with CCS; (ii) encouraging the Public Service Commission to consider authorizing recovery of cost-effective and prudently incurred costs that reduce carbon emissions; and (iii) encouraging the PSC to consider hydrogen production from coal with CCS to be a reasonable investment for protecting the long-term interests of Utah's utility rate payers.	Feb 19th – passed the House Mar 5th – passed the Senate Mar 18th – sent to the Lieutenant Governor	http://le.utah.gov/~2009/bills/hbillint/hjr012s01.pdf
West Virginia	Introduced on February 26, 2009, HB 2860 expresses the Legislature's support for CCS and: (i) Directs the Department of Environmental Protection to issue	**HB 2860** Feb 26th – sent to Judiciary Mar 18th – passed	HB 2860: http://www.legis.state.wv.us/Bill_Text_HTML/2009_SESSIONS/RS/amendments/HB2860%20H%20JUD%20AM%203-18%20_1.htm

State	Legislation	Status	Link to Bill Text/News
	regulations governing CCS; (ii) Sets forth requirements for the regulations (basically mirrors federal UIC); (iii) Establishes a Carbon Dioxide Sequestration Working Group to develop, among other things, a long-term CCS strategy for West Virginia; and (iv) Declares pore space to be an attribute of the surface estate. CO_2-EOR is not included in the storage scheme; instead, EOR operators are given the chance to convert their operations into storage. HB 2860 states, however, that nothing in the bill is intended to impede or impair an EOR operator from generating carbon credits. SB 396 is the companion bill.	Judiciary Mar 18th – sent to Finance Apr 7 –referred to Judiciary. On 2nd reading, it was amended and recommended Do Pass. Apr 10th—Passed Senate. May 4th—Approved by Governor. **SB 396** Feb 26th – introduced Feb 26th – to Energy, Industry and Mining (then Judiciary)	SB 396: http://www.legis.state.wv.us/E ext_HTML/2009_SESSIONS/RS/Bills/sb396%20intr.htm
Wyoming	Introduced on January 13, 2009, HB 56 would prohibit the use of hydrocarbon-containing pore space for storage without the written consent of the owner of the oil and gas lease.	Jan 22nd – failed on third reading	http://legisweb.state.wy.us/2009/Introduced/HB0056.pdf
Wyoming	Introduced on January 13, 2009, HB 57 clarifies that a severed mineral estate is dominant over pore space storage rights.	Jan 20th – passed the House Feb 17th – passed the Senate Feb 26th – signed by the Governor	http://legisweb.state.wy.us/2009/Enroll/HB0057.pdf
Wyoming	Introduced on January 13, 2009, HB 58 provides that injected CO_2 is presumed to be owned by, and thus liable for, the entity that injected it.	Jan 20th – passed the House Feb 19th – passed the Senate Feb 26th – signed by the Governor	http://legisweb.state.wy.us/2009/Enroll/HB0058.pdf
Wyoming	Introduced on January 13, 2009, HB 80 establishes procedures for the unitization of geologic sequestration sites.	Jan 21st – passed the House as amended Feb 19th – passed the Senate as amended	http://legisweb.state.wy.us/2009/Enroll/HB0080.pdf

State	Legislation	Status	Link to Bill Text/News
		Feb 27th – signed by the Governor	

Active/High-Priority Regulatory Developments/Regulations

State	Regulations	Status	Link to Regulatory Text/News
California	On February 24, 2009, CARB released its low carbon fuel standard. The LCFS acknowledges that CCS could be used to reduce the carbon intensity of specific regulated fuels.	April 23-24, 2009: Public Hearing	Staff Report: http://www.arb.ca.gov/fuels/lcfs/030409lcfs_isor_vol1.pdf
Kansas	On January 28, 2009, the Kansas Corporation Commission proposed regulations for the storage of CO_2 in brine-filled reservoirs. The regulations do not apply to CO_2-EOR except for one provision that purports to regulate drilling through CO_2-EOR operations. The regulations are being implemented pursuant to HB 2419, discussed below.	Public hearing will be held on March 26, 2009 and written comments are due on that date, too.	http://www.kcc.state.ks.us/conservation/hearing_032609.htm (notice of hearing) http://kcc.ks.gov/conservation/proposed_regs_032609.pdf (proposed regulations)
Oklahoma	Oklahoma is in the midst of implementing its geologic storage offset program pursuant to the Oklahoma Carbon Sequestration Enhancement Act. Regulations have been issued to implement the State's novel carbon offset certification program, which includes geologic storage. The Oklahoma Conservation Commission has announced that it shortly will start to accept offset and verification applications CO_2-EOR companies.	Applications are supposed to be made available shortly on the web site for the Oklahoma Conservation Commission.	http://www.ok.gov/conservation/Agency_Divisions/Water_Quality_Division/WQ_Carbon_Sequestration/Geologic_Offsets_/index.html
Utah	Utah's Carbon Capture and Geologic Sequestration Workgroup is meeting to develop legislative recommendations regarding regulation of CCS. The Workgroup consists of a steering committee, three subcommittees, an advisory committee, and a stakeholder group. This is being done pursuant to SB 202 Substitute, described in greater	No new meetings have been publicly announced but we encourage companies with interests in Utah to contact the relevant agencies. The Workgroup must provide a status report to the Legislature by July 1, 2009.	http://www.deq.utah.gov/News/2008/docs/New_Workgroup_Focuses_on_Carbon_Capture_Regs_090308.pdf http://www.climatechange.utah.gov/capture_sequestration.htm http://www.climatechange.utah.gov/CCGS_in_Utah.htm

detail below.

Enacted Legislation/Other Developments of Note

State	Legislation/Other Developments	When Signed Into Law	Link to Bill Text/News
California	AB 705 Would have authorized the development of a CCS regulatory regime in California. Although this effort failed, we continue to report it here because of its significance.	n/a: Died/stalled	http://www.leginfo.ca.gov/pub/07-08/bill/asm/ab_0701-0750/ab_705_bill_20080107_amended_asm_v96.pdf
Colorado	HB 06-1281 Directs the Public Utilities Commission to consider proposals by Colorado electric utilities to build one or more demonstration power plants using CCS-equipped IGCC technology.	June 1, 2006	http://www.state.co.us/gov_dir/leg_dir/olls/sl2006a/sl_300.htm
Colorado	HB 08-1164 Directs the Public Utilities Commission to consider the benefits of CO_2-EOR when utilities come forward with CCS plans.	June 2, 2008	http://www.leg.state.co.us/clics/clics2008a/csl.nsf/fsbillcont3/1085D654E83619EB872573680051EA4F?open&file=1164_rer.pdf
Connecticut	HB 5600 Authorizes the Department of Environmental Protection to issue CCS regulations.	June 2, 2008	http://www.cga.ct.gov/2008/TOB/H/2008HB-05600-R00-HB.htm CT has not yet started rulemaking proceedings to implement this law
Idaho	Idaho Carbon Sequestration Advisory Committee	n/a	The Committee is in the early stages of considering CCS-related issues and opportunities for the State. http://www.scc.idaho.gov/carbon%20sequestration%20main.htm
Illinois	SB 1704 Expresses State support for the FutureGen project, including assumption of liability for injected CO_2.	July 30, 2007	http://www.ilga.gov/legislation/fulltext.asp?DocName=&SessionId=51&GA=95&DocTypeId=SB&DocNum=1704&GAID=9&LegID=29844&SpecSess=&Session
Illinois	SB 1987 Creates a clean coal portfolio standard for the State to otherwise encourage the development of CCS-	January 12, 2009	http://ilga.gov/legislation/fulltext.asp?DocName=&SessionId=51&GA=95&DocTypeId=SB&DocNum=1987&GAID=9&LegID=35238&SpecSess=&Session=

State	Legislation/Other Developments	When Signed Into Law	Link to Bill Text/News
	equipped clean-coal projects		
Kansas	HB 2419 Authorizes the Kansas Corporation Commission to issue CCS regulations	March 28, 2007	http://www.kslegislature.org/bills/2008/2419.pdf
Kentucky	HB 1 Provides incentives for clean energy technologies, including CCS.	August 30, 2007	http://www.lrc.ky.gov/record/07s2/HB1.htm
Louisiana	HB 1220 Authorizes the State Mineral Board to enter into contracts, and assume responsibility for, sequestration storage facilities	July 2, 2008.	http://www.legis.state.la.us/billdata/streamdocument.asp?did=483706
Louisiana	HB 1117 Authorizes the Commissioner of Conservation to regulate CO_2 injections and establishes procedures for obtain leases for storage facilities.	June 17, 2008	http://www.legis.state.la.us/billdata/streamdocument.asp?did=499939
Oklahoma	SB 1765 Establishes a regulatory regime for CCS, while leaving open some issues related to whether the Department of Environmental Quality or the Corporation Commission is in the lead on specific aspects of CCS regulation	June 3, 2008	http://webserver1.lsb.state.ok.us/2007-08bills/HB/sb1765_hflr.rtf
Pennsylvania	HB 1202 Authorizes the substitution of CTL derived diesel for the State's biodiesel mandate, provided that the fuel's carbon emissions are offset "through carbon sequestration."	July 10, 2008	http://www.legis.state.pa.us/cfdocs/billinfo/billinfo.cfm?syear=2007&sind=0&body=H&type=B&BN=1202
Pennsylvania	SB 266 Directs the Department of Environmental Protection to conduct a climate study, which must include a discussion of CCS.	July 9, 2008	http://www.legis.state.pa.us/CFDOCS/Legis/PN/Public/btCheck.cfm?txtType=PDF&sessYr=2007&sessInd=0&billBody=S&billTyp=B&billNbr=0266&pn=1554
Texas	HB 149 Directs the Railroad Commission to be responsible for the CO_2 from the	May 31, 2006	http://www.legis.state.tx.us/tlodocs/793/billtext/pdf/HB00149F.pdf

State	Legislation/Other Developments	When Signed Into Law	Link to Bill Text/News
	FutureGen program.		
Utah	SB 202 Substitute Directs the Division of Water Quality and Division of Air Quality, in collaboration with the Division of Oil, Gas & Mining and the Utah Geological Survey, to present recommended rules to the Legislature's Administrative Rules Review Committee by January 1, 2011; a progress report must be made by July 1, 2009. The recommended rules shall exclude CO_2-EOR. SB 202 separately provides a 20% RPS; provided, however, that power produced from "qualifying carbon sequestration generation" does not count against the power sales baseline against which the 20% is applied. "Qualifying carbon sequestration generation" means a fossil-fueled generating facility located within the geographic boundary of the Western Electricity Coordinating Council that: (i) becomes operational or retrofitted on or after January 1, 2008; and (ii) reduces carbon dioxide emissions through permanent geological sequestration or "other verifiably permanent reductions … through the use of technology."	March 18, 2008	http://le.utah.gov/~2008/bills/sbillenr/sb0202.pdf
Washington	The State of Washington's Climate Advisory Team Final Report includes recommendations on CCS.	Released February 1, 2008	http://www.ecy.wa.gov/climatechange/InterimReport/122107_TWG_es.pdf (see "ES-5")
Washington	WAC 173-218-115: Specific Requirements for Class V Wells Used to Inject Carbon Dioxide for Permanent Geologic Sequestration The State of Washington has issued Class V CCS rules.	Adopted on June 19, 2008	http://apps.leg.wa.gov/WAC/default.aspx?cite=173-218-115
Wisconsin	The Governor's Task Force on Global Warming Final Report addressed CCS.	Released July 24, 2008	http://dnr.wi.gov/environmentprotect/gtfgw/documents/Final_Report.pdf

State	Legislation/Other Developments	When Signed Into Law	Link to Bill Text/News
Wisconsin	In 2008, the Public Service Commission opened an investigation as to the potential for CCS.	Investigation has closed; next steps are uncertain	http://psc.wi.gov/globalWarming/05EI145/index-carbonSequestration.htm
West Virginia	The "West Virginia Energy Opportunities Plan" supports CCS and calls on the Department of Environmental Protection to issue regulations	Report has been issued; next steps are uncertain	http://www.energywv.org/community/EOD.pdf
Wyoming	HB 90 Provides a regulatory framework for CCS.	March 4, 2008	http://legisweb.state.wy.us/2008/Enroll/HB0090.pdf
Wyoming	HB 89 Addresses pore space ownership.	March 4, 2008	http://legisweb.state.wy.us/2008/Enroll/HB0089.pdf

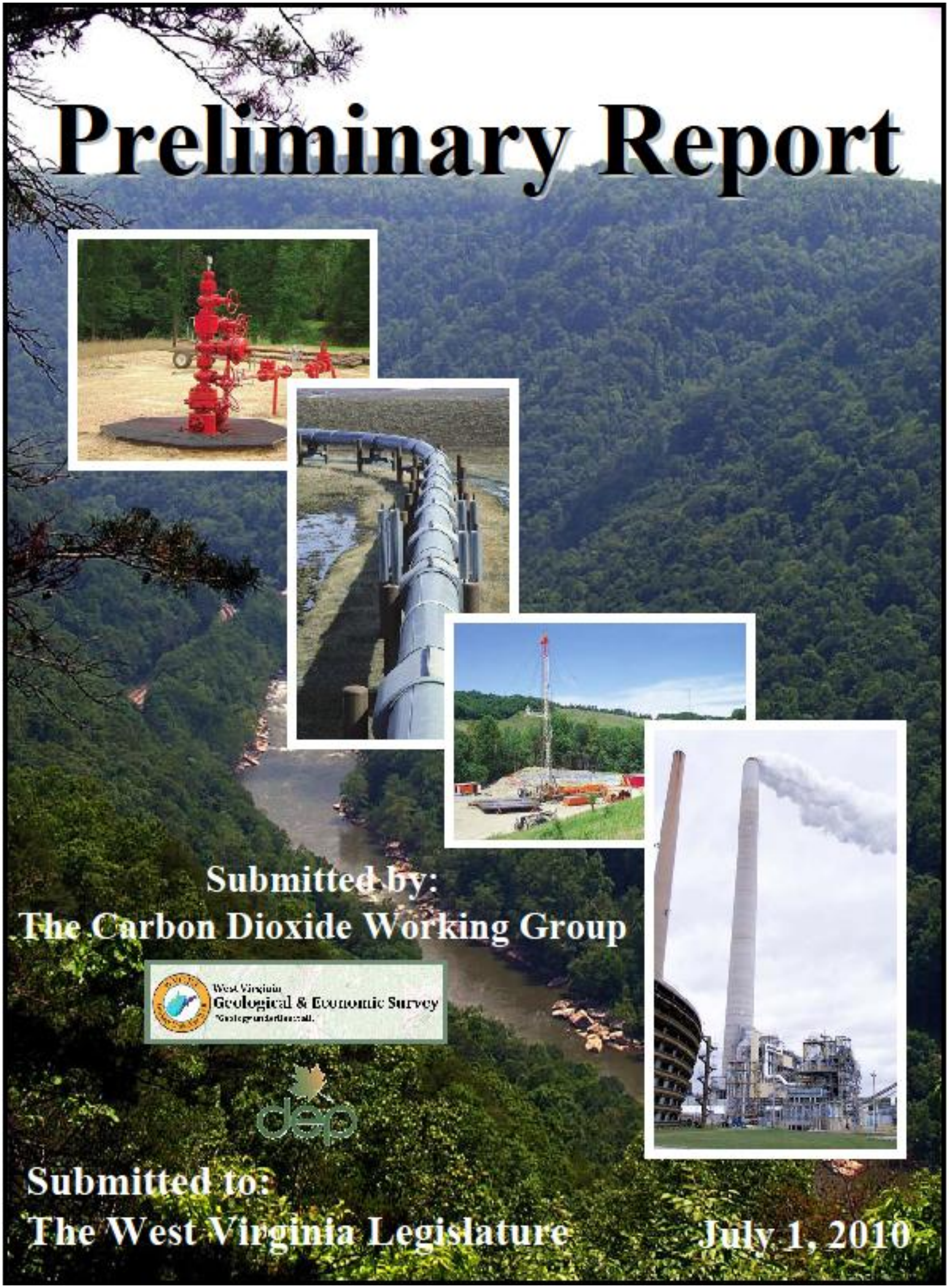
Reports included in appendices of the Final Report of the Workgroup for Legal Issues of Carbon Sequestration included:

CO2 Storage: A Legal and Regulatory Guide for States (2008) IOGCC

Guidelines for Carbon Dioxide Capture, Transport and Storage WRI (2008)

APPENDIX 8
Draft Report of the West Virginia CCS Workgroup

Preliminary Report



Submitted by:
The Carbon Dioxide Working Group

West Virginia
Geological & Economic Survey

dep

Submitted to:
The West Virginia Legislature

July 1, 2010

FOREWORD

The Carbon Dioxide Sequestration Working Group consists of members appointed by West Virginia Department of Environmental Protection ("WVDEP") Secretary Randy Huffman, and West Virginia Geological and Economic Survey ("WVGES") Director Dr. Michael Hohn. The Working Group would like to thank the WVDEP for use of its facilities and resources including the time and assistance of Kristin Boggs, Esq. and Jeff Knepper. Also, special thanks are offered to the WVGES, the West Virginia Division of Energy, the Department of Tax and Revenue, and other state agencies that have provided information and technical expertise. Many experts from these agencies, and from interested groups, traveled long distances to share their valuable experience about Carbon Capture and Sequestration. The Working Group is truly grateful for their assistance.

The Working Group reviewed a substantial body of data and reports related to various aspects of Carbon Capture and Sequestration. This Interim Report incorporates or refers to data and information from a large number of sources including federal and state agencies, and non-governmental organizations. Some of this data and information may incomplete or inaccurate. The citation to these sources does not necessarily mean the Working Group agrees with the data, information, or opinions cited.

This Interim Report provides preliminary conclusions and recommendations. These preliminary conclusions and recommendations are subject to further review and possible modification during the preparation of the Final Report.

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I. EXECUTIVE SUMMARY

I.A. BACKGROUND

During the 2009 Regular Session, the West Virginia Legislature passed HB 2860 which was added to the West Virginia Code as Carbon Dioxide Sequestration, Article 11A of Chapter 22. The Legislature listed among its findings that "[i]t is in the public interest to advance the implementation of carbon dioxide capture and sequestration technologies into the state's energy portfolio." Recognizing that there are administrative, technical and legal questions involved in developing this new technology, the Code authorized the West Virginia Department of Environmental Protection (WVDEP) Secretary to establish a Carbon Dioxide Sequestration Working Group ("Working Group"). The Working Group is charged with studying all issues related to the sequestration of carbon dioxide and to submit a preliminary report to the Legislature on July 1, 2010, followed up by a final report due on July 1, 2011. The final report must address, at a minimum, the following:

- A recommendation of the appropriate methods to encourage the development of carbon dioxide sequestration technologies;
- An assessment of the economic and environmental feasibility of large, long-term carbon dioxide sequestration options;
- A recommendation of any legislation the working group may determine to be necessary or desirable to clarify issues regarding the ownership and other rights and interest in pore space;
- A recommendation of the methods of facilitating the widespread use of carbon dioxide sequestration technology throughout West Virginia;
- Identification of geologic sequestration monitoring sites to assess the short-term and long-term impact of carbon dioxide sequestration;
- An assessment of the feasibility of carbon dioxide sequestration in West Virginia and the characteristics of areas within the state where carbon dioxide can be sequestered;
- An assessment of the costs, benefits, risks and rewards of large-scale carbon dioxide sequestration projects in West Virginia;
- An assessment of the potential carbon dioxide sequestration capacity in this state;
- Identification of areas of research needed to better understand and quantify the processes of carbon dioxide sequestration; and
- An outline of the working group's long-term strategy for the regulation of carbon dioxide sequestration in West Virginia.

(W. Va. Code § 22-11A-6(h)(1)-(10))

This Preliminary Report was prepared and submitted in compliance with the Carbon Dioxide Sequestration Act. It describes the efforts of the Group to date and indicates progress toward making recommendations and conclusions.

Notably, after the Carbon Sequestration Act was passed during the regular session in 2009, a Special Session was held in June 2009. During that session, the Legislature promulgated the Alternative and Renewable Energy Portfolio Standard, Article 2F of Section 24 of the West Virginia Code. This new law states that "[t]o continue lowering the emissions associated with electrical production, and to expand the state's economic base, West Virginia should encourage the development of more efficient, lower-emitting and reasonably priced alternative and renewable energy resources."

"Advanced coal technology" is included in the list of defined "alternative energy resources." W. Va. Code § 24-2F-3(c)(1). Advanced coal technology is defined as "a technology that is used in a new or existing energy generating facility to reduce airborne carbon emissions associated with the combustion or use of coal and includes, but is not limited to, *carbon dioxide capture and sequestration technology*, . . . and any other resource, method, project or technology certified by the commission as advanced coal technology." W.Va. Code § 24-2F-3(a) (emphasis added).

It is clear to the Working Group that passage of the Alternative and Renewable Energy Portfolio Standard almost contemporaneous with passage of the Carbon Dioxide Sequestration Act indicates the Legislature's high level of interest in carbon capture and sequestration technology and its desire for West Virginia to be a leader in deployment of such technology if feasible from an environmental, economical, and legal standpoint.

I.B. ORGANIZATION OF THE PRELIMINARY REPORT

While the list of ten items the Working Group is charged with considering may be categorized broadly into three areas, many of them overlap. This constituted some challenge with organization for a useful preliminary report. The Group decided to organize this report by way of discussing feasibility issues first, geology and technology issues second, and legal issues last. In each of these three broad sections, any preliminary conclusions and/or recommendations reached by the Group are clearly stated at the end of the section. Subsequent to that information is a list of items which will be studied over the next year prior to development of a Final Report.

The Preliminary Report provides preliminary conclusions and recommendations. These preliminary conclusions and recommendations are subject to further review and possible modification during the preparation of the Final Report.

I.C. FEASIBILITY SUBCOMMITTEE

The Working Group believes that it is highly likely that West Virginia will be faced with having to significantly reduce the state's emissions of greenhouse gases in the near future. The state currently emits approximately 102 million metric tons of greenhouse gases each year with about 86 million metric tons of that being emitted from coal-fired power plants. The state is one of the nation's largest exporters of electric power to other states. Power plants were originally built in the state to be near the primary fuel source and West Virginia contains enough generating capacity to meet the state demand and provide extensive power to its neighbors.

The United States Environmental Protection Agency ("USEPA") has designated carbon dioxide and other greenhouse gases as "regulated" pollutants and there is a strong desire on the federal level to reduce greenhouse gas emissions. This reality, coupled with increased international pressure on the US in this area, means emissions in West Virginia may soon have to be cut back. With these issues as a backdrop, the Feasibility Subcommittee concentrated on assessing the magnitude of the reductions West Virginia may be asked to make and whether or not CCS[1] technology can contribute to a potential solution to this challenge.

Factors to assess in this investigation include costs of such technology, impacts on the state's economy, public safety and environmental concerns, and goals of the state that may be impacted by CCS. This subcommittee also proposed some incentives the state may want to consider should it be determined that deployment of CCS is in the state's interest (see section IV.A.6.).

In general, the magnitude of the reductions needed to achieve the goals of any currently proposed emissions reduction targets are so large that multiple approaches are needed because no single technology or life style change can achieve them. Current Congressional proposals call for a reduction in US greenhouse gas emissions of 83% by 2050. Elimination of all coal-fired power in the nation would still leave 70% of the greenhouse gas emissions currently emitted from US sources (see Table A.1.). CCS may be part of the solution to greenhouse gas emissions, but significantly more will have to be done to achieve these goals.

The economic cost of CCS technology can be estimated, but because the technology is in the early stages of development, such cost projections are somewhat unreliable. Section IV.A.3. gives a comparative costing for various technologies with varying greenhouse gas impacts, but predicting costs at this time is extremely difficult. Technology development, economic recession and national and international affairs may play a huge role in such projections. Section IV.A.3.b. helps outline some of the information that may be needed to assess the overall impact of CCS on the economy of West Virginia, but acknowledges that much of the needed data are not yet available. The Legislature may want to inquire into this question in the coming near term.

From a public safety and environmental impact point of view, there are some important questions that still need to be resolved. The Mountaineer CCS project in Mason County, West Virginia, is attempting to answer some of these questions. The Legislature will want to carefully consider the observation in section IV.A.4. and continue to insist that appropriate technical consideration be given to designing regulatory structure to assure long term protection of these values.

In the coming year the Feasibility Subcommittee will assess and attempt to resolve some of the following topics:

1. In the face of growing concern over greenhouse gas emissions, should and if so to what extent should West Virginia investigate other methods of generating electrical and other forms of power?
2. Should the Legislature investigate potential regulations and or promotion of intrastate and interstate CO_2 pipelines?
3. What factors need to be considered in the assessment of the value of coal-fired power to West Virginia?
4. The subcommittee will delve deeper into the economic cost and impact on West Virginia of CCS technology.

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[1] The term "CCS" is used frequently throughout the Preliminary Report. The Working Group agreed that CCS shall be interpreted to refer to Carbon Capture and Sequestration instead of Carbon Capture and Storage. The terms "sequestration" and "storage" are often used interchangeably so the Group agreed to the use of "sequestration" throughout the report. The Legislature defines carbon dioxide capture and sequestration as "the capture and secure storage of carbon dioxide that would otherwise be emitted to, or remain in, the atmosphere." W. Va. Code §22-11A-2(9).

5. What facts need to be brought to the attention of the West Virginia Legislature to enable that body to make an informed decision about the importance of CCS technology development in the state?

I.D. GEOLOGY & TECHNICAL SUBCOMMITTEE

The Geology & Technical Subcommittee (G&T Subcommittee) is addressing three questions posed in the legislation: identifying monitoring sites for geologic sequestration [§22-11A-6(h)(5)], assessing the feasibility of carbon dioxide sequestration in West Virginia [§22-11A-6(h)(6)], and assessing the potential carbon dioxide sequestration capacity in the state[§22-11A-6(h)(8)]. In addition, this subcommittee addressed several technical questions referred to it by other subcommittees.

The G&T Committee reviewed legislation from several states addressing CO_2 sequestration monitoring, verification and accounting (MVA). While these laws directed state agencies to develop regulations, only one state, Washington, has developed regulations administered by a state agency.

Carbon Dioxide Sequestration Capacity

Potential carbon dioxide sequestration beneath West Virginia has been assessed by the Midwest Regional Carbon Sequestration Partnership (MRCSP). Several oil and gas or saline formations in the stratigraphic column have potential for storage or for providing a seal, preventing migration of a carbon dioxide plume. Coal, a valued natural resource in West Virginia, also presents storage potential in unmineable seams. Shale and coal have similar trapping mechanisms for sequestration where the carbon dioxide molecule is bound to the organic material or clay particles found in gas shales.

The MRCSP estimates the potential for geologic sequestration potential of carbon dioxide in West Virginia at about 60,810 million metric tons. This includes an estimate of storage potential in shales. In its second edition of the Carbon Sequestration Atlas of the United States and Canada, the National Energy Technology Laboratory (NETL) provides a range in geologic storage potential for West Virginia of between 4,873 and 14,994 million metric tons[2]. Storage potential in shales is not included in NETL's atlas; more research work needs to be conducted to better understand trapping mechanisms in shale, providing a better understanding of the storage potential in these rocks. Emission data in NETL's Atlas for West Virginia shows 29 sources from all industries emitting 102 million metric tons per year (see Table 4B2) which indicates that there is between 47 years and 147 years of storage capacity for the annual carbon dioxide sources in West Virginia. The third edition of the Atlas is scheduled for release in November 2010. Also, the United States Geologic Service will be providing an assessment of onshore storage potential for CO_2 per Congressional direction in the Energy Independence and Security Act of 2007. Storage potential estimates are resource estimates that need to be proven. This will be done to some degree during site characterization of a potential sequestration site. As with other natural resources such as oil and gas or coal, proved reserves are a smaller value than the resource estimate.

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[2] NETL will release the 3rd edition of the Atlas in November, 2010.

Monitoring, Verification, and Accounting of CCS

Monitoring geologic sequestration to ascertain the position of the carbon dioxide plume requires knowledge of the geologic setting of the storage reservoir. This geologic knowledge was originally developed during an initial assessment of the regional geology. The ability of this early assessment to provide sufficient details on the character of the geology in the area depends on the quality of the available database. Site characterization is a huge investment. It has been estimated that it will cost $100,000 per square mile to acquire 3-D seismic and $3,000,000 to drill and log an evaluation well plus 30% of these costs for data processing, modeling and other services[3]. One well will evaluate 25 square miles. A storage field covering 25 square miles will cost a little over $7,000,000 to partially characterize as these costs probably do not cover all of the details, including securing rights to the pore space, that need to be accounted for in presenting a storage field proposal before a regulatory body with the intent of gaining a permit. The quality of data available for this initial assessment will provide a level of confidence on whether or not to proceed, and whether or not a further investment in time and money is warranted.

It is during site characterization that the establishment of the MVA system begins. Initial sampling establishes a baseline for groundwater quality, and possibly for soil gases and ambient air quality. Consideration regarding technology to fulfill MVA needs will also be sorted out during site characterization. Direct measurement and sampling of the reservoir, seal and overlying strata can only be accomplished with a well. A core sample will provide direct measurement of porosity and permeability, and if recovered under special conditions, in situ fluid samples. Wireline or geophysical logging tools record physical properties of the stratigraphic section, rocks and fluids, cut by the well. There is well established technology to acquire seismic data. Core data provide the highest level of resolution while surface seismic data provide the broadest areal extent. With computers, core data are used to calibrate wireline logging data which in turn are used to calibrate seismic data; all of which provide an overall picture of the subsurface.

Additional data acquisition from an MVA program includes groundwater sampling from specific monitoring wells or local water wells, and may also include pressure and temperature monitoring from monitoring wells and injection wells, soil gas sampling, and ambient air monitoring around injection facilities.

The goal for any particular MVA program will be to confirm confinement and alert to a possible leak. Development of regulations and permitting standards will be necessary to establish goals that any MVA program will be required to meet.

Transmission of Carbon Dioxide

Delivering captured carbon dioxide to a storage site for sequestration will be accomplished by pipeline. This is a familiar form of transportation as about 3,900 miles of pipeline deliver carbon dioxide to numerous enhanced oil recovery (EOR) projects in West Texas, Wyoming, Mississippi and the Texas-Louisiana Gulf Coast. Through October 2007, there were 18 incidents along the carbon dioxide pipeline network without any injury or fatality. For the natural gas pipeline network, which is 400 times longer, there were 877

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[3] McCoy, S.T., 2008, The Economics of CO_2 Transportation by Pipeline and Storage in Saline Aquifers and Oil Reservoirs. PhD dissertation, Carnegie Mellon University, January, 2008.

injuries and 252 fatalities. In testimony before the House Subcommittee on Energy and the Environment, Ian Duncan of the Texas Bureau of Economic Geology stated that the rupture of CO_2 pipelines is the largest risk facing CCS deployment.[4] He further points out that "[u]ltimately the risk from pipelines depends on: siting of the pipelines (risks are site specific); operation of the pipelines to minimize possible corrosion (particularly the current industry focus on keeping the water levels in the CO_2 below saturation); and implementation of effective risk management and mitigation plans." Rupture is caused by an outside force which is the cause for only one incident on CO_2 pipeline but is the cause for 35% of the incidents on natural gas pipelines.[5] A distinct advantage for carbon dioxide is that it is not flammable, it will not support combustion. However, two points of concern regarding carbon dioxide are that it is an asphyxiant and heavier than air.

Carbon Dioxide Risk Assessment

Assessment of the risks of transporting and storing carbon dioxide is necessary to properly quantify liabilities and assure the public that projects awarded a permit have an excellent chance of meeting expectations regarding safe operations. The prime factor of consideration here, both for transportation and sequestration, is pressure. Captured carbon dioxide is most economically shipped in a dense or supercritical phase[6] where carbon dioxide has the viscosity of a gas but the density of a liquid. To optimize storage, carbon dioxide needs to be sequestered at depths that will maintain the supercritical phase. Depending on temperature and pressure gradient, this will be about 2,500 feet and deeper. While oil and gas production deplete the pressure of the reservoir, carbon dioxide sequestration will leave the reservoir at hydrostatic (pre-existing) pressure or slightly higher. Once injection ceases, the storage reservoir pressure will begin to return to pre-injection operation pressures. The USEPA recommends a 50 year post injection monitoring period, although the Administrator may modify this on a case-by-case basis, because it estimates that this is how long it will take the CO_2 storage reservoir pressure to return to regional hydrostatic pressure levels and provide a condition of non-endangerment.[7]

There is a substantial and growing body of carbon dioxide risk assessment literature. Relative to the scale envisioned for CCS, there is some experience in transporting and injecting carbon dioxide for enhanced oil recovery (EOR) for more than three decades. In a publication discussing the risk of CCS, one author contends that the risks of geologic storage of carbon dioxide are no greater than the risks associated with similar industrial activities currently in operation.[8] She further notes that "[b]ecause the technology for characterizing potential CO_2 storage sites, drilling injection wells, safely operating injection facilities, and monitoring will be adapted and fine-tuned from these mature industrial practices taking place today, it is reasonable to infer that the level of risk will be similar." The mathematical models used are undergoing rapid development and remain works in progress and further refinement of the risk assessments will be an iterative process. The risk assessment literature, subject to the limitations expressed, generally supports continuing forward to establish a framework for such projects. There is

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[4] Ian Duncan, 2009, Regarding The Future of Coal under Climate Legislation; Carbon Sequestration Risks, Opportunities, and Learning from the CO2-EOR Industry. Testimony before the U.S. House Committee on Energy and Commerce, Subcommittee on Energy and the Environment, March 10, 2009.

[5] Ibid

[6] In its critical phase, carbon dioxide is 88^{o}F at 1,073 psi or 31^{o}C at 7.4 MPa.

[7] EPA, 2008, Proposed rules for Underground Injection Control (UIC) Program for Carbon Dioxide (CO2) Geologic Sequestration (GS) Wells. (web link needed)

[8] Benson, A.M., *Carbon Dioxide Capture and Storage, Assessment of Risks from Storage of Carbon Dioxide in Deep Underground Geological Formations*, Lawrence Berkeley National Laboratory, April 2, 2006, p.4.

potential for sequestration of captured carbon dioxide in West Virginia. The state overlies the sedimentary section of a portion of the Appalachian Basin, one of the major sedimentary basins in the continental United States beneath eight states. Storage potential in saline formations, depleted oil and gas reservoirs and unmineable coal seams are all present. Analogous circumstances from natural gas storage and EOR suggest, but do not prove conclusively, that carbon dioxide geologic storage risks are manageable. There will always be some level of geologic risk. Saline formations provide most of the sequestration potential yet the natural gas storage industry much prefers depleted oil and gas reservoirs. Finding suitable saline storage will have a more exploratory aspect than for depleted oil and gas reservoirs which are a known quantity. Regional evaluation, selection of a suitable location for site characterization, acquisition of rights to the pore space, acquisition of permits, and installation of injection wells, pipelines and equipment may take three to four years. The rate at which storage reservoirs can be permitted and developed will likely dictate the rate of deployment of CCS technology. Without storage, there is no need for capture.

Over the next year, additional information on storage assessment is expected to be published. Phase III large-scale injection projects are underway by the Regional Partnerships. These projects will evaluate injectivity, performance of the reservoir, and the MVA program established to track injection activity. The Geology & Technology Subcommittee will evaluate and incorporate this information in the final report.

I.E. LEGAL SUBCOMMITTEE

The efforts of the Legal Subcommittee to assess legal issues began by undertaking a careful review of activities around the country in identifying significant policy, regulatory and legal issues raised by CCS projects. After identifying the universe of issues involved, initial efforts focused on property ownership and acquisition. Research was conducted on activities in other states and by such organizations as the Interstate Oil and Gas Compact Commission, CCSReg and the Midwest Governors Association. In addition, an evaluation was conducted of the consequence of allowing the current legal process already in place to control the acquisition of land to be used for a CCS project. The goal of this effort was to explore all options in order to create a solution tailored to West Virginia legislature's desire to site commercial scale CCS projects.

The Legislature has requested the Working Group to make recommendations to encourage the development of CCS and to examine factors integral to the construction, maintenance, and operation of CCS facilities, among other things. In response to this request, the Working Group has turned its initial attention to the manner in which pore space rights are to be acquired.

The resulting analysis has focused principally on two overarching factors: (1) the practicality and cost of any approach that required that all owners of pore space be identified and paid for the right to use pore space without regard to the landowners potential for use of the pore space, and (2) the constitutional requirements applicable to the circumstances under which the use of land required compensation as a taking.

With respect to the first of these factors, the Working Group recognizes that in West Virginia and much of the East, the number of property owners that could be within the footprint of a CCS project could be extremely large. It is assumed that a full scale CCS project could encompass an area the size of Mason County, West Virginia. In Mason County alone, there are nearly 20,000 surface owners and 1,000 mineral owners. On the conservative assumption that a typical title examination could cost $5,000 per tract, the cost to do title searches for a project with a footprint this large would be approximately $100 million. Added costs related to compensation to landowners and transactional costs related to acquiring the property rights cause the Working Group to conclude that an alternative course of action should be pursued.

Turning then to the constitutional requirements related to compensation for the use of land, the Working Group recognizes that not all use of private land result in a compensable taking. The United States Supreme Court and other courts have recognized a number of circumstances in which compensation was not required to be paid for the use of land. These cases have included in certain circumstances airplane over-flights of land and injection of material into underground foundations. By reviewing the facts and circumstances surrounding theses cases, the Working Group has developed a statutory mechanism that is believed to pass constitutional muster.

While the approach of dedicating certain pore space below 2,500 feet to public use is the pore space use approach favored by the majority of the Working Group at this time, the Working Group will continue to evaluate this approach, and alternative approaches, between now and the completion of its work.

The next phase of the efforts of the Legal Subcommittee will turn to issues that have not yet been addressed by the committee. These efforts will include attention to such issues as:

1. Permitting.
2. Groundwater Protection.
3. Administrative Fees.
4. Interstate Projects.
5. Preemption.
6. Report to Legislature.
7. Liability transfer.
8. Post Closure Trust Fund.
9. PSC Approval.
10. Ownership and Value of Stored CO_2.
11. Forced unitization.
12. Pipelines.

I.F. SUMMARY

Much research has been conducted by the Working Group through its subcommittees over the past year. The subcommittees will continue to study current law, emerging technologies, and the work of similar entities created in other states. We are committed to tackling the difficult and controversial issues and hurdles to aggressive deployment of CCS in West Virginia. The Working Group appreciates the assistance by way of resources including accommodations, personnel, and data offered by the WVDEP and the WVGES.

II. DETAILS OF THE WORKING GROUP

II.A. WORKING GROUP MEMBERS

The Act requires the appointment of certain members to the Working Group by the Secretary of the WVDEP, and the state geologist, the Director of the West Virginia Geological and Economic Survey. The following current members were appointed in compliance with the Act in July 2009 by Secretary Randy Huffman and Dr. Michael Hohn:

Experts in carbon dioxide sequestration or related technologies:
  Grant Bromhal - National Energy Technology Laboratory
  Cal Kent, Ph.D.- Marshall University
  Ken Nemeth - Southern States Energy Board
  Richard Winschel - Consol Energy, Inc.

Expert in environmental science:
  Stephanie R. Timmermeyer, Esq. - Timmermeyer PLLC

Expert in geology:
  Tim Grant - National Energy Technology Laboratory

Attorneys with expertise in environmental law:
  David M. Flannery, Esq.- Jackson Kelly PLLC
  Leonard Knee, Esq. - Bowles Rice McDavid Graff and Love, LLP

Expert in engineering:
  Paul Kramer - Allegheny Energy, Inc.

Experts in the regulation of public utilities in West Virginia:
  Billy Jack Gregg
  Earl Melton - WV Public Service Commission

Representative of a citizen's group advocating environmental protection:
  Vickie Wolfe - WV Environmental Council

Representative of a coal power electric generating utility advocating carbon dioxide sequestration development:
  Tim Mallan - Appalachian Power

Engineer with an expertise in the underground storage of natural gas:
  John Leeson - Dominion

Chairman of the National Coal Lessors:
  Nick Carter, who designated Greg Wooten as his representative

Representative of the Coal Association:
  Jim Laurita - MEPCO

Representative of West Virginia Land and Mineral Owners Association:
  Alan Dennis – Penn Virginia Coal Company

Representative advocating the interests of surface owners of real property:
  David B. McMahon, Esq.

II.B. MEETINGS

The full Working Group's first meeting occurred on August 12, 2010. During that meeting, the Group elected Stephanie R. Timmermeyer to Chair the Group and Tim Grant as Vice-Chair. The next full meeting was held on September 16, 2010 during which the Group voted to form three subcommittees because the list of ten items may be categorized into three discrete areas: feasibility, geology and technology, and legal.

The Feasibility Subcommittee is tasked with items 1, 2, 4, 7, 9, and 10 (with an emphasis on items 1, 2, 4, and 7). In addition, the Group asked this subcommittee to consider transportation and public outreach. Members consist of Tim Mallan, Chair, Cal Kent, Jim Laurita, Earl Melton, Stephanie Timmermeyer, and Vickie Wolfe.

The Geology and Technology Subcommittee is responsible for items 2, 5, 6, 8, 9, and 10 on the task list (with an emphasis on items 5, 6, and 8). Members include Tim Grant, Chair, Grant Bromhal, Leonard Knee, Paul Kramer, and John Leeson.

The Legal Subcommittee is responsible for items 2, 3, and 10 (with an emphasis on item 3). In addition, the Group asked this subcommittee to consider issues related to liability. Members include David Flannery, Chair, Alan Dennis, Dave McMahon, Greg Wooten.

The three subcommittees met numerous times over the next several months in person and via phone conference. The full Working Group met on four more dates: December 9, 2009, February 3, 2010, April 21, 2010, and May 25, 2010. During the April meeting, the Group made an informal decision to form a Drafting Committee made up of the Chair of the Working Group and the three Subcommittee Chairs to facilitate merging the subcommittee reports into this Preliminary Report.

II.C. RESOURCES

As stated in the Foreword, the Working Group reviewed a substantial body of data and reports related to various aspects of Carbon Capture and Sequestration. This Preliminary Report incorporates or refers to data and information from a large number of sources including federal and state agencies, and non-governmental organizations. Some of this data and information may incomplete or inaccurate. The citation to these sources does not necessarily mean the Working Group agrees with the data, information, or opinions cited.

A webpage was created on the WVDEP's website to post these resources, minutes from the meetings, subcommittee reports, and presentations of various speakers. The link is http://www.dep.wv.gov/executive/Pages/ccsworkinggroup.aspx.

III. STATUS OF THE REGULATION OF GREENHOUSE GASES

Even in advance of Congressional activity related to CO_2 emissions, many legislative, regulatory and judicial activities are underway at the state and federal level which have as their objective reducing the amount of CO_2 emitted to the atmosphere.

In West Virginia, in addition to the passage in 2009 of Carbon Capture and Sequestration legislation, the West Virginia Legislature passed the Alternative Generation Portfolio Standard bill which sets targets for electric utilities to provide for a mix of traditional and alternative sources of electricity. This legislation creates not only incentives for renewable sources of energy, but also electricity generation using alternative methodologies, including CCS.

On June 3, 2010, the USEPA published the final version of its "Prevention of Significant Deterioration (PSD) and Title V Greenhouse Gas Tailoring Rule" (75 Fed. Reg. 31,514) which establishes greenhouse gas emission requirements for stationary sources subject to the federal Clean Air Act PSD and Title V programs. The Tailoring Rule is the last of several actions being taken by USEPA in response to the U.S. Supreme Court's 2007 decision in *Massachusetts v. EPA* that the USEPA must regulate GHG emissions under the federal Clean Air Act if the agency determined that such emissions endanger the public health or welfare.

Finalization of the endangerment finding in December, 2009, authorized the agency to promulgate GHG control regulations for all sources of emissions. (74 Fed. Reg. 66,496 Dec. 15, 2009). The promulgation of USEPA's Motor Vehicle Rule in May 2010 triggered an obligation for the agency to regulate stationary sources of GHG emissions under the PSD and Title V permitting programs. The USEPA promulgated the Tailoring Rule to avoid the "absurd consequences" the agency itself identified would result from subjecting stationary sources of GHGs to the existing parameters of those programs.

Finally, in April, 2010, USEPA established a phase-in schedule for stationary source GHG obligations under the PSD program. 75 Fed. Reg. 17,004 (April 2, 2010).

The USEPA's regulatory initiatives are the subject of multiple legal challenges that may require many months to resolve.

On May 28, 2010, the U.S. Court of Appeals for the Fifth Circuit dismissed a plaintiff's appeal of a district court decision in a climate change tort case (*Comer v. Murphy Oil*). The district court held that property owners did not have standing to sue for climate change related damages and that climate change was a "political question" that should be decided by Congress. The Fifth Circuit decision conflicts with a Second Circuit decision in *Connecticut v. AEP*, which overturned the lower court's decision and remanded that case for trial.

These and other climate change initiatives will undoubtedly continue to play out, even as the Working Group continues to address the issues related to CCS.

IV. SUBCOMMITTEE REPORTS

IV.A. FEASIBILITY SUBCOMMITTEE REPORTS

IV.A.1. Introduction

The decision as to whether individual West Virginians or other greenhouse gas generators in West Virginia will be required to reduce emissions of these materials is apparently, at this time, not something the Legislature will be able to control. The U.S. House of Representatives passed a comprehensive bill in June 2009 (American Clean Energy and Security Act of 2009) and work has been proceeding on Senate counterparts. In addition**,** USEPA is proceeding on the basis of a 2008 decision by the United States Supreme Court to promulgate regulations that would require the control of greenhouse gas active materials.

Internationally a number of nations have embarked on programs to require reductions in the emissions of greenhouse gases in response to the Kyoto Protocol and many nations, including the United States, are actively involved in programs to mandate additional greenhouse gas emissions.

With the understanding that reductions in greenhouse gas emissions will be imposed on West Virginia sources, the Feasibility Subcommittee ("FSC") provides discussions of the following issues to the Legislature for its consideration.

Using §22-11A-6.(h) as a guide, the FSC was assigned the task of developing information and discussion of all or part of the following subsections:

(1) Recommend appropriate methods to encourage the development of carbon dioxide sequestration technologies;

(2) Assess the economic and environmental feasibility of large, long-term carbon dioxide sequestration operations;

(4) Recommend methods of facilitating the widespread use of carbon dioxide sequestration technology throughout West Virginia;

(7) Assess the costs, benefits, risks and rewards of large- scale carbon dioxide sequestration projects in West Virginia;

The Feasibility Subcommittee discusses these issues in Section A.2. through A.7 as follows:

A.2. Background - The Magnitude of the Task
A.3. Is CCS Feasible for West Virginia?
A.4. Cost of Various Technologies and Estimating the Economic Impact of Implementing CCS in West Virginia.
A.5. Environmental and Health Related Factors.
A.6. Incentives for CCS Technology.
A.7. Conclusions and Recommendations Being Discussed for the Final Report.

IV.A.2. Background – The Magnitude of the Task

Due to the large amount of coal produced in West Virginia the state is able to provide all the electric power needed to meet its own needs and is the second largest provider of electric power for export to other states.[9] West Virginia also produces the majority of its electric power by burning coal,[10] a process that releases more greenhouse gas in the form of CO_2 than other commonly used methods of power generation.[11] In view of the relatively large amount of CO_2 produced in the state and the contribution of coal production and utilization to the economy, the West Virginia Legislature should be aware of the impact that requirements for significant reductions in CO_2 could have on the state.

It is very likely that sources in West Virginia will be faced with having to reduce CO_2 emissions over the next few years by significant amounts. Currently there is no method to make such reductions without either curtailing in-state generation or constructing new lower carbon or zero carbon power plants. However, the development of CCS technology could allow West Virginia to continue as a major coal producing and electrical power exporting state.

As of October 2009 West Virginia became the first place in the world in which a slipstream carbon capture and geological sequestration facility associated with a commercial coal-fired electric power plant has come into operation. A great deal of operational and technical knowledge is being gained from this new facility. The state now has the opportunity to take part in the development of the administrative and legal processes needed to make this technology a useful tool for addressing greenhouse gas reduction throughout the world. This section of the report discusses the magnitude of the challenge to reduce CO_2 from a state, national and international perspective.

As stated previously in this report, in all likelihood West Virginia, the United States and many other nations will be committing to some form of greenhouse gas reductions in the near

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[9] West Virginia Energy Profile – USDOE EIA, retrieved 11/30/09.
http://tonto.eia.doe.gov/state/state_energy_profiles.cfm?sid=WV

[10] Ibid

[11] USDOE EIA Frequently Asked Questions – Environment, list of CO_2 emissions for various fuels per BTU.
http://tonto.eia.doe.gov/ask/environment_faqs.asp#CO2_quantity retrieved 11/30/09.

future. The West Virginia legislature can help set the course for the actions to be taken by the state to answer this challenge. The Legislators should be aware of two important factors in addressing these challenges. First these challenges will require significant changes to be accomplished within the state. Second, these challenges may present many opportunities for the state to use our natural, human and intellectual resources in a manner that benefits our citizens.

In the area of challenges, consider, for instance, the requirements that would be imposed on power generation in West Virginia by the American Clean Energy and Security Act of 2009(ACES)[12] which was passed by the U.S. House of Representatives in June of 2009. In essence, this act would require that total greenhouse gas emissions in the US from specified sectors of the economy should be reduced by 3% in 2013, 17% by 2020, 42 % by 2030 and 87% by 2050.[13] The base year for these percentage reductions is 2005, a year in which US Total GHG emissions were 7206 mmt CO_2 eq.[14]

To put these challenges in perspective, assume that West Virginia sources are required to reduce emissions by the percentages specified in the Act. As shown in the attached Table A.1, in 2007 West Virginia coal-fired power plants emitted approximately 85.6 million metric tons of CO_2 and in the base year of 2005 emissions from coal-fired electric production amounted to 84.1 mmt.[15]

Under the proposed ACES legislation, West Virginia sources would be required to reduce CO_2 emissions by approximately 2.52 mmt in 2012, 14.28 mmt in 2020 and 35.32 mmt by 2030. Note the allowance allocations available each year during the interims between these target dates also decline on a sliding scale (for instance in 2014 there would be a requirement for a 7.3% reduction from 2005 emissions).

On a national basis HR 2454 would limit emissions from certain sources to only 4,627 mmt in 2012, 5,056 mmt (from a broader list of sources) in 2020 and 3,533 mmt in 2010 from "capped sources" (which include coal-fired power plants).[16] Note that the allowed emissions allocations do not recognize any growth in electrical demand.[17]

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[12] For a short discussion of ACES see article in Wikipedia at: http://en.wikipedia.org/wiki/American_Clean_Energy_and_Security_Act This article also reports acronym as ACES although some sources Quote as ACESA.

[13] American Clean Energy and Security Act of 2009 - HB 2454 (as placed on Senate Calendar) Title VII, Section 703.

[14] For the purpose of this discussion when talking about emissions of CO_2, the term "mmt" (million metric tonnes) will be used as opposed to emissions of all GHGs which are reported in terms of mmt CO_2eq (CO_2 equivalent includes the emissions of the other so-called Kyoto greenhouse gases reported as the product of their actual tons emitted and the gas's global warming potential(GWP). Thus 1 ton of methane is reported as 21 tons of CO_2eq since the GWP for methane = 21). To confuse matters further, most listing of total emissions is now being reported internationally in terms of teragrams (Tg) of CO_2eq. A teragram is, however, equal to 1 million metric tons.

[15] USDOE EIA. State Historical Tables for 2008 Emissions by Energy Source, January 21, 2010 .http://www.eia.doe.gov/cneaf/electricity/epa/emission_state.xls

[16] Note that the rise in allowances in 2020 is due to an increase in the types of sources that are to be considered to be in the capped category between 2012 and 2020.

[17] The Energy Information Agency projects that in years 2008 through 2035 electrical demand in the US will increase at a rate of about 1% / year. Coal generation capacity would increase by about 24 GW using the assumptions used in their analysis. EIA admits that economy and concern about GHG emissions could significantly change that projection. USEIA, "Annual Energy Outlook 2010," Electrical Generation, December 2009. http://www.eia.doe.gov/oiaf/aeo/overview.html ,(Accessed 2/9/10)

TABLE A.1[18]

Some important numbers when considering emissions of Greenhouse Gases.

Electric Power Produced in US	4156 TWh[19] [20]
Electric Power Produced by Coal in US	2016 TWh[21]
World Production of Electric Power	18,778 TWh[22]
World non-Hydro Renewable Production	473 TWh[23]
West Virginia Coal-fired Electric Power	94 TWh[24]
West Virginia Renewable Power (Wind)	0.168 TWh[25]
Amount of CO_2 emitted in US Energy Production	5912 mmt[26]
Amount of CO_2 emitted by US coal-fired electric power	2155 mmt[27]
World Coal-fired Electric Production CO_2	12,496 mmt[28]
West Virginia Coal-fired Electric Power CO_2	85.6 mmt[29]
Total US GHG Emissions	7150 mmt CO_2eq[30]
Total World CO_2 Emissions (Anthropogenic)	29,914 mmt[31]

Options Available To West Virginia to Reduce CO_2 Emissions

While reductions in any listed greenhouse gas will count toward achieving the reductions required in the ACES proposal, the reductions most likely to occur in West Virginia will involve reductions in CO_2.[32] While technology is developing almost daily a number of facts should be

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[18] All data in this table is based on calendar year 2007, unless otherwise noted.

[19] A terawatt hour (TWh) is the amount of electrical power meeting a demand of 1 trillion watts for one hour. 1 TWH equals 1 million megawatt hours or 1 billion kilowatt hours, all of these terms are commonly used to designate large quantities of electrical power. To put this measure into perspective, 1 TWh is the amount of electrical power that would be used by a 100 watt incandescent light bulb if it burned continuously for approximately 1.2 million years.

[20] USDOE EIA. Net Generation by Energy Source, May 14, 2010. http://www.eia.doe.gov/cneaf/electricity/epm/table1_1.html.

[21] Ibid.

[22] USDOE EIA. International Energy Statistics – Coal - Generation http://tonto.eia.doe.gov/cfapps/ipdbproject/IEDIndex3.cfm?tid=2&pid=2&aid=12

[23] Reference is listed as *Non-hydro* as hydro is not considered to be renewable in many definitions. USDOE EIA. International Energy Statistics – Generation - Renewables http://tonto.eia.doe.gov/cfapps/ipdbproject/iedindex3.cfm?tid=2&pid=34&aid=12&cid=&syid=2004&eyid=2008&unit=BKWH&products=34

[24] USDOE EIA. State Historical Tables for 2008 – Generation by Energy Source http://www.eia.doe.gov/cneaf/electricity/epa/generation_state.xls

[25] Ibid

[26] Includes all energy production, electric generation, transportation, etc. USDOE EIA. Emissions of Greenhouse Gases Report – 2008, December 3, 2009. Table 5 Emissions of Carbon Dioxide for Energy and Industry. http://www.eia.doe.gov/oiaf/1605/ggrpt/carbon.html#total

[27] Ibid.

[28] USDOE EIA. International Energy Statistics - Coal –Generation – CO_2 Emissions http://tonto.eia.doe.gov/cfapps/ipdbproject/iedindex3.cfm?tid=90&pid=44&aid=8&cid=&syid=2003&eyid=2007&unit=MMTCD&products=1

[29] USDOE EIA. State Historical Tables for 2008 Emissions by Energy Source, January 21, 2010 http://www.eia.doe.gov/cneaf/electricity/epa/emission_state.xls

[30] USEPA Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2007 Executive Summary p. 6, April, 2009.SDOE EIA. http://www.epa.gov/climatechange/emissions/downloads09/ExecutiveSummary.pdf

[31] Note this is only for burning of fossil fuels, other GHGs not included. See: USDOE EIA**.** H.1co2 World Carbon Dioxide Emissions from the Consumption and Flaring of Fossil Fuels, 1980-2006 http://www.eia.doe.gov/pub/international/iealf/tableh1co2.xls

[32] The West Virginia 2005 baseload value represents the best estimate of total GHG emissions according to the Energy Information Agency. ACES does not specify the actual 2005 emissions to be used in determining individual compliance limits, only the national total of 7206 mmt. While demonstrated reductions in other GHG gases would yield larger reduction credit than CO_2 (e.g. 1 ton methane reduction = 21 tons CO_2 reduction) a discussion of CCS

borne in mind when looking at the options available to West Virginia CO_2 sources to achieve the reductions envisioned in this proposal.

Assuming there is some required reduction based on the timetable in the ACES proposal:

- In 2012 there is no technology currently forecast to be commercially available to actually remove CO_2 from the emission stream of coal-fired power plants.
- If ACES is able to move through the legislative process with most of its current language intact, there will be opportunity for much of the early compliance to be met by the use of offsets, which would allow West Virginia coal-fired sources to continue to operate.[33]
- West Virginia utilities could back off in-state generation and either build zero carbon generation or purchase such generation from others (including out of state sources).[34]
- West Virginia could reduce electrical demand by the percentages listed in ACES but would also have to increase the amount of reduction to account for any growth in demand.
- With each year seeing increasing requirements for reductions at some point actual reductions in the emissions of CO_2 from West Virginia sources would have to be accomplished.

What Carbon Capture and Sequestration Means

Carbon capture and storage is a technology that would remove carbon in the form of CO_2 from the emission stream of a power plant and store the removed material in a manner that would prevent it from entering the atmosphere. Methods being investigated for carbon capture have looked at either biological processes, using some form of living organisms that utilize CO_2 as a carbon source, or chemical processes which use a chemical reaction that absorbs or incorporates $CO_{2.}$

It is possible to design bioreactors that use living organisms to synthesize molecules that can be further processed into carbon-based fuel which can replace fossil based fuel. An example of such a process would use CO_2 captured from a power plant emission stream to enhance production of specific types of algae. The algae could then be processed into material that could be substituted for fossil fuel. The net effect would be a reduction in CO_2 emission.

Another possible biological sequestration strategy involves the uptake and long-term storage of carbon in biomass such as trees. This postpones the release of greenhouse- active materials to a point in the future. This type of storage requires some guarantee that the biomass is not handled in manner that would rapidly re-introduce the captured $CO_{2.}$[35]

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involves only CO_2 as this technology has not been proposed for other GHGs. If other deductions are shown to be feasible the impact of such deductions would proportionally lessen needed lowering of CO_2 quantities.

[33] ACES Title VII, Part D – OFFSETS

[34] For instance using WV's total 2007 production of 94 TWh and emissions of 85.6 mmt (see Table A.1) gives a state average of 0.91 mmt/MWh. With a reduction of 2.52 mmt needed for 2012, state utilities would have to reduce output by 2.77 TWh in 2012 and 15.70 TWh in 2020. It appears that WV would have to increase renewable generation by a significant amount (see Table A.1) to provide in-state generation to replace idled coal power.

[35] See for instance WORKING PAPER ON CARBON SEQUESTRATION SCIENCE

In general, chemical capture processes have come to focus on the geological storage of the captured material. In this process, captured CO_2 in a supercritical or dense phase is pumped underground to reside in a geological stratum that has been demonstrated to have the capacity to hold the material for very long time periods (thousands to millions of years).[36]

Biological capture and storage is a developing field of scientific interest. The Working Group feels that for this method of achieving greenhouse gas reduction any requirements the state may have to meet should not be ignored. The Group would encourage the state to support such research and development. However, the Working Group interprets the focus of §22-11A to be centered on the geologic sequestration of CO_2.[37] This report will therefore concentrate on techniques involving the capture of CO_2 from power plant emissions and the geologic storage of the captured CO_2.

Is There a Need For CCS?

Many references have stated that the development of CCS technology is critical to achieving the goal of reducing the emissions and atmospheric concentration of greenhouse gases. For instance in expressing disappointment with a decision by the Mississippi Public Service Commission to severely restrict funding for Southern Company's proposed IGCC plant with CCS, the position of Secretary of the Department of Energy, Stephen Chu, was described in Energy Daily as follows:

> "The energy secretary said the nation has to build large-scale CCS projects that will allow the continued use of coal in a carbon-constrained regulatory environment. 'Nothing ranks as high as CCS . . . among the tools that could be used to decrease carbon emissions,' Chu said. He acknowledged that that CCS projects are 'very costly and expensive,' but added: 'I think we have to push ahead.'"[38]

A look at the magnitude of CO_2 emissions listed in Table A.1 gives some idea of the amount of CO_2 that is emitted from electrical production on a worldwide, national and West Virginia basis. West Virginia coal-fired plants emitted 85.6 mmt of CO_2 in 2007 and, according to the timetable in ACES, would have to reduce that to roughly 50 mmt by 2030. The nation would have to reduce CO_2 from coal-fired plants by at least 908 mmt in that time frame. If the world were to try to meet the same reduction schedule, world coal-fired power would have to reduce emissions by another 4,800 mmt from current coal emission rates. Worldwide it is estimated that by 2030 overall coal use will increase to a level approximately 1.6 times the amount used in 2004. [39]

AND TECHNOLOGY, Office of Science, Office of Fossil Energy, U.S. Department of Energy, February 1999, available at: http://www.netl.doe.gov/publications/press/1999/seqrpt.pdf for an extensive discussion of the whole issue of biological sequestration.

[36] There are a lot of documents available dealing with geological sequestration. One of the most comprehensive references that is often quoted is IPCC Special Report on Carbon Dioxide Capture and Storage, Bert Metz, et al, Prepared by Working Group III of the Intergovernmental Panel on Climate Change, Cambridge University Press, 2005

[37] §22-11A-1(12) states that development of carbon dioxide capture and sequestration technologies is in the public interest. §22-11A-2(b) then defines Carbon dioxide sequestration as "…the injection of carbon dioxide and associated constituents into subsurface geologic formations intended to prevent its release into the atmosphere."

[38] Energy Daily "Chu Urges Mississippi Regulators. Southern Co. To Reach IGCC Deal." Friday, May 7, 2010 ED Vol. 38, No. 86 p. 4

[39] World Energy Council, "2007 Survey of Energy Resources" p. 2. The council projects that coal use would increase from 2772 mtoe in 2004 to 4441 mtoe in 2030. (mtoe = million tonnes of oil equivalent). http://www.worldenergy.org/documents/ser2007_final_online_version_1.pdf

In any discussion of world emissions, China is often of peak interest due to the fact the country exhibits the most significant emissions growth of any country in the world. In 2006 alone China increased its electric generation capacity by 74,660 MW.[40] While some of this capacity may be attributed to the installation of generators at the Three Gorges hydroelectric project, a significant amount likely involved coal-fired generation.[41] In fact between 2000 and 2006, China increased its generation capacity by about 72%.[42]

With so much coal-fired generation capacity currently installed and much of this capacity still brand new, especially in developing nations, much of the physical plant devoted to coal-fired power generation is likely to continue in service. Generally newly constructed power plants are expected to operate for 30 to 50 years. In an era in which reduction of CO_2 emissions is seen as critical, CCS provides a method to preserve this critical infrastructure and still make progress toward reducing greenhouse gas emission. The World Resources Institute states in the Executive Summary to its Guideline for Carbon Dioxide Capture, Transport, and Storage:

> "CCS is a critical option in the portfolio of solutions available to combat climate change, because it allows for significant reductions in CO_2 emissions from fossil-based systems, enabling it to be used as a bridge to a sustainable energy future."[43]

Is CCS the *"Only"* Solution to Climate Change?

The West Virginia Legislature must be clear on one very important point about CCS. No one who has a firm understanding of the challenges facing us in trying to find a solution to reconciling the world's energy needs with the desire to reduce atmospheric concentrations of greenhouse gases is proposing that CCS is the "only" solution to climate change. CCS is a method that if effectively demonstrated and widely deployed could have dramatic and potentially permanent impact on the emissions of CO_2 from large stationary sources. But with coal-fired electric production accounting for roughly 42% of world anthropogenic CO_2 emissions (see Table 1), even a total and immediate cessation of all coal-fired electric production (a totally impossible occurrence) would fall short of the 50% reduction by 2050 in human emissions identified as a combined US/European Union goal in the November 3, 2009 EU/US Summit meeting in Washington DC.[44]

Nor is CCS the least expensive of the many options identified for the reduction of greenhouse gas emissions.[45] For instance, The McKinsey Report proposes that on a per ton basis, CCS is not the least expensive method of reducing GHG emissions by a very large margin. However in looking at the amount of greenhouse gas reduction being proposed by many authorities, some will conclude that even with the employment of all the easier and less

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[40] USDOE EIA. 6.4 World Total Electricity Installed Capacity, January 1, 1980 - January 1, 2006 http://www.eia.doe.gov/pub/international/iealf/table64.xls

[41] As an example of the magnitude of such a construction schedule, the Appalachian Power Kanawha River Plant near Glasgow in Kanawha County has two 200MW units and is considered to be a major US generation facility. In 2006 China built plants at a rate that would be equal to bringing one of the Kanawha River generating units on line every single day for the entire year. During the same year US generating capacity increased by a total of 8,081 MW or roughly 11% of the Chinese capacity added in that year.

[42] USDOE EIA. 6.4 World Total Electricity Installed Capacity, January 1, 1980 - January 1, 2006 http://www.eia.doe.gov/pub/international/iealf/table64.xls

[43] World Resource Institute, Guidelines for Carbon Dioxide Capture, Transport, and Storage, 2008, p.8

[44] 2009 EU – US Summit Declaration, accessed 11/25/09, available at: http://ec.europa.eu/external_relations/us/sum11_09/docs/declaration_en.pdf

[45] See for instance McKinsey&Company Reducing U. S. Greenhouse Gas Emissions: How Much at What Cost, December 2007, Executive Summary, U.S Mid-Range Abatement Curve 2030 p. xiii.

expensive methods of reduction there will still be a pressing need for even some of the most expensive technologies.

Wedge Stabilization Analysis

To understand the magnitude of this effort, the Legislature needs to look at the multiple factors involved in a total remake of the electric power system in the state, in the nation and in the world. In an article in the journal *Science* in August 2004, S. Pacala and R. Socolow of Princeton University proposed the now-famous Stabilization Wedges process of looking at how current technology could address the challenge of climate change.[46] The authors looked first at the levels of rising emissions over the last 50 years. They then projected what the atmospheric concentration would be in the 2050s assuming the same rate of increase as the historical data. Using the result they had calculated, they postulated the employment of existing technologies that would be needed to reach a concentration in 2050 that did not exceed the level reached in 2004. In other words their proposal would not reduce emissions from current levels but only recreate the emissions level that existed in 2005.

The analysis shows that by 2050 the technologies employed would have to result in a total worldwide reduction of 8 billions tons per year of CO_2eq. The authors then assigned to each of 8 specific strategies an annual reduction goal of 1 billion tons each. On a graph each of these goals develops into a wedge shaped figure that starts representing a small deployment of the technology which reaches 1 billion tons in 2050 as the technology is more widely adopted (Figure A.1) The basic idea is to achieve a lifestyle for all the world's inhabitants that approaches that common in the western world and still meet the projected greenhouse gas emissions goals.

Over the roughly 50 years of the process each wedge represents a total reduction equal to 25 billion tons. Different technologies are then analyzed to determine what level of deployment of the technology would be needed to achieve one wedge. For instance replacing every single incandescent light bulb in the entire world with CFLs would yield ¼ of one wedge. For CCS to achieve a single wedge it would have to be installed at 800,000 MW of coal-fired power plants. Currently this would equal the total number of coal plants in the US plus almost all the generation capacity of China (regardless of power source). The authors note that at the time of the report there were three projects in the world (all were natural gas treatment projects) injecting 1 mmt/year each. By 2055 there would have to be 3500 such projects to achieve one wedge.

Other technologies that would equal one wedge:

- Efficiency – Double the fuel efficiency of every automobile on earth or reduce the total numbers of miles driven by ½.
- Efficiency – Double the efficiency of all plants producing electrical power but keep electrical demand at its current level.
- Fuel Switching – (Note CCS is included in this category) Replace 1400 coal-fired power plants by an equal number of natural gas plants.
- Renewables – Replace an equivalent capacity of coal-fired plants by 1 million wind turbines each with a capacity of 2 MW.

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[46] Pacala, Stephen W., and Robert H. Socolow, 2004: *Stabilization Wedges: Solving the Climate Problem for the Next 50 Years with Current Technologies*. *Science*, **305**, doi:10.1126/science.1100103 968-972

- Renewables – Replace an equivalent capacity of coal-fired plants with 20,000 square kilometers of solar panels. [47]

This analysis lists 15 different technologies that the authors consider to be currently available and notes that no technology would have to necessarily supply an entire wedge on its own for the program to achieve its goals. Any combination of methods contributing either parts of or multiple wedges could be employed to achieve the stabilization desired. It should be noted again that this analysis would not achieve an emission reduction below the 2005 baseline. It would only preserve the emissions status quo of the base year.

Figure A.1
Error! Objects cannot be created from editing field codes.

Note: Figure 1.A is a slide from *Wedges PowerPoint Presentation: Carbon Mitigation Project. For access information see Footnote 47.*

The Wedge Stabilization discussion illustrates the important point that any reduction scheme is going to have to utilize multiple tools. But all reduction strategies have to take into account the growing electrical demand in a world where over 1.6 billion people still have no access to electrical power.[48]

CCS is not a perfect solution to concerns over climate change. There is no single solution currently known and the world is going to have to embark on many new paths in an attempt to stabilize greenhouse active emissions.

West Virginia is already in the lead by virtue of its having the first coal-fired power plant CCS project in the world operating in Mason County. A project such as this, along with others being planned and developed around the world, may be able to demonstrate that CCS can have an immediate and lasting impact on atmospheric carbon content. The state is in the position to learn much about how such a project actually will work. The opportunity to help develop the administrative processes, laws and regulations that will be a model for others to follow can be in the hands of the West Virginia Legislature.

IV.A.3. Is CCS Feasible for West Virginia?

With the acknowledgement that there is a significant probability that CCS is likely to be one of the methods needed to achieve the greenhouse gas reduction goals the world and the nation are likely to set, the questions to be considered by West Virginia may be summarized as follows:

1. What factors need to be considered in determining if CCS is feasible and beneficial for West Virginia?
Question 1 is addressed in this section and Section.A.4

2. What factors need to be addressed to be able to assure the citizens of West Virginia that CCS is safe in terms of human health and the environment?
Question 2 is addressed in Section.A.5.

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[47] To learn more about Wedge Stabilization see the web page at: http://cmi.princeton.edu/wedges/
for a quick PowerPoint see: http://cmi.princeton.edu/wedges/Wedges_slides_8.ppt#12

[48] USDOE EIA. International Energy Outlook 2009, Chapter 5 – Electricity, May 27, 2009
http://www.eia.doe.gov/oiaf/ieo/electricity.html, accessed 12/1/09.

3. What are the technical issues (both engineering and geological) that must be addressed to ensure the efficacy of CCS in West Virginia?
   Question 3 is addressed in Section IV.B
4. What legal and liability issues need to be decided before CCS can be pursued in West Virginia? And finally,
   Question 4 is addressed in Section IV.C
5. If the Legislature were to decide that CCS would be beneficial to West Virginia, what actions should be undertaken by the Legislature and the State Administration to ensure the realization of these benefits for the citizens of the state?

Other aspects will be part of the Working Group's efforts over the next year.

The Working Group suggests that the following factors will have to be considered by the West Virginia Legislature before an informed decision can be made.

- Will West Virginia have a need for CCS?
- If so, when will that need become a reality?
- What is currently available to meet such a need using CCS?
- Are there alternatives to CCS for meeting those needs?
- What are the projected costs and benefits to West Virginia and how do these compare with the costs and benefits of alternatives?

Looking at these factors individually the Working Group offers the following discussion.

Will West Virginia have a need for CCS?

Earlier in this report there was a discussion of the probability for CO_2 emission reductions in the near future. West Virginia currently has 14,715 MW of coal-fired power plants and approximately 39 utility-owned coal-fired generating units.[49] Table A.1 shows that in 2007, West Virginia coal-fired generation emitted 85.6 mmt of CO_2eq. West Virginia could choose to meet upcoming GHG reduction goals by simply backing off generation. As the state is a net exporter of electrical power this could be done without reducing in-state electrical power usage. However, before choosing this option the state would want to further examine the economic impact of such an action. As stated previously in this report, CCS could provide a method whereby existing coal-fired generation could continue at the same or even increased levels.

From a national perspective, as of 2005 there were approximately 1470 coal-fired generating units in the United States representing 313,380 MW of capacity.[50] A simple proportional reduction could mean that 53,275 MW of this total would have to achieve 100% reduction in CO_2 emissions by 2020 to meet the 17% reduction goal listed in ACES. While there may be other methods of achieving compliance with the requirements outlined in ACES,[51] at some point a significant portion of the 313,380 MW of coal-fired power will either have to be retrofitted with CCS or retired. In addition, as shown in Table A.1, there is considerable coal-fired generation world wide, In many countries, especially in developing nations, the often

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[49] USDOE EIA. Generating Units - http://www.eia.doe.gov/cneaf/electricity/page/capacity/existingunits2005.xls
Total MW - http://www.eia.doe.gov/cneaf/electricity/st_profiles/sept04wv.xls

[50] USDOE EIA. Electric Power Industry 2008: Year in Review, Table 1.1. Existing Net Summer Capacity by Energy Source and Producer Type, 1997 through 2008 http://www.eia.doe.gov/cneaf/electricity/epa/epaxlfile1_1.pdf

[51] For instance carbon offsets, energy efficiency measures, energy conservation practices and repowering with lower or zero carbon emitting resources.

readily available coal may still be the most economic option for these countries to provide the standard of living that they have not yet been able to achieve. It is possible that many of these nations will choose to continue to build new coal-fired generation and will not have the ability to develop low carbon technology to do so. CCS technology, developed in West Virginia and other US states could be shared with some of these nations in a manner to lower world-wide emissions.

It may not be possible to say that the development of CCS in West Virginia is absolutely essential. However, the challenges discussed above demonstrate that CCS could be an integral part of achieving the goal of greenhouse gas reduction pending a satisfactory resolution of issues such as listed in questions 2 through 4 above.

When will a need for CCS become a reality?

There are a number of unknowns in answering this type of question. The first is the prospect for the establishment of binding legislative or regulatory action mandating some form of reduction in greenhouse gas emissions. The second is the actual form that such reduction requirements will take and what other methods may be allowed to enable emitting sources to develop technical and administrative processes needed to achieve reductions.

Regarding legally binding requirements ACES has now been joined by the American Power Act (also called the Kerry – Lieberman bill) which is the Senate version of ACES. There are many similarities between the bills both of which follow a cap and trade program for greenhouse gases. There are many different projections regarding the possible approval of the bill in the US Senate, but should it pass, there would need to be a conference version agreed to by both houses. The timing of such a consensus between the two houses is unknown at this time.

The USEPA, on May 14, 2010, released its “Tailoring Rule” which sets a roadmap of how the Agency will handle air quality permitting for stationary sources of greenhouse gases in the wake of its endangerment declaration. This declaration issued on December 7, 2009 states that the emission of greenhouse gases in the United States constitutes an endangerment to public health and welfare. As of January 2, 2011 power plants (and other sources) emitting greenhouse gases will have to consider these emissions in any decisions made regarding their impacts on air quality.

There are currently conflicts between the programs that would be set up under the congressional action and those established under the USEPA actions, but under either approach the emissions of greenhouse gases, including $CO_{2,}$ will be controlled to some extent in the near future.

The actual form of whatever regulatory or legislative requirements are chosen for GHG emission control will have a very large impact on the timing for the need for CCS. For example in the proposed ACES there is an allowance for a phase-in for CO_2 reduction from coal-fired power plants as such sources could use emission offsets in the early years. In such a case the need for CCS could be postponed until the post-2020 period.

However if reductions are called for too early or are too stringent to be compatible with the technical, administrative and economic demands of CCS, coal-fired generation may be precluded from using CCS. Utility generators may then be forced into investment in lower carbon natural gas generation (with a CO_2 emission approximately ½ of that emitted by coal) in the years before CCS is ready.[52] In this situation, a market for coal-fired CCS may not ever exist. A need to shift to natural gas generation in the next ten years could also tend to lock in generators to using gas for a period long enough to allow the recovery of the cost associated with the investment Natural Gas CCS is, of course, an option although the technology is currently not being developed. In determining whether CCS is indeed in the best interest of the state, the Legislature may have to decide whether coal or natural gas generation of electrical power allows the best future for the state of West Virginia.

Such a situation could be encountered in some legislative actions or if the USEPA must proceed with regulatory controls under existing Clean Air Act requirements. If the USEPA carries through with its proposed regulation of CO_2 some have argued that the Agency could have to set limits in a manner that may force utilities into programs that would take effect in ways the Agency may not have considered.[53] If the USEPA must develop restrictions that impose large reductions before CCS is commercially available this may cause CCS to become less attractive and accelerate any move away from coal as a power source.

The best atmosphere for the use of CCS and for the continued ability for the nation to be able to use coal as an energy source, would be one in which significant reductions in CO_2 emissions would not be required until the demands noted above have time to be resolved. Estimates of when CCS will become commercially available (i.e. technically developed and economically feasible) vary depending on who is making the projection. In general, it is anticipated that this is most likely to happen in the 2020 -2030 time period.[54]

What is currently available to meet such a need

There are currently a number of technologies that are being considered for providing efficient, commercially available CCS at the lowest possible cost. Any currently considered methods (none of which are commercially available) tend to be energy intensive and thus very expensive. Some proposed methods of carbon capture would require a different from of boiler technology while others would involve extensive boiler retrofit. The Working Group will postpone analysis of the available technologies until the final July 2011 report.

However, it should be noted that various businesses operating in West Virginia are already taking a leading role in investigating and developing CCS.

- The AEP/APCo Mountaineer Plant CCS Process Validation Project is the first project in the world in which an actual 20 MW slipstream from the emissions of a coal fired power plant is subjected to a carbon dioxide capture process with the captured material sequestered in a geological strata

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[52] For example, Calpine Corporation in a presentation discussing its new Russell City Energy Center cited its proposed permit limit for CO_2 of 1100 lbs/MWh but referenced reports of NGCC plants achieving results of 800 lbs/MWh. A coal plant, usually emitting 2000 lbs/MWh, would emit <800lbs/MWh with a removal efficiency of 60%. Calpine Corporation. GHG BACT Analysis Case Study. Presentation to EPA Climate Change Work Group, November 19, 2009 (as updated February 3, 2010). Slides 8-9. http://www.epa.gov/air/caaac/climate/2010_02_GHGBACTCalpine.pdf (Accessed February 10, 2010)

[53] See, for instance, Greenhouse Gas Regulation under the Clean Air Act Does Chevron *Set the EPA Free?* December 2009 Resources For the Future. Available at: http://www.rff.org/Publications/Pages/PublicationDetails.aspx?PublicationID=20964

[54] See for instance "Facts and Trends: Carbon Capture and Storage (CCS)" World Business Council on Sustainable Development, October 2006 which in 2006 predicted a 20 year time frame or "Future of Coal," Testimony before the Committee on Energy and Natural Resources, United States Senate by Bryan Hannegan, Vice President, Environment, Electric Power Research Institute, March 22, 2007 who stated that to achieve the goals being discussed in upcoming legislative efforts all new plants would need CCS after 2020.

approximately 8000 feet below surface grade at the plant. The project has been actively operating since October 1, 2009 and is successfully capturing and sequestering CO_2. The capture technology being demonstrated in this project is the chilled ammonia process developed by Alstom, an international company that designs, manufactures and supplies products and systems for power generation.

- AEP and APCo are also performing the preliminary work on developing the first commercial scale CCS project in coordination with a grant from USDOE. The 235 MW project will also capture and sequester carbon dioxide from a portion of the emissions from the Mountaineer 1300 MW generating unit using the Alstom chilled ammonia process.

  The project is being undertaken in conjunction with a diverse technical advisory committee that includes recognized experts in the field of geologic carbon dioxide storage. This group will include participants from Schlumberger Limited, Battelle, Lawrence Livermore National Laboratory, Massachusetts Institute of Technology, The Ohio State University, West Virginia University, The University of Texas, West Virginia Geological Survey, Ohio Geological Survey, CONSOL Energy and the West Virginia Department of Commerce Division of Energy. Additionally, Battelle and Schlumberger will work directly with AEP to design and deploy the carbon dioxide storage system.
- Alstom and Dow CO_2 Capture Pilot Plant **-** On September 10, 2009, The Dow Chemical Company (Dow) and Alstom dedicated a carbon dioxide (CO_2) capture pilot plant at the South Charleston facility. In 2008, the two companies entered into a Joint Development Agreement to develop this technology, and in March 2009 announced plans to design and construct the pilot plant.

  This pilot plant will capture CO_2 from the flue gas of a coal-fired boiler at the South Charleston plant. The pilot plant will use proprietary advanced-amine technology to capture approximately 1,800 metric tons of CO_2 per year. The pilot plant will operate for two years, generating and collecting data that can be used to optimize and implement this technology at coal-fired power plants worldwide. This new process will significantly reduce the amount of energy required for CO_2 separation and capture.

  The Alstom pilot plant is running well. The process in on-line daily, recovering CO_2 from the Dow coal-fired boiler flue gas. Data from the plant is being used for R&D purposes and process information for future pilot scale and full-scale carbon capture projects throughout the world. Tests include long-term chemical degradation, carbon capture efficiency, energy efficiency, analytical methods, operating procedures and control strategies. Current test plans project operation into 2011.[55]
- CONSOL Energy, with partial funding from the U.S. Department of Energy and in collaboration with West Virginia University, began injecting CO_2 into an "unmineable" coal seam in Marshall County, West Virginia, in September 2009 to simultaneously sequester the CO_2 and to enhance the projection of coalbed methane. The WVDEP issued a Class II Underground

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[55] Amos, J. , Dow Environmental Manager – Personal communication, June 1, 2010.

> Injection Control permit for the project. The team expects to inject up to 20,000 tons of CO_2 over the course of two or more years and to continue to monitor the site for up to two additional years.[56]

Are there alternatives to CCS for meeting those needs?

Using ACES as a surrogate for predicting future reduction requirements and the 2005 base emission rate from West Virginia sources of 84.1 mmt, electric generation sources in West Virginia would have to reduce emissions to 83 mmt CO_2eq in 2012, 71 mmt by 2020, 50 mmt by 2030 and 15 mmt by 2050.[57] Such reductions in emissions cannot be achieved without either a technology to remove and permanently store CO_2 from power plant emissions or a significant reduction in coal use for electric generation.

Natural Gas

One suggestion, a large shift to natural gas generation, would perhaps postpone the need to capture and store CO_2 but as stated above natural gas still emits roughly one half the CO_2 that results from coal-fired generation. Emission reductions outlined in either ACES or the American Power Act would require further controls in the post 2020 period.

Nuclear Power

More reliance on nuclear power could be an alternative to CCS. Nuclear power is widely used in Europe and throughout the US. Despite fears about its safety, it has the best safety record of any fuel for electric generation. There are currently 26 applications for nuclear power plants in the US pending before the NRC.[58] West Virginia, however, has not pursued such options in the past. Conceivably, this is an option that the state could pursue. However, if this course were to be pursued, the Legislature may have to revisit the apparent barrier to the employment of nuclear power in articles §16-27A-1 and §16-27A-2 of the state code, which require that a nuclear power plant must be economically feasible and that a permanent national repository for nuclear waste disposal has been proven safe and functional.

Hydro Generation

West Virginia does have access to significant water resources, a factor that has contributed to the ability of the state to utilize its coal supplies to export electrical power. Hydropower could be further developed in the state. West Virginia has areas with significant elevation change across the state that could allow the exploitation of the stored energy located in upland areas. While the construction of dams for energy generation is not favorably considered under current public sentiment, in an era of changing energy options and increasing CO_2 concerns, the state may be able to further investigate hydropower. In addition, small scale hydro which does not involve building dams is a promising use of West Virginia's water resources. While the contribution will be small and not a major offset to coal production for dispersed use it should be considered an option.

Wind

Wind power is becoming an important state resource. West Virginia is already one of the leading states for commercial wind development in the eastern US and other sites are under

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[56] Winschel, R. A., Director of Research Services, CONSOL Energy, Inc. Personal Communication, June 7, 2010.

[57] Based on % reductions listed in ACES Title VII section 702 and base 2005 emission from all generating sources of 85,649,741mmt from US Energy Information Agency, State Historical Emissions Tables for 2008, line 21929. http://www.eia.doe.gov/cneaf/electricity/epa/emission_state.xls retrieved January 22, 2010.

[58] Deutch, J et. al. *Update of the MIT 2003 future of Nuclear Power*, Massachusetts Institute of Technology, Cambridge MA

construction and in the planning stage. As of the date of this report, West Virginia has 330 MW of wind capacity producing commercial electrical power.[59] This makes West Virginia the state with the 5th largest installed capacity east of the Mississippi River.[60] Wind power may be becoming more difficult to build as public opposition is often seen to utility scale plants. Major wind resources in West Virginia appear to be located on the eastern ridge lines, an area that many feel needs to be protected. Utilization of commercial wind development is also extremely reliant on the availability of adequate transmission capacity. West Virginia may not have sufficient wind capacity to ever become self sufficient in electrical production using wind alone, but appropriate utilization of the state's wind resource could be an important aspect of a diversified energy portfolio.

Biomass

Biomass co-firing and wood-fired power generation are two other sources of base-load electricity that could be produced in West Virginia. Based on physical quantities, wood residue available in the State could support several power plants of up to about 50 MW. However, the variability of transport costs due to the fuel's locations relative to a plant site could restrict plant size. A single such 50 MW plant operating at an 80 to 90 percent capacity factor would provide less than half a percent of electricity currently generated in the State. The relative capital cost of such a plant is competitive and production tax credits could apply depending on how associated forestry management contributes to carbon levels.

Biomass produced to be co-fired with coal could play a larger role but is not widely developed. Switchgrass or some other energy crop, as well as wood residue, can be compressed into bricks or pellets that on a ton-per-ton basis contain an energy value comparable to Powder River Basin coal.[61] Trial switchgrass crops on former surface-mined lands in West Virginia are presently being evaluated for yield. Generally, pilot scale tests co-firing no more than 20% biomass with 80% coal have been assessed.[62] Overall, biomass represents a modest and underutilized energy resource that if it became available could theoretically, employing the mix cited in these pilot studies supply up to 20 percent of energy inputs for base-load power generation. This would, of course, depend heavily on the supply of low cost biomass within an economically viable distance from the power plant.

Solar

It is sometimes assumed that West Virginia has limited potential for solar electricity due to low insolation. However, Germany, whose population is about 50 times that of West Virginia, currently obtains about one percent of its electricity from solar. Insolation should be greater in West Virginia than in Germany, since our state lies roughly 12 degrees further south. Much of Germany's solar capacity has been installed since its Feed-In Tariff (FIT) law was restructured in 2000. Additional incentives for solar installation could be considered in West Virginia.[63]

It should be noted that the city of Nitro has received monies from the the USEPA to conduct, in partnership with the West Virginia Brownfields Assistance Center, "a one year study to collect critical solar data to evaluate the potential for solar power development at the commercial, community and local business scale by using some of the over 800 acres of former

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[59] American Wind Energy Association, West Virginia Profile http://www.awea.org/projects/Projects.aspx?s=West+Virginia , retrieved 1/26/10

[60] American Wind Energy Association, Summary map of state wind capacity. http://www.awea.org/projects/ retrieved 1/28/10.

[61] Presentation by Mid-West Biofuels on October 28, 2009.

[62] http://www.eesi.org/files/cofiring_factsheet_030409.pdf

[63] http://www.worldwatch.org/node/5449#notes

industrial properties. Data collected will be compared to existing NREL (Department of Energy's National Renewable Energy Lab) information on solar generation potential, as well as provide valuable clean energy information for the Nitro community and surrounding areas."[64]

Energy Efficiency

In its *2009 State Energy Efficiency Scorecard*[65], the American Council for an Energy Efficient Economy ranked West Virginia at 45 and included it among the states that "most need to improve." Based on studies of this type some may conclude that enhanced energy efficiency programs would dramatically reduce the need for CCS retrofits, would be less expensive, and would involve none of the environmental and legal issues associated with CCS. Discussions regarding energy efficiency will continue in the Feasibility Subcommittee.

Maryland and Ohio both mandate that utilities have plans to reduce consumer demand by 15 % by 2015. Through energy efficiency programs, West Virginia could meet a significant portion of its greenhouse gas reduction requirements and save money for consumers in the process. . According to the American Council for an Energy Efficient Economy, implementation of the energy efficiency provisions in the ACES Act could result in creation of 2700 jobs annually in West Virginia, save consumers $521/year (2007 $/household), and lower CO_2 emissions by 6 mmt.[66] An energy efficiency bill has been introduced in the West Virginia legislature in 2009 and 2010 (HB 4012 for 2010). In the 2009 session, the West Virginia Legislature recognized the importance of energy efficiency measures by including "*energy efficiency technologies"* as methods to be used for compliance with the state's goals as established in the West Virginia Alternative and Renewable Energy Portfolio Standard Act.

CO_2 Transport

Another potential alternative to CCS would involve the participation by West Virginia in some of the various projects currently being proposed involving the transport of captured CO_2 to places where it may be considered to be a valuable commodity. CO_2 can be effectively utilized and potentially geologically stored in enhanced oil and gas recovery operations. There are many areas of the United States with recoverable oil and gas reserves that can not be economically produced with other methods. Many of these reserves still possess significant reserves but are not being worked due to a lack of useable $CO_{2.}$

In addition almost any commercial scale CCS project would require multiple injection sites, some of which may be located at areas some distance from the point of generation of the CO_2. This could involve the construction of intrastate and potentially even interstate pipelines. There are technical, legal, administrative and public safety issues involved that West Virginia may need to address. The Working Group is looking at further development of this subject for the final report in July 2011.

What are the projected costs to West Virginia?

In any assessment of the cost of deploying CCS in the state there are a number of areas that must be addressed to answer the question. First is the actual economic cost of installing and operating CCS feasible for facilities operating in the state. Second what impact would the installation of such technology have on the overall economy of West Virginia. And third what

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[64] http://www.epa.gov/reg3hscd/bf-lr/newsletter/2009-Fall/repower.html

[65] http://aceee.org/pubs/e097.pdf?CFID=1338466&CFTOKEN=56457960

[66] Gold, R., L. Furrey, S. Nadel, J. Laitner, and R. N. Elliott, 2009. Energy Efficiency in the American Clean Energy and Security Act of 2009: Impacts of Current Provisions and Opportunities to Enhance the Legislation. American Council for an Energy-Efficient Economy, Report E096.

are the potential impacts on the safety and health of the people of West Virginia and the overall environmental integrity of the state. These areas are addressed in the next two sections of this report.

Question 1: What factors need to be considered in determining if CCS is feasible and beneficial for West Virginia?

IV.A.4. Cost Comparisons of Various Technologies

How expensive is the installation of possible technologies expected to be and is such an expenditure in the best interest of the state? A literature-based study was performed in an attempt to estimate some of the cost associated with constructing and operating a CCS facility and how these costs may compare with other low-carbon alternatives.

It should be noted that the costs included in this section should be considered as a comparison type analysis and should be viewed as representing the result of a specific set of assumptions which may vary over time. The Subcommittee would like to caution those reading this report that even comparative rankings listed herein may change as conditions evolve. As discussed earlier (see page 20) CCS may not be the least expensive of a number of different means of achieving some of the goals associated with a desire to reduce carbon dioxide emissions. The Feasibility Subcommittee will continue to evaluate the need for CCS to be part of the State's efforts to achieve these goals. The Legislature will have to decide which of the proposed means of achieving these goals are in the best interest of the citizens of West Virginia.

Cost of Various Technologies

The purpose of this study was to determine the economic feasibility of Carbon Capture and Sequestration (CCS) for fossil fuel electric generation in the State of West Virginia as compared with alternative electric generating technologies. We have reviewed publicly available documents for the costs of electric generating technologies and CCS technologies. The cost data vary widely as there is little operating history of CCS costs. The published CCS information that is readily available consists of projected costs based upon data from operating generation plants, and information learned generally from experimentation and demonstration CCS projects.

The widely accepted method of evaluating the economic feasibility of an electric generation technology is to determine the Levelized Cost of Electricity (LCOE) produced. The levelized cost considers all of the components of cost including permitting, financing and capital cost, as well as the components that make up a plants fixed and variable operating costs levelized over the life of the facility. A number of studies are available which examine the capital and levelized costs of a variety of electric generating technologies. Data was selected from the Energy Information Administration Annual Energy Outlook 2009 and three studies prepared under the auspices of the DOE/NETL. The first DOE study *"Cost and Performance Baseline for Fossil Energy Plants DOE/NETL 2007/1281 Volume I Bituminous Coal and Natural Gas to Electricity"* Rev1 examined the cost of new electric generating facilities. The second DOE study: *"Carbon Dioxide Capture from Existing Coal Fired Power Plants DOE/NETL-401/110907"* examines the cost associated with adding CCS to existing facilities. The third study: *"CO_2 Capture Ready Coal Power Plants DOE/NETL 2007/1301 Final Report April 2008"* examined the cost effectiveness of including in the original design of a coal-fired power plant the capability to retrofit a CCS system.

The competing energy forms were compared on a levelized cost of electricity basis to determine relative cost competitiveness. The results of the effort in executive summary format are contained herein.

As noted above, the data varied widely. The final projected costs in this report are not to be construed as projected costs of production on an individual generating site basis. The inputs for O&M can vary widely for each source depending on geographic location, fuel supply costs, etc. A true cost analysis would need to be performed on a case by case basis taking into consideration additional variables such as local legislation, demand for base load vs. peaking power needs, capacity factors of the various generating forms to meet demand, infrastructure needs, etc. The reported costs should be used to generally compare competing technologies to determine whether CCS is in the realm of competitiveness, and therefore whether the State of West Virginia should even consider legislation to promote its use.

The capital costs as published in the studies are provided in Table A.2 for plants without and with CCS. The reported capital costs are listed to show the relative size of initial investment needed for the competing technologies, however, many of the figures are dated, and actual current capital costs are likely significantly higher.

In Table 2, the IGCC with CCS $/kw cost is listed at $3496/kw. A company is planning to build a $1.75 billion coal gasification power in Ector County, Texas. Summit Power Group's Texas Clean Energy Project calls for it to be a 400-megawatt net (560 MW gross) integrated combined cycle (IGCC) plant that is designed to capture 90 percent of the carbon dioxide produced. According to a news release, the plant will capture 3 million tons of CO_2 annually, which will be used for enhanced oil recovery in the Permian Basin. Using the numbers being proposed by Summit Power as current estimates for IGCC Construction (hard costs) with 90% CO_2 capture, the data would translate to approximately $3125/kw (gross) or 4375/kw (net).

Another proposed IGCC facility in Mississippi is expected to be in service in 2013 has a total system cost of $3000/kw with 50% carbon capture. This information is from Southern Company's public comments.

The costs of a nuclear power facility as stated in the EIA report appear to be much lower that the current estimates by utilities and others which are in excess of $6000/kw.[67] Ontario Hydro recently announced canceling a large Nuclear power plant project as the capital costs have now exceeded $10,000/MW. The capital cost estimate shown in Table 1 is approximately 50% of the current low end estimate of the cost of an advanced nuclear plant currently under consideration.

The reported capital costs for adding CCS to an existing PC coal plant include the initial capital for constructing the plants, and therefore are overstated.

Cost figures in Table A.2 do not include the offsite capital costs of power transmission or infrastructure, which could be substantial particularly for wind and solar since the generating capacity per power unit is very small and substantial expansion of the current transmission would be required for infrastructure to accommodate many smaller generating units. The capital costs for infrastructure requirements of solar powered generation could be negated to a degree with alternative roof top installations.

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[67] Federal Energy Regulatory Commission Increase Costs in Energy Markets (Staff Report) June 9, 2008.

TABLE A.2
Capital Cost $/kw

Capital Cost				
			EIA Study 2007$	
			Note 2	
Natural Gas Combined Cycle (NGCC)			948	
NGCC with CCS			1890	
Wind			1923	
New Pulverized Coal (PC)			2058	
Integrated Gasifier Combined Cycle (IGCC)			2378	
Nuclear			3318	
IGCC with CCS			3496	
Biomass			3766	
New PC with CCS		Note 3	3846	
Solar			5021	
Existing PC with retrofit CCS		Note 4	5050	
Notes:				
1) Source: US Energy Information Administration Annual Energy Outlook 2009 except as otherwise noted. Cap Ex costs taken from EIA Annual Energy Outlook 2009 Assumption to the Annual Energy Outlook 2009 Table 8.2 Cost and Performance Characteristics of New Central Station Electricity Generating Technologies				
2) Overnight capital costs including contingency factors, excluding regional multipliers and learning effects. Interest charges are also excluded. These costs represent new projects initiated in 2008 expressed in $2007. Capital costs are shown before investment tax credits are applied where applicable				
3) The capital cost of a PC unit with CCS was not included in the EIA study. The data provided in the Cost and Performance Baseline for Fossil Energy Plants DOE/NETL 2007/1284 Volume I Bituminous Coal and Natural Gas to Electricity Rev 1 August 2007 was used to determine the incremental cost of adding a CCS to a PC unit as a percentage of the capital cost of a PC unit without CCS. That percentage was applied to the capital costs of a PC unit as defined in the EIA study to estimate the cost of a PC unit with CCS.				
4) The capital cost of retrofitting a PC unit with CCS was not included in the EIA study. The data provided in the CO_2 Capture Ready Coal Power Plants DOE/NETL 2007/1301 Final Report April 2008 was used to determine the incremental cost of adding a CCS to an existing PC unit as a percentage of the capital cost of a new PC unit without CCS. That percentage was applied to the capital costs of a new PC unit as defined in the EIA study to estimate the cost of an existing PC unit with CCS. The total cost is conservatively high as the retrofitted PC unit would have a depreciated value with respect to the capital cost of a new PC unit and thus the total capital cost would be less than the cost of a new PC unit and a retrofitted CCS as stated herein.				

TABLE 3.A
Ranking of Levelized Costs $/mwhr

			EIA Study 2007$					
			w/o CCS	Rank		w CCS	Rank	Notes
Nuclear			107.3	4		107.3	1	
Biomass			107.4	5		107.4	2	
IGCC with CCS at DOE Target Price			N/A			113.9	3	4
NGCC			79.9	1		115.7	4	
IGCC			103.5	3		122.6	5	
New PC with CCS at DOE Target Price			N/A			127.7	6	3
Wind			141.5	6		141.5	7	
New PC			94.6	2		175.6	8	
Existing PC Retrofitted w CCS			N/A			201.2	9	2
Solar			263.7	7		263.7	10	
Notes:								
1) Overnight capital costs including contingency factors, excluding regional multipliers and learning effects. Interest charges are also excluded. There costs represent new projects initiated in 2008 expressed in $2007. Capital costs are shown before investment tax credits are applied where applicable								
2) The levelized cost of energy (LCOE) of retrofitting a PC unit with CCS was not included in the EIA study. The increase in LCOE as a result of retrofitting a CCS was defined in Carbon Dioxide Capture from Existing Coal-Fired Power Plants DOE/NETL-401/110907 (Final Report Original Issue Date, December, 2006 Revision Issue Date November, 2007). The percent increase over the base case (no CCS) was applied to the base case LCOE of a PC unit as defined in the EIA study to determine the incremental LCOE to retrofit CCS to an existing PC unit. The LCOE of a retrofitted PC unit as stated here is conservatively high as the retrofitted PC unit would have a depreciated value with respect to the capital costs of a new PC unit and thus the LCOE would be less than the cost of a new PC unit with a retrofitted CCS as stated herein.								
3) DOE's goals for CO_2 capture in combustion systems as stated in DOE document: Existing Plants, Emission and Capture - Setting CO_2 Program Goals, dated April 20,2009 (DOE/NETL-2009/1366) are to limit the maximum increase in LCOE to 35%. This value was used to determine the LCOE in the table above.								
4) DOE's goal for CO2 capture in gasifier systems is to limit the maximum increase in LCOE to 10%. This value was used to determine the LCOE in the table above.								

Table 3.A presents the levelized costs of the various technologies. In the EIA data, for cases without CCS, NGCC is the low cost alternative followed by pulverized coal, IGCC, nuclear, biomass, and wind. Specific site factors and other factors would weigh into the selection of a specific technology for a selected site. Solar appears to be higher than the other technologies.

When CCS is included, fossil fuel technologies would incur an incremental increase in LCOE due to the capital and operating costs of the CCS. Table 3.A includes the EIA estimates of the LCOE based on current CCS technology development. However, DOE has established goals of advancing technology such that the incorporation of CCS in a gasification process or in a combustion process will not increase the LCOE by more that 10% and 35% respectively. Therefore estimated LCOE's for those technologies were also provided which reflected the achievement of the DOE goals.

In the study, the ranking of nuclear improves with the requirement for CCS. The results indicate that nuclear provides a low LCOE. However, the capital and operating costs of the advanced nuclear design are the least known among all of the technologies and as stated earlier, the capital cost estimate shown in Table A.2 is approximately 50% of the current low end estimate of the cost of an advanced nuclear plant currently under consideration.

Biomass provides a low LCOE when CCS is a requirement. This is due to the fact that biomass would not be required to install CCS systems. Biomass is followed in succession by IGCC achieving DOE cost goals, NGCC with CCS, IGCC with current pricing, PC achieving DOE cost goals and wind. The cases of a new PC with current CCS cost estimates and an existing PC with retrofit CSS cost estimates follows with the solar option resulting in the highest LCOE.

On a levelized basis, with CCS included, the ranking of some of the renewable technologies improves (nuclear and biomass). The fossil fuel technologies remain economically viable when compared to the other renewable technologies particularly if the DOE costs goals are at least partially achieved.

The data compilation suggests that CCS technologies should continue to be pursued to provide not only a viable means to capture and store carbon, but also to retain the competitiveness of the fossil fuels we are abundantly blessed with in West Virginia. The actual supply of electricity in a region will be a makeup of several sources of supply based upon the actual LCOE of each source, and its capacity for base load supply.

Study Scope: Estimating the Economic Impact of Implementing CCS in West Virginia

Second, in our consideration of the costs of CCS, what must we know before we can estimate the impact that such a program would have on the economy of West Virginia? An additional study looked at what would need to be done to address this question.

Implementing carbon capture and sequestration (CCS) will require Federal mandates and/or financial incentives. West Virginia-based emitters will not undertake the expenses associated with CCS without being required to do so or being faced with a more expensive alternative to reduce CO_2 emissions such as cap-and-trade or carbon taxes. Because it participates in regional markets for electricity and coal, West Virginia will not implement CCS on its own due to competition. An analysis of the impact of CCS in West Virginia is highly linked with the impacts of doing so in most of the Eastern U.S.

CCS is a capital-intensive activity and most emitters have little experience with it. While the use of CO_2 injection in the oil and natural gas industry is a highly developed technology, that experience is only partially transferable to emissions from electric generators using coal. To fully implement CCS will take many years, and the nature of capture will change as the technology used by emitters changes.

The economic impact of CCS in West Virginia depends much on the timeframe desired to be evaluated. The need for new fossil-powered electricity generation capacity will depend on growth in demand. In the next 20 years, much new generating capacity will be built to meet state renewable portfolio standards, which emphasize the use of alternative and renewable fuels. Under the West Virginia Alternative and Renewable Energy Portfolio Standard, electricity generated from coal with CCS counts; however, this is not the case in other states. Energy efficiency measures could also suppress demand growth. Thus, it is likely that most carbon will initially be captured with equipment added onto existing units. However, in 20 to 40 years a different type of generating capacity may be needed and new fossil units may be built with capture technology. As with all forecasting analyses, the longer the time-frame of evaluation the more assumptions will need to be made about demand and technology.

Pending Legislation

The current movement toward carbon regulation is generally focused on either carbon taxation or cap and trade. CCS is a stand-alone alternative if mandated or would be incentivized with a sufficiently large tax or very low cap on carbon emissions. If an imposed tax or the cost of emission permits under cap-and trade in terms of costs per ton of emitted carbon is greater than the cost of CCS, then affected industries will elect to do CCS.

Based on historical experience it is reasonable to assume that the costs of CCS technology will fall dramatically as implementation and research continue. The pace of this progress is difficult to predict and becomes more uncertain the longer the time frame used for evaluation. Any public policy which makes coal less competitive will provide an additional incentive for private research, but much of that research will require subsidization. For good reason firms are reluctant to make major financial commitments to newer technologies. Often the cost is high, the technology unproven and the certainty that even newer technologies with lower costs and increased efficiencies will emerge, makes the commitment of private capital less likely at the outset of CCS implementation.

Depending on market forces, the regulatory environment and the pace of introduction of alternative fuels, it may be possible for coal generators to pass the costs of CCS on to the consumers of electricity. Evaluating the ability of electric generators to do this would have to be part of any impact analysis. Incurring the costs of CCS in West Virginia could be better economically for the State than for its utilities to simply pass along the cost of the tax or to participate in cap-and-trade, because a new industry will develop around CCS and with it jobs and expertise. The trade-off between the creation of a new CCS industry and the possibility of forward shifting of the CCS cost would also need investigation.

Scale of Implementation

There are 14 or 15 coal-fired power plants in West Virginia that would currently be affected by carbon legislation. Carbon dioxide emissions from these plants amount to a little more than 86 million metric tons, about 3.4% of national levels from the electric power industry. It is likely that one or two of these plants would be retired if carbon capture were to be mandated. This would be determined by the costs of retrofitting older plants. If cap-and-trade is used these plants would be eligible for carbon emission credits. Closing them and using the credits to offset emissions elsewhere could prove to be a viable business strategy. A handful of industrial direct coal users would also be affected. In any analysis of the future of generation in West Virginia some assumptions would need to be made about which plants might be subject to closure.

Current Projects

West Virginia is the site of several projects developing CCS Technology. A short description of these projects is found on pages 26-27. Because of these pilot projects, West Virginia is now a leader in deployment of CCS. If CCS becomes widespread the State will benefit from this experience. But the small scale of most of these projects, while producing valuable information, are only the first steps in proving the feasibility of CCS.

Categories of Impact

There will be both positive impacts from spending and negative impacts from increased costs due to implementation of CCS. The primary costs of CCS will be borne by coal-fired power plants. Primary Impacts:

Higher electricity prices for residential, industrial and commercial consumers

The estimated costs of CCS vary by type of generator. Capture can take place pre or post-combustion, with pre-combustion costs appearing more costly at present compared to adding technology to existing steam units. Older estimations have been as low as around $36/tonne (IPCC in 2002) but more recent figures are closer to $90 for CCS post-combustion. In 2007, MIT estimated that a carbon price of $30/tonne would make CCS cost competitive. In West Virginia rates could more than double, with residential rates expected around 18 to 19 cents per KWh.[68]

Because West Virginia's electricity mix is 98 percent coal and other states in the region have lower coal shares, the price impact will be higher in West Virginia than in other states. The indirect effects will include reducing any competitive advantage that exists for manufacturing inputs and to disproportionately reduce disposal income for households. Correlated federal incentives to induce energy efficiency investment for all sectors and to reimburse low-income households will offset some of the negative impacts and could cause some manufacturers to remain in West Virginia rather than moving to areas where products costs are lower.

Reduced and less competitive electricity exports

West Virginia is among the largest exporters of coal-fired electricity. Based on its overall generation mix, West Virginia exported nearly 59 million MWh of coal-fired electricity in 2007, more even than large coal-fired generating states such as Texas and Pennsylvania, which exported 25 million MWh and 40 million MWh respectively of coal-fired electricity in 2007.[69] Electricity exports contribute to low electricity prices for WV customers. While it is expected that coal-fired power generation in WV will need to be maintained at current levels or more for at least 20 years, the long-term generation mix could be significantly different. Carbon capture at a power plant also requires diverting a portion of the plant's output to that capture, thus reducing the amount of electricity that can be delivered to customers.

Changed sourcing of coal for power generation

The cost of carbon capture could change the origin of coal supply as some regional power plants may choose to substitute cheaper, low-btu or other coal for West Virginia coal. Sub-bituminous coal from Wyoming's Powder River Basin can be brought to West Virginia at competitive prices and WV power plants with new pollution control technologies can purchase

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[68] Presentation by Mark Dempsey of Appalachian Power at the "Energy and Natural Resources Symposium" on October 29, 2009. It is uncertain what technology cost assumptions are incorporated within these figures.

[69] US DOE, EIA. 2007 State Electricity Profiles.

cheaper coal from areas like the Illinois Basin. On the other hand, IGCC technology is not compatible with PRB coal which greatly reduces the fuel options for that type of plant.

Creation of a new industry with uncertain cost and indirect effects

Industries that buy carbon byproducts can be indirectly impacted by the industry. Capture costs can be offset when there is a market for chemical byproducts resulting from the separation of carbon. For example, when CCS is linked to enhanced oil and gas recovery, the economies improve. The most similar existing industry to a CO_2 transport and storage industry is probably drilling oil and gas wells. Studies estimate the cost of transport and storage of CO_2 at around $15 per ton.[70]

Dynamic Modeling

Estimation of the economic impact of CCS on the West Virginia economy must be modeled dynamically to capture net impacts and because it will only be accomplished over several years. Assumptions regarding the phasing of implementation, the number of years to full implementation and the percent of carbon captured each year in the interim are important variables. In the next 20 years, the impact will be seen largely as retrofits to existing fossil units, while in the following 20 years new fossil and/or nuclear units will be built. The phasing of implementation can also be influenced by the availability and costs of alternative fuels.

The net effect of higher generation cost and less generation will depend on the timing of CCS implementation, demand response and other electricity suppliers. Quantification will require development of a credible set of assumptions to simulate consumer and industrial response.

There is also a question of a long-term health impact from reducing carbon emissions. Will West Virginia see a direct or indirect positive impact to reducing emissions or will the benefits be felt more in coastal areas? Research should be done to evaluate the option of including such impacts.

Methodology

Review of the literature

It will be necessary to review the relevant articles and reports related to CCS. A primary focus must be on costs of CCS and the anticipated pace of introduction of new technology. Further, the literature must be queried to determine the price responses of consumers to changes in electric consumption. This will allow a determination of what the loss of demand for coal generated electricity in West Virginia will be. In addition, the literature will be searched to determine the costs of switching to alternative or renewable fuels. So long as CCS is cost competitive with these substitutes the loss of markets will be reduced.

Consultation

Much, if not most, of the relevant information and data will have to come from the electric and coal industries themselves. Extensive work has already been accomplished on CCS

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[70] J. J. Dooley,R. T. Dahowski, C. L. Davidson, "*On The Long-Term Average Cost of CO2 Transport and Storage,*" US Department of Energy, Washington, DC, March 2008 http://www.pnl.gov/main/publications/external/technical_reports/PNNL-17389.pdf

by them. That work will be incorporated into the analysis. Also, those with pertinent information in energy related research organizations should be contacted.

Statement of assumptions

For any analysis to proceed, certain key assumptions must be made and clearly identified. The validity of the analysis will rest on the validity of the assumptions. Different assumptions will lead to different outcomes. Considering that West Virginia electricity is primarily exported to users out of state, all assumptions must be region wide and not limited to West Virginia. Among the assumptions to be considered are:

- The current and projected costs of CCS under various technologies
- The level of demand response to increased prices for coal generated electricity
- The costs and availability of alternate fuels
- Uses and markets for CO_2
- Public policies regarding CO_2

Development of scenarios

For that reason it may be necessary to develop alternative scenarios using different sets of assumptions in order to capture as many as possible of the projected outcomes. What scenarios would be considered would have to be a decision based on input from affected parties. The choice of scenarios would have to be limited to those “most likely” to happen.

Analysis

The analysis being dynamic must use a dynamic economic model. The most widely used dynamic model is REMI. REMI allows for a determination of the impact on income, output and employment from alternative public policies. It can project outcomes up to 20 years. It also can pinpoint the impact of those policies by most major industries. The output from the model would be translated into both written and graphic formats for distribution.

Review

The analysis should have extensive review prior to public distribution. It should be considered by those who have consulted on the project as well as additional reviewers familiar with CCS and electric energy markets.

Distribution

Following the review and inclusion of the results of that review, the report should be made public. Particular attention should be made to placing it in the hands of the decision makers.

An analysis this complex would take at least a year for completion.

Summary

The impact of implementing CCS in West Virginia depends on the relative impact of doing so in the region. Other states in the region will also be impacted and have different resources that can be used to meet the requirements of CCS. Isolating West Virginia's share of the impacts will require developing 20 to 40-year assumptions related to market share of power generation, coal production, biomass production and the industry of carbon storage itself. Assumptions regarding technology and the timeframe of implementation are equally important. Considering the importance of coal to the West Virginia economy an analysis of CCS impacts would provide important information for both industry and government.

Question 2: What factors need to be addressed to be able to assure the citizens of West Virginia that CCS is safe in terms of human health and the environment?

IV.A.5. What potential environmental and health related factors need to be addressed prior to reaching a decision regarding the feasibility of encouraging CCS in West Virginia?

The known potential human and environmental issues relevant to the feasibility of CCS include asphyxiation; explosiveness; risk to groundwater; effects on plant life; effects on seismic activity; effectiveness of CCS as a means of decreasing greenhouse gas emissions; increases in energy requirements due to efficiency losses; increases in water use; and increases in other air emissions.

Three avenues of release of CO_2 to the surface where it can present a human hazard are pipeline leaks, well leaks and seepage through the subsurface to ground level.

Asphyxiation

CO_2 is heavier than air and when concentrated it can pool near the ground, displacing oxygen. Proper siting, construction, maintenance and monitoring of CO_2 injection wells is vital to avoiding leaks into confined spaces such as basements, cellars, or other structures in or near the storage field. Should a well blowout or pipeline leak occur out in the open, the CO_2 likely would disperse quickly enough as to pose minimal risk of asphyxiation of human and animals.

Explosiveness

Unlike natural gas, CO_2 is not flammable. However, in order to maintain the supercritical or dense phase state, it is transported under high pressures. A sudden release of pressure due to a pipeline puncture would be 'explosive' in character but not flammable. There would be, however, considerable potential for harm to humans and animals in the immediate area of such an explosion.

With respect to transport, it should be noted that 3,769 miles of CO_2 transport pipeline are already in place in the U.S., and during the period 1994-2006, 18 "incidents" resulted in no fatalities or injuries (See Table IV.B.3). Based on historical data, the probability of injuries and fatalities from CO_2 pipeline "incidents" appears much lower than that for natural gas transmission pipelines. Still, extreme care should be taken in decisions as to siting of pipelines, operation of the pipelines to minimize possible corrosion, and implementation of effective risk management and mitigation plans.

Risks to groundwater

The protection of groundwater throughout a CCS project is vital to the water resources in West Virginia. Risks to groundwater quality arise from the potential for CO_2 to mobilize organic or inorganic compounds, acidification and contamination by trace compounds in the CO_2 stream, intrusion of native saline groundwater into drinking water aquifers, and the potential for the CO_2 to displace subsurface fluids. The probability of many of these risks occurring may be decreased by a thorough site characterization, sound injection well construction, sufficient monitoring, and enforcement of existing regulations. More detail can be found in Section IV.B.

Effects on plant life

Elevated levels of CO_2 in the soil from well leaks, pipeline leaks or seepage can negatively affect soil ecosystems and potentially kill plants if sufficient oxygen displacement and/or soil acidification occurs. Proper siting, construction, maintenance and monitoring of CO_2 injection wells is vital to avoiding leaks into soil. See Section IV.B.V.2 for more details.

Seismic activity

Proper siting of CO_2 storage reservoirs and proper injection procedures are vital to avoid inducing seismic activity. Geomechanical considerations include:

- Avoid regional tectonic stress near breaking strength of rock
- Avoid potential reservoir where fracture porosity is dominant
- Avoid low permeability reservoirs
- Avoid injection rates that can significantly increase pore pressure over a wide area.

Effectiveness

Does CCS make coal "carbon neutral"?

The goal for carbon capture from stationary sources is 90 percent. Modeling of IGCC, NGCC and pulverized coal (PC) technology[71] shows capture from gross power output (see Tables A.4 and A.5) between 86.98% (ConocoPhillips IGCC) and 89.44% (GE IGCC). Capture measured at net power output is between 88.33% (NGCC) and 85.26% (subcritical PC).

What is the likelihood the CO_2 will "stay put" after it's injected?

If it does not, then all our efforts and expense are for naught. Regarding retention of sequestered CO_2, the Intergovernmental Panel on Climate Change has stated that "Observations from engineered and natural analogues as well as models suggest that the fraction retained in appropriately selected and managed geological reservoirs is very likely to exceed 99% over 100 years and is likely to exceed 99% over 1,000 years."[72]

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[71] NETL, 2007, Cost and Performance Baseline for Fossil Energy Plants. DOE/NETL 2007/1281. Found at: http://www.netl.doe.gov/energy-analyses/baseline_studies.html

[72] IPCC, 2005: IPCC Special Report on Carbon Dioxide Capture and Storage. Prepared by Working Group III of the Intergovernmental Panel on Climate Change [Metz, B., O. Davidson, H.C. de Coninck, M. Loos, and L.A. Meyer (eds)]. Cambridge University Press, Cambridge, United Kingdon and New York, N.Y., USA, 442 pp.

Impact of capture technology on power generation

The amount of energy required to power carbon capture equipment increases parasitic load (see Total Auxiliaries Table A.5) reducing the net output of electricity. Each technology was modeled to maintain either gross power output for gas turbines or net power for steam turbines[73]. For each technology modeled, the difference with and without capture equipment is posted in Table A.4 and the percent change is posted in Table A.5. Compensating for this increase in parasitic load, 45.49% to 57.28% for IGCC technology and 288.21% to 290.07% for NGCC and PC technology is reflected in the increase consumption of coal by 2.19% to 4.54% for IGCC technology and 42.63% to 47.72% for PC technology. This combination of higher parasitic load and higher fuel consumption to compensate decreases the efficiency of coal plants by an amount ranging from 14.92% to 22.14% or IGCC technology and 30.43% to 32.34% for pulverized coal technology (see Tables A.4 and A.5). If CCS is employed on a large scale, therefore, significant additional amounts of coal may be consumed to maintain electricity generating output. If the additional coal consumption is focused on pulverized coal technology instead of IGCC technology, the amount of coal required is expected to increase by more than 42% (Table A.5). This will result in a concomitant increase in coal-related environmental, property and human health effects; these include, but are not limited to, water pollution, land degradation, loss of ecosystem services, flooding, generation of slurry from the processing of coal, damage to roadways from heavy coal trucks, and coal ash disposal.

Increases in water requirements

Tables A.4 and A.5 show that CCS is expected to increase water requirements for coal plants by an amount ranging from 10.06% (Conoco-Phillips IGCC) to 126.95% (subcritical PC).

Effects on other air emissions

Tables A.4 and A.5 also show that, while CCS will result in decreased emissions of SO_2 and NO_x at IGCC plants, emissions of NO_x, particulates and mercury will increase at pulverized coal plants. This could necessitate the installation of additional pollution control equipment in order to comply with permit requirements.

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[73] Ibid 71, see exhibits 3-18 & 3-34, 3-51 & 3- 67, 3-84 & 3-100, 4-7 & 4-17, 4-28 & 4-38, 5-7 & 5-17.

Table A.4

Change in power generation, consumption of raw materials and generation of by-products due to installation of Carbon Capture equipment[74]

		Changes due to installation of Capture Equipment				
	General Electric Energy IGCC	Conoco Phillips E-Gas^{TM} IGCC	Shell Global Solutions IGCC	Subcritical PC	Supercritical PC	NGCC
Gas Turbine/Steam Turbine Power - kWe	-290	-30	-400	96,608	83,185	0
Sweet Gas Expander Power - kWe	-870	-	-	-	-	-
Steam Turbine Power - kWe	-24,230	-48,640	-54,065	-	-	-50,110
Total Power - kWe	-25,390	-48,670	-54,465	-	-	-50,110
Total Auxiliaries - kWe	59,185	56,460	64,250	97,440	87,340	28,360
Net Power - kWe	-84,575	-105,130	-118,715	-832	-4,155	-78,470
Net Plant Efficiency - %(HHV)	-5.7	-7.6	-9.1	-11.9	-11.9	-7.1
Net Plant Heat Rate (Btu/kWe)	1,583.0	2,076.0	2,368.0	4,448.0	3,813.0	1,094.0
Consumables						
As-Received Coal/NG Feed - (lb/h)	10,745.0	13,966.0	20,556.0	208,890.0	175,345.0	0.0
Thermal Input - kWt						
Raw Water Usage - m^3/min (gpm)	575.0	378.0	771.0	7,886.0	6,718.0	2,168.0
SO_2 (lb/MWh)	-0.019	-0.022	-0.004	Negligible	Negligible	Negligible
No_x (lb/MWh)	-0.040	-0.033	-0.025	0.164	0.143	0.006
Particulates (lb/MWh)	0.003	0.005	0.007	0.030	0.027	Negligible
Hg (lb/MWh)	0.3×10^{-6}	0.4×10^{-6}	0.5×10^{-6}	2.7×10^{-6}	2.4×10^{-6}	Negligible
CO_2(Gross) (lb/MWh)	-1,305.0	-1,263.0	-1,260.0	-1,555.0	-1,472.0	-697.0
CO_2(Net) (lb/MWh)	-1,549.0	-1,477.0	-1,459.0	-1,608.0	-1,519.0	-704.0

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[74] NETL, 2007, Cost and Performance Baseline for Fossil Energy Plants. DOE/NETL 2007/1281. Found at: http://www.netl.doe.gov/energy-analyses/baseline_studies.html

Table A.5:

Percent change in power generation, consumption of raw materials and generation of by products due to installation of Carbon Capture equipment.

		Changes due to installation of Capture Equipment				
	General Electric Energy IGCC	Conoco Phillips E-Gas^{TM} IGCC	Shell Global Solutions IGCC	Subcritical PC	Supercritical PC	NGCC
Gas Turbine/Steam Turbine Power - kWe	-0.06%	-0.01%	-0.09%	16.56%	14.34%	0.00%
Sweet Gas Expander Power - kWe	-12.20%	-	-	-	-	-
Steam Turbine Power - kWe	-8.11%	-17.47%	-19.04%	-	-	-25.05%
Total Power - kWe	-3.30%	-6.55%	-7.28%	-	-	-8.79%
Total Auxiliaries - kWe	45.49%	47.39%	57.28%	296.44%	290.07%	288.21%
Net Power - kWe	-13.21%	-16.86%	-18.67%	-0.15%	-0.76%	-14.00%
Net Plant Efficiency - %(HHV)	-14.92%	-19.34%	-22.14%	-32.34%	-30.43%	-13.98%
Net Plant Heat Rate (Btu/kWe)	17.74%	23.91%	28.51%	47.95%	43.72%	16.28%
Consumables						
As-Received Coal/NG Feed - (lb/h)	2.19%	3.01%	4.54%	47.72%	42.63%	0.00%
Thermal Input - kWt						
Raw Water Usage - m^3/min (gpm)	14.36%	10.06%	20.33%	126.95%	123.47%	86.31%
SO_2 (lb/MWh)	-20.21%	-24.18%	-4.55%	Negligible	Negligible	Negligible
No_x (lb/MWh)	-9.85%	-7.62%	-6.05%	26.75%	24.70%	10.00%
Particulates (lb/MWh)	5.66%	9.62%	14.00%	26.32%	25.23%	Negligible
Hg (lb/MWh)	7.14%	9.52%	12.50%	27.00%	21.28%	Negligible
CO_2(Gross) (lb/MWh)	-89.44%	-86.98%	-89.43%	-87.36%	-87.57%	-89.02%
CO_2(Net) (lb/MWh)	-88.26%	-85.38%	-88.00%	-85.26%	-85.67%	-88.33%

IV.A.6. Incentives for CCS Technology

The decision concerning whether or not to take steps to provide incentives for the deployment of CCS Technology in West Virginia obviously must come subsequent to determining whether or not this technology is feasible. However, in advance of that determination, the Legislature has tasked the Working Group with researching plausible incentives.

Regulatory Certainty

Regulatory certainty is arguably the single most important step the state can take to incentivize deployment of CCS technology in West Virginia. To that end, the legal issues concerning pore space ownership and liability for sequestered CO_2 need to be resolved and are being considered by the Working Group. A clearly defined set of regulations and a definitive agency authority needs to be named to handle these projects. Further, a multi-agency team should be formed to address all issues for a permit applicant during the submittal process. At a minimum this would include WVDEP, PSC, WVDNR, WVEGS and WVDO.

The American Clean Energy and Security Act (ACES Act)

While the ACES Act has not been promulgated, it remains the most viable bill currently being considered by Congress concerning a carbon cap-and-trade program. Language in the bill also promotes R&D and early deployment of CCS primarily by the creation of a carbon storage research corporation which uses funds to issue grants and financial assistance for commercial scale CCS projects. The bill proposes funding of $1.1 billion per year for no more than 10 years. If the Act or an Act with similar provision is passed by Congress, the Working Group recommends that the Governor charge the West Virginia Development Office to make an extraordinary effort to make use of these monies by mandating at least one grant application be submitted each year.

The ACES Act also proposes to provide allowances to the first facilities that implement capture and secure geologic storage that results in a 50% reduction in annual CO_2 emissions. The West Virginia Alternative and Renewable Portfolio Standards Act, promulgated in 2009, places a mandate on the electric industry to utilize renewable and alternative fuels, and does allow generators to meet the standards by employing CCS. This legislation should be reviewed to ensure that West Virginia is maximizing the incentive and that it is actually useful for generators as written.

The American Recovery and Reinvestment Act (ARRA)

The ARRA was passed by Congress in 2009 and included tax incentives for CCS technology. It expanded tax credit bonds allocated to states and large local governments to finance clean energy projects including those incorporating CCS technology. There was also money made available for an “advanced energy property investment credit” providing 30% credit for investment in property designed to capture and sequester CO_2 as part of a qualified advanced energy manufacturing project. After consulting with the West Virginia Department of Tax and Revenue to explore whether a similar property tax credit for West Virginia is feasible, the Working Group has learned that there are many tax credits available in West Virginia for R&D, business expansion, and pollution control devices. The Feasibility Subcommittee will perform further research to ensure that the existing credits are accessible for those willing to invest in CCS technology in the state so that the state credits may dovetail the federal incentives.

Rate Incentive

The PSC is currently directed to provide rate incentives for clean coal technologies which reduce SO_2 and NO_x emissions via the following law:

> **§24-2-1g. Rate incentives for utility investment in qualified clean coal and clean air control technology facilities.**
>
> (a) The Legislature hereby finds and declares that the state of West Virginia has been a major supplier of coal to the electric power industry both within and

> outside of the state of West Virginia; the congress of the United States is currently considering legislation to limit the emissions of oxides of sulfur and nitrogen from coal-fired electric generating plants; the continued use of coal for generating electrical energy can be accomplished in an environmentally acceptable manner through the use of current state of the art and emerging clean coal and clean air technology; it is in the interest of the economy of West Virginia to encourage the use of such technologies for the production of electricity and steam; revenues from the continued production of coal are important to the State of West Virginia and are necessary for the funding of education and other vital state services; the construction of electric utility generation and transmission facilities may continue for many years following the finalization of plans for such facilities; and the prudence of the construction of such facilities may be affected by changing conditions during the extended interval between finalization of plans and completion of construction.
>
> (b) Upon a finding that it is in the public interest of this state, as provided in section one, article one of this chapter, the public service commission shall authorize rate-making allowances for electric utility investment in clean coal and clean air technology facilities or electric utility purchases of power from clean coal technology facilities located in West Virginia which shall provide an incentive to encourage investments in such technology
>
> (c) For purposes of this section a qualified clean coal or clean air technology facility must use coal produced in West Virginia for no less than seventy-five percent of its fuel requirements.
>
> (d) The public service commission shall determine, at such time and in such proceeding, form and manner as is considered appropriate by the commission, the extent to which any electric utility investment or purchases of power qualify for incentive rate-making pursuant to this section.

The Working Group suggests that a bill be proposed that adds CCS technology to this law.

Pre-qualifying Storage Sites

"Pre-qualifying" storage sites would entail a group of state agencies taking steps to locate and ensure the viability of potential sites as locations to sequester CO_2. Many factors would be considered such as topography, infrastructure, geology, etc. While entities would still be required to follow the normal permitting process that is established, investment in the process would be incentivized given that initial steps have been taken to certify that the storage site is permittable. This procedure will be further investigated by the Feasibility Subcommittee.

IV.7. Conclusions and Recommendations Being Discussed for the Final Report

IV.7.A Conclusions

1. The timeline for requirements to restrict the emissions of greenhouse gases is, at present, uncertain. However regulation at some point n the next few years is near certainty.

2. The task of reducing greenhouse gas emissions to the levels that many contend are necessary to avoid negative impacts of predicted climate change is monumental and will require major changes in the manner of producing and using energy. There is currently no proposed technology or acceptable life style adjustment that can meet these goals. In short, no one currently knows how to meet the projected goals for GHG reduction.

3. Carbon Capture and Sequestration is one of many tools that can be used to meet the goals of reducing carbon emissions. The development and deployment of CCS may also allow West Virginia to continue to use its current electrical power generation infrastructure and coal supplies.

4. Technology that is commercially able to capture and store carbon dioxide emissions from coal fired electric generation is not currently available.

IV.7.B. Recommendations Being Discussed for the Final Report

1. Should the CCS Work Group discuss and determine if a recommendation be made stating: West Virginia should continue to investigate ways to remain a net producer of energy. The state has many natural resources that can be utilized to produce marketable energy and is ideally located to provide energy to energy hungry heavily populated areas of the nation. The state should actively pursue renewables, conventional, hydro and all other primary sources of electrical production while developing technology and administrative procedures aimed at aligning energy production with the environmental and societal goals of its citizens.

2. The Feasibility Subcommittee will consider if West Virginia should investigate whether participation in interstate pipeline projects for the transportation and storage of carbon dioxide may be beneficial to the state and its citizens.

3. The feasibility of establishing CCS in West Virginia is heavily related to the importance of coal to the state. While the revenues associated with the state's coal industry have been the subject of several studies, others have suggested that there are significant economic and social costs associated with the use of West Virginia coal that should be included in any assessment of coal's impact on the state welfare. The FSC had some discussion of these issues and will engage in further inquiry prior to the drafting of the Final Report.

4. The economic impacts of actively participating in the development of CCS are still uncertain. The SC will attempt to reach more resolution on this.

5. With the USEPA's regulation of GHG in by January, 2010 and a large interest in congressional action and potential international implications, the SC will attempt to present an understandable update of where WV stands in the area of Climate Change in the final report.

Question 3: What are the technical issues (both engineering and geological) that must be addressed to ensure the efficacy of CCS in West Virginia?

IV.B. GEOLOGY & TECHNOLOGY REPORT

IV.B.1. Introduction

The Geology & Technology subcommittee was asked to focus on three questions posed in the legislation: identifying monitoring sites for geologic sequestration [§22-11A-6(h)(5)], assessing the feasibility of carbon dioxide sequestration in West Virginia [§22-11A-6(h)(6)], and assessing the potential carbon dioxide sequestration capacity in the state[§22-11A-6(h)(8)]. In addition the technical subcommittee addressed several technical questions referred to it by other subcommittees. The Geology & Technology subcommittee notes that carbon capture and storage research and development is an area of rapid change. These technologies are undergoing substantial change and refinement. There are many unanswered technical, policy and regulatory questions. The West Virginia Legislature recognized this with the establishment of the Carbon Dioxide Sequestration Working Group. The technical subcommittee fully expects that changes will occur that West Virginia will have to adapt to.

West Virginia has a history of oil & gas and coal production and both indicate the potential for sequestration of captured CO_2. The Midwest Regional Carbon Sequestration Partnership (MRCSP) has identified several stratigraphic horizons that may have potential for sequestration[75]. Initial estimates of the geologic storage capacity for carbon dioxide in West Virginia suggest that there is between 47 years and 147 years[76] of injection for the annual carbon dioxide emissions from 29 sources[77] in West Virginia. These values for storage potential will be refined as additional information is obtained on suitability of geologic formations, storage capacity and potential injectivity other relevant factors.

Establishment of a monitoring, verification and accounting (MVA) system to confirm the position of the CO_2 plume in the reservoir as well as detect a possible leak will be required. Initial MVA activity will be based on limited information available prior to site characterization when acquisition of baseline data is initially considered. Site characterization activities in integrating surface and subsurface data will improve understanding of the geologic setting and the design of a suitable MVA program. Development of regulations and permitting standards will be necessary as will the establishment of the appropriate expertise within state agencies.

Assessment of the risks of transporting and storing carbon dioxide is necessary and essential in developing a MVA program as well as establishing levels for financial liabilities. There is a substantial body and growing body of carbon dioxide risk assessment literature. There is, relative to the scale envisioned for CCS, limited experience in transporting and injecting carbon dioxide for enhanced oil recovery (EOR). Analogous areas of experience such as natural gas transportation and storage, and underground injection of wastes suggest, but do not establish that carbon dioxide can be safely transported and stored.

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[75] Wickstrom, L.H. et al., 2005, Characterization of Geologic Sequestration Opportunities in the MRCSP Region, Phase I Task Report Period of Performance: October 2003-September 2005, DOE/NETL DE-PS26-05NT42255

[76] NETL, 2008, Carbon Sequestration Atlas of the United States and Canada, second edition. Found at: http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlasII/index.html

[77] See Appendix xx – List of WV sources from NATCARB

Identify geologic sequestration monitoring sites to assess the short-term and long-term impact of carbon dioxide sequestration - §22-11A-6(h)(5)

Monitoring, Verification and Accounting (MVA)

Injection of captured CO_2 in a supercritical or dense phase is a high pressure operation that increases the pressure in the storage reservoir for some radial distance from the injection well. It is essential to monitor two fundamental factors during and following injection of captured CO_2: the plume itself and pressures associated with the plume[78]. These two factors will be monitored over the injection, post-injection (both are within the short-term time period) and long-term stewardship time periods for each CO_2 storage reservoir. A basic goal is to know the location of the edge of the plume and associated pressure front. Surface and subsurface monitoring provides the necessary data needed to demonstrate that the CO_2 plume is not migrating beyond the boundaries of its trap and presenting an endangerment[79] situation, either to groundwaters (underground source of drinking waters (USDW)), the atmosphere, ecosystems and for human health.

Monitoring of the injected CO_2 will be done in the subsurface and at the surface. The most obvious location for monitoring is in well bores and more specifically at the injection well. Well bores are a data point providing direct measurement of the storage reservoir, the seal or cap rock and overlying stratigraphic horizons including groundwater aquifers. Aside from injection wells, monitoring wells located at some distance from injection wells can provide observation points to monitor storage reservoir pressure as well as formation water/CO_2 plume chemistry. Groundwater wells in proximity to the underlying CO_2 plume are also important points of observation and measurement. Surface measurements will be conducted at surface facility locations including delivery point of captured CO_2, point of separation to storage field pipeline system, injection wells and within the area of as well as at the perimeter of the expanding CO_2 plume in the subsurface.

An MVA program will be established prior to site characterization because a key component for a successful MVA programs, baseline measurements, will be collected during site characterization. A known location for MVA activity is the injection well but location of these wells depends on storage reservoir geology which in turn will dictate monitoring well locations. The areal extent of the CO_2 plume will depend on storage reservoir architecture. Knowledge of reservoir architecture will depend on well control and seismic data. Knowledge of reservoir architecture will improve with operations and continuous data collection by a MVA program. The USEPA proposed rules for Class VI injection wells will require an update of the Area of Review (AoR) for each injection well every 10 years or less[80]. A MVA program will be unique to each CO_2 storage reservoir and will reflect the geologic characteristics present in the subsurface. The details of a MVA program, the selection of technology and location of monitoring sites is the decision of the operator with the approval of the regulatory oversight board.

A wide range of technology is available to monitor, verify and account for the character and lateral extent of a CO_2 plume in the subsurface. Application of this technology begins during site characterization when baseline measurements are established. This information is

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[78] NETL, 2009, Monitoring, Verification, and Accounting of CO_2 Stored in Deep Geologic Formations. DOE/NETL-311/081508. Found at: http://www.netl.doe.gov/technologies/carbon_seq/refshelf/MVA_Document.pdf

[79] As proposed, an operator can be released from obligations under a Class VI injection permit when non-endangerment can be demonstrated.

[80] EPA, 2008, Proposed rules for Underground Injection Control (UIC) Program for Carbon Dioxide (CO2) Geologic Sequestration (GS) Wells.

critical in providing recognition and assessment of data deviations away from baseline measurements.[81]

Technologies are available for all aspects of captured CO_2 injection operations. Geophysical methods at the surface which includes 2-D and 3-D seismic that if repeated over consistent time intervals can provide 4-D seismic provide broad geographic coverage of subsurface stratigraphy. In the wellbore, geophysical or wireline logging tools can provide subsurface measurements of formation fluids and the rock material that can be tied to and calibrate the surface seismic data. Wireline logs are run after a well is drilled before casing is set (i.e. open hole well logs) and also after casing is set. Cased-hole logging is done to verify quality of the cement job binding the casing to the surrounding rock and to detect leaks or potential paths of migration behind casing. Vertical seismic profiles (VSP) or cross-well seismic is data gather from wellbores that can be tied to surface seismic data. Cores or sidewall cores are taken when wells are drilled and provide direct measurement of the porosity and permeability of the storage reservoir, cap rock or seal and other formations sampled.

The USEPA's proposed Class VI injection well rules will require continuous monitoring of injection pressures of the injection well[82]. This provides for continuous mechanical integrity testing (MIT) they believe is important and which is usually done at 5 year intervals for Class I, II and V wells[83]. Subsurface pressures can also be acquired from non-injection wells with downhole pressure sensors.

Surface monitoring will include leak detection from surface equipment used for injection, soil gas analyses and ambient monitoring of the near surface atmosphere. Airborne monitoring techniques are also available. Perhaps one of the more important, especially during site characterization, is an aeromagnetic technique for detecting old wellbores[84].

Legislative Activity

Several states have passed legislation regarding carbon capture and sequestration. With respect to monitoring, each piece of legislation only provides general direction to the appropriate regulatory body to develop more specific requirements for monitoring and verification. Location of specific monitoring sites will depend upon the question to be answered the technology selected. Regulations will provide the questions and the site operator will select the technology with the understanding that they, the operator, are responsible for providing a suitable and acceptable answer. It must be recognized by all involved that available technology for recording geologic information at depth has some limitations regarding degrees of accuracy and/or level of resolution.

Only the state of Washington has developed specific regulations in response to legislation. Washington's legislation only required that the governor "develop policy recommendations on how the state can achieve the greenhouse gasses emissions reductions goals established under section 3 of" of the bill[85]. The Department of Ecology, with the help of a working group, established rules for CO_2 injection projects[86]. These rules require that a Permit Application include, among other items, information regarding "Location of all pertinent surface

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[81] EPA, 2008, Vulnerability Evaluation Framework for Geologic Sequestration of Carbon Dioxide. Technical Support Document. EPA430-R-08-009

[82] Ibid 95

[83] Ibid 95

[84] SEQURE™Well Finding Technologies, see: http://www.netl.doe.gov/newsroom/netlog/sept2007/Sep07netlog.pdf

[85] Engrossed Substitute Senate Bill 6001. Found at: : http://apps.leg.wa.gov/documents/billdocs/2007-08/Pdf/Bills/Session%20Law%202007/6001-S.SL.pdf. Retrieved: February 23, 2010

[86] Norman, D.K. and J. Stormon, 2007, White Paper: Feasibility of Using Geologic Formations to Sequester Carbon Dioxide (CO_2), Department of Ecology. Found at: http://www.ecy.wa.gov/climatechange/docs/co2sequestrationfinal_082807.pdf. Retrieved February 23, 2010.

facilities, including atmospheric monitoring within the boundary of the project", a "leak detection and monitoring plan using subsurface measurements to monitor movement of the CO_2 plume both within and to detect migration outside of the permitted geologic containment system." (WAC 173-218-115)[87]. This leak detection and monitoring plan includes "monitoring of pressure responses and other appropriate information immediately above caprock of the geologic containment system." One of the terms and conditions attached to a permit is that "The monitoring program shall include observations in the monitoring zone(s) that can identify migration to aquifers as close stratigraphically to the geologic containment system as practicable."(WAC 173-218-115). Specific items to monitor as specified in the regulations are:

- Characterization of injected fluids
- Continuous recording of injection pressure, flow rate and volume
- Continuous recording of pressure on annulus between tubing and long string casing
- Monitoring zone leak detection
- Sufficient monitoring to confirm the spatial distribution of the CO_2 in the subsurface

Each specific item to be monitored suggests a monitoring location but the regulations avoid suggesting or mentioning specific locations. Location of monitoring devices will depend on the technology and the parameter that needs to be recorded. Washington's regulations are comprehensive but not prescriptive; they provide the potential operation a good sense of what is expected for safe operations of a captured CO_2 storage field and what questions need to be answered. It will be up to the operator to select suitable technology that will record the necessary information with which to answer the questions.

Montana legislation (Senate Bill No. 498)[88] specifies that captured CO_2 injection permits include requirements for applicable pressure and fluid chemistry data as well as monitoring and verification. One specific request is an "adequate baseline monitoring of drinking water wells within 1 mile of the perimeter of the geologic storage reservoir." One mile from the perimeter of the geologic storage reservoir could be quite a distance from the CO_2 plume on initial injection. It will be interesting to see what regulations appear per this specific request.

Louisiana legislation (House Bill No. 661) provides the commissioner of conservation the duties and powers to promulgate rules and regulations requiring "interested person to place monitoring equipment of a type approved by the commissioner . . . ," and that monitoring will be regulated by rules developed by the commissioner.[89]

North Dakota legislation (Senate Bill No. 2095) requires the industrial commission to determine before a permit is issued "that the storage operator will establish monitoring facilities and protocols . . . ." The commission is also required to "take action that carbon dioxide does not escape from a storage facility." This will require an MVA program.

Each of the legislatures from Washington, Montana, North Dakota and Louisiana provided direction to their respective executive departments charged with captured CO_2 sequestration regarding overall goals. The specifics are left to the regulator to develop as Washington's Department of Ecology did for that state. Washington's regulations deferred to the prospective operator the selection of specific technology with which to fulfill regulatory requirements.

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[87] Washington UIC Program, Dept. of Ecology, Found at: http://www.ecy.wa.gov/biblio/wac173218.html

[88] Montana, 61st Legislature, Senate Bill No 498, found at: http://data.opi.mt.gov/bills/2009/billpdf/SB0498.pdf

[89] Louisiana, Regular Session, 2009, House Bill No. 661, found at: http://www.louisianalawblog.com/uploads/file/HB-661(1).pdf

Assess the feasibility of carbon dioxide sequestration in West Virginia and the characteristics of areas within the state where carbon dioxide could be sequestered- §22-11A-6(h)(6)

IV.B.1.a. The kinds of geological formations which might work.

Feasibility for carbon dioxide sequestration in West Virginia is a reflection of the geology of West Virginia. West Virginia is, essentially, located entirely within the extents of the Appalachian Basin. This is a foreland basin[90] oriented along a general northeast-southwest axis, extending from north central Tennessee to central New York. Structurally, the strata within the basin becomes deeper to the southeast where it is bounded by the Allegheny Structural Front[91](Figure 4B3). Within West Virginia, this general trend is broken by two northeast-southwest trending structural features, the Rome Trough and the Upland Horst which is bounded by the Allegheny Structural Front (Fig.4B3). In southern West Virginia the Rome Trough is structurally deeper to the Upland Horst but both features merge to a common depth in northeastern West Virginia. The sedimentary section ranges from 8,000 feet to more than 20,000 feet in the Rome Trough and in the northeastern corner of the state.

Clastics, carbonates, and coal seams comprise the stratigraphic section found in West Virginia. The two dominant carbonate sedimentary rocks are limestones and dolomites. Sandstones and shales are clastic rocks. Sandstones and carbonates are the dominant reservoir rocks for oil and gas with shale commonly providing the seal. Sometimes a tight (very low to essentially no permeability) carbonate rock will act as the seal trapping oil and gas within a reservoir. Long known as a source rock as well as an excellent cap rock for reservoirs, organic rich shales have been recognized, as early as the 1970s, as a reservoir from which natural gas can be produced. A trap rock or seal represents a sharp reduction in permeability blocking further migration of fluids or gas.

All four of these sedimentary rock types can provide suitable conditions for sequestration of captured carbon dioxide. Sandstones, carbonates and (unmineable) coal seams are recognized as potential reservoir rocks while shale or a tight carbonate can provide the seal, or confining barrier. MRCSP provided an estimate of storage potential for shales in their Phase I report.[92] In their Sequestration Atlas, NETL did not provide an estimate of storage potential for shales.[93] The ability of shale to act as a sequestration reservoir is still under study.

The Midwest Regional Carbon Sequestration Partnership (MRCSP), one of the seven regional partnerships created by DOE/NETL, encompasses West Virginia and most of the states overlying the Appalachian Basin. The MRCSP conducted an evaluation of sequestration potential within the area of the partnership during Phase I of their project period.

The stratigraphic section present under West Virginia is illustrated in Figure 4B1. Formations with sequestration potential are illustrated in blue and formations that can provide a seal or act as a confining unit are illustrated in lime green.

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[90] Wickstrom, L.H. et al., 2005, Characterization of Geologic Sequestration Opportunities in the MRCSP Region, Phase I Task Report Period of Performance: October 2003-September 2005, DOE/NETL DE-PS26-05NT42255.

[91] Roen, J.B., and B.J. Walker, 1996, The Atlas of Major Appalachian Gas Plays, West Virginia Geological a nd Economic Survey, Publication V-25.

[92] Wickstrom, L.H. et al., 2005, Characterization of Geologic Sequestration Opportunities in the MRCSP Region, Phase I Task Report Period of Performance: October 2003-September 2005, DOE/NETL DE-PS26-05NT42255

[93] NETL, 2008, Carbon Sequestration Atlas of the United States and Canada, second edition. Found at: http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlasII/index.html

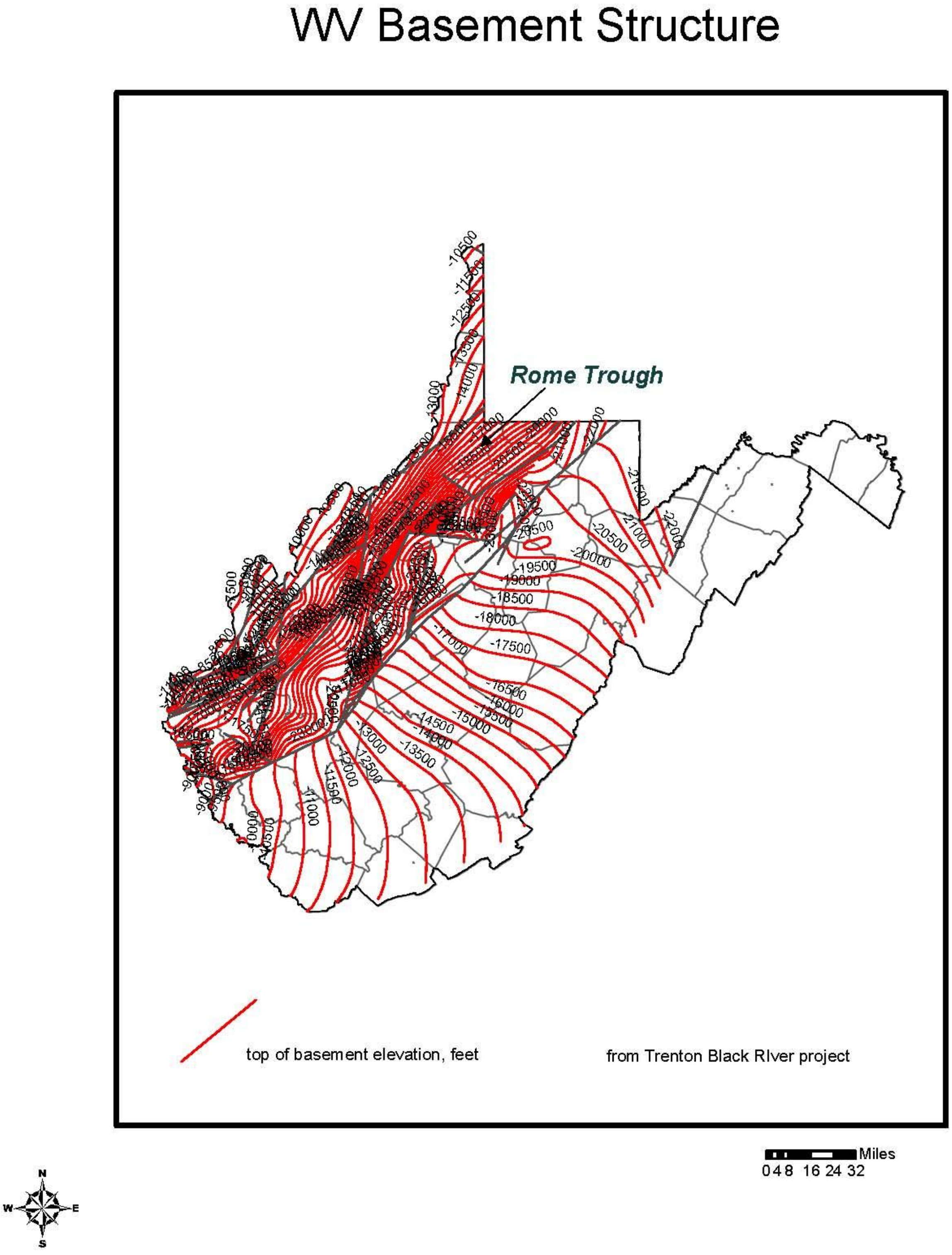

Figure 4B1: Structure contours on top of crystalline basement rock

Figure 4B2: Illustrative schematic of potential sequestration horizons in the stratigraphic section of West Virginia.

Geologic Systems & Series		Terminology Used on 1968 State Geologic Map		Former Terminology if different (WV Geological Survey County Reports)		Oil & Gas "Sands" (Drillers' Terms)
Permian		Dunkard Gp				Carroll
Pennsylvanian	Upper	Monongahela Gp				Minshall, Murphy, Moundsville, Cow Run, Little Dunkard, Big Dunkard
		Conemaugh Gp				
	Middle	Allegheny Fm				Burning Springs Gas & Lower Gas, Horse Neck
	Lower	Pottsville Gp				Salt Sands (1st, 2nd, 3rd)
Mississippian	Upper	Mauch Chunk Gp				Princeton, Ravencliff, Maxon, L. Maxon, Little Line
	Middle	Greenbrier Gp				Blue Monday, Big Lime, Keener, Big Injun, Squaw, Weir
	Lower	MacCrady Fm				
		Price Gp				
Devonian	Upper	Hampshire FM		Catskill		Berea, Gantz, Fifty Foot, Thirty Foot, Gordon Stray, Gordon, Fourth, Fifth, Bayard, Elizabeth, Warren First & Second, Clarendon(Tioga), Speechley, Balltown(Cherry Grove, Riley, Benson, Alexander, Elk, Sycamore
		"Chemung Gp"				
		Brallier Fm		Portage		
	Middle	Harrell Shale	Millboro Shale	Genesee		
		Mahantango Fm		Hamilton		
		Marcellus Fm				
		Onesquethaw Gp	Onondaga Ls	Huntersville		Corniferous
			Huntersville Chert			
			Needmore Shale			
	Lower	Oriskany Ss				
		Helderberg Gp				
Silurian	Upper					
		Tonoloway Fm		Bossardville	Cayugan (Salina) Series	
		Wills Creek FM		Rondout		
		Williamsport Fm		Bloomsburg		Newburg Sand
	Middle	McKenzie Fm		Niagara	Niagaran Series	Lockport Dol. Newburg Dol.
		Rochester Shale		Clinton		Keefer Ss, Big Six Sand
		Keefer Ss				
		Rose Hill Fm				
	Lower	Tuscarora Ss		White Medina		Clinton Gas Sand, Medina Gas Sand,
Ordovician	Upper	Juniata Fm		Red Medina		
		Oswego FM		Gray Medina		
		Reedsville Shale				
	Middle	Martinsburg Fm	Trenton Gp	Martinsburg		Trenton-Black River, Glenwood at base.
		Nealmont Ls		Chambersburg	Moccasin	
		Black River Gp			Stones River	
		New Market Ls	St. Paul Gp (St Peter Ss)	Chazy		Chazy-Stones River, St. Peter
		Row Park Ls				
	Lower	Pinesburg Station Dol	Beekmantown Gp (Rose Run, Copper Ridge)		Knox	Knox Dol., Rose Run Sand
		Rockdale Run Fm				
		Stonehenge Ls				
Cambrian	Upper	Conococheague Fm				Trempealeau
	Middle	Elbrook Fm				
	Lower	Waynesboro Fm				
		Tomstown Dol				
		Antietam Fm	Chilhowee Gp			
		Harpers Fm				
		Weaverton-Loudoun Fm				
		Catoctin Fm				
Pre-Cambrian						
		Crystalline Rock				

Confining Unit	Sequestration Target	Organic Shale	Coal –bearing Interval	Basement

Sequestration potential is present in the:

- Upper Devonian Sandstones
- Lower Devonian Oriskany Sandstone
- Lower Silurian Sandstones
- Ordovician St. Peter Sandstone
- Cambrian Rose Run Sandstone & Copper Ridge Dolomite
- Basal Rome Trough Sandstone

Confining units are present above each formation with sequestration potential presenting multiple barriers to migration. At the top of the stratigraphic section are the Pennsylvanian coals.

It should be pointed out that West Virginia has a naturally occurring CO_2 reservoir. Indian Creek field is located in Kanawha County, West Virginia. The reservoir is the Lower Silurian Tuscarora Sandstone. As is the case with all the Tuscarora fields, it is located on an anticline (the northeast plunging nose of the Warfield anticline). Porosity is developed in the fractures associated with the structure. The Warfield anticline is asymmetric and water is reported downdip to the southeast of the productive wells. Apparently porosity pinches out downdip to the northwest and also off the northeast plunging nose of the anticline.

More than 30 wells were drilled in the field between 1973 and 1987. Food grade carbon dioxide along with methane are produced; the gas is reported to be more than 60% carbon dioxide.[94,95,96] Approximately 20 bcfg has been reported as produced from 1981 through 1992.[97]

IV.B.1.b. The extent and location of potentially feasible formations

The occurrence of oil & gas production in West Virginia illustrates the general extent of potentially feasible geologic formations for sequestration (Figure 2). Oil and gas fields are primarily found northwest of the Allegheny Structural Front to the Ohio River (Figure 2) and this will be the general area within which saline storage potential will be found.

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[94] Hamak, J.E., and Sigler, Stella, 1991, Analyses of natural gases, 1986-1990: U.S. Bureau of Mines Information Circular IC 9301, 315 p.

[95] Hamak, J.E., and Gage, B.D., 1992, Analyses of natural gases, 1991: U.S. Bureau of Mines Information Circular IC 9318, 97 p.

[96] Jenden, P.D., Drazan, D.J., and Kaplan, I.R., 1993, Mixing of thermogenic natural gases in northern Appalachian basin: American Association of Petroleum Geologists Bulletin, v. 77, p. 980-998.

[97] Avary, K.L., 1996, Play Sts: The Lower Silurian Tuscarora Sandstone Fractured Anticlinal Play: *in* Roen, J.B. and Walker, B.J., eds., The Atlas of Major Appalachian Gas Plays: West Virginia Geological and Economic Survey, Volume V-25, p. 151-155.

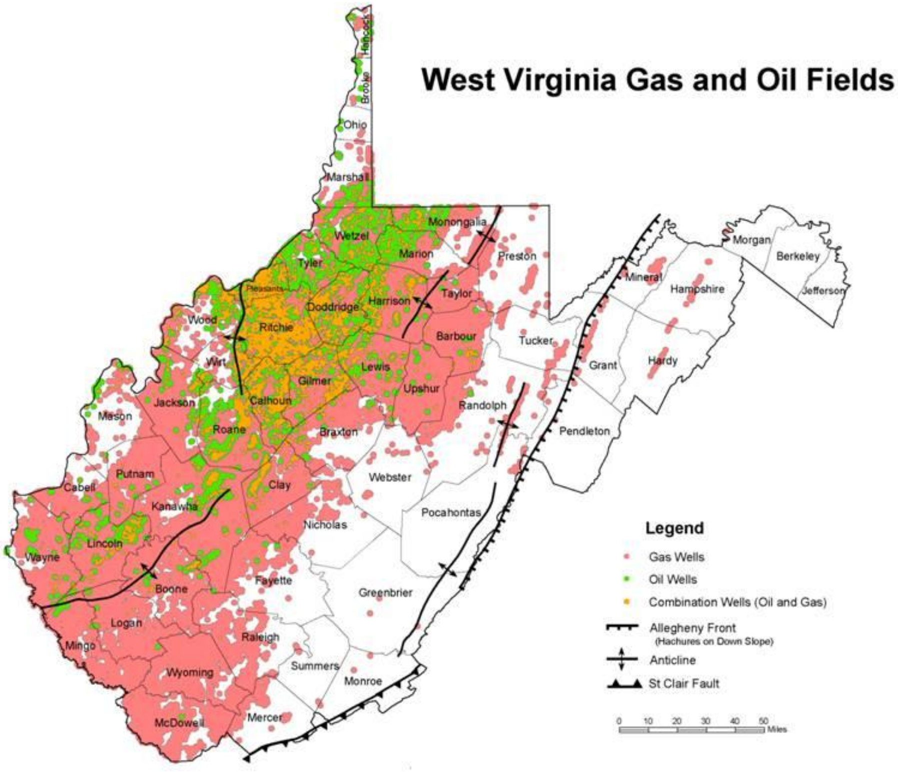

Figure 4B3: Distribution of oil & gas fields in West Virginia

It should be noted here that the Appalachian Power Company Mountaineer Plant along the Ohio River in New Haven (Mason County), West Virginia recently began injection of captured CO_2 into the Rose Run sandstone and Copper Ridge dolomite. A seal is provided by the Beekmantown dolomite which immediately overlies the Rose Run[98].

IV.B.1.c. Ability to assess specific CO_2 storage project feasibility

The purpose for any CO_2 storage field is to sequester the CO_2 captured from the source(s) with whom they have a contract. The operator of a storage field believes they have a certain amount of storage volume that will accept injection over a period of time. The source(s) hopes the storage field will be in operation over the life of their plant. Why does the storage field operator believe that they have sufficient storage capacity? Why was that location selected? Where was the necessary information found?

The ability to assess any specific project location and potential depends on the quality of the initial data available or that can be acquired. NATCARB data published in the Carbon Sequestration Atlas of the United States and Canada suggest a range of storage potential for the various states. These values represent a storage resource that needs to be proven. When an exploration well discovers oil and/or gas and establishes production, a portion of the oil and gas resource has been proven. Carbon sequestration reverses the process in a sense. Here, the resource is potential storage capacity representing the ability to inject captured carbon dioxide over a period of time. This potential needs to be proven, a process that begins with site characterization. But why select any particular site for CO_2 storage operations? We know oil and gas fields have storage capacity but these potential storage fields represent only a small

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[98] Mountaineer Injection Well Geological Report,

portion of the storage capacity needed to meet proposed legislative mandates. Saline reservoirs represent the largest potential for sequestration of captured carbon dioxide. Oil and gas exploration did its best to avoid discovering water. Unless it occurs above a producing field, saline horizons are not well drilled and there will be less data available. Any potential storage field developer may or may not have a need to sequester a specific volume of captured CO_2. They may only be conducting an opportunity search. Emission sources though will have specific needs that must be met. An initial assessment will provide some perspective on the size of potential storage fields. Publicly available data and information will be critical for initial evaluation of storage potential, selecting a site for further site characterization. Sources of this information will be the state geological survey, publications in professional journals and academia. With this data, a prospective storage field developer should be able to determine prospective areas, how much territory will be required to cover the extent of a potential plume of sequestered CO_2 and what additional data needs to be acquired. John Tombari of Schlumberger Carbon Services estimates that it will cost $100,000 per square mile to acquire 3-D seismic and $3,000,000 to drill and log an evaluation well plus 30% of these costs for data processing, modeling and other services[99]. He estimates that one well will evaluate 25 mi^2. With 3-D seismic and one new well with modern data, characterizing a storage field covering 25 square miles will cost a little over $7,000,000. These costs probably do not cover all of the details that need to be accounted for, for example spotting all plugged and abandoned wells, in presenting a storage field proposal before a regulatory body with the intent of gaining a permit. The quality of data available for this initial assessment will provide a level of confidence on whether or not to proceed, whether or not a further investment in time and money is warranted.

Assess the potential carbon dioxide sequestration capacity in this state-§22-11A-6(h)(8)

IV.B.1.d. Calculation of available sequestration capacity

IV.B.1.d.i. Existing estimates

As noted above, the potential storage capacity for sequestering captured CO_2 is a resource value. Like any other natural resource, such as oil & gas or coal, actual storage capacity has to be proven. For oil & gas or coal, this involves drilling a well to gain an actual measurement of the resource and establishing a proved reserve. With production, a better understanding of an oil & gas reservoir is gained over time. Having a better understanding of the reservoirs potential, proved reserve values are sometimes increased. A proved reserve, while a more certain value, is also smaller than the value attached to the resource. For CO_2 sequestration, proving the resource potential will be done by site characterization and injection during field operations will further refine the understanding of a reservoir's storage capacity.

The Midwest Regional Carbon Sequestration Partnership (MRCSP) is one of seven regional partnerships assembled by DOE/NETL to evaluate, test and demonstrate carbon sequestration potential across the United States. States within the MRCSP are Michigan, Ohio, West Virginia, Maryland, Pennsylvania, New York, the northeastern half of Indiana and the eastern half of Kentucky. Geologic horizons or formations (Figure 4B2) considered for sequestration potential by the Midwest Regional Carbon Sequestration Partnership are:[100]

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[99] McCoy, S.T., 2008, The Economics of CO_2 Transportation by Pipeline and Storage in Saline Aquifers and Oil Reservoirs. PhD dissertation, Carnegie Mellon University, January, 2008.

[100] Ibid, 90

- Upper Devonian:
  - Hampshire Group (Berea Sandstone)
  - Greenland Gap Group
  - Rallier Formation
- Lower Devonian:
  - Oriskany Sandstone*
- Lower Silurian:
  - Newburg Sandstone
  - Keefer Sandstone
  - Brassfield Formation
  - Cabot Head Formation
  - Tuscarora Sandstone* (Medina Group)
- Upper Ordovician:
  - Black River Group
  - St. Peter Sandstone
- Upper Cambrian:
  - Rose Run Sandstone*
  - Copper Ridge Dolomite
- Lower Cambrian:
  - Un-named Basal Sandstone* (below Rome Formation)

At the top of the stratigraphic section in West Virginia are the coal bearing strata:

- Pennsylvanian*:
  - Monongahela Group
  - Conemaugh Group
  - Allegheny Group
  - Pottsville Group
  - Kanawha Group
  - New River Group
  - Pocahontas Formation

The sequestration potential for the organic rich shales was also evaluated:

- Devonian*:
  - Ohio Shale
  - Java Formation
  - West Falls Formation
  - Sonyea Formation
  - Genesee/Harrell Formation
  - Marcellus Formation

The MRCSP estimated the potential storage volume for each state within the partnership[101] (for West Virginia an * designates which units above contribute to the estimates in Table 4B1). Volumetric capacity for saline and oil & gas reservoirs was calculated at 10% efficiency. In a volume of sedimentary rock, the intergranular space is known as porosity, the pore space. This pore space represents some portion of the rock volume expressed as a percentage and is occupied by fluids, water or oil, or gases. Storage efficiency with respect to captured CO_2 is the percentage of pore space that may be occupied by the injected CO_2. A 10% storage efficiency means that the sequestered CO_2 will only occupy 10% of the pore space for that particular oil & gas reservoir or saline formation. While an organic rich shale will have some storage capacity within its fracture system, a much larger volume of captured CO_2 may be stored by adsorption onto the clay minerals and organic matter. Storage capacity for the coals is also an adsorption process. There are several factors that can impact sequestration potential for organic rich shales and coals. The potential storage for each was calculated at 10% efficiency as

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[101] Ibid 90

applied to saline and oil & gas reservoirs. It should be noted that only unmineable coal seams are considered in these estimates of storage potential in coal for captured CO_2.

NETL has combined the work of the seven regional partnerships in the Carbon Sequestration Atlas of the United States and Canada[102]. This publication posts the potential storage for captured CO_2 for each state (or province) in the partnerships as well as an estimate for offshore capacity. The storage potentials posted in the Atlas represent a high-low range reflecting storage efficiency for saline reservoirs of between 1 and 4 percent. A recent analysis of storage efficiency by the IEA confirms the 1 to 4 percent range used by NETL[103]. The impact of the efficiency value on storage potential, a resource that needs to be proven, is apparent in Table 1. NETL did not apply storage efficiency to oil & gas reservoirs. Instead, CO_2 storage potential is calculated using volumetric and production based methods. Oil & gas storage potential is a single value in NETL's Atlas. Since coals retain CO_2 by adsorption, storage potential for unmineable coal seams is a range based on pressure gradient for a particular basin, average formation temperature, and coal rank if available. The Atlas did not consider shale storage potential. The range of storage potential in Table 4B1 is due to saline storage potential as unmineable coal seams only contribute about 1 to 3 percent of onshore lower 48 potential.

Table 4B1: Potential Storage Capacity for Captured CO_2 in West Virginia

	Shales	O & G	Coal	Saline	Total	Efficiency
MRCSP	19,000	600	110	41,100	60,810	10%
NETL (low)	-	1,353	177	3,343	4,873	1%
NETL (high)	-	1,353	177	13,463	14,994	4%

All values are in million metric tons (NETL's Atlas 3rd edition due Nov 2010).

As required in the Energy Independence and Security Act (EISA) of 2007, USGS will assess the onshore storage potential for captured CO_2.[104]

Except for oil & gas reservoirs, the area over which these storage estimates apply is the geographic extent of each horizon evaluated. As noted earlier, these values represent a resource that needs to be proven which will be accomplished to a large degree by the characterization process. Like any other resource such as coal or oil, while proving a resource provides a more reliable value upon which to base economic decisions, this value is usually a reduction of the earlier resource value.

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[102] NETL, 2008, Carbon Sequestration Atlas of the United States and Canada. Found at: http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlasII/index.html

[103] IEA Greenhouse Gas R&D Programme (IEA GHG), "Development of Storage Coefficients for CO_2 Storage in Deep Saline Formations", 2009/13, October 2009.

[104] USGS, 2009, Development of Probabilistic Assessment Methodology for Evaluation of Carbon Dioxide Storage, OFR 2009-1035.

IV.B.2. Refinements of estimates

IV.B.2.a. Information needed

Storage capacity in any potential reservoir is a function of porosity or void space found within any suitable rock. Permeability connects the pore space and allows flow through the reservoir. This available porosity and permeability has a top and bottom (height), a net portion of the whole formation or stratigraphic interval within which it occurs. This available porosity and permeability also is not uniformly distributed over the areal extend of the formation or stratigraphic interval within which it occurs. Estimates of storage potential presented in this report assume an areal distribution of porosity over the extent of the prospective formation or stratigraphic interval. That is why these resource values need to be proven. It will take time, money and acquisition of suitable data.

Pore space is not empty. In oil & gas reservoirs there is some percentage of oil, gas and water in each pore space and below the oil/water contact the pore space is 100 percent water with some amount of dissolved solids. Pore space in saline formations or reservoirs will be fully occupied by water with some amount of dissolved solids. Knowledge of what is occupying the pore space in a prospective storage reservoir will be essential to reservoir modeling for site characterization and developing an MVA program. This critical reservoir information is provided by a combination of drilling data, core data, wireline or geophysical log data and seismic data.

IV.B.2.b. Unknowns

Good permeability is essential for injectivity and good porosity is essential for storage capacity. The use of ‘good’ here is relative, using ‘suitable’ or ‘sufficient’ would have sufficed but all illustrate the elusive nature of porosity, permeability and injectivity. We know that high numerical values for each are what every storage field operator is looking for. A souce will capture so many tonnes of CO_2 day in and day out. Every captured tonne needs to be sequestered and it is up to the storage field operator to provide the injection rate necessary. If permeability values are low then more injection wells will be need or more height over which to inject, a greater net injection interval. A second horizon for injection or another field area may be necessary to meet the needs of a source.

How these two critical variables, porosity and permeability, are distributed over any geographic extent is determined by reservoir architecture reflecting the depositional environment and post-depositional processes that can modify porosity and permeability of the host sediment, clastic or carbonate. Oil & gas reservoirs have some number of wells drilled within and around their boundaries that can provide some sense of reservoir architecture. Saline reservoirs will probably have less well control with which to determine reservoir architecture. Drilling evaluation wells and acquiring seismic data will provide critical information and both will be part of the site characterization process. The quality and areal extent of the seal may be less problematic in that bulk characterizations can satisfy concerns on seal integrity. Even though a site might be well characterized, sufficient to gain a permit, there will always be some level of geologic uncertainty.

IV.B.2.c. How much CO_2 needs to be stored

Amount generated by a power plant

A 1,000 MW bituminous pulverized coal power plant, operating at 85 percent capacity and capturing 90 percent of its carbon dioxide emissions will produce 6.24 million tonnes of

Table 4B2: List of emission sources with annual emissions in metric tons

Plant / Facility	Company	Industry Sector	County	Annual CO_2 Emissions
John E Amos	**Appalachian Power Co.**	**Power**	**Putnam**	**15,231,230**
Harrison	**Monongahela Power Co.**	**Power**	**Harrison**	**12,862,820**
Mt. Storm	**Dominion Virginia Power**	**Power**	**Grant**	**10,961,580**
Mitchell	**Ohio Power Co.**	**Power**	**Marshall**	**7,973,820**
Mountaineer	**Appalachian Power Co.**	**Power**	**Mason**	**7,663,480**
Pleasants	**Monongahela Power Co.**	**Power**	**Pleasants**	**7,224,740**
Fort Martin	**Monongahela Power Co.**	**Power**	**Monongahela**	**6,895,640**
Big Sandy[1]	**Kentucky Power Co.**	**Power**	**Lawrence**	**6,048,400**
Philip Sporn	**Central Operating Co.**	**Power**	**Mason**	**5,383,580**
Weirton Steel	**Weirton Steel Corp.**	**Iron & Steel**	**Weirton**	**3,957,880**
Kammer	**Ohio Power Co.**	**Power**	**Marshall**	**3,449,410**
Mingo Country CBM	**CONSOL**	**Gas Processing**	**Varney**	**2,836,420**
Kanawha River	**Appalachian Power Co.**	**Power**	**Kanawha**	**2,338,270**
Albright	**Monongahela Power Co.**	**Power**	**Preston**	**1,760,340**
Willow Island	**Monongahela Power Co.**	**Power**	**Pleasants**	**1,367,590**
Martinsburg	**Capital Cement Corp.**	**Cement**	**Martinsburg**	**831,020**
Grant Town Power Plant	**Edison Mission Power**	**Power**	**Marion**	**790,850**
Rivesville	**Monongahela Power Co.**	**Power**	**Marion**	**608,430**
Natrium Plant	**PPG Industries Inc.**	**Power**	**Wetzel**	**593,320**
Kenova	**MarkWest Hydrocarbon Inc.**	**Gas Processing**	**Wayne**	**498,350**
Copley Run		**Gas Processing**	**Lewis**	**491,278**
Hastings	**Dominion Resources**	**Gas Processing**	**Wetzel**	**486,190**
North Branch	**Dominion Virginia Power**	**Power**	**Grant**	**485,310**
Morgantown Energy Facility	**Dominion Energy NUGs**	**Power**	**Monongahela**	**448,840**
Alloy Steam Station	**Elkem Metals Co.**	**Power**	**Fayette**	**297,990**
West Union		**Gas Processing**	**Doddridge**	**200,973**
Schultz		**Gas Processing**	**Pleasants**	**111,653**
Ergon Refining		**Refining**	**Newell**	**110,780**
Cobb[2]	**MarkWest Hydrocarbon Inc.**	**Gas Processing**	**Kanawha**	**101,290**
Total Annual Emissions				**102,011,474**

1 - Kentucky Power Co. Big Sandy plant is on the Kentucky side of the Big Sandy River.

2 – Cobb Gas Processing plant is listed twice

carbon dioxide in a year.[105] On a daily basis for sequestration, this is about 100,000 barrels of CO_2 per day for injection. In 2009, West Virginia oil production averaged about 155,000 barrels of oil per month or 5,000 barrels of oil per day.[106] If this 1,000 MW plant has a 50 year project life, then about 1.8 billion barrels of CO_2 will need to be sequestered. In the world of oil & gas production, this is a giant field (>500 million barrels recoverable) and they are not commonly found.

In the second edition of the Sequestration Atlas, 29 sources in West Virginia emit about 102.0 million tonnes (597 million barrels) of CO_2 per year (Table 4B2). The table was assembled by the MRCSP. Two interesting points to make regarding the plant list: 1) the Big Sandy power plant is across the Big Sandy River from West Virginia in Kentucky and 2) the Cobb Gas Processing plant was listed twice while the owner, MarkWest, only mentions on site on their company web site. With an estimate storage resource potential between 4,873 and 14,994 million tonnes, West Virginia has between 47 and 147 years of injectivity.

Including Kentucky Power Company's Big Sandy power plant on a list of emissions for West Virginia highlights an important consideration regarding CCS. Emissions do not respect political boundaries and neither will CO_2 plumes in the subsurface. There are several power plants on the West Virginia side of the Ohio River. West Virginia can only address what it can control but it will be important to work with adjoining states.

The area needed for storage

Estimating the area needed for a storage field is difficult. Because of the buoyancy of CO_2 relative to saline formation fluids, the standard model used in modeling CO_2 injection displays an inverted cone with the accumulation of the CO_2 gathering at the top of the reservoir against the seal (Figure 4B4). This simple model assumes a homogeneous reservoir that ignores geologic variability of reservoir architecture.

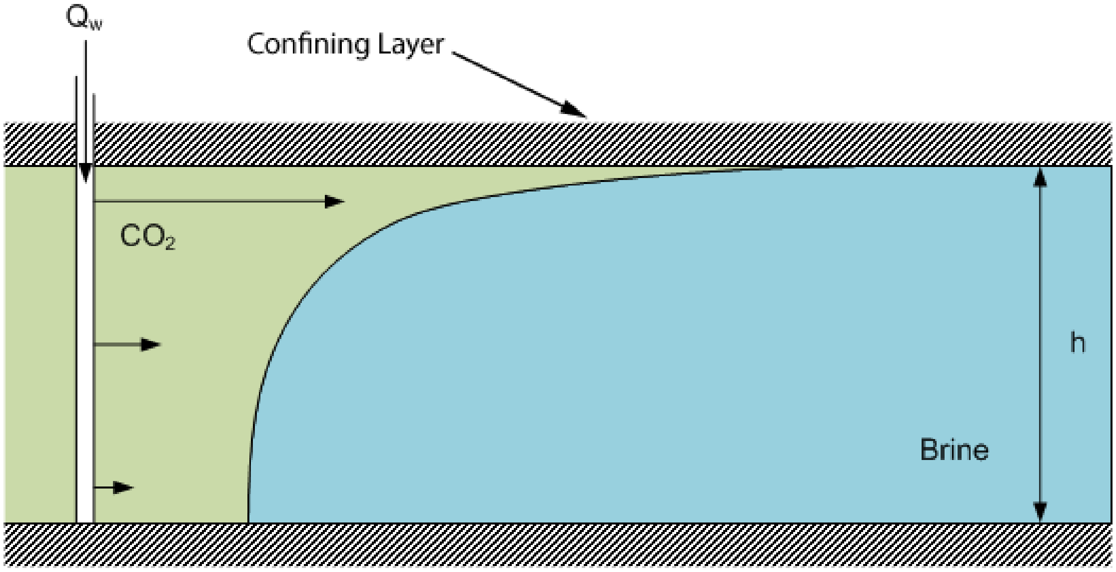

Figure 4B4. Simple model of CO_2 injection into a storage reservoir.(unknown source) (Q_w = injection rate, h = height of reservoir interval)

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[105] MIT, 2007, The Future of Coal. Found at: http://web.mit.edu/coal/

[106] EIA: http://tonto.eia.doe.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=MCRFPWV1&f=M

A simple model as illustrated in Figure 4B4 will require more acreage to secure the rights to the pore space for the top of the plume than the base of the plume. Any reservoir will have internal permeability barriers that will compartmentalize the porous and permeable space available for storage. If the simple model in Figure 4B4 included several permeable barriers acting as internal traps within the reservoir then the area of the plume would be reduced. Modeling done by Advanced Resources International suggests that the plume area could be reduced by 60% from that of the simple model in Figure 4B4.[107]

An important consideration here is that the stratigraphic section present in West Virginia has multiple horizons with storage potential. Utilizing each of these horizons for sequestration of captured CO_2 will create a stacking of storage reservoirs, one above the other or overlapping to some extent. This is true for oil and gas fields, especially for structurally trapped hydrocarbons. Discoveries on structure are first made in the shallow reservoir but upon drilling deeper, oil and gas is often encountered in lower reservoirs. Stacked and/or overlapping reservoirs will help reduce the areal extent of sequestered CO_2 plumes has measured at the surface. Important considerations here will be the location of surface facilities, wells and monitoring sites as these plumes expand with injection.

The Carbon Sequestration Working Group (CSWG) in Wyoming did some modeling utilizing a value of so many million tonnes of CO_2 sequestered per square mile.[108]. Modeling done by the Wyoming State Geological Survey suggested a plume area factor of 0.133 mi^2 per million tonnes CO_2 injected. The CSWG cited a NETL value of 0.75 mi^2 per million tonnes of CO_2 injected but they thought that this was too conservative for their purposes and adopted a value of 0.15 mi^2 per million tonnes injected, an 80 percent reduction in area needed to cover the plume in the subsurface. As noted above, modeling done by ARI shows that multiple permeability barriers within the reservoir can reduce the areal extend of a CO_2 plume by 60 percent. How many tonnes of CO_2 will be stored per square mile will end up being formation specific. However, until these hard values are determined, the above mentioned values will be used to do 'back of the envelop' estimates and evaluate prospective areas for further site characterization. Which value or what value to use will be up to whoever is conducting the evaluation.

Combining some factors already presented, one well evaluating 25 mi^2 and storage factors of either one million metric tons per 0.15 mi^2 or 0.75 mi^2, one can see how well the storage needs are met for three power plants of different output and emissions (Table 4B3). The two storage factors, one million metric tons (1Mt) per 0.15 mi^2 or 0.75 mi^2, can reflect either a change in porosity or change in height or thickness of the injection-storage interval or even a change in storage efficiency. Looking at a potential storage field covering 25 mi^2; if this field had a storage factor of 1Mt per 0.15 mi^2 it will hold 166 Mt but only 33 Mt with a storage factor of 0.75 mi^2. The difference between these two storage factors is eight years of injection activity for the John Amos plant. For the Willow Island plant, the 0.15 mi^2 storage factor over 25 mi^2 can easily accommodate the emissions of for a 30 year plant life; for the 0.75 mi^2factor a second storage field will be required to sequester the 42 Mt of emissions. Plant output for the Willow Island plant is about the same as the average boiler size for the coal fired electric power fleet.[109] It was mentioned earlier that it will cost a little over seven million dollars for one evaluation well

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[107] Kuuskraa, V., 2009, Using Reservoir Architecture to Maximize CO2 Storage Capacity at SECARB's Mississippi Test Site; presented at GHGT-9, Washington, D.C., November 2009.

[108] Report and Recommendations of The Carbon sequestration Working Group to the Joint Minerals, Business and Economic Development Committee and the Joint Judicial Committee of the Wyoming State Legislature, September, 2009. Found at: http://deq.state.wy.us/out/downloads/1%20FinalReport081909.pdf

[109] Across the United States, there are 1,445 coal fired boilers for electric power generation with a combined nameplate capacity of 337,300 MW[109], an average of about 233 MW per boiler. EIA: http://www.eia.doe.gov/cneaf/electricity/epa/epat1p2.html

and 3-D seismic to cover 25 mi^2. For the Phil Sporn plant, this should just cover site characterization if the storage factor is 1 Mt per 0.15 mi^2. With the smaller storage factor site characterization cost increase five times for the Phil Sporn plant.

Table 4B3: Years of injection for emissions of various plants**.**

Plant Name	**Power MW**	**CO_2 Emissions Mt/yr**	**CO_2 Emission 30 yr Plant Life Mt**	**Years injection – 25 mi^2 area**	
				[0.15mi^2] [166Mt]	**[0.75mi^2] [33 Mt]**
John Amos	2,932	15.2	456	10.9	2.2
Phil Sporn	1,105	5.4	162	30.7	6.1
Willow Island	213	1.4	42	118.5	23.5

Data needed for better estimates of potential storage capacity

The challenge here is to estimate the amount of square area that will need to be characterized and permitted in order to secure the rights to the pore space for sequestration over the life of a particular project. The position and stability of a three dimensional plume of CO_2 in the subsurface is related back to two dimensional surface area. The best set of data that any CO_2 storage field operator will have will be at the end of operations when injection is completed and the field is decommissioned. At this point in time, one know for certain how much CO_2 is sequestered and its areal extent. Thirty or fifth years earlier, the level of certainty for both was much less yet projections were made based on modeling incorporating data on hand at the time. This early information was presented to a regulatory body in order to gain a permit to develop and operate a CO_2 storage field.

Essential data necessary for better storage calculations is porosity, permeability, height of injection interval, areal extend of porosity and permeability and how much pore space will the CO_2 occupy, the efficiency factor. As noted earlier, initial data sources will include the USGS and state geological databases, academic studies and publication, and professional publications. Saline formations are estimated to provide for most of the sequestration yet these formations will have the smallest database. Except for the CO_2 efficiency factor, much to most of this data can be found for oil & gas reservoirs. For saline formations this data will be more difficult to assemble.

Key information is porosity and permeability. Porosity can be calculated from well logs but permeability measurement requires a rock sample in the form of a core. Both require a well to have been drilled or to be drilled. If this information doesn't exist then a well will have tgo be drilled. Drilling a well requires a permit which requires a drilling unit which requires acreage or leases. Is it worth drilling the well before committing to site characterization? Is there any seismic data to support further work on the prospect? An important step here is moving from initial assessment to site characterization as this step will require an investment of millions to tens of millions of dollars. Making an investment in a subsurface resource requires sufficient data and information to assure investors that the risk is acceptable, that there is an acceptable probability that the project will go forward.

It is widely considered that a CO_2 storage field developer will have to secure the rights to utilize subsurface pore space for sequestration per state regulation. Securing this right is a strategic decision upon which to make an investment. How much area to secure to establish rights to pore space is problematic because the actual extent of the subsurface saline reservoir is unknown. A right of access will have to be established for site characterization to provide access for seismic data acquisition, drilling of a well or wells and initial MVA activity. Some seismic

Vibroseis coverage can be acquired along public highways. Knowing how much area for which to secure pore space rights at the beginning of the process of developing a CO_2 storage field may come down to individual "rule of thumb," the storage factor (see Table 4B3). The ability to assess economic potential for CO_2 sequestration and proceed with site characterization and securing the rights to subsurface pore space over a broad areal extent will depend on the quality of geologic data available for initial assessment of subsurface potential.

Reservoir assumptions impact estimates of potential storage capacity. Dominant reservoir modeling to date assumes an open reservoir where the CO_2 pressure front does not encounter a boundary resulting in increasing injection pressures. The formations utilized for injection at Sleipner and at In Salah are considered open reservoirs. While some consider most reservoirs closed, many believe reservoir have more open than closed characteristics.[110] A solution to maintaining constant injection pressure is the co-production of formation waters during injection, providing pressure relief and creating an open reservoir. The Wyoming State Geological Survey (WSGS) modeled co-production of formation waters during sequestration operations.[111] WSGS model was able to render about 80 percent of the produced water potable, injecting the reaming 20 percent into the subsurface. They noted this potable water has agricultural or residential potential or can possibly be released to streams or rivers. Co-production of formation waters adds another level to operations requiring additional capital, raising operating expenses and requiring additional permits.

IV.B.3. Possible Failure of Sequestration

IV.B.3.a. Mechanisms of failure

Carbon dioxide could escape from the subsurface through a well casing failure, a well cement failure, a failure at the well head, a well blowout, improperly reworked (workover) wells, improperly abandoned or unmarked wells or a geologic path such as a fault or fractures or a combination. A well failure appears to be one of the more likely causes of a release of CO_2 from underground storage. Pipeline failure presents another possibility of release of CO_2 to the atmosphere. CO_2 pipelines will deliver the CO_2 to the storage field and a field pipeline network will distribute the CO_2 to the injection wells. Inadvertent release of captured CO_2 can range from minimal and possibly undetectable to catastrophic. The ability to detect leakage from a storage reservoir will depend on the level of resolution of the MVA technology and vigilance of the operator. Preventing catastrophic release from pipelines or wells will depend mostly on the quality of the trained personnel operating these facilities.

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[110] Economides, M.J. and Ehlig-Economides, C.A., 2009, Sequestering Carbon Dioxide in a Closed Underground Volume, SPE Paper 124430, Presented at SPE ATCE meeting in New Orleans, October 2009.
Dooley, J.J. and Davidson, C.L., 2010, A Brief Technical Critique of Ehlig-Economides and Economides 2010: "Sequestering Carbno Dioxide in a Closed Underground Volume", PPNL-19249

[111] Surdam, R.C., Zunsheng, J., Stauffer, P., and Miller, T., 2010, An integrated strategy for carbon management combining geological CO_2 sequestration, displaced fluid production, and water treatment. Challenges in Geologic Resource Development No. 8, Wyoming State Geological Survey.

Pipelines

Table 4B4: Pipeline Incidents Statistics for the United States from 1994-2006

Pipelines	**Natural Gas**		**Hazardous Liquids**	**CO_2**
	Transmission	**Grid**		
Number of Incidents	1,241	1,707	2,048 (1)	18
Number of Fatalities	29	223	24	0
Number of Injuries	112	765	101 (2)	0
Property Damage	$745 million	$780.9 million	$1,006 million	$1.15 million
2006 Mileage (3)	320,073	1,214,439	160,873	3,769

Source: *PHMSA Annual and HL Accident and Gas Incident Reports as of October 15, 2007.*

(1) The reporting criteria changed on February 7, 2002, adding small spills down to five gallons. For continuity with past trending, the data from accidents used in our statistical summary occurring after this date includes only accidents meeting the reporting criteria: accidents with gross loss greater than or equal to 50 barrels; those involving any fatality or injury; fire/explosion not intentionally set; highly volatile liquid releases with gross loss of five or more barrels; or those involving total costs greater than or equal to $50,000.

(2) Does not include 1,851 injuries that required medical treatment reported for the October 1994 accidents that were caused by severe flooding near Houston, Texas.

(3) Transmission mileage includes transmission and gathering miles. Distribution miles include distribution main miles only.

The total miles of CO_2 pipelines is 0.25 percent of the total natural gas pipeline miles, both transmission and grid pipelines. Natural gas grid pipelines are the distribution segment of the system, found in areas of higher population density than transmission lines which are cross-country. The higher number of injuries and fatalities for grid natural gas pipeline reflect their proximity to more urban areas. Natural gas pipelines are designed to bring their product from the reservoir to the consumer. The conceptual framework of a CO_2 pipeline network is opposite that of the natural gas pipeline network. Carbon dioxide pipelines will transport their product from a source that may or may not be in an urban area to a storage field located in areas of low population density. The grid portion of the CO_2 pipeline network will be in the storage field or among the storage fields. The captured CO_2 will be removed from the 'market' area and returned to the field.

To accomplish the task of significantly reducing CO_2 emissions envisioned for CCS technology, the present CO_2 pipeline network will be greatly expanded. Simple modeling studies done to date suggest a pipeline network of between 6,000 and 36,000 miles transporting as much as 54 Gt of captured CO_2.[112] The actual CO_2 pipeline network could be double the mileage estimate of these studies, even triple yet still be less that the overall network of that for hazardous liquids and still only a fraction of the natural gas pipeline network. Unlike natural gas, CO_2 is not flammable and does not represent an explosive risk, an important point that should reduce the level of risk associated with these pipelines. Carbon dioxide will be transported under higher pressures than that for natural gas to maintain the supercritical or dense phase state. A common accident for pipelines is a puncture due to construction activity. The sudden release of pressure due to puncture of a CO_2 pipeline will be 'explosive' in character but not flammable. There is considerable potential of harm for those in the immediate area. However, the potential for injuries associated with a much longer CO_2 pipeline network should

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[112] Carbon Sequestration & Storage: Developing a Transportation Infrastructure. Prepared for the INGAA Foundation, Inc. by ICF International. February 2009. Available at: http://www.ingaa.org/cms/31/7306/7626/8230.aspx.

Dooley, JJ, RT Dahowski, and CL Davidson. "Comparing Existing Pipeline Networks with the Potential Scale of Future U.S. CO_2 Pipeline Networks." Presented at 9th International Conference on Greenhouse Gas Control Technologies on November 16-18, 2008, at the Omni Shoreham Hotel in Washington DC. Available at: http://www.sciencedirect.com/science/article/B984K-4W0SFYG-7D/2/a0db295a18b4fe6099846c2ab2738bb0.

not appreciably increase, the possibility for incidents and an increase in fatalities even less. This will depend on urban proximity to the greatly expanded CO_2 pipeline network yet the non-flammable nature of CO_2 should keep the potential for fatalities lower than that for natural gas pipeline incidents.

In testimony before the House Subcommittee on Energy and the Environment, Ian Duncan of the Texas Bureau of Economic Geology stated "It has been suggested in the literature that the incident rate CO_2 pipelines can be estimated from that for natural gas pipelines. USDOT statistics recorded ten incidents of CO_2 pipelines failures. The DOT data suggest that these incidents were caused by: relief valve failure (four incidents); weld, gasket, valve packing failure (three); corrosion (two); and outside force (one). Similar DOT statistics for a very large data set of natural gas pipelines in the US showed the reasons for failure as: outside force, including damage by contractors, farmers and utility workers (35%); corrosion (32%); other, such as vandalism, train derailment and improper operation of manual valves (17%); weld and pipe failures (13%); and operator error (3%). There is good reason to believe that the rate of incidents (rupture, puncture etc) for CO_2 and natural gas pipelines should be the same if CO_2 sequestration is implemented on a large scale. It is important to note that even if the rates of incidents for CO_2 and natural gas pipelines begin to look the same in the future; my judgment is that the risk will still be lower for CO_2 pipelines (a conclusion that appears to be increasingly supported by governmental reports and academic studies). I also believe that the risk from rupture of CO_2 pipelines is the largest risk facing a future CO_2 sequestration industry. If this conclusion proves correct then this places strong bounds on the risks of geologic CO_2 sequestration. Ultimately the risk from pipelines depends on: siting of the pipelines (risks are site specific); operation of the pipelines to minimize possible corrosion (particularly the current industry focus on keeping the water levels in the CO_2 below saturation); and implementation of effective risk management and mitigation plans."[113] Note that in the testimony, there is only one incident of outside force rupturing a CO_2 pipeline while this category accounts for 35 percent of natural gas pipeline failures. Although it may be more rural relative to the natural gas pipeline network, expanding the CO_2 pipeline network will expose it to more opportunities of outside force rupturing.

The Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) has had, since 1988, oversight authority of transportation of CO_2 by pipeline.[114] Carbon dioxide is non-combustible and non-toxic. It is heavier than air. When concentrated it can pool near the ground, displacing oxygen. With time it dissipates, forming a cloud. Because of these properties and the fact that CO_2 is transported as a compressed gas and/or in high concentrations, it is classified as a hazardous material and subject to the Hazardous Material Transportation Laws and DOT's implementing laws. Pursuant to legislation establishing DOT's oversight of CO_2 pipeline, the Department extended its existing hazardous liquids pipeline rules to CO_2 pipeline operations.[115]

PHMSA works closely with certain state agencies to provide oversight of CO_2 pipeline network. Their "integrity management regulations, which currently apply to transmission pipelines (liquid and gas), require operators to conduct risk assessments of the condition of their pipelines; develop and implement risk control measures to remedy safety problems, worst first; and evaluate and report on program progress and effectiveness. Under integrity management

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[113] Ian Duncan, 2009, Regarding The Future of Coal under Climate Legislation; Carbon Sequestration Risks, Opportunities, and Learning from the CO2-EOR Industry. Testimony before the The U.S. House Committee on Energy and Commerce, Subcommittee on Energy and the Environment, March 10, 2009.

[114] Krista L. Edwards, Deputy Administrator, Pipeline and Hazardous Materials Safety Administration, Department of Transportation, testimony before the Committee on Energy and Natural Resources, United States Senate, January 31, 2007.

[115] Ibid

programs, operators are identifying and repairing pipeline defects before they grow to failure, producing steady declines in the numbers of serious incidents."[116]

PHMSA "operates five regional pipeline safety offices and is authorized to employ 111 inspection and enforcement professionals for fiscal year 2008. In addition to compliance monitoring and enforcement, PHMSA's regional offices respond to and investigate pipeline incidents and participate in the development of pipeline safety rules and technical standards. Our regional offices also work closely with PHMSA's State program partners, which employ approximately 400 pipeline inspectors and directly oversee the largest share of the U.S. pipeline network, including most intrastate pipelines. Under our Congressionally-authorized Community Assistance and Technical Services (CATS) program, PHMSA's regional offices provide safety-focused community outreach and education. With the current wave of pipeline expansion, and increasing commercial and residential development around existing pipelines, the CATS program is serving a vital role in educating the public about pipeline safety and encouraging risk-informed land use planning and safe excavation practices."[117]

The WVDEP or another agency may want to coordinate CO_2 pipeline oversight efforts with the Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA). PHMSA already has oversight relationships with states where CO_2 pipelines are in operation.

Well failure

Well failure, either leakage behind casing or an actual blowout, is a second avenue of release of CO_2 to the atmosphere. A change in pressure in the well annulus will alert the operator to a potential leak requiring a closer examination of the well and possibly a well workover. A workover is when a well is opened for repairs and for wells open to high pressure reservoirs this presents the possibility of a well blowout. Carbon dioxide injection wells are high pressure wells. Several blowouts have occurred during operations of West Texas EOR fields from production and injection wells.[118] Release of CO_2 from these blowouts is estimated to range from less than 1 mmcf per day to 10 mmcf per day (~53 to 530 metric tons per day).[119] Cause of these blowouts range from corrosion, leaking gaskets, valves left open or mechanical failure. No injuries of fatalities occurred due to these well blowouts. A carbon dioxide well blowout presents unique challenges. These are high pressure wells and the sudden release of pressure is a high velocity phenomenon that quickly clears out the well. The sharp drop in pressure and gas expansion results in adiabatic cooling. The released CO_2 quickly drops below its triple point providing for the formation of dry ice particles.[120] With anticipate growth of the CO_2 injection business, proper training of CO_2 storage field personnel as well as well workover and well drilling crews is critical for safe operations as well as preventing inadvertent release of CO_2.

The USEPA has published a Technical Support Document: *Vulnerability Evaluation Framework for Geologic Sequestration of Carbon Dioxide*. This document provides a series of evaluation matrixes covering all aspects involved in developing a storage field prospect with the goal of minimizing risk, the probability of sequestered CO_2 migrating beyond its intended boundaries. The USEPA's proposed Class VI injection rules will support this effort. NETL is publishing a series of 'best practices' manuals covering all aspects of CO_2 sequestration. The

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[116] Ibid
[117] Ibid
[118] Duncan, I.J., Nicot, J-P., and Choi, J-W, 2008, Risk Assessment for future CO2 Sequestration Projects Based CO_2 Enhanced Oil Recovery in the U.S. Elsevier. Available online at www.sciencedirect.com
[119] Skinner, L., 2003, CO_2 blowouts: An emerging problem. World Oil, January 2003, p. 38 - 42
[120] Ibid

USEPA will also develop 12 Technical Guidance documents to inform potential operators, regulators and the public on the various aspects of CO_2 sequestration. West Virginia has established primacy for issuance of permits under USEPA's UIC program. This will most likely continue for Class VI permits. This permit will require construction standards for injection wells.

Other failure mechanisms

Release of CO_2 to the atmosphere by means other than via a well or pipeline failure is an important consideration. An often cited incident is the loss of life associated with large release of CO_2 from Lake Nyos in Cameroon, Africa. In August of 1986, a large volume of CO_2 was released from the lake. This cloud of CO_2 moved downhill from the lake, suffocating about 1,700 people. To the southeast, Lake Monoun had a smaller release resulting in 37 fatalities.[121] Both lakes are in the volcanic region of Cameroon. The CO_2 is from the magma beneath the lakes. This situation is not characteristic of West Virginia or Appalachian Basin geology.

Other potential migratory pathways for CO_2 are old well bores, faults that cut to or near the surface or fracture patterns. A potential danger here is that CO_2 may migrate along these pathways and accumulate in confined space, for example the cellar of near-by house or a structure in or near the storage field. A leak from a Kansas natural gas storage field migrated via an old well bore through the vadose zone (shallow subsurface above the water table) into the cellars of buildings in near-by town.[122] With sufficient accumulation, the natural gas was ignited resulting in several fatalities and destruction of the building. Although non-flammable, CO_2 in sufficient concentration will cause asphyxiation as occurred at Lake Nyos.

Out in the open, it may be difficult for CO_2 to build up to dangerous levels. Monitoring of one of the well blowouts mentioned above recorded CO_2 levels of approximately 4750 ppm (0.475%) 200 feet away and these accumulations dissipated in about 30 minutes.[123] In Utah, the Crystal Geyser is a CO_2 charged eruption of cold waters via an old wellbore. The well was drilled in 1935 for oil exploration. While this well represents an example of poor oversight of a well permit and improper plugging of an abandoned well, it is a tourist attraction and presents no apparent danger.[124]

Natural gas storage in aquifers provides examples on the challenges and potential failure of these types of reservoirs. In 2008, there were 401 active natural gas storage fields: 34 salt caverns, 43 aquifer and 324 depleted oil & gas fields.[125] Total amount of gas in storage, 5.9 TCF, represents about 120 million metric tons (assuming pure methane)[126], slightly more than the 102 million metric tons of annual CO_2 emissions for West Virginia. As the numbers suggest, aquifer natural gas storage is much less desirable than depleted oil & gas reservoir storage. Depleted oil & gas reservoirs are known traps. Development of aquifer natural gas storage has a few drawbacks. Its geological characteristics are not as thoroughly known, as with depleted reservoirs. Some exploratory wells may need to be drilled to gather rock data (wireline logs and core samples), seismic data may be required to confirm the structural configuration of the trap

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[121] Trying to Tame the Roar of Deadly Lakes, Marguerite Holoway, New York Times, February 27, 2001. Found at: http://www.nytimes.com/2001/02/27/science/trying-to-tame-the-roar-of-deadly-lakes.html?sec=&spon=&partner=permalink&exprod=permalink. Retrieved April 17, 2010

[122] Fredlund, D.F., 2008, The Evolving Regulatory Freamework to Govern Carbon Sequestration, presented at the 7th Annual Conference on Carbon Capture & Sequestration, Pittsburg, Pa.

[123] Ibid, 132

[124] Crystal Geyser, Wikipedia: http://en.wikipedia.org/wiki/Crystal_Geyser. Retrieved April 18, 2010.

[125] EIA, Underground Natural Gas Storage Capacity: http://www.eia.doe.gov/dnav/ng/ng_stor_cap_dcu_nus_a.htm

[126] Lawrence Berkeley National Laboratory article on "Relevance of Underground Natural Gas Storage to Geologic Sequestration of Carbon Dioxide" by Marcelo J. Lippmann and Sally M. Benson.

and injectivity test may be necessary.[127,128] It can take up to four years to develop an aquifer natural gas storage field, twice the time needed of a depleted reservoir,[129] and a further ten or more years before the full extent of storage capacity is realized as the natural gas bubble is increased in area. Development of aquifer storage is a more exploratory procedure than for depleted reservoirs which impacts the economics for these particular projects.

Aquifer natural gas storage is a high pressure operation, exceeding hydrostatic but not fracture gradient pressures, required to displace formation waters and represents a much higher storage efficient, approaching 100 percent, than what is expected for CO_2 storage (Table 4B1). This is necessary to create the bubble and provide for high delivery rates when the stored gas is produced and shipped to market. The high pressure nature of natural gas storage is the main cause of leakage.[130] Most of the leakage is through well failure although some natural gas may be lost at the margins of the bubble. Some operations will drill collector wells to recover natural gas that has escaped the reservoir.[131]

Natural gas storage in aquifers typically is done at a site that appears to have appropriate structure and a trap to contain hydrocarbons. However, since no hydrocarbons were initially discovered in the formation, the nature and quality of the trapping mechanism is not well established. It raises questions about the containment and sealing capability of the apparent trap and the integrity and tightness of the caprock. The Manlove Storage Field in Champaign County, Illinois initially injected natural gas into a St. Peter sandstone reservoir. Natural gas was discovered in the overlying glacial drift shortly after injection began. Natural gas was then injected into the deeper Galesville sandstone but leakage was also detected. Drilling deeper, injection of natural gas was finally secured in the Mt. Simon sandstone because the overlying Eau Clair formation provided a suitable seal.[132]

IV.B.4. Kinds of impacts

IV.B.4.a Groundwater contamination

Regulations Protecting Groundwater

The protection of groundwater throughout a CCS project is vital to the water resources in West Virginia. The current regulations that govern the protection of groundwater include: West Virginia Code, Chapter 22, Article 11 (Water Pollution Control Act) Section 8, Chapter 22 Article 12 (Groundwater Protection Act), and Legislative Rules, Title 47, Series 13 (Underground Injection Control) Sections 12 and 13. The priority for all of these rules is the protection of groundwater.

Risks to Groundwater via CCS

Risks to groundwater quality arise from the potential for CO_2 to mobilize organic or inorganic compounds, acidification and contamination by trace compounds in the CO_2 stream, intrusion of native saline groundwater into drinking water aquifers, and the potential for the CO_2 to displace subsurface fluids. The probability of many of these risks occurring may be decreased by a thorough site characterization, sound injection well construction and sufficient monitoring.

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[127] Ibid

[128] Storage of Natural Gas, found at: http://www.naturalgas.org/naturalgas/storage.**asp**

[129] Ibid 140, 141

[130] Ibid 140

[131] Ibid 141

[132] Midwest Geological Sequestration Consortium, 2005, An assessment of Geological Carbon Sequestration Options in the Illinois Basin, Phase I Final Report. Found at: http://sequestration.org/publish/phase1_final_rpt.pdf

IV.B.4.b. Permit Requirements

In addition to the rules and regulations which protect groundwater, there are other factors that CCS permits will utilize to protect groundwater. A thorough characterization of the injection site and a geological investigation of the injection formations will aid in the identification of potential avenues for groundwater contamination. Adequate confining zone formations are also necessary to limit the possibility of CO_2 migration into the lower most drinking water aquifer.

Each proposed CCS site should be considered on an individual basis. For instance, the AEP Mountaineer Project has over a thousand feet of confining zone formations between the injection zone and the lower most aquifer. At another site there may only be 500 feet of confining zone formations and be equally capable of protecting groundwater. Using the site characterization and the geological investigation a decision will be made to determine if the vertical separation is sufficient.

Groundwater Quality

USDW is an aquifer that "supplies any public water system, or contains a sufficient quantity of ground water to supply a public water system and currently supplies drinking water for human consumption or contains fewer than 10,000 milligrams/liter of total dissolved solids (TDS)"[133]

Table 4B5: Classification of Water based on Total Dissolved Solids[134]

Water Classification	TDS milligram per liter
Fresh	0 – 1,000
Brackish	1,000 – 10,000
Saline	10,000 – 100,000
Brine	➢ 100,000

Prior to any injection activities, the present USDW groundwater quality at the site must be determined. This may be completed by sampling via groundwater monitoring wells at locations approved by the CCS permit. A minimum of four quarters of monitoring should be completed before injection activities begin. This will enable the facility to compare background groundwater results to the results after injection has begun and throughout the closure and post-closure periods. A change in the groundwater quality parameters may give an indication of contamination.

IV.B.4.c. CO_2 Injection Well Construction

Under the Class V UIC regulations, the CO_2 injection wells must adhere to the construction requirements for a Class I hazardous waste injection well. These requirements are meant to ensure the protection of groundwater resources. If these rules and regulations are met, the probability for groundwater contamination via the injection well is at a minimum.

The USEPA proposed Class VI injection well rules closely follow those established for Class I injection wells. Surface casing for the well is to be set deep enough to place the ground water horizons behind pipe. Surface casing is to be cemented back to surface. Long casing set to total depth or through the injection zone is to be cemented back to surface casing. Injection of CO_2 will be through tubing set inside the long casing string and tied to a packer set just above the injection zone. The packer set point in the casing will have cement on the backside of the casing.

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[133] EPA, Glossary if Underground Injection Control Terms. Found at: http://www.epa.gov/r5water/uic/glossary.htm#usdw

[134] Fetter, C.W., 2001, Applied Hydrogeology, Prentice-Hall, Inc., Upper Saddle River, NJ. Table 10.1, p. 386.

Through the ground water horizons, CO_2 will be transported to the injection zone via tubing set inside the long casing string that is cemented back to surface and is itself set inside the surface casing that is also cemented back to surface casing.[135]

Also the proposed Class VI rule, the area between the tubing and long-string casing, the annulus, is to be filled with a non-corrosive fluid to protect the casing and tubing. Pressure in the annulus is to be monitored continually for any changes that can indicate a leak. Automatic shut-off valves are to be place downhole as part of the tubing and at the surface as part of the wellhead. Injection pressures are to be limited at 90% of fracture gradient pressure[136]. Many states limit injection pressures for Class II wells to 80% of fracture gradient pressures.

Regulations in West Virginia require surface casing to be set through the lowest ground water horizon or coal seam, whichever one is deeper.

IV.B.4.d. Induced Seismicity

Sequestration of captured CO_2 will result in an increase of subsurface pressures in the storage reservoir. There are three important pressure gradients in the subsurface, hydrostatic, fracture, and lithostatic. Now, as a method to stimulate production, high injection pressures are used to induce a hydraulic fracture in the reservoir. High injection pressure here is sustained only long enough to create the length of fracture desired and designed. This technique may be utilized during the completion process of a CO_2 injection well prior to injection operations. To avoid damaging the storage reservoir or the overlying seal, injection pressures over a longer period of time than used for completion stimulation must be less than the fracture gradient (Fig. 4).

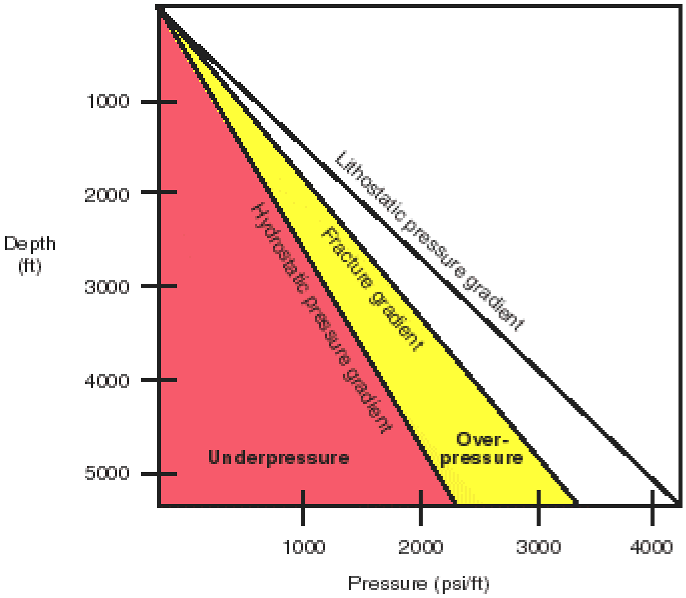

Figure 4B5: Subsurface pressure gradients[137]

In depleted oil & gas reservoirs, the reservoir pressure will be less than the hydrostatic pressure. For saline reservoirs, reservoir pressure will, in most situations, be at hydrostatic pressure. Hydraulic fracturing of an oil & gas reservoir is a production stimulation technique that momentarily exceeds fracture gradient pressures. For situations of induced seismicity,

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[135] Ibid 95

[136] Ibid 95

[137] Found at: http://www.glossary.oilfield.slb.com/DisplayImage.cfm?ID=159

injection pressures are greater than fracture gradient pressure for either a sustained period of time or in an abnormal subsurface stress environment.

The most widely know incident of induced seismicity occurred at the Rocky Mountain Arsenal near Denver, Colorado between 1962 and 1965. An injection well was drilled to 12,054 feet in the granitic basement rock of the Rocky Mountain front. Formation pressure was measured at 4,133 psi. Injection began at 4,403 barrels per day at 6,033 psi, 1,900 psi over hydrostatic pressure. If fracture gradient was 1.0 psi per foot, this injection pressure should have been reasonable, but the injection zone was granite and the only available porosity was fracture porosity; matrix or intergranular porosity was absent. The first earthquakes occurred within weeks of injection. USGS set up a monitoring system and recorded a total of 710 earthquakes . Injection ceased in 1965. Shortly thereafter final three earthquakes of magnitude 5.0 to 5.2 occurred.[138]

To the north in Rangely Oil Field, waterflooding of the reservoir for secondary recovery began in 1957. This waterflooding triggered earthquakes. A study done by USGS showed that the epicenter of these earthquakes centered in the reservoir and that fluid pressures greater than 4,061 psi in the reservoir "would increase the number of earthquakes from one or two to thirty or forty per month."[139] Subsequently, Stanford University conducted large scale water injections into a fault in Rangely Field that was considered to be near failure. A magnitude 3.1 earthquake was created but the vast majority of induced seismic events were less than a 1 magnitude. Rangely Field is now under active CO_2 injection for tertiary recovery (EOR).[140]

Geomechanical considerations in evaluating a potential CO_2 storage reservoir include:

- Avoid regional tectonic stress near breaking strength of rock
- Avoid potential reservoir where fracture porosity is dominant
- Avoid low permeability reservoirs
- Avoid injection rates that can significantly increase pore pressure over a wide area.

The first two geomechanical considerations listed above are self evident. The next two are somewhat elusive and are tied to rates of injection. Permeability essentially dictates injectivity. High rates of injection require good permeability and/or a thick zone for injection, characteristics unique for each reservoir and injection well. Low permeability means more injection wells to achieve the same rate of injection that fewer wells with better permeability can accomplish. Avoiding increased reservoir pressure over a wide area relates to internal barriers within the reservoir. These barriers can be a change in porosity and/or permeability, faults, or resistance in the displacement of formation fluids, due in part to the first two items. Maintaining a constant rate of injection at this point will increase pressure. Lowering the rate of injection will allow a constant, yet lower, injection pressure. As noted earlier, one way to relieve this situation is to produce the formation waters at some distance from the injection wells, lowering the reservoir pressure and allowing for higher rates of injection. However, handling produced waters adds another level to operations.

Earthquakes that have impacted West Virginia over the last century or more are listed in Table 2. Four of these earthquakes (1897, 1959, 1969, and 1974) have occurred in the Giles County vicinity of the state boundary between SE West Virginia and western Virginia.

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[138] Rahn, P.H., 1996, Engineering Geology: An Environmental Approach. Second Edition, Prentice-Hall, Upper Saddle River, N.J., 657 p.

[139] Ibid

[140] World Resources Institute (WRI), 2006, CCS Guidelines: Guidelines for Carbon Dioxide Capture, Transport, and Storage. Washington, DC: WRI.

Earthquakes occur in West Virginia more frequently than suggested by Table 2. Since 1974, the USGS has recorded 48 earthquakes ranging in magnitude of 2.1 to 4.5. Of the 48 events, 24 were between 2.0 and 2.9, 19 were between 3.0 and 3.9 and 5 were between 4.0 and 4.9. Earthquake magnitude, based on the Richter scale,[141] is logarithmic and measures the energy released by an event. The Modified Mercalli (MM) scale[142] measures the severity of the event and is expressed in Roman numerals.

On the Richter scale, a 3.5 magnitude represent the value below which an earthquake is generally not felt but recorded. Between 3.5 and 5.4, an earthquake is often felt but rarely causes damages. Only 12 of the earthquakes recorded since 1974 have been greater than 3.5.

On the MM scale, at a value of III, people inside a building may feel the earthquake but those outside most likely will not. At a value of V, people inside and outside will realize an earthquake has occurred and minor damage will occur such has broken dishes and spilled fluids. Only four earthquake events with a MM value of V have affected West Virginia between 1897 and 1974 (Table 4B6).

USGS also records seismic events resulting from mining explosions. Between 1997 and 2000, 155 mining explosion events were recorded. None of these events were greater than 3.5. Of the 155 recorded events, 108 were between 2.0 and 2.9 and 45 were between 3.0 and 3.5.[143]

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[141] http://www.seismo.unr.edu/ftp/pub/louie/class/100/magnitude.html

[142] http://www.seismo.unr.edu/ftp/pub/louie/class/100/mercalli.html

[143] http://earthquake.usgs.gov/earthquakes/eqarchives/mineblast/

Table 4B6: Earthquakes affecting West Virginia (USGS)[144]

Year	Location	Where Felt	Magnitude	MM Scale Where Felt in WV[2]
1897	Giles Co., Virginia		5.9[1]	VIII
1909	Charles Town - Martinsburg			V - VI
1935	Timiskaming, Quebec	Moundsville – Wheeling	6.25	IV
		Charleston, Fairmont, Parkersburg, Ravenswood, Sutton, Wellsburg		I - III
1937	Anna, Ohio	Huntington	5.4[1]	I – III
1943	Ohio	Wheeling		I – III
1944	Cornwall, Ontario / Massena, New York	Parkersburg	5.8[1]	I - III
1959	Virginia – West Virginia border	Lindside		IV
		Rock Camp		I - III
1968	Southern Illinois	Hamlin, Huntington, Parkersburg, Point Pleasant, Wayne, Williamson	5.4[1]	I - III
1969	SE West Virginia	Athens, Lerona, Elgood	4.5[1]	VI
		Itmann, Logan, Pipestem, Ramp		V
1970	West Virginia (west central portion)	Charleston, Eskdale, Hamlin, Hurricane, Saint Albans		IV
1972	Morgantown	Morgantown: recorded on WVU seismograph		
1974	Giles Co., Virginia	Gap Mills, Pickaway		V
1974	NW West Virginia / SE Ohio	Parkersburg, Ravenswood,		V
		Belleville, Cottageville, New Haven, Morgantown		IV

1 Largest earthquake to occur in this state
2 Modified Mercalli scale

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[144] US Earthquake History by State. Found at: http://earthquake.usgs.gov/earthquakes/states/

The Nagaoka CO_2 injection project in Japan injected 10,400 tons of CO_2 into a saline aquifer at 1,100 meters between 2000 and 2005. Monitoring was conducted between 2005 and 2007. The Niigata earthquake of 6.6 magnitude struck in July 2007 and "No CO_2 leakage has been observed."[145]

IV.B.5. Risks Assessment

The capture, transportation, and geologic storage of carbon dioxide present environmental and safety risks. What these risks are, and whether they are manageable, are critical questions for the future of carbon sequestration. Identification and estimation of the magnitude of the various risks associated with pipeline transportation and sequestration of captured CO_2 is also important to site selection, permitting, and liability issues. Not understanding and managing the risks of carbon dioxide transportation and geologic storage could invite failure of an environmentally critical program.

What is risk? USEPA defines risk as "the chance of harmful effects to human health or to ecological systems resulting from exposure to an environmental stressor." A stressor is "any physical, chemical, or biological entity that can induce an adverse response. Stressors may adversely affect specific natural resources or entire ecosystems, including plants and animals, as well as the environment with which they interact." [146]

Risk has been defined in the context of CO_2 sequestration as:

> "two factors - the probability (frequency) of a specified hazardous event and the severity of the consequences from that event. Risk can be defined as the product of these two factors:
>
> $$\text{Risk} = \text{Frequency} \times \text{Consequences}$$
>
> Thus, one can have the same level of risk for a frequent event with a low level of damage as for a rare event with a very high level of damage. Therefore, in developing a risk assessment, one must evaluate both frequency and potential damage from an event."[147]

Risk assessment has been described as "the process leading to the characterization of a risk."[148] A risk assessment typically has four components: hazard identification, dose response assessment, exposure assessment, and risk characterization. Risk assessments can range from qualitative, through semi-quantitative, to highly quantitative. The literature of risk assessment is enormous.

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[145] Gassnova, 2010, International CCS Technology Survey. Issue 6. February 2010. Found at: www.gassnova.no

[146] www.epa.gov/risk/basicinformation.htm Reference to or quotation from particular sources should not be taken as approval of the views expressed by the source.

[147] Risk Assessment and Management For Long-Term Storage of CO_2 In Geologic Formations, Dawn Deel, Kanwal Mahajan, Christopher R. Mahoney, Howard G. McIlvried, and Rameshwar D. Srivastava. Systemic, Cybernetics and Informatics volume 5 number one, page 79.

[148] Footnote 1, page 15, Science and Decisions: Advancing Risk Assessment (2009), The National Academies Press.

The field of risk assessment continues to evolve. The first major work on risk assessment the so-called Red Book was published in 1983.[149] In 2006 the federal Office of Management and Budget proposed a Risk Assessment Bulletin to guide federal agencies in risk assessments.[150] Recently the National Research Council was asked by USEPA to form a committee to develop scientific and technical recommendations to improve the risk analysis used by USEPA. The result was a publication titled “Science and Decisions: Advancing Risk Assessment.”

The value of risk assessment continues to be debated.[151] A principal concern with risk assessment is scientific uncertainty. The Red Book addressed this concern as follows:

> When scientific uncertainty is encountered in the risk assessment process, inferential bridges are needed to allow the process to continue. The Committee has defined the points in the risk assessment where such inferences must be made as *components*. The judgments made by the scientists/risk assessor for each component of the risk assessment often entail a choice among several scientifically plausible options; the Committee has designated these *inference options*.

Despite the issues raised by risk assessments they are the tool most commonly used in analyzing risk. Understanding risk assessments, and their strengths and limitations is a necessary element of determining the feasibility of carbon dioxide transportation and geologic storage.[152]

IV.B.5.a. Risk Assessment Specific to Carbon Dioxide Transportation and Sequestration

Risk assessment is already occurring in the field of carbon dioxide transportation and sequestration. The literature on this subject is already significant, and is rapidly expanding. There are two sources of information and data to inform risk assessments about carbon dioxide: first, the existing experience in transportation and use of carbon dioxide for enhanced oil recovery (EOR); and second, the experience in analogous areas such as the transportation and storage of natural gas.[153]

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[149] "Risk Assessment in the Federal Government: Managing the Process". National Research Council. 1983. National Academy Press. This is sometimes known as the Red Book.

[150] Scientific Review Of the Proposed Risk Assessment Bulletin From the Office Of Management And Budget, Committee to Review the 0MB Risk Assessment Bulletin National Research Council (2007).

[151] An Overview of "Science and Decisions: Advancing Risk Assessment", Jonathan Levy et al., Volume 17, Issue 1, Risk in Perspective, Harvard Center for Risk Analysis. www.hcra.harvard.edu

[152] Risk assessment must be accompanied by the companion disciplines of risk management and risk communication. These companion disciplines are equally important.

[153] See generally, "Comparison of risks from carbon dioxide and natural gas pipelines", A. McGillivray & J Wilday, Health and Safety Laboratory, Harpur Hill, Buxton, Derbyshire, SK17 9JN. 2009.

Pipelines

There are presently about 3,800 miles of carbon dioxide pipelines in operation in the United States.[154] These pipelines are regulated by the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration. See generally 49 USC 5101 et seq. and 49 USC 60101 *et. seq*. Department of Transportation regulations in some circumstances require that a pipeline project perform a risk assessment. 49 CFR Part 195.

The principal risks in the pipeline transportation of carbon dioxide are leaks or ruptures.[155] These can occur in various ways. Once a leak or rupture occurs its impact depends on the material released, the magnitude of the release, the local conditions, and the immediate population in the vicinity of the leak. While carbon dioxide is not flammable, it is heavier than air and can settle into depressions creating a risk of asphyxiation.[156] An unfortunate example of this occurred at Lake Nyos in Cameroon[157] yet there is evidence that accumulations of CO_2 will disperse in a safe and reasonable amount of time.[158] It is a risk that must be recognized.

An example of a risk assessment for a carbon dioxide pipeline is found in Appendix E Carbon Dioxide Pipeline Risk Analysis HECA Project Site Kern County, California, Prepared for Hydrogen Energy International LLC, May 19, 2009.[159] This particular pipeline is about 4 miles long and is for EOR.

This particular risk assessment begins by defining risk as "a combination of the probability of a scenario versus the severity of its consequences." [p. 1-3]. The risk analysis is described as a semi-quantitative analysis based on historical data. It identifies scenarios with adverse consequences that may occur, estimates potential consequences, estimates the likelihood of occurrence, and evaluates the risk.

The risk analysis develops frequencies of occurrence estimates and potential consequences, and establishes a risk index. Particular kinds of failure are considered. Perhaps the most significant part of the analysis is a consideration of the historical failure rate of carbon dioxide pipelines. [p.2-1, Table 4B4]. The accident/spill records of carbon dioxide pipelines were obtained from data provided by the Office of Pipeline Safety of the DOT. A historical failure rate for carbon dioxide pipelines was created. Air modeling was done to estimate the potential impacts from a hypothetical accidental release. Finally, worst-case scenarios are evaluated. The result of this analysis is a projected failure rate for each failure mode [for example equipment failure, corrosion, operator error etc.]. The projected failure rate is determined by multiplying the historic failure rate per mile of carbon dioxide pipeline per year times the total length of

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[154] Kadnar, J.O. Experience in the CO2 Transportation via Pipeline, in CCS Web Conference on CO_2 Transport, Health And Safety Issues, [US Department of Transportation], 2008 International Energy Agency: Paris.

[155] See generally, "Carbon Dioxide Pipelines: A Preliminary Review Of Design and Risks", J. Barrie et al.,

[156] Some authors express the view that pipeline transportation of carbon dioxide is safe. "Years of experience have led to a regulatory regime and operating procedures that make the operational subsystem [pipeline transportation] a safe, reliable and time-tested component of a CO2 storage system." Environmental Assessment of Geologic Storage of CO_2. Jason J. Heinrich et al., Laboratory for Energy and the Environment, Massachusetts Institute of Technology, Presented at the Second National Conference on Carbon Sequestration, Washington, DC, May 5-8, 2003.

[157] Ibid 135

[158] Ibid 137,

[159] Available at http://www.energy.ca.gov/sitingcases/hydrogen_energy/documents/applicant/revised_afc/Volume_II/Appendix%20E.pdf. The subcommittee expresses no view about whether this risk assessment is legally sufficient, complies with any particular requirement, is technically sufficient, or appropriate to the circumstances. It is given simply as an example of a recent carbon dioxide pipeline risk assessment.

carbon dioxide pipeline. The report concludes with a risk evaluation which is principally presented through a Project Risk Matrix. Mitigation measures are then described. The risk probability calculation concludes that the failure rate for the 4 mile carbon dioxide pipeline is estimated to be about 0.0007 failures per year.

Earlier testimony was presented citing the low incident rate for CO_2 pipelines which is supported by information in Table 4Bxx. This data shows that 18 incidents occurred over a 3,769 mile network over more than 30 years of operations, less than one incident per year across the whole network. On a per mile basis, this is 0.0002 incidents per year. There were no injuries or fatalities due to any of these incidents. This kind of analysis is typical of risk assessment. Its advantage is that it provides a quantitative, or in this case a semi-quantitative assessment of the risks involved. This is very useful. The disadvantage is that it contains a number of assumptions and estimates, not all of which are readily apparent. The value of the risk assessment depends as much on the validity of the data as it does on the validity of the model.

Geologic Sequestration

Geologic storage of carbon dioxide presents the risk of escape of carbon dioxide to the surface presenting a potentially hazardous situation to human health and the environment.[160] In addition, there are risks of: contamination of water supplies and potentially usable groundwater supplies; mobilization of contaminates in underground formations; and potentially increasing the expense of production of coal, gas and other mineral resources in the vicinity of sequestration operations. Finally, there is a risk of triggering a seismic event.

There is limited experience with projects that are only geologic storage of carbon dioxide. This limited experience requires consideration of analogous situations. Injection and storage of carbon dioxide underground has similarities to, and significant differences from, underground injection of brine wastes from oil and gas development, underground injection of wastes, injection of carbon dioxide for enhanced oil recovery, and the storage of natural gas. This experience can be used to assess the risks of geologic storage, and also to identify areas where the existing geologic information is inadequate.[161] In general it is believed that the risks of geologic storage of carbon dioxide change over time. The risks are greatest during and immediately after active injection. Thereafter, with the decline of reservoir pressure towards earlier in situ levels the risks decline.[162] Since long-term storage of carbon dioxide is measured in hundreds of years or longer, the potential long-term risks must be carefully considered. There is a significant and growing body of risk assessment literature directed at the geologic storage of

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[160] "The amount of CO2 that would need to be injected into geologic storage reservoirs to achieve a significant reduction of atmospheric emissions are very large. A 1000 MW coal-fired power plant emits approximately 30,000 tonnes of CO2 per day, 10 Mt per year (Hitchon, 1996). When injected underground over a typical lifetime of 30 years of such a plant, the CO2 plume may occupy a large area of order 100 km² or more, and fluid pressure increase in excess of one bar (corresponding to 10 m water head) may extend over an area of more than 2, 500 km² (Pruess, et al. 2003). *On CO2 Behavior in the Subsurface, Following Leakage from a Geologic Storage Reservoir, Pruess, Karsten, Lawrence Berkeley National Laboratory. 2006.*

[161] How analogous situations can be used to estimate risks associated with geologic storage of carbon dioxide is discussed in greater detail in table 5.5 of Underground Geologic Storage in Carbon Dioxide Capture and Storage, IPCC Special Report, 2005. Found at: http://www.ipcc.ch/publications_and_data/publications_and_data_reports_carbon_dioxide.htm

[162] "It is an important technical consideration that "risk" associated with injected CO2 is not constant with time. The probability of an unexpected event increases as injection volumes and subsurface pressure ramp up and this requires close monitoring during the operations phase. After injection stops, as pressure equilibriates, and natural trapping mechanisms take effect, the injected CO2 becomes progressively more in mobile." A Technical Basis for Carbon Dioxide Storage; CO2 Capture Project, 2009. The CO2 Capture Project is an effort funded by a consortium of energy companies.

carbon dioxide.[163,164] Of particular interest is the development of modeling techniques for carbon dioxide storage. These risk assessments will generally consider two kinds of scenarios: (1) the general risk of escape of carbon dioxide to the atmosphere, i.e., that the long-term storage of carbon dioxide will not be achieved; and (2) more specific risks of injury to human health and the environment. There are also models for specific subparts of geologic storage such as models for leaks associated with well integrity.[165] As particular projects go forward there will be site-specific risk assessments. The ultimate risk assessment will be done by those who finance sequestration projects.

Two authors, quoted below, conclude that the risks of geologic storage of carbon dioxide are manageable. These authors rely upon the experience in similar fields such as natural gas storage and enhanced oil recovery for their views.[166]

> With appropriate site selection informed by available subsurface information, a monitoring program to detect problems, a regulatory system, and the appropriate use of remediation methods to stop or control CO_2 releases if they arise, the local health, safety and environmental risks of geologic storage would be comparable to risks of current activities such as natural gas storage, EOR, and deep underground disposal of acid gas. *Carbon Dioxide Capture and Storage, Summary for Policymakers And Technical Summary, Intergovernmental Panel on Climate Change, p. 11.*

> On a project –by- project basis, the risks of geologic storage of CO_2 are expected to be no greater than the risks associated with analogous industrial activities that are under way today. Oil and gas production operations, natural gas storage, and disposal of liquid and hazardous waste have provided experience with underground injection of fluids and gases on a massive scale. The injection volume of an individual storage project will be comparable to large-scale CO_2 EOR projects taking place in the U. S. today. Because the technology for characterizing potential CO_2 storage sites, drilling injection wells, safely operating injection facilities, and monitoring will be adapted and fine-tuned from these mature industrial practices taking place today, it is reasonable to infer that the level of risk will be similar. *Carbon Dioxide Capture and Storage, Assessment of Risks from Storage of Carbon Dioxide in Deep Underground Geological Formations, Sally M. Benson Earth Sciences Division, Lawrence Berkeley National Laboratory, version 1.0 April 2, 2006 p. 4.*

Risk assessment of the long term storage of carbon dioxide at a particular site is done or assisted by mathematical modeling or simulations. Typical of this approach is the risk assessment done for the Weyburn project in Saskatchewan, Canada. Weyburn is an enhanced oil

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[163] A very useful companion to the risk assessment literature is "Vulnerability Evaluation Framework For Geologic Sequestration of Carbon Dioxide", July 10, 2008 United States Environmental Protection Agency, EPA 430-R-08-009. US EPA developed the Vulnerability Evaluation Framework to identify those conditions that could increase the potential for adverse impacts from geologic storage of carbon dioxide. It is a non-quantitative assessment.

[164] A comprehensive overview of international risk assessment issues is found in "Phase I Final Report from CSLF Risk Assessment Task Force", October 2009, Carbon Sequestration Leadership Forum.

[165] See for example, "Supercritical CO2 Leakage Modeling For Well Integrity In Geological Storage Project", E. Houdu et al. Excerpt from proceedings of the COSMOL Conference 2008 Hanover.

[166] Again citation to, or quotation from particular sources does not indicate approval of the views cited to or quoted.

recovery project using carbon dioxide.[167] This risk assessment used two different mathematical models to assess the probability that carbon dioxide will remain stored for the foreseeable future. The modeling estimates that "[t]here is a 95% probability that 98.7% to 99.5% of the initial CO_2 in place will remain stored in the geosphere for 5000 years."

The most thorough site-specific risk assessment for geologic storage to date comes from the FutureGen project.[168] Table 6-11 Estimated Range of Failure Probabilities For Each Release Scenario By Candidate FutureGen Site estimates the probabilities of various failures including: upward rapid leakage through caprock; release through induced faults; and leaks due to undocumented deep wells. The time frame for consideration is 1000 to 5000 years.

For each scenario the probability of at least one failure in the time period is estimated, as is the probability of one failure annually. For the Jewett Texas site scenario, upward rapid leakage through caprock, the probability of at least one failure over the life of the project [1000 to 5000 years] is given as 0.003 to 0.14; while the estimated frequency of one failure occurring annually is 0.000001 to 0.00001.

These estimates, and the approach used to arrive at them, are the current state of the art. The value of these estimates is limited by a lack of track record [real-world data] for such projects, the assumptions necessary to make the estimates, and the nascent state of the models used. Nonetheless, for these two examples, and they may not represent the whole population, the risk assessment estimates very low risk.

Only a few conclusions can be drawn about the current state of risk assessment for geologic sequestration of carbon dioxide. First, such risk assessment for geologic storage is still in its infancy. There is very little real-world data on which to base a quantitative risk assessment. Analogous circumstances from other fields suggest, but do not prove, that carbon dioxide geologic storage risks are manageable. Second, the mathematical models used are undergoing rapid development and remain works in progress. Third, refinement of the risk assessments will be an iterative process. Fourth, the risk assessment literature, subject to the limitations expressed, generally supports continuing forward to establish a framework for such projects.

IV.B.6. Conclusion for Geology & Technology Subcommittee

There is storage potential for sequestration of captured CO_2 in West Virginia. Present estimates of between 4,873 and 14,994 million metric tons can provide between 47 and 147 years of injection activity based on an annual statewide emission rate of 102 million metric tons. Storage potential is a resource and like any other natural resource it needs to be proven. This will be accomplished by the site characterization process prior to securing a permit to operate a CO_2 storage field.

The potential for sequestration of CO_2 extends over most of the state of West Virginia. Considering the potential for saline formation sequestration, the potential for sequestration of CO_2 probably exceeds the geographic range of oil & gas production in the state. The state overlies the sedimentary section of a portion of the Appalachian Basin, one of the major sedimentary basins in the continental United States. Thickness of this sedimentary section varies

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[167] See generally, Theme 4: Long-Term Risk Assessment Of the Storage Site, IEA GHG Weyburn CO2 Monitoring and Storage Project Summary Report 2000-2004, Volume III. From Proceedings of the Seventh International Conference Greenhouse Gas Control Technology, September 5-9, 2004, Vancouver, Canada. See page 212.

[168] Final Risk Assessment Report for the FutureGen project environmental Statement (revision to October 2007). See section 6.

from about 8,000 feet to more than 20,000 feet. Potential for saline formation, depleted oil & gas reservoirs and unmineable coal seams are all present. Research on sequestration mechanisms in shales is continuing and these may present future opportunity. Due to geologic structural complexities along the Allegheny Structural Front, sequestration potential along the eastern boundary of West Virginia is very limited to non-existent.

Technology for a MVA program is available. How this technology will be applied, locations for sensors and/or sampling will depend on the overall geology of any particular storage field. Legislative activity to date has set general standards, one of which is compliance with SDWA and USEPA's UIC program. Legislation delegates responsibility for promulgation of rules to a state agency. The Department of Ecology in Washington is the only state agency to date to develop regulations regarding sequestration of carbon dioxide. The USEPA plans to release their proposed UIC Class VI rules in late 2010 or early 2011. Available technology is that used in oil & gas exploration and production and its ability to differentiate between oil, natural gas and water is well tested. Level of resolution varies from pore scale with cores (subsurface rock samples) to formation scale with wireline logs to 2-D or 3-D seismic which cover wide geographic areas. The regional partnerships assembled by DOE/NETL are conducting research projects that further our understanding in the application of this technology for sequestration of CO_2.

Looking at examples from natural gas storage and EOR suggest, but do not prove conclusively, that carbon dioxide geologic storage risks are manageable. The sheer scale of finding "appropriately selected and managed geological reservoirs" with which to sequester thousands of millions of metric tons of captured CO_2 will be a daunting task. Risks associated with CO_2 pipeline and injection well operations are better understood that storage of CO_2. EOR operations inject, produce and re-cycle their CO_2. This process restricts the extent of the CO_2 in the subsurface. Geologic risks associated with sequestration, the long-term retention of CO_2, are more inferred from current practices. Depleted oil & gas reservoirs present a known reservoir with an effective seal. Saline reservoirs are not as well known and their extent and associated seal need to be discovered and assessed. As with the natural gas storage industry, there will successes and failures.

The process of developing a CO_2 storage reservoir, a regional geologic evaluation, selecting a suitable location for site characterization, securing rights to the pore space, securing permits, installation of injection wells, pipelines and equipment will take three to four years. The rate at which storage reservoirs can be permitted and developed will dictate the rate of deployment of CCS technology. Without storage, there is no need for capture.

Over the next year, information on storage assessment will be published. Phase III, large-scale injection project are underway by the partnerships. These projects will evaluate injectivity and the performance of the reservoir and the MVA program established to track injection activity. Geology & Technology subcommittee will evaluate and incorporate this information n the final report.

Question 4: What legal and liability issues need to be decided before CCS can be pursued in West Virginia?

IV.C. LEGAL SUBCOMMITTEE REPORT

IV.C.1. Background

As climate change is becoming a growing international concern, significant progress is being made by companies and states interested in assuring that there will be a place in the nation's energy future for coal fired electric power generation. Much of this effort is being focused on carbon capture and sequestration ("CCS") technology as holding the promise of being able to store carbon dioxide emissions from power plants and industrial facilities underground in deep storage sites. With several hundreds of years of storage potential at many locations across the nation, CCS is attracting much attention.

Initial CCS legislation was enacted by the West Virginia Legislature in 2009. The legislation created a carbon capture and storage regulatory program and created a working group to assess a variety of issues. CCS facilities are authorized by the legislation to the extent that the owner or operator holds an underground injection control permit authorized by state law for that purpose. W.Va. Code 22-11A-3(b). The Working Group is required to issue a final report to the Legislature by July 1, 2011, which would address such issues as the ownership and acquisition of pore space and responsibility for long-term liability. Resolution of these issues will be critical in order to provide for the development of commercial scale CCS operations in West Virginia.

The effort to assess legal issues began by undertaking a careful review of activities around the country in identifying significant policy, regulatory and legal issues raised by CCS projects. In addition, several guest speakers provided information on program development in other jurisdictions. Among the guest speakers were Mary Throne, a member of the Wyoming legislature, Lynn Helms Director, North Dakota Industrial Commission, Department of Mineral Resources), Sean McCoy and Lee Gresham of CCSReg/Carnegie Mellon University, Sara Smith, Chair of the Kentucky CCS Working Group, and Kurt Waltzer, Clean Air Task Force and contributor to the CCS recommendations of the Midwest Governors Association.

After identifying the universe of issues involved, initial efforts focused on property ownership and acquisition. Research was conducted on activities in other states and by such organizations as the Interstate Oil and Gas Compact Commission, CCSReg and the Midwest Governors Association. In addition, an evaluation was conducted of the consequence of doing nothing more than to allow current legal process to control the acquisition of land to be used for a CCS project. The goal of this effort was to explore all options in order to create a solution tailored to West Virginia legislature's desire to site commercial scale CCS projects.

The discussion of legal issues in this report will begin with a review of some of the more significant state level activities on CCS. The discussion will then turn to the six possible options which have been identified with a statement of the advantages and disadvantages of each option also provided. Next, the report will set forth the independent analysis of the Legal Subcommittee with respect to the law related to the circumstances under which the United States Constitution requires that a property owner be compensated for the use of property. The report will then offer an initial statement of which of the options involved is favored at this time, even though all other options will continue to be evaluated over the remainder of the study period of the Working Group. Specific text is then offered for the several property acquisition matters that have thus far been considered. Finally a list of issues that have not yet been addressed is offered as the starting point for the continued discussion of the Working group for the coming year.

IV.C.2. State-Based CCS Programs

Significant activity is occurring around the country in the development of state-based CCS programs. Among these initiatives are the following:

IV.C.2.a. IOGCC

In 2007 the Interstate Oil and Gas Compact Commission ("IOGCC") issued its model program for the storage of carbon dioxide in geologic formations. Even though the USEPA is applying the Safe Drinking Water Act regulatory program to CCS facilities, the IOGCC model program is premised on the belief that the regulation of CO_2 geological storage should be left to the states. With respect to property rights, the IOGCC model program provides that an applicant should acquire the property rights to use pore space in the geologic formation for storage. While much of the IOGCC's model program addresses the need to acquire property rights through negotiation or eminent domain, the model program specifically states that the IOGCC is less concerned about what mechanism is used to acquire those rights and is more concerned that all necessary property rights be acquired by valid, subsisting and applicable state law. Following completion of the project, an operator would be obligated to monitor the project to assure its integrity. At the completion of that period, title to the facility would be transferred to the state and the operator and all generators of CO_2 injected would be released from all regulatory liability. The program establishes a trust fund that would assess a fee on each ton of CO_2 injected. The trust fund provides the financial resources for the state to take title to the project at the end of its operating life.

IV.C.2.b. Kansas

In 2007, Kansas established the authority to develop rules for CCS facilities. Kan Stat. Ann. §§55-1637 through 1640. Proposed administrative regulations issued in March 2009 address operational requirements for an environmental permitting program. Among those requirements is that the applicant must hold necessary property and mineral rights and own financial instruments that demonstrate financial responsibility. Kansas law does not define who owns pore space, nor does it define the level of financial responsibility required. To obtain a post-closure determination, the facility operators must demonstrate that the plume and storage pressure have stabilized. Upon written approval of post-closure status, the operator would plug the remaining monitor wells at which point the CO_2 storage facility permit would be revoked and any financial assurance instrument would be released. All future remediation or monitoring activities would be performed by the state.

IV.C.2.c. Louisiana

In 2009, the Louisiana Legislature passed new CCS legislation. Louisiana R.S. 30:1101 through 1111. This bill authorizes expropriation by the state or certain corporations engaged in CCS not only for a storage facility but also for pipelines for transportation. Ten years, or any other time frame established by rule, after cessation of injection, a certificate of completion of injection operations would be issued at which time the storage operator, generators of the carbon dioxide, the owners of the carbon dioxide, and all other owners otherwise having an interest will be released from any and all regulatory duties or obligations and any other liability associated with or related to the storage facility. The statute authorizes a storage operator's fee.

IV.C.2.d. Montana

The Montana legislature passed CCS legislation (SB 498) in 2009 which established a CCS regulatory framework and addressed pore space ownership. Unless otherwise documented, the surface owner owns the pore space for geologic carbon sequestration. The bill also protects the existing rights of mineral owners and does not change common law regarding surface and mineral rights. Operators will pay a fee on each ton of CO_2 injected into a storage reservoir based on anticipated actual expenses that will be incurred by agencies implementing the program. Prior to project completion, an operator is liable for the operation and management of the CO_2 injection well, the storage reservoir and the injected or stored CO_2. The completion and transfer of ownership and liability from the operator to the state is a process that takes 30 years: (a) 15 years after injection of CO_2 ends, a certificate of completion will be issued if the operator is in full compliance with all rules and (b) for a period of an additional 15 years after the certificate of completion is issued, the operator must continue adequate monitoring of the wells and reservoir and continue to accept all liability. Following the 15 year period of required monitoring and verification, if the operator has title to the storage reservoir and the stored CO_2, it may transfer the title to the state if the operator meets all requirements. Once the title is transferred to the state, the state is granted all rights and interests in and all responsibilities associated with the geologic storage reservoir and the stored CO_2. The transfer releases the operator from all regulatory requirements and liability associated with the reservoir and the stored CO_2. If the operator does not transfer title to the state, the operator accepts liability indefinitely for the reservoir and the stored CO_2.

IV.C.2.e. North Dakota

In 2009, Senate Bills 2139 (pore space and property issues) and 2095 (carbon dioxide storage operational issues) were enacted into law. This legislation creates a legal and regulatory framework for carbon capture and storage and addresses pore space and property issues relevant to carbon capture and storage, including placing title to pore space in all strata underlying the surface with the owner of the overlying surface estate. If a storage operator does not obtain the consent of all persons who own the storage reservoir's pore space, the state may require that the pore space owned by non-consenting owners be included in a storage facility and subject to geologic storage. This is accomplished through the amalgamating provision, which is similar to unitization, requiring the consent of 60% of the property owners.

Multiple funds are established to defray the expenses incurred by regulatory agencies throughout the carbon sequestration process. The actual fee amount is to be based upon the anticipated expenses that will be incurred in regulating storage facilities during their construction, operation, and pre-closure phases. The storage operator has title to the carbon dioxide injected into and stored in a storage reservoir and holds title until a certificate of project completion has been issued. While the storage operator holds title, the operator is liable for any damage the carbon dioxide may cause, including damage caused by carbon dioxide that escapes from the storage facility.

After project completion and application for closure, consideration will be given to issuing a certificate of project completion. Such certificate may not be issued until at least 10 years after carbon dioxide injections have ended. Once a certificate is issued, title to the storage facility and to the stored carbon dioxide transfers without payment of any compensation to the state and the storage operator and all persons who generated any injected carbon dioxide are released from all regulatory requirements and other liability associated with the storage facility.

IV.C.2.f. Oklahoma

Also in 2009, Oklahoma passed the "Geologic Storage of Carbon Dioxide Act" (S.B. 610). The act provides the legal framework to encourage the long-term geologic storage of carbon dioxide in Oklahoma. The Corporation Commission is granted the authority to grant certificates of public convenience and necessity and to authorize storage facilities which allows the storage operator to initiate the condemnation action necessary to site the facility. The act is almost silent with regard to addressing potential liability associated with CCS activities. However, it provides for the establishment of financial sureties or bonds.

IV.C.2.g. Wyoming

In 2009, Wyoming passed three bills to address ownership and liability issues related to geological storage of carbon dioxide. H.B. 57 clarifies that mining and drilling rights will be prioritized over geologic sequestration activities. H.B. 58 provides that the injector holds the title and liability for sequestered carbon dioxide and all other materials injected during the sequestration process. H.B. 80 establishes a procedure for unitizing geologic sequestration sites, whereby pore space rights from multiple parties would be aggregated for the purposes of a carbon storage project as long as 80 percent of the parties approve the project. This suite of bills complements that which was passed in 2008. H.B. 89 specified ownership of pore space. The 2008 legislation declared that the ownership of all pore space in all strata below the surface lands and waters of the state is declared to be vested in the owners of the surface above the strata. H.B. 90 established an operational regulatory program.

The legislation in the various states is setting the legal and regulatory framework for CCS projects in advance of the development of federal legislation. This work is allowing the current development of experimental CCS projects across the country. If commercial scale CCS projects are to be developed in time to play a meaningful role in framing national policy with respect to global climate change, these efforts to address legal issues must be accelerated. The WVCCS legal subcommittee is working toward resolution of the legal issues associated with the ownership and acquisition of pore space and responsibility for long-term liability.

IV.C.3. Pore Space Acquisition Options

As the result of its survey of proposals by other states and organizations, the subcommittee identified six alternatives related to the nature and extent of the obligation of an operator of a facility engaged in the geologic sequestration of carbon dioxide to acquire the property rights for that purpose. Those six alternatives are as follows:

Option 1. Existing Law

Legislation passed in 2009 provides an initial framework for CCS projects and in doing so relies upon the present state Water Pollution Control Act. While that 2009 legislation does not explicitly address eminent domain, eminent domain provisions do exist elsewhere in statutory law (see W.Va. Code, Chapter 54, Article 2). Even though the legislation requires that "necessary" legal rights to sequester CO_2 be demonstrated as part of the permitting process, the legislation does not define what rights are "necessary."

Advantages:

- Property rights may be acquired under existing property law.
- Existing law does not state what legal rights are necessary to sequester CO_2.
- This process would not require amendments to the current legislation.
- New legislation to begin acquiring the property rights would not be required.
- Current CCS law may allow electric utilities and others, such as the Public Energy Authority and the gas pipeline authority, to exercise eminent domain without further amendment.

Disadvantages:

- Requires a title search of existing property instruments to determine property ownership, which is time-consuming and expensive (there are 19,491 surface parcels and 1,026 mineral tracts in Mason County alone).
  - surface owners, oil and gas owners, coal owners, other mineral owners, and lien holders (deeds of trust, tax liens, judgment liens, other liens) must be identified.
  - A very conservative estimate of the title report costs would be $5,000 per tract.
- In the likely event all the necessary property cannot be acquired through negotiation, a condemnation action must commence.
- All compensation is paid by the condemnor along with the costs (commissioners, jury trial, etc.).
- Eminent domain is not authorized for any party other than utilities already having the power of eminent domain.
- Compensation to land owners would likely be variable.
- Uncertainty exists about the ownership of pore space and the obligation to acquire the right to use that pore space.

Option 2. Streamline Existing Law

Streamline existing law by including some or all of the following suggestions: (1) allow the use of tax records (updated to include transactions occurring in the past year) or other alternative methods to identify pore space ownership; (2) use Administrative Law Judge's ("ALJ") (or create a specific special master) as a first step in setting compensation; (3) expand the scope of existing eminent domain authority (gas pipelines, PEA); (4) expand entities with Certificate of Necessity from DEP/PSC (PSC would likely need to be involved for rates); (5) allow companies other than existing utilities the right to acquire the property rights and operate such facilities; (6) clarify who owns pore space under various scenarios; and (7) protect operators from common law claims (*e.g.* trespass) where CO_2 moves onto property not yet acquired.

Advantages:

- Simplifies the title search.
- Reduces costs and time.

- Might be able to provide some structure for controlling compensation.
- Does not purport to change existing ownership of pore space, but rather it simply creates a presumption of ownership in certain circumstances and allows that presumption to be rebutted, thereby protecting the rights of the owners.
- Allows an expanded group of applications.

Disadvantages:

- Requires changes to existing law.
- Still requires compensation for all property owners.
- Does not address the "windfall" value that may be created for the use of pore space for CO_2 sequestration.

Option 3. Public Use

The Midwest Governors Association has proposed that a state either unitize pore space or declare the subsurface below 2,500 feet not associated with hydrocarbon development to be accessible for public use. A fixed fee per acre will be provided for the use of the pore space. Eminent domain would be authorized. This option has not yet been enacted into law by any state.

Advantages:

- Eliminates the uncertainty associated with determining the identity of the owner of the pore space.
- Simplifies compensation (set at nominal amount).
- Use of police powers may preclude (or minimize) compensation.

Disadvantages:

- Creates uncertainty to the extent that compensation is set below "fair market value."
- The issue of whether a legislative declaration of pore space below 2,500 feet constitutes a taking, which would trigger payment of just compensation, has not yet been tested.
- Due to variations in West Virginia's geology, the strata available for carbon dioxide sequestration may dip causing a depth line to pass in and out of a given stratum, potentially complicating the issue.
- Operator would still be required to bear the burden of determining ownership of pore space and of taking the right to use the pore space, even if CO_2 sequestration does not materially impair the pore space owner's use.

Option 4. Unitization

Unitization of pore space rights has been suggested by the Midwest Governors Association and has been enacted into the laws of North Dakota and Wyoming. The concept has not been applied to an actual CCS operation. Unitization would mandate that pore space rights can be used for CCS if a majority of rights are obtained by consent. Compensation for those additional rights is required and must be determined.

Advantages:

- The law could be amended to allow for its expanded use, as has been done in other states (such as Wyoming and North Dakota).
- The taking could occur without reliance upon new eminent domain authority.
- Efficient method.

Disadvantages:

- Current West Virginia law would need to be changed to expand unitization to include CO_2.
- Historically, unitization has assumed continued payment to the property owner.
- With CCS, there is no apparent, continual revenue stream or "product" beyond the operational stage of the project.
- The Wyoming program does not address how the affected property owners will be compensated.
- The price paid for the use of the pore space must be sufficient to entice a majority of the pore space owners to voluntarily relinquish the pore space for this to work effectively.
- It presumes an arms length/fair transaction between the parties, which may not always be the case.

Option 5. Permit Authorization

The Carnegie Mellon CCSReg Project has offered a comprehensive regulatory framework for geologic sequestration ("GS") based upon the balancing of the interests of private property owners with the public benefit of GS, and reducing the possibility of interference with other productive non-GS uses of the subsurface that are also in the public interest. This framework should enable UIC regulators to permit GS projects and allocate use of subsurface pore space under an expanded version of the UIC program. Under this framework, regulators would consider the trade-offs between private interests and the public benefit of a proposed GS project, determining the safest, most efficient and equitable use of the pore space, including non-GS uses. This framework should increase the potential for either avoiding most subsurface property disputes outright, or resolving them at the outset in a stable and predictable environment that is fair and equitable to all affected parties. An approval by UIC regulators to allow the sequestration of CO_2 in that pore space could be challenged as a *per se* physical taking of property that requires compensation. A detailed discussion of the law of "takings" is set forth elsewhere in this report. U.S. Courts have consistently ruled that due to the overarching public benefit of underground disposal of fluid waste, technical trespass claims against waste injection operators properly licensed through the UIC permitting process are compensable only if a material impairment with use of the subsurface or the surface can be demonstrated. This same rationale has been applied to state-authorized enhanced oil and natural gas recovery operations and field unitization—that is, claims for subsurface trespass must yield to the public interest of efficiently producing natural resources. The CCSReg proposal and recommendations are set forth in a policy paper "Governing Access to and Use of Pore Space for Deep Geologic Sequestration" dated July 13, 2009.

Advantages:

- Expedited process and minimize cost.
- Property issues would be addressed during the permit process.
- Eliminating trespass would be very helpful.
- Eliminates the economic windfall that would be created by the passage of legislation mandating that pore space rights be obtained for CO_2 sequestration.

Disadvantages:

- Cutting off unasserted property rights, particularly for minors, may pose a problem.
- May unduly delay the issuance of the permit and without a valid permit it may not be possible to utilize the power of eminent domain needed to acquire the necessary pore space.

Option 6. Reverse Rule of Capture

Based upon the current application of the UIC program, the Ohio federal district court case involving the UIC program and the experience of the State of Florida with the underground injection of treated municipal wastewater, one option would be to establish a program that does not call for the taking of pore space rights. In Florida, property rights are generally not taken in connection with its extensive treated municipal waste disposal via the UIC program nor are they taken in connection with the underground injection of hazardous waste (however this often occurs on public land or offshore).

Advantages:

- Sequestration projects may be able to sequester carbon dioxide into pore space where they have no surface or mineral ownership interests.
- Reverse rule of capture involves acquiring rights to usage as opposed to ownership rights.
- Using the reverse rule of capture would eliminate the need to acquire the property rights to pore space.
- This would save considerable time and money.

Disadvantages:

- This approach might require characterization of this activity more as waste (and not commodity) management, which may create RCRA implications.
- Only a minority of states have adopted the reverse rule of capture rule and it is unclear whether states other than Ohio would follow this rule.
- It may subject the CCS operator to trespass or other common law claims.

Additional Legal Research on Permit Authorization Option

The Subcommittee also considered additional legal research related to the option of allowing the permit in a proper case to authorize the use of pore space. This research addresses implications of the "Takings Clause" of the Fifth Amendment of the Constitution of the United States and of common law tort actions. Many of the cases discussed involve the injection of salt water or waste water into subsurface formations and its migration under properties of adjoining landowners. These cases are therefore analogous to the injection of carbon dioxide into subsurface pore space formations.

As discussed in the attached legal research, the law with respect to "takings" is principally addressed in four decisions of the United States Supreme Court.

Causby v. United States, 328 U.S. at 258 (1946), involved the question of whether the federal government's frequent and regular flights of aircraft over a property owner's land at low altitudes constituted a taking. 328 U.S. at 258. While the Supreme Court of the United States held that there was a taking under these circumstances, its holding was premised on the fact that the flights were "so low and so frequent as to be a direct and immediate interference with the enjoyment and use of the land." *Id*. at 266. Otherwise, the Court recognized, flights over private land are not a taking. *Id*. Specifically, the Court observed:

> [i]t is ancient doctrine that at common law ownership of land extended to the periphery of the universe – *Cujus est solum ejus est usque ad coelum*. But that doctrine has no place in the modern world. The air is a public highway, as Congress has declared. Were that not true, every transcontinental flight would subject the operator to countless trespass suits. Common sense revolts at the idea. To recognize such private claims to airspace would clog these highways, seriously interfere with their control and development in the public interest, and transfer into private ownership that to which only the public has a just claim.

Id. at 260. Thus, the Court recognized that "[t]he airplane is part of the modern environment of life, and the inconveniences which it causes are normally not compensable under the Fifth Amendment. The airspace, apart from the immediate reaches above the land, is part of the public domain." *Id*. at 266.

In *Penn Central Transportation Company v. City of New York*, the Supreme Court of the United States was faced with the question of whether the designation of a privately owned property as a "landmark" by a city landmark preservation committee, thereby preventing further construction on the property, amounted to a "taking" of the property without just compensation. 438 U.S. 104 (1978). The New York Court of Appeals concluded that there was no taking of the property since the landmark law did not transfer control of the property to the City, but rather, only restricted Penn Central's exploitation of it. *Id*. Further, the New York Court of Appeals found that Penn Central was not denied due process. The U.S. Supreme Court affirmed the decision of the New York Court of Appeals and identified several factors that have particular significance in resolving such claims. *Id*. These factors included the economic impact of the regulation on the property owner, the extent to which the regulation interfered with "distinct investment backed expectations," and the character of the government action, i.e., was the interference a physical invasion of the property by government or was the interference a public program adjustment to benefits and burdens of economic life in order to promote the common good. *Id*. In finding that landmark law did not interfere with Penn Central's present use of the Terminal, that Penn Central was still permitted to profit from its use of the Terminal and to obtain a reasonable return in its investment, and that Penn Central was not denied all use of the pre-existing air rights as they were transferable to other parcels in the vicinity, the Court concluded that the interference with Penn Central's property by the landmark law was not of such a magnitude that required the exercise of eminent domain and payment of compensation. *Id*. at 136.

In *Loretto v. Teleprompter Manhattan CATV Corp.*, the Supreme Court of the United States addressed the question of whether "a minor but permanent physical occupation of an owner's property authorized by government constitutes a 'taking' of property for which just compensation is due under the Fifth and Fourteenth Amendments of the Constitution." 458 U.S. 419, 421 (1982). At issue was a New York statute that required a landlord to permit cable television companies to install cable television facilities, or equipment, on the landlord's property for which the landlord was permitted to demand payment from the company of no more than an amount determined by a State Commission to be reasonable. The State Commission, acting in accordance with the statute, determined that a one-time payment of $1 was a reasonable fee. The Supreme Court of the United States held that the statute constituted a taking of property for which the property owner was entitled to just compensation under the Fifth and Fourteenth Amendments. Syl., *Loretto*, 458 U.S. 419. In arriving at this conclusion, the Supreme Court recognized that "[w]hen the 'character of the governmental action,' *Penn Central Transportation Co. v. New York City*, 438 U.S. 104, 124, 98 S.Ct. 2646, 2659, 57 L.Ed.2d 631, is a permanent physical occupation of real property, there is a taking to the extent of the occupation without regard to whether the action achieves an important public benefit or has only minimal economic impact on the owner." Syl., *Loretto*, 458 U.S. 419. There are, however, some distinguishable facts between those presented in *Loretto* and those involved with carbon sequestration. For instance, *Loretto* involved the installation, or "direct physical attachment," of cable facilities, which included plates, boxes, wires, bolts, and screws, to a building such that the facilities were "completely occupying" space immediately above and on the building's roof and along the building's exterior walls. These areas of the building are readily accessible and usable by its owners and may easily be put to other uses if so desired. Conversely, with respect to carbon sequestration in formations at least 2,500 feet beneath the surface, a property owner, unless already having an existing or reasonably foreseeable use of such a formation, cannot access this portion of his or her property without the expenditure of very significant financial resources and the use of sophisticated and expensive machinery and equipment. Thus, such formations are not even remotely readily accessible or easily put to other uses by the property owner. Further, in *Loretto*, the property to which the cable facilities were directly physically attached was of substantial economic value to its owners (i.e., residential rental property) and was in existing use by its owners (i.e., the property currently was being rented as residential living space by the owners).

The Loretto case was applied in *FPL Farming, Ltd. v. Texas Natural Resource Conservation Commission* in which a neighboring landowner's challenge to a state environmental commission's order allowing an industrial waste injection operator to increase a maximum injection rate of the industrial waste to a saltwater formation beneath the surface. No. 03-02-00477, 2003 WL 247183 (Tex.App.-Austin, Feb. 6, 2003). FPL contended that the permits amounted to an unconstitutional taking by allowing the waste plume to migrate under its property. *Id*. at 5. FPL asserted that it lost its right to possess the subsurface by being denied its ability to exclude the waste plume therefrom. *Id*. FPL also asserted that it lost its right to use the subsurface because the migrating waste plume would prevent FPL from mining the subsurface for brine or constructing its own injection well. *Id*. While the Court acknowledged that a permanent physical occupation occurs with government action that destroys a property owner's right to possess, use, and dispose of its property, the Court cast aside FPL's assertions as speculative. *Id*., citing *Loretto v. Teleprompter Manhattan CATV Corp.*, 458 U.S. 419, 435 (1982). The Court also found that FPL failed to meet the *Loretto* test for establishing a permanent physical invasion and a public taking in that FPL failed to demonstrate that it was denied an opportunity to apply for a brine mining permit or an injection well permit (i.e., that it was denied its right to possess, use, and enjoy the subsurface of its property) and that it was impaired in its right to sell its land as a result of the amended permits. *Id*. So, the Court concluded that there was no public taking of FPL's property as a result of the Commission's orders.

In *Lucas v. South Carolina Coastal Council*, the Supreme Court of the United States was asked to determine whether a land-use regulation's substantial impact on the economic value of private property constituted a taking under the Fifth and Fourteenth Amendments requiring the payment of just compensation. 505 U.S. 1003, 1007 (1992). Specifically, the State of South Carolina's Beachfront Management Act barred the petitioner, Lucas, from erecting any permanent habitable structures on his beachfront property, which he had purchased for that very purpose prior to the enactment of the Act. The Supreme Court of the United States found that the Act amounted to a taking of Lucas's property, entitling him to just compensation. In finding that the Act constituted a regulatory taking of Lucas's property, the Court held that regulations that deny a property owner of all "economically viable use of his land" amounts to a taking for which payment of just compensation is required. Syl., *Id*. at 1004. It is doubtful that the *Lucas* analysis would be problematic or used to attempt to invalidate a regulation permitting carbon sequestration in formations at least 2,500 feet beneath the surface since the property owner would still be entitled to all other uses of the property, whether economically viable or not.

Based on the foregoing case law, the Subcommittee concluded that the following concepts/provisions should be considered for incorporation into underground carbon sequestration legislation:

- The legislation should elaborate, in detail, on the policy reasons for using subsurface formations for CO_2 sequestration, including public health, climate change, importance of coal industry to the state, recognition of justified limitations on subsurface property rights, and the public interest in the development of subsurface formations for CO_2 sequestration. The legislation should emphasize that subsurface CO_2 sequestration is a necessary and vital part of the modern environment of life in light of the challenges the world faces with climate change and increasing energy demands (echoing language used in *Causby*);
- The legislation should declare that the foregoing public policy concerns warrant the state's use of police power in ensuring that subsurface formations throughout the state can be used for the purpose of CO_2 sequestration;
- The legislation should declare that pore space, non-hydrocarbon bearing formations within the boundaries of the state and (a) 2,500 feet beneath the surface or (b) between 2,500 feet and 12,000 feet beneath the surface ("Formations") that are not under an existing or reasonably foreseeable use by the respective property owner are part of the public domain

(analogous to airspace "apart from the immediate reaches above the land, is part of the public domain" *Causby*);

- The legislation should authorize the West Virginia Department of Environmental Protection (or other state agency) to regulate the access to and use of the Formations for CO_2 sequestration;
- The legislation should authorize the DEP to define, by regulation, a permitting process by which parties may apply for a permit that authorizes the parties to access and use, exclusively for a defined length of time, the specific areas of the Formations defined and approved in the permit applications; the legislation and/or the regulations should require the party seeking the permit to obtain rights to use the surface from the surface owner for the injection well site;
- The legislation and/or the regulations should specify that, once an order granting a permit is issued and the party has secured the required surface rights to construct and operate an injection well, that party may access and use the permitted areas of the Formations for CO_2 sequestration in compliance with all provisions of the permit;
- The legislation and/or regulations should allow a property owner to pursue an inverse condemnation proceeding to recover damages if the property owner can establish that it has suffered actual physical damages to its property caused by the migration of CO_2 into the portion of the Formation beneath the owner's property or that the migration of the CO_2 has actually interfered with the owner's existing or reasonably foreseeable use of its property. Otherwise, the injecting party will not be liable for common law tort claims brought by the property owner, including trespass and nuisance.

IV.C.4. Initial Assessment of Pore Space Acquisition Methodology

The Legislature has requested the Working Group to make recommendations to encourage the development of CCS and to examine factors integral to the construction, maintenance, and operation of CCS facilities, among other things. In response to this request, the Working Group has turned its initial attention to the manner in which pore space rights are to be acquired.

The resulting analysis has focused principally on two overarching factors: (1) the practicality and cost of any approach that required that all owners of pore space be identified and paid for the right to use pore space without regard to the landowners potential for use of the pore space, and (2) the constitutional requirements applicable to the circumstances under which the use of land required compensation as a taking.

With respect to the first of these factors, the Working Group recognizes that in West Virginia and much of the East, the shear number of property owners that could be within the footprint of a CCS project could be extremely large. In Mason County, West Virginia alone, there are nearly 20,000 surface owners and 1,000 mineral owners. On the conservative assumption that a typical title examination could cost \$5,000 per tract, the cost to do title searches for a project with a footprint as large as Mason County would be approximately \$100 million. Added costs related compensation to landowners and transactional costs related to acquiring the property rights cause the Working Group to conclude that an alternative course of action should be pursued.

Turning then to the constitutional requirements related to compensation for the use of land, the Working Group recognizes that not all use of private land result in a compensable taking. The United States Supreme Court and other courts have recognized a number of circumstances in which compensation was not required to be paid for the use of land. These cases have included in certain circumstances airplane over-flights of land and injection of material into underground foundations.

The Working Group carefully assessed the proposal of the Midwest Governors Association to establish as having a public use certain pore space located below 2500 feet.

In addition the Working Group carefully evaluated the recommendation of the Carnegie Mellon CCSReg Project which offered a comprehensive regulatory framework for GS based upon the balancing of the interests of private property owners with the public benefit of GS, and reducing possibility of interference with other productive non-GS uses of the subsurface that are also in the public interest. This framework was based on the premise that UIC regulators shuld be enabled to permit CCS projects and allocate use of subsurface pore space under an expanded version of the UIC program. Under this framework, regulators would consider the trade-offs between private interests and the public benefit of a proposed CCS project, determining the safest, most efficient and equitable use of the pore space, including non-CCS uses. This framework should increase the potential for either avoiding most subsurface property disputes outright, or resolving them at the outset in a stable and predictable environment that is fair and equitable to all affected parties.

By reviewing the facts and circumstances surrounding theses cases, the Working Group has developed a statutory mechanism set forth in the following section that is believed to pass constitutional muster. While the dedication of certain pore space below 2,500 feet to public use is the approach favored by the majority of the Working Group at this time, it will continue to evaluate the public use approach as well as alternative approaches.

IV.C.5. Legislative Elements

The following are elements of a legislative proposal that the Subcommittee has concluded to be appropriate to address several components of the West Virginia Carbon Dioxide Sequestration Act (W. Va. Code 22-11A-1 through 9). Following the statement of each element, specific legislative language is set forth that would implement that element.

Pore Space Acquisition

Before injection begins the applicant would need to demonstrate that is either has (or is expected to have through immediate right of entry in an eminent domain action or otherwise) "necessary" property rights related to a CCS facility.

Existing provision: W. Va. Code 22-11A-5(a)(6):

> A site and facilities description, including a description of the proposed carbon dioxide sequestration facilities and documentation sufficient to demonstrate that the applicant has, or will have prior to the commencement of the operation, all legal rights, including without limitation the right to surface or pore space use, necessary

to sequester carbon dioxide and associated constituents into the proposed carbon dioxide sequestration site;

A “necessary” right would include appropriate rights needed for surface usage (i.e. pipelines, surface facilities, wells locations etc.), appropriate rights needed for the construction of wells (including the rights to drill through any hydrocarbon bearing formations) and appropriate rights to use certain geologic strata for the sequestration of carbon dioxide. The acquisition of these rights would take place in customary fashion utilizing such concepts as voluntary negotiation or condemnation.

A “necessary” right shall not include the right to use a portion of a geologic strata for the purpose of sequestering CO_2 in the event that such geologic strata is located below 2500 feet and does not have a reasonably foreseeable use for a purpose other than the sequestration of carbon dioxide.

Amendment of existing section: W. Va. Code 22-11A-1

(a) The Legislature finds that:

(1) Carbon dioxide is a colorless, odorless gas that can be produced by burning carbon and organic compounds;

(2) Carbon dioxide is emitted into the atmosphere from a number of sources including fossil-fueled power plants, automobiles, certain industrial processes and other naturally occurring sources;

(3) By far, fossil-fueled power plants are the largest source of carbon dioxide emissions. These power plants emit approximately one-third of carbon dioxide emissions worldwide;

(4) On average, the United States generates approximately fifty-one percent of its electricity from coal-burning plants, which are a prominent source of carbon dioxide emissions;

(5) West Virginia’s reliance on electricity produced from coal is even more pronounced, as West Virginia generates approximately ninety-eight percent of its electricity from coal burning power plants;

(6) There is increasing pressure, both nationally and worldwide, to produce electrical power with an ever-decreasing amount of carbon dioxide emissions;

(7) West Virginia is a state rich in natural resources, and its economy depends largely upon the demand for energy produced from materials found within the state, not the least of which is coal;

(8) As demand for energy produced from alternative and renewable resources rises, new technologies are needed to burn coal more cleanly and efficiently if West Virginia is to remain competitive as an energy producing state;

(9) Carbon dioxide capture and sequestration is the capture and secure storage of carbon dioxide that would otherwise be emitted to, or remain in, the atmosphere. This technology is currently being used and tested to reduce the carbon footprint of electricity generated by the combustion of coal;

(10) The science of carbon dioxide capture and sequestration is advancing rapidly, but the environmental effects of large, long-term carbon dioxide sequestration operations are still being studied and evaluated;

(11) Although the state is committed to expanding its portfolio of alternative and renewable energy resources, electricity generated from these resources is insufficient in the near term to meet the rising demand for energy;

(12) It is in the public interest to advance the implementation of carbon dioxide capture and sequestration technologies into the state's energy portfolio;

(13) Inasmuch as the subsurface sequestration of carbon dioxide is a necessary and vital part of the modern environment of life in light of the challenges the world faces with climate change and increasing energy demands, it is appropriate for the state to use its police power to ensure that subsurface formations throughout the state can be used for the purpose of carbon dioxide sequestration in accordance with this article;

(14) It is in the public interest to declare as a public use the use of certain deeper geologic strata for the purpose of carbon dioxide sequestration in accordance with a permit issued pursuant to this article, so long as those geologic strata do not have a current or reasonably foreseeable use for any purpose other than the geologic sequestration of carbon dioxide;

(15) The state should provide for a coordinated statewide program which authorizes the exclusive access to and use of specific areas of the geologic formations and otherwise regulates the injection, storage and withdrawal of carbon dioxide and fulfilling the state's primary responsibility for assuring compliance with the federal Safe Drinking Water Act, including any amendments thereto.

(1~~3~~6) The transportation by pipeline and sequestration of carbon dioxide by a public utility engaged in the generation of electricity may be integral to the construction, maintenance and operation of electric light, heat and power plants operating in the state; and

(1~~4~~7) Therefore, in order to expand more rapidly the generation of electricity with little or no carbon dioxide emissions, it is critical to encourage the development of carbon dioxide capture and

> sequestration technologies; to examine factors that may be integral to the construction, maintenance and operation of carbon dioxide sequestration facilities; and to study the economic and environmental feasibility of large, long-term carbon dioxide sequestration operations.

The subcommittee notes that subsections 2, 3, 4, 5, and 6 of the above findings contain factual statements that should be reviewed for current accuracy.

Proposed new subsection:

> (a) For the purpose of [W. Va. Code 22-11A-5(a)(6) (correct citation to be added later)] a necessary legal right to sequester carbon dioxide and associated constituents into the proposed carbon dioxide sequestration site shall include appropriate rights to utilize the surface of the land involved in addition to the rights to use certain geologic strata for the sequestration of carbon dioxide; however, a necessary legal right shall not include the right to use for that purpose those portions of a geologic strata located at a depth of two thousand five hundred feet or more below the surface of the land which, on the effective date of a permit issued pursuant to this article, do not have a current or reasonably foreseeable use for a qualifying purpose. Such right to use such geologic strata located at a depth of two thousand five hundred feet or more below the surface is hereby dedicated to be a public use and no compensation shall be required to be paid solely for such use.

Proposed new definitions:

> "Qualifying purpose" means the lawful use of geologic strata for any significant purpose, including but not limited to, the storage of natural gas, or the extraction of coal, oil, natural gas, coalbed methane or other minerals in paying quantities utilizing then-current production techniques or technologies that are feasible for use in the region, but does not include the use of such strata for the purpose of storing or sequestering carbon dioxide.
>
> "Permit issued pursuant to this article" means a permit issued by the secretary pursuant to this article for the sequestration of carbon dioxide in geologic strata.

The CCS permit will be the mechanism for determining whether there is an existing use, for seeking to resolve that competing use and for authorizing the use of the geologic strata for the sequestration of carbon dioxide.

Proposed new section:

> (a) Property owners potentially affected by a proposed sequestration facility shall have the opportunity to demonstrate the project will impair a current or reasonably foreseeable use of the geologic strata for a qualifying purpose during the permit

> application's public comment period. If impairment is demonstrated, the secretary shall issue a permit for the project upon the condition that the operator:
>
> (1) reach a contractual agreement with such owner resolving the claim of a preexisting interest;
>
> (2) modify the project so that it avoids the impairment; or
>
> (3) initiate condemnation proceedings to acquire the property rights likely to be materially impaired.
>
> (b) In the absence of a showing that the geologic strata proposed for use has a current or reasonably foreseeable use for a qualifying purpose that is likely to be materially impaired by the proposed project, the public interest associated with sequestering carbon dioxide in geologic strata to help mitigate effects of climate change shall prevail over any right of the owners of any rights in such strata to exclude operators who are properly licensed pursuant to this article. Therefore, an operator conducting activity pursuant to a permit issued pursuant to this article for the sequestration of carbon dioxide in such strata shall have the right to inject into and occupy the geologic strata within the boundaries designated by such permit in all areas in which all portions of such geologic strata are located at a depth of two thousand five hundred feet or more below the surface of the land and, which on the effective date of such permit do not have a current or reasonably foreseeable imminent use for a qualifying purpose that is likely to be materially impaired by the proposed project.

[Note: Additional drafting on this provision may be necessary to make it clear that the 2500 feet measurement is the minimum distance between the upper most portion of the reservoir and lower most portion of the surface of the land overlying the projected plume area.]

Restriction on usage of hydrocarbon bearing and other formations

The operator should not be allowed to store CO_2 in geologic strata bearing coal, oil, natural gas, coalbed methane, or other minerals which could be extracted in paying quantities utilizing then current production techniques or technologies that are feasible for use in the region unless that formation is owned by the operator, or has permission of the owner to authorize such a use.

Proposed new section:

> (a) The owner or operator of a sequestration facility shall obtain a permit pursuant to this article from the secretary prior to the construction, operation or modification of a sequestration facility. Any entity owning or operating a sequestration facility in existence on the effective date of this article is hereby authorized to continue operating until such time as the secretary has established operational and procedural requirements applicable to

such existing sequestration facilities and the entity owning or operating such facility has had a reasonable opportunity to comply with those requirements.

(b) A sequestration facility for carbon dioxide is hereby authorized, provided that the secretary shall first issue a permit authorizing such proposed sequestration of carbon dioxide and designating the horizontal and vertical boundaries of the sequestration facility. In order to authorize a sequestration facility for carbon dioxide, the secretary shall find as follows:

(1) That an applicant has obtained or applied for a certificate of public convenience and necessity from the public service commission pursuant to this article;

(2) That (a) the formation has characteristics suitable for or which can be made suitable for the storing of carbon dioxide through fracturing or other demonstrated techniques, (b) the boundaries of the sequestration facility can be established with reasonable certainty and (c) the sequestration facility is otherwise suitable and feasible for the injection, storage and, if proposed, withdrawal of carbon dioxide;

(3) That the use of the sequestration facility for the sequestration of carbon dioxide will not contaminate other formations containing fresh water, oil, natural gas, coal, coalbed methane, or other minerals that could be extracted in paying quantities utilizing then-current production techniques or technologies that are feasible for use in the region;

(4) That the sequestration facility will not be used to inject carbon dioxide into that part of a geologic strata that is within the certificated boundaries (including the protective area) of an existing natural gas storage field certificated by the federal energy regulatory commission or the public service commission;

(5) That the sequestration facility will not be used to inject carbon dioxide into a geologic strata bearing oil, natural gas, coal, coalbed methane, or other minerals capable of being produced in paying quantities utilizing then-current production techniques or technologies that are feasible for use in the region, unless the proposed operator demonstrates that it owns the affected oil, natural gas, coal, coalbed methane, or other minerals in such geologic strata within the proposed boundaries of the sequestration facilities or has the permission of the owner to authorize such a use,

(6) That the sequestration facility will be operated in such a manner as to protect human health and the environment; and

> (7) That the qualities of the carbon dioxide to be managed will not compromise the safety or structural integrity of the sequestration facility.
>
> (c) In the event one sequestration facility is or may interfere with another sequestration facility, the secretary shall resolve the dispute by taking such remediation actions, enforcement actions or permit modifications as may be necessary to resolve the dispute and to avoid future interference.

Primacy of mineral estate

Statutory and common law regarding primacy of a mineral estate should not be altered, nor should there be a limit on the right of a mineral owner to make reasonable use of the subsurface for mineral exploration or production. The holder of a mineral interest should not be prevented from exercising its lawful rights in a manner that will not compromise the safety or integrity of the CO_2 sequestration project. If such rights cannot be exercised without compromising the sequestration project, such activities should be restricted or precluded to the extent necessary to protect the safety or integrity of the sequestration project, without compensation being required. If the mineral interest owner or holder believes the prohibition amounts to an uncompensated regulatory taking, the interest-holder may, of course, file an inverse condemnation claim.

Proposed amendment to § 22-11A-8:

> (a) Nothing in this article shall be deemed to affect the otherwise lawful right of a ~~mineral owner~~ person to drill or bore through or otherwise exercise rights near a formation in which carbon dioxide is being sequestered ~~sequestration site, if done~~ in accordance with the rules promulgated ~~under~~ pursuant to this article to protect the safety and integrity of ~~for protecting~~ the carbon dioxide sequestration project ~~site~~ against the escape of carbon dioxide.

[Note: Additional editing to the subsection may be needed to address the term “near”.]

> (b) The injection of carbon dioxide for purposes of enhancing the recovery of coal, oil, natural gas, coalbed methane or other minerals pursuant to a project approved by the department shall not be subject to the provisions of this article. Nothing in this article is intended to impede or impair the ability of ~~an oil, natural gas or coalbed methane operator to inject carbon dioxide through an approved enhanced oil, natural gas or coalbed methane recovery project and~~ any party entitled thereto to establish, verify, register and sell emission reduction credits ~~associated with the project~~.
>
> (c) Except as herein specifically provided, nothing in this article shall alter or amend existing state law regarding correlative property rights or the primacy of the coal, oil, natural gas, coalbed

methane or other mineral estate. [Note: Additional research may lead to further changes to this provision.]

(~~c~~d) The Office of Oil and Gas shall have jurisdiction over any subsequent extraction of sequestered carbon dioxide that is intended for commercial or industrial purposes.

(e) Except as herein specifically provided, nothing in this article shall alter, amend, diminish or invalidate rights to use subsurface pore space that were acquired by contract or lease prior to the effective date of this article, including, without limitation, rights acquired for the underground storage of natural gas, or in connection with the extraction or production of coal, oil, natural gas, coalbed methane or other minerals, including, without limitation, rights for the secondary recovery of coal, oil, natural gas, coalbed methane or other minerals by injection of carbon dioxide or water or by other means.

Eminent domain

To the extent that it is necessary for an operator to take an interest in property, the issuance of a permit under this article in conjunction with PSC approval shall be sufficient to authorize the use of eminent domain. Existing powers of eminent domain are to be preserved.

Proposed new section:

(a) Except as provided in subsection (b) of this section, any sequestration operator or pipeline operator is hereby authorized, after obtaining any permit from the secretary required by this article and any certificate of public convenience and necessity from the public service commission required by this article, to exercise the power of eminent domain to acquire surface and subsurface rights and property interests necessary or useful for the purpose of constructing, operating or modifying the sequestration facility or carbon dioxide transmission pipeline, including easements and rights-of-way across lands for pipelines transporting carbon dioxide to and among facilities constituting said sequestration facility.

(b) No sequestration operator or pipeline operator may exercise the power of eminent domain for the purpose set forth in subsection (a) of this section:

(1) to obtain title to coal, oil, gas, coalbed methane, or other minerals which on the effective date of any permit from the secretary required by this article are capable of being produced in paying quantities utilizing then-current production techniques or technologies that are feasible for use in the region, except in accordance with subsection __, or

> (2) to obtain right of way for a pipeline to transport carbon dioxide that is withdrawn from a sequestration facility to a location that is outside the boundaries of the storage facility.
>
> (c) The exercise of the right of eminent domain granted in this article shall not prevent entities from drilling through the sequestration facility in such manner as shall comply with the requirements of the secretary sequestration issued for the purpose of protecting the sequestration facility against pollution or invasion and against the escape or migration of carbon dioxide. Furthermore, the right of eminent domain set out in this article shall not prejudice the rights of the owners of said lands or other rights or interests therein as to all other uses not acquired for the storage facility.
>
> (d) The eminent domain authority authorized under this article shall be in addition to any other power of eminent domain authorized by law.
>
> (e) No rights or interests in sequestration facilities acquired for the injection and sequestration of carbon dioxide by an operator who has obtained a permit pursuant to this act shall be subject to the exercise of the right of eminent domain authorized by this act. The secretary, however, may reopen an earlier permit for the purpose of balancing the interest of two or more projects with competing interests. The secretary shall modify one or more of the original permits to the extent necessary to resolve such competing interests.

Pore space compensation

In determining the amount of compensation to be paid to a property owner for the taking of any necessary property rights related to the use of pore space, no value shall be attributed to the present or future use of that pore space for the sequestration of CO_2.

Proposed new section:

> (a) In any case in which property may lawfully be taken for a public use, application therefore may be made by petition to the circuit court or the judge thereof in vacation, of the county in which the estate is situated. If a tract lies partly in one county and partly in another, the application in relation thereto may be made in either county. Except as provided in section ___, the condemnation proceeding shall be conducted pursuant to the provisions of article two, chapter fifty-four of this code; provided that in determining the amount of compensation to be paid to a property owner for taking of any necessary property rights related to the use of pore space, no value shall be attributed to the present or future use of that pore space for the sequestration of carbon dioxide.

Trespass and Nuisance

If at any time it is determined by a court of competent jurisdiction that an operator is required to own a property right that the operator does not then own, the operator shall be required to obtain that property right, but would not be subject to common law or other claims (i.e. trespass or nuisance) for the failure to have owned that property right.

Proposed new section:

> (a) In the event it is determined by a court of competent jurisdiction that an operator who is operating in compliance with a valid permit issued pursuant to this article is required to obtain a property right that the operator does not then own, the operator shall be required to obtain that property right, but the operator shall not be liable under common law for claims of trespass or nuisance based upon the failure to have owned that property right; provided, however, that such an operator shall not be protected from such claims if the operation involved impedes the recovery of coal, oil, natural gas, coalbed methane, or other minerals capable of being produced in paying quantities utilizing then-current production techniques or technologies that are feasible for use in the region.
>
> (b) In the event the owner of such geologic strata believes such use is a *per se* physical taking of property without just compensation, the aggrieved owner may file an inverse condemnation action.

Property owner identification and notice

One additional option for steam-lining the process of undertaking eminent domain would be to rely upon tax records to determine property ownership. No effort has yet been undertaken to prepare specific provisions related to this possibility.

Role of ALJs

As an alternative to filing an eminent domain action in circuit court, it may be desirable to allow application to be made to a panel of administrative law judges or special board of appraisers which might be empowered to determine compensation to be paid for property rights to be taken (subject, of course, to appeal to an appropriate circuit court). No effort has yet been undertaken to prepare specific provisions related to this possibility.

IV.C.6. Other issues to be addressed by the Legal Subcommittee

Permitting

The operator shall be required to obtain a permit pursuant to the West Virginia Carbon Dioxide Sequestration Act from the DEP prior to the construction, operation or modification of a carbon dioxide sequestration facility. In order to obtain the permit, DEP shall require the applicant to obtain a certificate of public convenience and necessity from the public service commission ("PSC") in addition to the other requirements. This permit application shall be transparent with the federal Safe Drinking Water Act, relating to the state's participation in the underground injection control program, and the state's requirement to obtain a "well work" permit. The operator will be required to demonstrate appropriate financial responsibility throughout the injection process and through closure. The permitting requirements should mandate that construction on the facility begin within a specified period of time following permit issuance.

Groundwater Protection

The Groundwater Protection Act currently contains exemptions for activities that involve direct contact with groundwater. At the time the Groundwater Protection Act was enacted in 1994, the possibility of injecting carbon dioxide in geologic formations was not known to the Legislature. Since carbon sequestration is very similar to the activities that were exempt from coverage under various portions of the Groundwater Protection Act, it is appropriate to expand those exemptions to include carbon dioxide sequestration wells in the same manner that UIC Class 2 and 3 wells are currently exempt.

Administrative Fees

Permit application fees shall be assessed for applications filed with each of the DEP and the PSC. In addition, an administrative trust fund shall be created to offset the cost of administering the remainder of CCS regulatory program.

Interstate Projects

Due to the fact that the geologic basins containing formations suitable for geologic sequestration cross state boundaries creating the likelihood that plumes from the injection formation could cross into another state, it may be necessary to authorize the Secretary to enter into reciprocal agreements with other governments or government entities.

Preemption

All laws should be preempted other than those specifically authorized to regulate carbon dioxide sequestration facilities (in much the same way as those laws are currently preempted under the Groundwater Protection Act).

Report to Legislature

The Secretary shall submit timely reports to the legislature assessing the effectiveness of the carbon dioxide sequestration program.

Liability transfer

Liability transfer should be authorized during the post closure period to promote CCS activities. Ownership of the storage facility including the stored carbon dioxide shall transfer to a quasi-public entity, the state, or the federal government upon the issuance of a certificate of completion by the Secretary of the DEP.

Post Closure Trust Fund

A trust fund should be established to provide funds to maintain the facility in the post closure phase and to purchase insurance and if necessary to respond to claims. Provision should be made for the handling of subsequent sequestration facilities.

PSC Approval

As noted above in 7.a., a certificate of public convenience and necessity shall be required from PSC before beginning construction of the storage facility or carbon dioxide transmission pipeline. The power of eminent domain shall be authorized to any storage operator or pipeline operator who obtains a permit under the West Virginia Carbon Dioxide Sequestration Act and obtains a certificate of public convenience and necessity from the PSC.

Ownership and Value of Stored CO_2

The owners of geologic strata being used for the storage of carbon dioxide need to receive assurances that they will be allowed to participate in any economic value that may be associated with the removal of the carbon dioxide for profit. Such provisions might addresses ownership of the CO_2 underground as well as assuring that the owners of the geologic strata in which CO_2 is stored are not subject to liability related to that storage.

Forced unitization

Forced unitization will continue to be evaluated as an administrative mechanism for obtain necessary rights to use pore space.

Pipelines

Pipelines will be an important part of a successful CCS program. Additional evaluation will be undertaken about pipeline to include their siting and permitting. In addition, attention will need to be given to the acquisition of rights of way for pipelines.

V. MINORITY OPINIONS

V.A. Minority Report on Risk Assessments for Long Term Geologic Storage of Carbon Dioxide.

By John Leeson on June 14, 2010

There have been some risk assessments for long term geologic storage of carbon dioxide. My understanding is that some of the risk assessments have been done or assisted by mathematical modeling or simulations.

I do not have confidence in calculated probabilities of carbon dioxide loss from geologic storage.

In my opinion, there is insufficient current information and carbon dioxide storage history to accurately determine risk probabilities of carbon dioxide loss from geologic storage, particularly from aquifers. Most of the potential carbon dioxide storage capacity in West Virginia is in saline aquifers.

It seems to me that the risk of carbon dioxide loss will likely be different from different geologic formations used for storage such as depleted oil and gas fields, coal beds and aquifers. One general calculated risk probability value is not likely to adequately describe the risks of storage in various types of formations.

V.B. WVCCS Working Group Legal Subcommittee Minority Report.

June 30, 2010

Prepared by David McMahon, J.D.; Surface owners representative.1624 Kenwood Road, Charleston, WV 25301. Voice/VoiceMail 304-415-4288 E-mail: wvdavid@wvdavid.net

This minority report on the work of the Legal Subcommittee will not be lengthy because this is an interim report, and because of constraints on funding for the participation of pubic interest members. It will only be on one of the subjects that the Legal Subcommittee addressed without waiving the right to comment on other aspects of the final report. A comment in an earlier draft of this Minority Report on the issue of ultimate "liability transfer" took the position that the sequestering entity should always retain some liability, like a deductible, for public policy reasons. Since the Legal Subcommittee has not discussed that issue, the comment was removed.

Acquisition of right to use the pore space

The Carbon Dioxide Sequestration Working Group was initiated by Legislation. The introduced version of that legislation included a presumption that the owner of the surface of any tract of land also owned the pore space – meaning that it would need to be purchased or taken the same as any other interest in land before it could be used for carbon sequestration. How far we have come.

That initial universal presumption did go too far, and it was not included in the final legislation. There are circumstances where the fee owner of a tract of land deeds the surface to another owner, and the clear contemplation of the parties is that the purchaser is only getting the surface (and even that surface is subject to the mineral owners rights to use the surface for obtaining the minerals using methods in the contemplation of the partes at the time of the severance deed). That surface owner does not own, and should not be presumed to have, any rights to the pore space in that limited situation.

However, in many, probably most cases, the deeding away of oil and gas, or coal, or minerals, by someone who kept what was not deeded away, did not contemplate the deeding of the right to use pore space. Indeed that has been the working premise of the long established conventional natural gas storage industry in West Virginia for many, many years. So lots of surface owners own pore space even if they do not also own the minerals.

And owners who own the minerals but not the surface are not so concerned about the effects on the surface or the potential harm to groundwater etc. But those mineral owners who do also own the pore space believe that they have something valuable – increasingly valuable it turns out.

The legal subcommittee recognized early on that the subcommittee could provide a number of different options for a legal regime and process for establishing the right to sequester carbon dioxide in the pore space of land owned by others. There are opponents of carbon sequestration who may well sue to stop it. The options will be on a continuum that includes a consideration of the possible law suit to stop it. On one end is a regime and process that will guarantee that there will be no successful legal challenge on basis of taking or trespass, but which require much greater time and effort and expense to accomplish. On the other end of the continuum are regimes and processes which will be quick and cheap, but unlikely to stand up to constitutional and other challenges in the courts.

A distilling of the subcommittee's progress would be that its thinking started almost on one end of the spectrum, but ended up at the other end of the spectrum. The subcommittee learned more and more about how difficult it would be to identify the owners of the pore space and contact them to purchase the right to use it or, in the event they were unwilling to sell it for the price offered, condemn it. Also, the political difficulties of condemnation legislation entered into the analysis. So the subcommittee searched harder and harder for some alternative. Without finding any legal authority that this report believes is solid, it abandoned notice and negotiated purchase/condemnation of individual tracts. While this minority report can only compliment the thoroughness and openness of the effort, the result in the interim report is not fair to the owners of pore space, whoever they may be, or to owners of other interests in the land whether they be surface or gas. And in addition it will not likely stand up to constitutional scrutiny. And the result is certainly not certain enough of its constitutionality to prevent carbon sequestration from being held up by long litigation over its constitutionality. In addition, its apparent unfairness to land interest owners will probably not have a greater likelihood of success in the Legislature than would increasing condemnation rights.

The subcommittee's current recommendation is in essence that,

> "We can pump carbon dioxide under your land at such high pressures that it will not turn to gas. We can do it without your permission unless you get some general notice sent to the public and point out during a permit process that the project will 'impair a current or reasonably foreseeable use of the geologic strata [not strata above and below that strata that may be impaired, but the strata used for sequestration] for a qualifying purpose'. And we do not have to pay you for doing this under your land unless you have a current or reasonably foreseeable economic use utilizing then-current production techniques or technologies that are feasible for use in this region. The reason we can do this is that we need to do this really badly and it is too hard to do it any other way, so we think the courts will say it is not a trespass or a taking. And if we do need to take it from you because you have a current economic use for it, then we will compensate you on what the pore space was worth to you the seller and not to us the buyer."

The report analogizes the sequestering of carbon dioxide to the regime of law for disposal of *treated* municipal waste water in Florida or a court case for salt water disposal in Ohio. This minority report does not think that our courts will find those processes to be analogous to carbon sequestration, or that, our courts would be persuaded by the legal reasoning of those regimes and cases in other states even if the circumstances were analogous.

When we started we were cynical that using someone's property without finding and compensating them was not going to be acceptable. Since we figured out how hard that would be, we have convinced ourselves that it is possible to do it differently. We have figured this out only in the face of the difficulty of doing it otherwise. We have not come to this conclusion based on based on newly discovered law or facts.

What the committee should do is a further investigation of processes and statutory evidentiary, valuation and other presumptions in order to more economically find the owners and compensate them.

One particular problem is that using one formation for carbon sequestration will make it more difficult to drill to gas (or other) resources in lower formations. This could cause producers to want to drill instead on tracts where there is no carbon sequestration, and so lower the value of the tracts underlain by carbon sequestration. A possible avenue of investigation to address that is to keep escrows to compensate owners for the extra cost of drilling through formations used for carbon sequestration in the event the owner ever finds it necessary or convenient to drill through the formation used for carbon sequestration to deeper gas or other resources.

Below is a list of the interests who would oppose the use of their land for carbon sequestration and their rationale. It is supplied both to show some of the legal reasoning to be avoided and show the motivation to oppose carbon sequestration.

1. It’s mine and I don't want you doing with it just because its mine and not yours and this is America and you should not be able to take it any more than you should be able to take my guns.
2. It’s mine and I do not want it harmed – particularly the surface and groundwater, but all of it really. You say that supercritical carbon dioxide will not get loose and come to the surface, but I do not believe you. You can't prove a negative to my satisfaction – that it will not harm me or my land somehow. Particularly when we have 1) 50,000 active oil and gas wells in the state with un-cemented annular spaces in between the cementing of the surface/coal casing and the cementing of the production pipe at the bottom of the hole near the production formation, and 2) there are 9000, or maybe more, pre-1929 orphaned oil and gas wells that have not been plugged at all and more than 10,000 post-1929 wells that need plugged that the State does not have the resources to make the industry plug. I do not want that carbon sequestered under me.
3. It’s mine and you are taking it and you need to pay me. Fundamental fairness. How come those people in New York don't have to pay me for it just because they need it very badly. You can say you can trespass onto me without paying me or “taking” it because I am suffering no harm. But if it has value to you, how come you are now saying it has no value to me.
4. It’s mine and you are ruining/diminishing the speculative value of the formation you are using and the formations below it. Just because I am not using it now, or have no immediate plans to drill through it to possible deeper formations right now, does not mean it does not have value to me. No one thought the Marcellus Shale was worth anything three years ago, but new discoveries and technologies have made it the most valuable gas find ever in West Virginia! Some day they will discover deeper gas or some other valuable substance, but it will cost more to get through the formation where the carbon dioxide is sequestered so they will go do it on someone else’s land. Don’t tell me that speculative value does not mean anything. If that was true, surface owners could buy their minerals back for what they sold it for.

The draft recommendation saying that those objections are not relevant because “It’s not yours,” will be an inadequate response to these interest groups, and the courts and the Legislature.

APPENDIX 9
House Bill 259
2011 Kentucky Legislative Session

AN ACT relating to economic development.

Be it enacted by the General Assembly of the Commonwealth of Kentucky:

➔SECTION 1. A NEW SECTION OF KRS CHAPTER 353 IS CREATED TO READ AS FOLLOWS:

As used in Sections 1 to 7 of this Act, unless the context requires otherwise:

(1) "Cabinet" means the Energy and Environment Cabinet;

(2) "Carbon dioxide" means anthropogenic carbon dioxide of sufficient purity and quality as to not compromise the safety and efficiency of the reservoir to securely contain it;

(3) "Carbon injection well" means a well drilled or converted and operated for the purpose of injecting carbon dioxide into subsurface rock formations for geologic storage;

(4) "Division" means the Division of Oil and Gas within the Department for Natural Resources;

(5) "Geologic storage" means permanent or temporary underground storage of carbon dioxide in a reservoir;

(6) "Permeability" means a measure of the capacity of reservoir strata to accept and transmit fluids, including carbon dioxide;

(7) "Pore space" means the voids in subsurface reservoir strata suitable to contain stored carbon dioxide;

(8) "Pore space owner" means the surface owner unless the pore space has been severed from the surface estate, in which case the pore space owner shall include all persons reasonably known to own an interest in the pore space;

(9) "Reservoir" means a subsurface volume of rock with sufficient porosity and permeability to be suitable for the injection and storage of carbon dioxide, and that has adequate seals to prevent leakage of carbon dioxide;

(10) "Seal" means a subsurface stratum or formation sufficiently impermeable to

prevent vertical or lateral movement of injected carbon dioxide out of the storage reservoir;

(11) "Secretary" means the secretary of the Energy and Environment Cabinet;

(12) "Storage facility" means the underground reservoir, underground equipment, and surface buildings and equipment utilized in the storage operation, excluding pipelines used to transport the carbon dioxide to the storage and injection site. The reservoir component of the storage facility shall include a necessary and reasonable areal buffer and subsurface monitoring zones as required by the permit issued by the USEPA for the demonstration carbon injection well;

(13) "Storage operator" means any person holding a permit from the USEPA to operate a storage facility; and

(14) "USEPA" means the United States Environmental Protection Agency.

➔SECTION 2. A NEW SECTION OF KRS CHAPTER 353 IS CREATED TO READ AS FOLLOWS:

The General Assembly finds and declares that:

(1) The geologic storage of carbon dioxide will benefit the environment and the citizens of the Commonwealth;

(2) It is vital that long-term geologic storage of carbon dioxide in the Commonwealth be accomplished without disturbance of surface, mineral, or water resources and that public safety is ensured;

(3) Carbon dioxide has current and potential value and its geologic storage may allow for its orderly withdrawal as necessary for commercial, industrial, or other uses, including for enhanced oil and gas recovery;

(4) Development and deployment of carbon capture and storage technology in the Commonwealth will allow industries to utilize diverse fuel sources, create jobs, contribute to state and local tax bases, and enable Kentucky industries to remain competitive in the global economy; and

(5) Attracting demonstration or pilot scale projects that incorporate carbon storage or projects that integrate carbon capture and storage is an economic development priority that will create jobs for Kentuckians and favorably position the Commonwealth for future leadership and growth in the field of carbon storage.

➔SECTION 3. A NEW SECTION OF KRS CHAPTER 353 IS CREATED TO READ AS FOLLOWS:

(1) The division is authorized to seek primary jurisdiction and authority over matters relating to the geologic storage of carbon dioxide in the Commonwealth once these programs have been developed at the federal level.

(2) The cabinet shall seek one (1) to five (5) demonstration projects for location in the Commonwealth. Projects shall be approved by the secretary or a designee. To be approved, a project shall inject carbon dioxide into pore space that contains no economically recoverable minerals at the time of the injection and shall:

- ***(a) Incorporate carbon storage or integrate carbon capture and storage technology; or***
- ***(b) Be a carbon capture and storage project that is associated with a project that has otherwise qualified and been approved for incentives under KRS 154.27-010 to 154.27-090, the Incentives for Energy Independence Act.***

(3) Within eighteen (18) months of obtaining approval of a demonstration project from the cabinet, the applicant shall file the necessary application for a Class V well with Region 4, U.S. Environmental Protection Agency (USEPA), The applicant must begin work on the demonstration project within eighteen (18) months of the date the Class V well permit is granted by the USEPA. The applicant may request an extension of time from the cabinet. If the requirements of this subsection have not been met within the time allowed and the cabinet has not granted an extension of time, the cabinet may revoke its approval of the demonstration project.

(4) The cabinet shall provide testimony on the program's development annually, beginning in 2012, at meetings of the Interim Joint Committee on Natural Resources and Environment and the Special Subcommittee on Energy unless the chairs of the committees direct otherwise. The testimony shall include specific recommendations for legislative action, including necessary appropriations.

➔SECTION 4. A NEW SECTION OF KRS CHAPTER 353 IS CREATED TO READ AS FOLLOWS:

(1) The storage operator shall negotiate with the pore space owners and acquire rights needed to access the pore space.

(2) If, after good-faith negotiation, the storage operator cannot locate or cannot reach an agreement with all necessary pore space owners, but has secured written consent or agreement from the owners of at least fifty-one percent (51%) of the interest in the pore space for the storage facility, the division shall order the pooling of all pore space included within the proposed storage facility if the division:

(a) Holds a hearing after notice pursuant to KRS Chapter 13B; and

(b) Finds that the requirements of this section and Section 5 of this Act have been met.

For the purposes of this section, any unknown or nonlocatable owners shall be deemed to have consented or agreed to the pooling, provided that the storage operator has complied with the publication requirements of Section 5 of this Act.

(3) A carbon injection well shall be exempt from the provisions of KRS 353.651 and 353.652 and 805 KAR 1:100, regardless of the depth of the well.

➔SECTION 5. A NEW SECTION OF KRS CHAPTER 353 IS CREATED TO READ AS FOLLOWS:

(1) The storage operator shall provide a list to the division of all persons reasonably known to own an interest in pore space proposed to be pooled in an application to

the division for a pooling order. A pooling order shall be made only after the division provides notice to all pore space owners proposed to be pooled and after a hearing has been held.

(2) The division shall set and collect a fee adequate to pay expenses associated with the conduct of administrative hearings for pooling of pore space.

(3) If the proposed pooling order concerns pore space with unknown or nonlocatable owners, the storage operator shall publish one (1) notice in the newspaper of the largest circulation in each county in which the pore space is located. The notice shall appear at least twenty (20) days prior to the hearing on the application for the pooling order. The notice shall:

- *(a) State that an application for a pooling order has been filed with the Division of Oil and Gas in the Department for Natural Resources;*
- *(b) Describe the pore space proposed to be pooled;*
- *(c) In the case of an unknown pore space owner, indicate the name of the last known owner;*
- *(d) In the case of a nonlocatable pore space owner, identify the owner and the owner's last known address;*
- *(e) State that any person claiming an interest in the pore space proposed to be pooled should notify the director of the division and the storage operator at the published address within twenty (20) days of the publication date; and*
- *(f) Give the date, time, and location of the hearing.*

(4) A pooling order shall authorize the long-term storage of carbon dioxide beneath the tract or portion. The order shall also authorize, where necessary, the location of carbon injection wells, outbuildings, roads, monitoring equipment, and access to them. The pooling order shall identify the compensation to be paid to unknown, nonlocatable, and nonconsenting pore space owners and the basis for valuation of the pooled interest.

(5) A certified copy of any pooling order shall be entitled to be recorded in the office of the county clerk of the county or counties in which all or any portion of the pooled tract is located. Recordation of the order shall be notice of the order to all persons.

➔SECTION 6. A NEW SECTION OF KRS CHAPTER 353 IS CREATED TO READ AS FOLLOWS:

(1) Upon completion of active injection, the storage operator shall notify the division of the completion and close and plug the carbon injection wells as required by the permit issued by USEPA for the demonstration carbon injection wells.

(2) The storage operator shall monitor the storage facility for leakage and migration for the time period and by the methods required by the permit for the carbon injection wells after completion of active injection and plugging of the carbon injection wells.

(3) The ownership and liability for a storage facility may be transferred to:

(a) The federal government if a federal program exists; or

(b) The Finance and Administration Cabinet pursuant to subsections (4) to (6) of this section if a federal program does not exist.

(4) If no federal program exists, and the storage operator seeks to transfer the ownership and liability of a storage facility to the Finance and Administration Cabinet, after completion of the required period of monitoring following completion and plugging, the storage operator shall notify the division of its intent to transfer ownership of the stored carbon dioxide and associated liability to the Finance and Administration Cabinet. The storage operator shall provide evidence to the division of the satisfactory completion of all permit conditions pertaining to the demonstration carbon injection well. Upon receipt and evaluation of satisfactory evidence, the division shall forward the evidence to the Finance and Administration Cabinet with a recommendation for the transfer of

ownership of the stored carbon dioxide and liability. The storage operator may then apply to the Finance and Administration Cabinet for the transfer of ownership and liability for the stored carbon dioxide.

(5) Ownership of and liability for the stored carbon dioxide shall remain with the storage operator until the transfer is completed.

(6) Upon receipt of the evidence and recommendation of the division and the application for transfer by the storage operator, the Finance and Administration Cabinet shall take appropriate action to effect a transfer.

➔SECTION 7. A NEW SECTION OF KRS CHAPTER 353 IS CREATED TO READ AS FOLLOWS:

(1) The secretary of the cabinet shall take affirmative steps to initiate discussions with surrounding states to develop a coordinated and unified approach to subsurface migration of stored carbon dioxide and may enter into reciprocal agreements with states that share a border with Kentucky that:

(a) Affirm that accidental or unforeseen migration of subsurface stored carbon dioxide across state lines shall not be treated by the states as trespass;

(b) Provide a mechanism for resolution and compensation for unforeseen migration incidents, including necessary monitoring arrangements to track or arrest future migration; or

(c) Establish a process whereby reservoirs that cross state lines can be created where it is geologically and mutually advantageous to do so.

(2) The cabinet shall report to the Governor and the Legislative Research Commission on the progress of discussions held under this section. The report shall be presented in writing and through testimony to the Special Subcommittee on Energy and the Interim Joint Committee on Natural Resources and the Environment annually unless the chairs of these committees direct otherwise. Reporting shall begin in 2012 and continue until the cabinet is satisfied that all

necessary agreements have been reached and has reported that conclusion.

AN ACT relating to the capture and transportation of carbon dioxide.

Be it enacted by the General Assembly of the Commonwealth of Kentucky:

➔SECTION 1. A NEW SECTION OF SUBCHAPTER 27 OF KRS CHAPTER 154 IS CREATED TO READ AS FOLLOWS:

(1) For the purposes of this section, "carbon dioxide transmission pipeline" has the same meaning as in Section 2 of this Act.

(2) If a carbon dioxide transmission pipeline company has received a construction certificate from the Kentucky State Board on Electric Generation and Siting under Section 6 of this Act and is unable to contract or agree with the owner after a good-faith effort to do so, the company may condemn the lands and material for the use and occupation of the lands that are necessary for:

  (a) Constructing, maintaining, utilizing, operating, and gaining access to a carbon dioxide transmission pipeline and all necessary machinery, equipment, pumping stations, appliances, and fixtures for use in connection with a carbon dioxide transmission pipeline; and

  (b) Obtaining all necessary rights of ingress and egress to construct, examine, alter, repair, maintain, operate, or remove a carbon dioxide transmission pipeline and all of its component parts.

(3) The proceedings for condemnation shall be as provided in the Eminent Domain Act of Kentucky.

(4) Carbon dioxide transmission pipelines, and the routing, construction, maintenance, and operation of them are, as a matter of legislative determination, declared to be a public use essential to the fulfillment of the purposes of this chapter.

➔Section 2. KRS 154.27-010 is amended to read as follows:

As used in this subchapter:

(1) "Activation date" means the date on which an approved company begins incurring

recoverable costs or engaging in recoverable activity pursuant to the tax incentive agreement. The activation date shall be set forth in the tax incentive agreement and shall be a date within five (5) years of the date of final approval of the tax incentive agreement. The authority may extend the five (5) year period to no more than seven (7) years upon written application for an extension by the approved company. To implement the activation date, the approved company shall notify the authority of its intent to activate the tax incentives authorized in the tax incentive agreement. The activation date shall apply to all incentives included in the tax incentive agreement regardless of whether the approved company has met the requirements to receive all incentives at that time. If the approved company does not implement the activation date before the date established in the tax incentive agreement, the activation date shall be the date established in the tax incentive agreement;

(2) "Affiliate" has the same meaning as in KRS 154.22-010;

(3) (a) "Alternative fuel facility" means a facility located in Kentucky that is newly constructed on or after August 30, 2007, or an existing facility located in Kentucky that is retrofitted or upgraded on or after August 30, 2007, and that, after the new construction, retrofit, or upgrade, primarily produces for sale alternative transportation fuels. For a retrofit of an existing facility, the new modification or addition within the facility shall primarily produce alternative transportation fuel for sale.

(b) The alternative fuel facility may produce electricity as a by-product if the primary purpose for which the facility is constructed, retrofitted, or upgraded, and the primary function of the facility remains the production and sale of alternative transportation fuels;

(4) "Alternative transportation fuels" has the same meaning as in KRS 152.715;

(5) "Approved company" means a corporation, limited liability company, partnership, registered limited liability partnership, sole proprietorship, business trust, or any

other entity approved for incentives for an eligible project;

(6) "Authority" means the Kentucky Economic Development Finance Authority established by KRS 154.20-010;

(7) "Base amount" means the tons of coal, thousand (1000) cubic foot units (Mcf) of natural gas, or gallons of natural gas liquids purchased and used or severed and used by the approved company as feedstock for an eligible project during the twelve (12) months prior to the month in which the approved company first begins receiving incentives under KRS 143.024 or 143A.025, and 154.27-060, that were subject to the tax imposed by KRS 143.020 or 143A.020;

(8) "Biomass resources" has the same meaning as in KRS 152.715;

(9) (a) "Capital investment" means:

1. Obligations incurred for labor and to contractors, subcontractors, builders, and materialmen in connection with the acquisition, construction, installation, equipping, upgrading, or retrofitting of an eligible project;

2. The cost of acquiring land or rights in land and any cost incident thereto, including recording fees;

3. The cost of contract bonds and of insurance of all kinds that may be required or necessary during the course of acquisition, construction, installation, equipping, upgrading, or retrofitting of an eligible project which is not paid by the contractor or otherwise provided;

4. All costs of architectural and engineering services, including test borings, surveys, estimates, plans, specifications, preliminary investigations, supervision of construction, and the performance of all the duties required by or consequent upon the acquisition, construction, installation, equipping, upgrading, or retrofitting of an eligible project;

5. All costs required to be paid under the terms of any contract for the

acquisition, construction, installation, equipping, upgrading, or retrofitting of an eligible project; and

6. All other costs of a nature comparable to those described in this subsection.

(b) "Capital investment" does not include costs described in paragraph (a) of this subsection that are paid for with funds received from the federal government or that are reimbursed by the federal government;

(10) "Carbon capture ready" means planning for or anticipating capture of carbon dioxide in a manner to facilitate continued operation of the facility in compliance with applicable federal requirements;

(11) ***"Carbon dioxide transmission pipeline" means the in-state portion of a pipeline, including appurtenant facilities, property rights, and easements, that is used exclusively for the purpose of transporting carbon dioxide to a point of sale, storage, or other carbon management applications;***

(12) "Center for Applied Energy Research" means the University of Kentucky Center for Applied Energy Research;

(13)[~~(12)~~] "Commonwealth" means the Commonwealth of Kentucky;

(14)[~~(13)~~] "Construction period" means the period beginning with the activation date of the eligible project and ending on a date set forth in the tax incentive agreement, which shall be no later than five (5) years from the activation date;

(15)[~~(14)~~] "Department" means the Department of Revenue;

(16)[~~(15~~]) "Eligible project" means:

(a) An alternative fuel facility or a gasification facility meeting the investment requirements of KRS 154.27-020;

(b) An energy-efficient alternative fuel facility meeting the investment requirements of KRS 154.27-020;[~~ or~~]

(c) A renewable energy facility meeting the investment requirements of KRS

154.27-020;*** or***

(d) A carbon dioxide transmission pipeline meeting the investment requirements of Section 3 of this Act;

(17)[~~(16)~~] "Energy-efficient alternative fuel facility" means a facility located in Kentucky that is newly constructed on or after August 30, 2010, or an existing facility located in Kentucky that is retrofitted or upgraded on or after August 30, 2010, and that, after the new construction, retrofit, or upgrade, will produce for sale energy-efficient alternative fuels. For a retrofit of an existing facility, the new modification or addition within the facility shall produce for sale energy-efficient alternative fuels;

(18)[~~(17)~~] "Energy-efficient alternative fuels" means homogeneous fuels that:

(a) Are produced from processes designed to densify feedstock coal, waste coal, or biomass resources; and

(b) Have an energy content that is greater than the feedstock coal, waste coal, or biomass resource;

(19)[~~(18)~~] "Estimated labor component" means the projected percentage of the total capital investment attributable to labor;

(20)[~~(19)~~] (a) "Facility" means a single location within the Commonwealth at which machinery and equipment are used in a manufacturing process that transforms raw materials into a product with commercial value.

1. The facility shall include the physical plant structure where the manufacturing process occurs and machinery and equipment within the physical plant structure.

2. The facility may include:

a. On-site machinery and equipment used exclusively for processing coal or other raw materials for use in the manufacturing process at the facility;

b. For an alternative fuel facility or gasification facility, on-site power station operations, if those operations are primarily used to produce electricity for the facility;

c. On-site refining operations, if those operations are used exclusively to refine and blend fuels produced by the facility; and

d. The in-state portion of a pipeline, including appurtenant facilities, property rights, and easements, if the exclusive purpose of the pipeline is to transport carbon dioxide from the facility to a point of sale, storage, or other carbon management applications.

(b) "Facility" shall not include any mining operations, or drilling and production operations for natural gas;

(21)[~~(20)~~] "Gasification process" means a process that converts any carbon-containing material into a synthesis gas composed primarily of carbon monoxide and hydrogen;

(22)[~~(21)~~] (a) "Gasification facility" means a facility located in Kentucky that is newly constructed on or after August 30, 2007, or an existing facility located in Kentucky that is retrofitted or upgraded on or after August 30, 2007, and that, after the new construction, retrofit, or upgrade, primarily produces for sale:

1. Alternative transportation fuels;
2. Synthetic natural gas;
3. Chemicals;
4. Chemical feedstocks; or
5. Liquid fuels;

from coal, waste coal, coal-processing waste, or biomass resources, through a gasification process. For a retrofit of an existing facility, the new modification or addition within the facility shall primarily produce one (1) or more of the products set forth in this paragraph.

(b) The gasification facility may produce electricity as a by-product if the primary purpose for which the facility is constructed, retrofitted, or upgraded, and the primary function of the facility remains the production and sale of alternative transportation fuels, synthetic natural gas, chemicals, chemical feedstocks, or liquid fuels;

(23)[~~(22)~~] "Kentucky gross profits" has the same meaning as in KRS 141.0401;

(24)[~~(23)~~] "Kentucky gross receipts" has the same meaning as in KRS 141.0401;

(25)[~~(24)~~] "Post-construction incentives" means the incentives available under KRS 154.27-060 and 154.27-080;

(26)[~~(25)~~] "Renewable energy facility" means a facility located in Kentucky that is newly constructed on or after August 30, 2007, or an existing facility located in Kentucky that is retrofitted or upgraded after August 30, 2007, and that, after the new construction, retrofit, or upgrade, utilizes:

(a) Wind power, biomass resources, landfill methane gas, hydropower, or other similar renewable resources to generate electricity in excess of one (1) megawatt for sale to unrelated entities; or

(b) Solar power to generate electricity in excess of fifty (50) kilowatts for sale to unrelated entities.

For a retrofit of an existing facility, the modification or addition shall primarily result in the production of electricity as described in paragraph (a) or (b) of this subsection;

(27)[~~(26)~~] "Resident" has the same meaning as in KRS 141.010;

(28)[~~(27)~~] "Retrofit" means a modification or addition to an existing facility that results in the production of a new and different product or uses a new or different process to produce the same product at the facility. Modifications or additions to a facility that maintain, restore, mend, or repair a facility shall not be considered a retrofit of the facility, and shall not be considered part of the capital investment if undertaken at the same time as a retrofit;

(29)~~[(28)]~~ "Synthetic natural gas" has the same meaning as in KRS 152.715;

(30)~~[(29)]~~ "Tax incentive agreement" means an agreement entered into in accordance with KRS 154.27-040;

(31)~~[(30)]~~ "Termination date" means a date established by the tax incentive agreement that is no more than twenty-five (25) years from the activation date; and

(32)~~[(31)]~~ "Upgrade" means an investment in an existing facility that results in an increase in the productivity of the facility. Increased productivity shall be measured in relation to the type of products that are required to be produced by that facility to be an eligible project.

➔Section 3. KRS 154.27-020 is amended to read as follows:

(1) This subchapter shall be known as the "Incentives for Energy Independence Act."

(2) The General Assembly hereby finds and declares that it is in the best interest of the Commonwealth to induce the location of innovative energy-related businesses in the Commonwealth in order to advance the public purposes of achieving energy independence, creating new jobs and new investment, and creating new sources of tax revenues that but for the inducements to be offered by the authority to approved companies would not exist.

(3) The purpose of this subchapter is to assist the Commonwealth in moving to the forefront of national efforts to achieve energy independence by reducing the Commonwealth's reliance on imported energy resources. The provisions of this subchapter seek to accomplish this purpose by providing incentives for companies that, in a carbon capture ready manner, construct, retrofit, or upgrade facilities for the purpose of:

(a) Increasing the production and sale of alternative transportation fuels;

(b) Increasing the production and sale of synthetic natural gas, chemicals, chemical feedstocks, or liquid fuels, from coal, biomass resources, or waste coal through a gasification process;

(c) Increasing the production and sale of energy-efficient alternative fuels; or

(d) Generating electricity for sale through alternative methods such as solar power, wind power, biomass resources, landfill methane gas, hydropower, or other similar renewable resources.

(4) To qualify for the incentives provided in this subchapter, the following requirements shall be met:

(a) For an alternative fuel facility or gasification facility that uses oil shale, tar sands, or coal as the primary feedstock, the minimum capital investment shall be one hundred million dollars ($100,000,000);

(b) For an alternative fuel facility or gasification facility that uses biomass resources as the primary feedstock, the minimum capital investment shall be twenty-five million dollars ($25,000,000);

(c) For an energy-efficient alternative fuel facility, the minimum capital investment shall be twenty-five million dollars ($25,000,000);

(d) For an alternative fuel facility located in Kentucky that is newly constructed on or after August 1, 2010, or an existing facility located in Kentucky that is retrofitted or upgraded on or after August 1, 2010, and that, after the new construction, retrofit, or upgrade, primarily produces for sale alternative transportation fuels using natural gas or natural gas liquids as the primary feedstock, the minimum capital investment shall be one million dollars ($1,000,000); provided that the authority may approve a maximum of five (5) projects that meet the requirements of this paragraph;~~[and]~~

(e) For a renewable energy facility, the minimum capital investment shall be one million dollars ($1,000,000)***; and***

(f) For a carbon dioxide transmission pipeline, the minimum capital investment shall be fifty million dollars ($50,000,000).

(5) The incentives under the Incentives for Energy Independence Act are as follows:

(a) An advance disbursement of post-construction incentives for which an approved company has been approved, the maximum amount of which is based upon the estimated labor component of the total capital investment of the eligible project, and the utilization of Kentucky residents during the construction period as set forth in KRS 154.27-090;

(b) Sales and use tax incentives of up to one hundred percent (100%) of the taxes paid on purchases of tangible personal property made to construct, retrofit, or upgrade an eligible project, as set forth in KRS 139.517 and 154.27-070;

(c) Up to eighty percent (80%) of the severance taxes paid on the purchase or severance of:

1. Coal that is subject to the tax imposed under KRS 143.020 and that is specifically used by an alternative fuel facility, energy-efficient alternative fuel facility, or a gasification facility as feedstock for an eligible project, as set forth in KRS 143.024 and 154.27-060; or

2. Natural gas or natural gas liquids that are subject to the tax imposed under KRS 143A.020 and that are specifically used in an alternative fuel facility described in subsection (4)(d) of this section as feedstock for an eligible project, as set forth in KRS 143A.025 and 154.27-060;

(d) Up to one hundred percent (100%) of the Kentucky income tax imposed under KRS 141.040 or 141.020, and the limited liability entity tax imposed under KRS 141.0401 on the income, Kentucky gross profits, or Kentucky gross receipts of the approved company generated by or arising from the eligible project, as set forth in KRS 141.421 and 154.27-080; and

(e) Authorization for the approved company to impose a wage assessment of up to four percent (4%) of the gross wages of each employee subject to the Kentucky income tax:

1. Whose job was created as a result of the eligible project;

2. Who is employed by the approved company to work at the facility; and
3. Who is on the payroll of the approved company or an affiliate of the approved company;

as set forth in KRS 154.27-080.

(6) The maximum recovery from all incentives approved under this subchapter for an eligible project shall not exceed fifty percent (50%) of the capital investment in the eligible project.

(7) The incentives available to an approved company shall be negotiated with and approved by the authority.

(8) If a newly constructed facility that qualifies for incentives under this subchapter is later upgraded or retrofitted in a manner that would qualify for incentives under this subchapter, the retrofit or upgrade shall be a separate eligible project, and the minimum investment requirements and carbon capture readiness requirements, if required, shall be met for the retrofit or upgrade to qualify for incentives under this subchapter.

(9) The General Assembly finds that the authorities granted by this subchapter are proper governmental and public purposes for which public moneys may be expended.

➔Section 4. KRS 278.495 is amended to read as follows:

(1) As used in this section***:***[~~,~~]

(a) "Carbon dioxide transmission pipeline" means the in-state portion of a pipeline, including appurtenant facilities, property rights, and easements, that is used exclusively for the purpose of transporting carbon dioxide to a point of sale, storage, or other carbon management applications; and

(b) "Master meter system" means a pipeline system for distributing gas within a definable area, such as, but not limited to, a mobile home park, housing project, or apartment complex, where the operator purchases metered gas from an outside source for resale through a gas distribution pipeline system. The gas distribution pipeline system supplies the ultimate consumer, who either purchases the gas directly through a meter or by other means, such as through rents.

(2) Notwithstanding any other provision of law, the commission shall have the authority to regulate the safety of natural gas facilities which are:

(a) Owned or operated by any public utility, county, or city, and used to distribute natural gas at retail; or

(b) Comprising a master meter system.

The commission may exercise this authority in conjunction with, and pursuant to, its authority to enforce any minimum safety standard adopted by the United States Department of Transportation pursuant to 49 U.S.C. sec. 60101 et seq., or any amendments thereto, and may promulgate administrative regulations consistent with federal pipeline safety laws in accordance with provisions of KRS Chapter 13A as are necessary to promote pipeline safety in the Commonwealth. In exercising this authority, however, the commission shall consider the impact of any action it takes on small businesses engaged in the installation and servicing of gas lines, master meter systems, or related equipment and shall act so as to ***ensure***~~[assure]~~ that no unfair competitive advantage is given to utilities over such small businesses.

➔Section 5. KRS 278.700 is amended to read as follows:

As used in KRS 278.700 to 278.716, unless the context requires otherwise:

(1) "Board" means the Kentucky State Board on Electric Generation and Transmission Siting created in KRS 278.702;

(2) "Merchant electric generating facility" means, except for a qualifying facility as defined in subsection (7) of this section, an electricity generating plant, together with associated facilities, that:

(a) Is capable of operating at a capacity of ten megawatts (10MW) or more; and

(b) Sells the electricity it produces in the wholesale market, at rates and charges not regulated by the Public Service Commission;

(3) "Person" means any individual, corporation, public corporation, political subdivision, governmental agency, municipality, partnership, cooperative association, trust, estate, two (2) or more persons having a joint or common interest, or any other entity, and no portion of KRS 224.10-280, 278.212, 278.214, 278.216, 278.218, and 278.700 to 278.716 shall apply to a utility owned by a municipality unless the utility is a merchant plant as defined in this section;

(4) "Commence to construct" means physical on-site placement, assembly, or installation of materials or equipment which will make up part of the ultimate structure of the facility. In order to qualify, these activities must take place at the site of the proposed facility or must be site-specific. Activities such as site clearing and excavation work will not satisfy the commence to construct requirements;

(5) "Nonregulated electric transmission line" means an electric transmission line and related appurtenances for which no certificate of public convenience and necessity is required; which is not operated as an activity regulated by the Public Service Commission; and which is capable of operating at or above sixty-nine thousand (69,000) volts;

(6) "Residential neighborhood" means a populated area of five (5) or more acres containing at least one (1) residential structure per acre;~~[and]~~

(7) "Qualifying facility" means a cogeneration facility as defined in 16 U.S.C. sec. 796(18)(b) which does not exceed a capacity of one hundred fifty megawatts (150MW) that is located on site at a manufacturer's plant and that uses steam from the cogeneration facility in its manufacturing process, or an industrial energy facility as defined in KRS 224.01-010 that does not generate more than one hundred fifty megawatts (150MW) for sale and has received all local planning and zoning approvals***; and***

(8) "Carbon dioxide transmission pipeline" means the in-state portion of a pipeline, including appurtenant facilities, property rights, and easements, that is used exclusively for the purpose of transporting carbon dioxide to a point of sale, storage, or other carbon management applications.

➔Section 6. KRS 278.714 is amended to read as follows:

(1) No person shall commence to construct a nonregulated electric transmission line ***or a carbon dioxide transmission pipeline*** without a construction certificate issued by the board. An application for a construction certificate shall be filed at the offices of the Public Service Commission along with an application fee as set forth in subsection (5) of this section. ***The board may hire a consultant to review the transmission line or carbon dioxide pipeline and provide recommendations concerning the adequacy of the application and proposed mitigation measures. The board may direct the consultant to prepare a report recommending changes in the route of the carbon dioxide pipeline or the route of the electric transmission line. Any consultant expenses or fees shall be borne by the applicant.***

(2) A completed application shall include the following:

(a) The name, address, and telephone number of the person proposing construction of the nonregulated ***electric*** transmission line ***or the carbon dioxide transmission pipeline***;

(b) A full description of the proposed route of the ***electric*** transmission line ***or the carbon dioxide transmission pipeline*** and its appurtenances. The description shall include a map or maps showing:

1. The location of the proposed line ***or pipeline*** and all proposed structures that will support it;

2. The proposed right-of-way limits;

3. Existing property lines and the names of persons who own the property

over which the line ***or pipeline*** will cross; and

4. ***a.*** The distance of the proposed ***electric transmission*** line from residential neighborhoods, schools, and public and private parks within one (1) mile of the proposed facilities;***or***

b. The distance of the proposed carbon dioxide transmission pipeline from residential neighborhoods, schools, and parks, either private or public within one thousand (1,000) feet of the proposed facilities;

(c) ***With respect to electric transmission lines,*** a full description of the proposed line and appurtenances, including the following:

1. Initial and design voltages and capacities;
2. Length of line;
3. Terminal points; and
4. Substation connections;

(d) A statement that the proposed ***electric*** transmission line and appurtenances will be constructed and maintained in accordance with accepted engineering practices and the National Electric Safety Code;

(e) ***With respect to both electric transmission lines and carbon dioxide transmission pipelines,*** evidence that public notice has been given by publication in a newspaper of general circulation in the general area concerned. Public notice shall include the location of the proposed ***electric transmission*** line ***or carbon dioxide pipeline***, shall state that the proposed line ***or pipeline*** is subject to approval by the board, and shall provide the telephone number and address of the Public Service Commission; and

(f) Proof of service of a copy of the application upon the chief executive officer of each county and municipal corporation in which the proposed ***electric transmission*** line ***or carbon dioxide transmission pipeline*** is to be located, and upon the chief officer of each public agency charged with the duty of planning land use in the general area in which the line ***or pipeline*** is proposed to be located.

(3) ***With respect to electric transmission lines,*** within ninety (90) days of receipt of the application, or one hundred twenty (120) days if a local public hearing is held, the board shall, by majority vote, grant or deny the construction certificate either in whole or in part. Action to grant the certificate shall be based on the board's determination that the proposed route of the line will minimize significant adverse impact on the scenic assets of Kentucky and that the applicant will construct and maintain the line according to all applicable legal requirements. In addition, the board may consider the interstate benefits expected to be achieved by the proposed construction or modification of electric transmission facilities in the Commonwealth. If the board determines that locating the transmission line will result in significant degradation of scenic factors or if the board determines that the construction and maintenance of the line will be in violation of applicable legal requirements, the board may deny the application or condition the application's approval upon relocation of the route of the line, or changes in design or configuration of the line.

(4) A public hearing on an application to construct a nonregulated electric transmission line may be held in accordance with the provisions of KRS 278.712.

(5) ***The board shall convene a local public information meeting upon receipt of a request by not less than three (3) interested persons that reside in the county or counties in which the carbon dioxide pipeline is proposed to be constructed. If the board convenes the local public information meeting, the meeting will be in the county seat of one (1) of the counties, as determined by the board, in which the proposed carbon dioxide pipeline will be located. The meeting shall provide an opportunity for members of the public to be briefed and ask the party proposing***

the carbon dioxide pipeline questions about the pipeline.

(6) Pursuant to KRS 278.706(3) and (5), the board shall promulgate administrative regulations to establish an application fee for a construction certificate for***:***

(a) A nonregulated transmission line~~[in accordance with KRS 278.706(3)]~~***; and***

(b) A carbon dioxide transmission pipeline.

(7) With respect to carbon dioxide transmission lines, within ninety (90) days of receipt of the application or one hundred twenty (120) days if a local public information meeting is held, the board shall, by majority vote, grant or deny the construction certificate either in whole or in part. Action to grant the certificate shall be based on the board's determination that the proposed route of the pipeline will minimize significant adverse impact on the scenic assets of Kentucky and that the applicant will construct and maintain the line according to all applicable legal requirements. In addition, the board may consider the interstate benefits expected to be achieved by the proposed carbon dioxide transmission pipeline in the Commonwealth. If the board determines that locating the transmission line will result in significant degradation of scenic factors or if the board determines that locating the carbon dioxide transmission line will be in violation of applicable legal requirements, the board may deny the application or condition the application's approval upon relocation of the route of the pipeline.

APPENDIX 9

Military Vehicle Demonstration on FT Fuel from Simulated Coal-Derived Syngas

Demonstration of Fischer-Tropsch Fuel produced from Simulated Coal-derived Syngas in 6x6 LASSO® Utility Vehicle

Submitted to:
National Energy Technology Laboratory (NETL)

Principal Authors:

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Submitted: September 5, 2009

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ACRONYMS, ABBREVIATIONS AND NOMENCLATURES

F-T	Fischer-Tropsch
HMMWV	High Mobility Multi-Purpose Wheeled Vehicle
LASSO®	Land and Sea Special Operations
lbs	Pounds
NASA	National Aeronautics and Space Administration
SOCOM	Special Operations Command
US	United States
UTV	Utility Terrain Vehicle

1.0 INTRODUCTION

1.1. 2009 Selfridge Air Show

On August 21-23, 2009, representatives from VSE Corporation's Alternative Fuels Team participated in a demonstration of Fischer-Tropsch (F-T) neat fuel, produced from simulated coal-derived syngas, at Selfridge Air National Guard Base near Mt.Clemens, MI in conjunction with their bi-annual Air Show. Selfridge hosts this public open house to allow the residents of the metro Detroit area a rare opportunity to interact with fighter pilots and their maintenance crews in an effort to demonstrate where their defense dollars are spent each year. Air Show organizers expected an estimated 175,000 people, providing free admission and free parking throughout the event.

The theme for this year's show, "*A Showcase of the Advancement of Military Aerospace Technology that has Occurred Since Aviation's Inception*," served as an appropriate backdrop for an F-T fuel demonstration of this type. Over the last several years, the US Air Force has been strongly committed to the certification of their aircraft and ground support equipment on Fischer-Tropsch fuels in preparation for the day when a domestically produced jet fuel will propel our fighter jets and their support infrastructure. This demonstration, proposed and conducted by VSE Corporation's Alternative Fuels Team, helped to further public awareness of the alternative measures the US military is taking to reduce our dependency on foreign oil by finding a viable domestically produced source of fuel.

Throughout the demonstration, the F-T neat fuel was run in an off-road, 6x6, material handling vehicle, which was developed by VSE Corporation for the Special Operations community, called the LASSO® vehicle. The three day demonstration consisted of a one-day, ride and drive, soldier demonstration, and two public demonstration days. Throughout the soldier demonstration day, several active-duty base soldiers took the LASSO® vehicle for performance test drives, noting the performance characteristics of the vehicle as well as the fuel. During the public demonstration days, the LASSO® vehicle was demonstrated statically to create auxiliary power supporting off-board booth electronics as well as on test drives throughout the show grounds to showcase the visibly reduced emissions, due to the cleaner burning F-T fuel. VSE Corporation team members staffed a booth throughout the two public demonstration days that was located adjacent to the “Technology Hangar” which showcased other new and emerging military technologies including fuel cell powered vehicles, unmanned surveillance robots, and materials exhibits provided by NASA.

The three day event provided the VSE team with some high-traffic exposure to both military and civilian personnel allowing for the necessary exchange of ideas which leads to continued improvement. The VSE team received critical input from active-duty on base personnel which will fuel additional improvement on the LASSO® design as well as some excellent remarks about the clean burning Fischer-Tropsch fuel. The following report will summarize the comments received throughout the demonstration, including information on the Fischer-Tropsch fuel used during the three day test, the LASSO® vehicle itself, and the results of the demonstration.

2.0 F-T DIESEL FUEL FROM SIMULATED COAL-DERIVED SYNGAS

The F-T diesel fuel was produced in Rentech’s pilot-scale, nominal 10 barrel per day Product Demonstration Unit (PDU) in Denver, CO. This plant produces, and then processes, simulated coal-derived syngas, a mixture of carbon monoxide and hydrogen, to make finished F-T diesel and jet fuels.

Rentech's Product Demonstration Unit (PDU) is located in Commerce City, Colorado at the Rentech Energy Technology Center (RETC). The PDU is believed to be the only fully-integrated synthetic transportation fuels production facility operating in the United States. This facility is designed to produce over 400 gallons per day of ultra-clean synthetic jet fuel, aviation fuel, ultra-low sulfur diesel, and specialty waxes and chemicals and is scalable for greater output.

The PDU demonstrates the successful design, construction and operation of a fully-integrated synthetic fuels and chemicals facility utilizing the Rentech Process. It represents the first time Rentech has operated an integrated facility. While operating the PDU, the Rentech FT catalyst demonstrated greater efficiency and yielded more product than predicted. In addition, a quality of syngas was produced at the PDU that is typically created from solid feedstocks such as coal and biomass. This demonstrates that the

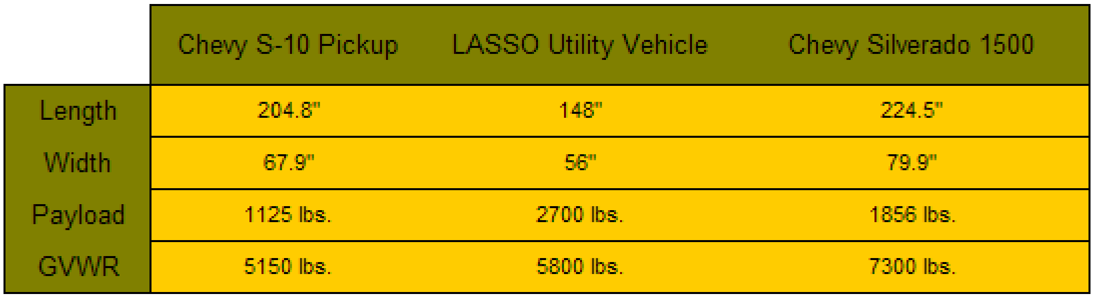
Rentech catalyst can successfully react with syngas streams from a wide variety of feedstocks including natural gas, biomass and abundant fossil-based resources such as coal, petroleum coke, etc.

Rentech has recently made a significant investment in one company that has gasifier technology, and bought another such company outright. Although these gasifier technologies are focused primarily on biomass, Rentech intends to incorporate the capability of using at least some fraction of coal in the feedstock for the "new" pilot-scale gasifier that is planned to be added to the existing PDU plant over the next year or so. Rentech has indeed demonstrated that they intend to persevere in their goal of producing F-T fuels from both coal and biomass, resources that the US has in abundance.

3.0 LASSO™ UTILITY VEHICLE

The LASSO® Utility Vehicle is a purpose-built, all-terrain vehicle specifically designed to meet the mission requirements of the Special Operations community. The need for a light, agile, vehicle capable of hauling equipment in the severe off-road conditions of their current mission in the Middle East is a pressing concern. Currently, several off-the-shelf UTV solutions, including utility variants from the John Deer Gator product line, are being employed to handle these duties. However due to the design limitations of this commercial approach, these units have not performed well in the harsh environments they've encountered. VSE Corporation was contracted by US SOCOM to design a solution capable of addressing the load hauling and material handling needs of today's soldier. Now in its third iteration of vehicle prototypes, the LASSO® vehicle is a direct response to this need, including the requirement for internal transportability within a V-22 (Osprey).

Intended as a potential replacement for the M-274 Military Mule, which was designed in the 1950's, the LASSO® is built to carry 2000 lbs. of payload in addition to two fully equipped soldiers. Its full-time six-wheel drive with fully independent suspension and 9" of travel keeps all wheels in contact with the ground, allowing the three-cylinder turbo-diesel engine to keep the vehicle moving forward through rough terrain. The LASSO® has 12” of ground clearance, boasts an 18” fording depth, and traverses grades of 60% even when fully loaded. Its top speed is limited to 30MPH, but geared as a tractor much like the Military Mule, this speed is appropriate for its intended mission. This light combat support and combat service support utility vehicle is a highly capable and versatile tool worthy of adding to the US Military’s ground vehicle arsenal. When compared to the size and load carrying capability of familiar commercial solutions, as seen in the chart below, one can get a better appreciation for why this solution is so unique.



	Chevy S-10 Pickup	LASSO Utility Vehicle	Chevy Silverado 1500
Length	204.8"	148"	224.5"
Width	67.9"	56"	79.9"
Payload	1125 lbs.	2700 lbs.	1856 lbs.
GVWR	5150 lbs.	5800 lbs.	7300 lbs.

Table 1: Comparing LASSO® to Familiar Chevrolet Products

4.0 SELFRIDGE AIR SHOW DEMONSTRATION

Preparations for the three-day Selfridge demonstration began months in advance as VSE team members attended all Air Show planning meetings on base in an effort to ensure that the demonstration would run smoothly in August. Booth location information, tent setup, and logistics were coordinated directly with personnel from Selfridge. Representatives from the 127th Logistics Readiness Squadron were also contacted to assist with the field test of the equipment and to make certain that the necessary regulations were followed when bringing this prototype vehicle onto a military base for testing.

To prepare the LASSO® vehicle for the three day demonstration, the fuel tank was emptied of all remaining diesel fuel and one gallon of the F-T fuel produced from simulated coal-derived syngas, was used to completely flush the system prior to a full fill up. The fuel filter was also replaced. A one-gallon sample of the F-T fuel was taken for future reference. The 14 gallon vehicle fuel tank was then filled with F-T fuel and the engine was run for a few minutes at the shop in order to identify in advance any compatibility issues that might occur during the weekend. None surfaced at this time.

In order to properly convey the intentions of the test demonstration, custom signage was created to mark the test LASSO® vehicle. Vinyl signs for the hood and left and right sides of the bed were professionally printed and installed on the vehicle. VSE Corporation and Rentech logo magnets were also created for the front and rear in order to ensure that all surfaces were clearly marked to attract additional visitor traffic. This custom signage marked the vehicle as running on synthetic diesel fuel (as shown at the right) and highlighted the production of this fuel from US domestic resources.

4.1. Day One: Ride & Drive Soldier Demonstration

Military personnel in uniform agreed to test drive the FT-fueled LASSO® vehicle on base throughout the day during the first day of the Air Show. This first day is generally reserved for base personnel and their families as well as the local media. With pedestrian traffic lower than normal, these soldiers were able to give the vehicle a thorough test, taking it through off-road conditions on base and taxiing materials in support of the Air Show to assist in show preparations.

Figure 1: TSgt Frank and TSgt Henderson test drive the LASSO® Vehicle.

Figure 2: Test drive con't

Figure 3: Test drive con't

Figure 4: Test drive con't

4.2. Day Two & Three: Public Demonstration Days

When the Air Show opened to the public for the second and third days of the demonstration, the LASSO® vehicle was setup in an outdoor location adjacent to the Technology Hangar. The Technology Hangar was situated in a high traffic area next to approximately a dozen static aircraft on exhibit. The Technology Hangar included displays and demonstrations of other emerging technologies including NASA exhibits, unmanned remote-operated surveillance robots, and fuel-cell powered vehicles. The outdoor location was required so that the LASSO® vehicle's high-tech diesel engine could run nearly continuously (attracting even more attention) on the F-T diesel fuel, thus producing auxiliary electric power for the demonstration video, which was shown on a large monitor to attract even more interest from the crowd.

VSE personnel were on hand to talk with visitors and answer questions about either the performance characteristics of the LASSO® vehicle or the neat (i.e. unblended) F-T diesel fuel it was running on. CTC personnel also helped support the LASSO® vehicle F-T fuel demonstration, as well as the related Defense Assured Fuels Initiative Project, which is being conducted by CTC and VSE in partnership. The objective of this related project is to evaluate F-T jet fuel blended 50:50 with conventional JP-8 jet fuel in Air Force ground vehicles and ground support equipment at Selfridge. Located adjacent to the LASSO® was a bomb-loader lift-truck (called a "jammer") fueled by the F-T jet-fuel blend. This unusual looking piece of specialized aircraft ground support equipment attracted even more attention, and reinforced the military utility of domestically produced F-T fuel, whether it is used blended or neat.

As pedestrian traffic slowed later in the day, additional uniformed soldiers offered to drive the LASSO® vehicle (slowly and carefully) through the crowd and along the main taxiway of show center. The LASSO® vehicle was used in crowd control and crowd movement operations at the end of the final day of the Air Show.

Figure 5: LASSO® vehicle providing power to support laptop computer and LCD monitor.

Figure 6: Auxiliary 115VAC outlet providing pure sine wave regulated electric power.

Figure 7: Custom Vinyl signage applied to the hood of the LASSO® vehicle.

Figure 8: Members of the VSE and CTC show support team

Figure 9: Discussing the performance characteristics of the F-T fuel.


Figure 10: Q & A During Public Demonstration Days


Figure 11: Q & A During Public Demonstration Days (con't)

Figure 12: Q & A During Public Demonstration Days(con't)

Figure 13: Test Driving the LASSO$^{®}$.

5.0 SUMMARY

5.1. User Impressions on the F-T fuel

Throughout the three day demonstration, exposure to military personnel with combat experience, as well as to the thousands of public visitors who visited the booth proved invaluable. Soldiers who test drove the vehicle remarked that they noticed a reduced exhaust smell as compared to conventional fuel. They were also impressed by the absence of particulate collecting on the cross frame member next to the vehicle exhaust, which are both characteristics of the clean burning F-T fuel.

LASSO® designers who handled the fuel during changeover operations noticed the water-like clarity of the F-T fuel that is in marked contrast to the amber color of conventional diesel fuel. They also mentioned the lack of a strong odor, ("a kerosene smell") typically associated with conventional diesel, when handling the F-T fuel. The F-T fuel was almost odorless by comparison during flush and fill operations. When comparing the performance of the LASSO® vehicle driving on the F-T diesel, to the test drives taken on conventional fuel, both designers remarked that they noticed no change.

5.2. User Impressions on the LASSO® Utility Vehicle

The LASSO® vehicle design team also benefitted from having its vehicle exposed to the military community throughout the demonstration. Military users were very forth coming with ideas for improvement and positive feedback on the need for a niche vehicle, such as the LASSO®, reaffirming the team's design and marketing approach.

One primary focus areas of the vehicle design was to incorporate as many standard HMMWV parts onto the LASSO® vehicle to allow for a familiarity to potential military operators. Ignition switches, master light switches, driving light and taillights, along with things as simple as the fuel cap are all borrowed from the HMMWV inventory to provide an intuitive operator manual based on experience with the HMMWV. Several pairs of uniformed soldiers, throughout the weekend test drove the LASSO® vehicle and each pair was given no special instructions. Although many of the operations were simple enough to figure out, the design team found that there was some confusion over the correct position of the water fording switch. Figure 13 below shows the position of the water fording switch during normal operations. In a few cases, soldiers were inclined to flip the switch down based on the idea that if they are not fording water, the switch should be in the "off" or "down" position. In the down position, the cooling fans are turned off and to protect the electrical fuses from the increased load the fans will see if they activate under water. However, if the fans are inactive when not submerged the vehicle will overheat, which is what happened. To rectify this misunderstanding, the design team is planning a clearer label or a guarded toggle to clarify things.

Figure 14: Water Fording Switch

Most of the base personnel who approached the vehicle were very impressed by the vehicle’s performance capabilities. The ability to carry 2700 lbs. of payload and traverse the terrain as advertised is a great need for military customers across the armed forces. With the vehicle bed in the upright allowing the vehicle’s undercarriage to be exposed, many soldiers found the amount of engineering that went into the design and build of the frame, suspension, and powertrain to be fascinating.

6.0 APPENDICIES

Appendix A – Selfridge Air Show Poster

2009 Selfridge Airshow Aug 22-23

featuring the

USAF Thunderbirds

Selfridge Air National Guard Base, Mich.

Gates Open at 8 a.m.

Admission Free

Parking Free

SelfridgeAirShow.org

Hanger Party and Open Air Concert - Friday, Aug. 21

Military Acts - Civilian Performers - Warbirds

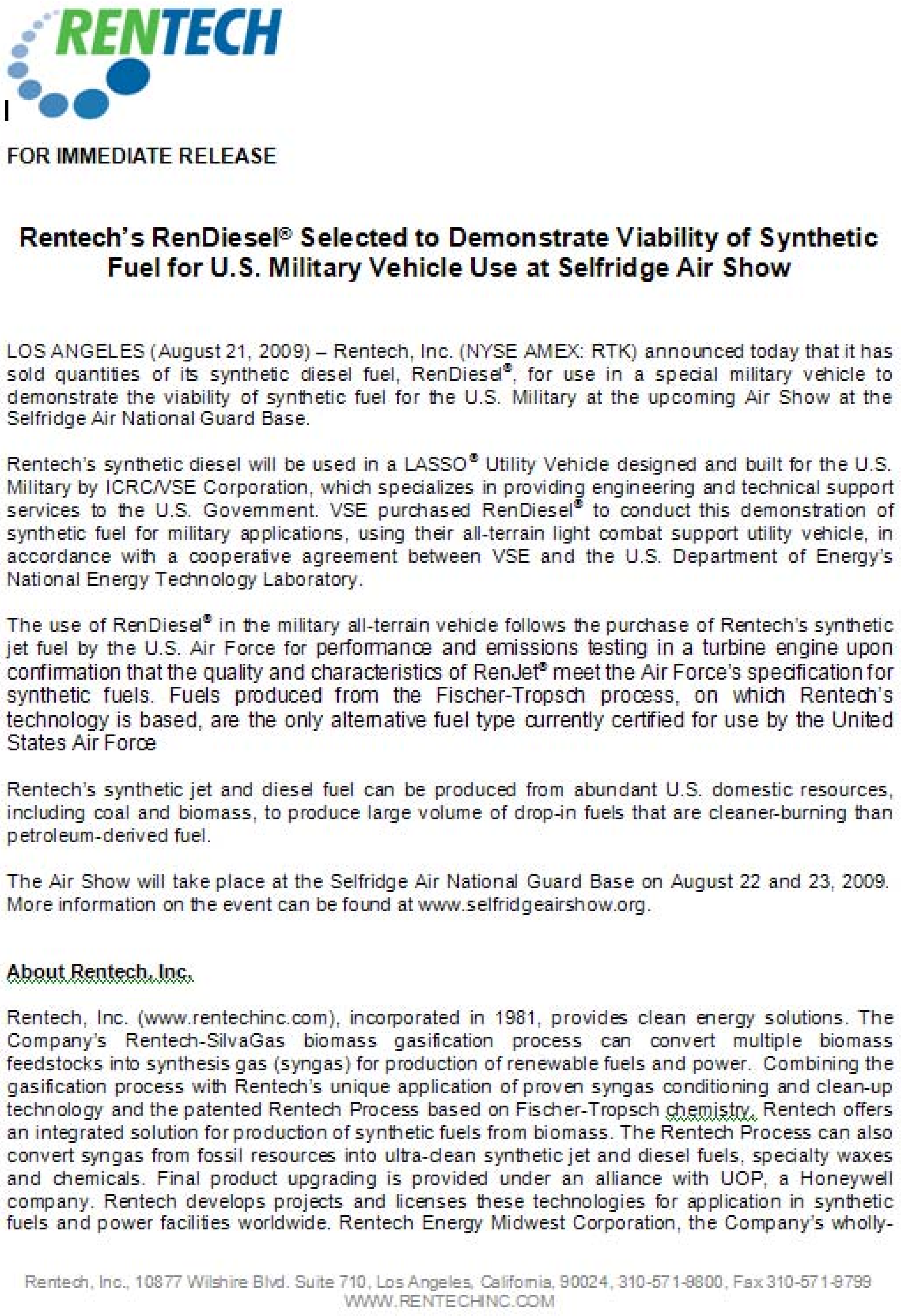
USAF Thunderbirds - AF Academy Wings of Blue - F-18 Super Hornet Demo Team

Gene Soucy, Wing Walker - F-104 Starfighters - De Havilland and Skywriter

Coast Guard Dolphin Helicopter - Blackhawk Helicopter - and Many More!

presented with PARTNERSHIP 4 GIVING

Appendix B – Rentech, Inc. Press Release



RENTECH

FOR IMMEDIATE RELEASE

Rentech's RenDiesel® Selected to Demonstrate Viability of Synthetic Fuel for U.S. Military Vehicle Use at Selfridge Air Show

LOS ANGELES (August 21, 2009) – Rentech, Inc. (NYSE AMEX: RTK) announced today that it has sold quantities of its synthetic diesel fuel, RenDiesel®, for use in a special military vehicle to demonstrate the viability of synthetic fuel for the U.S. Military at the upcoming Air Show at the Selfridge Air National Guard Base.

Rentech's synthetic diesel will be used in a LASSO® Utility Vehicle designed and built for the U.S. Military by ICRC/VSE Corporation, which specializes in providing engineering and technical support services to the U.S. Government. VSE purchased RenDiesel® to conduct this demonstration of synthetic fuel for military applications, using their all-terrain light combat support utility vehicle, in accordance with a cooperative agreement between VSE and the U.S. Department of Energy's National Energy Technology Laboratory.

The use of RenDiesel® in the military all-terrain vehicle follows the purchase of Rentech's synthetic jet fuel by the U.S. Air Force for performance and emissions testing in a turbine engine upon confirmation that the quality and characteristics of RenJet® meet the Air Force's specification for synthetic fuels. Fuels produced from the Fischer-Tropsch process, on which Rentech's technology is based, are the only alternative fuel type currently certified for use by the United States Air Force

Rentech's synthetic jet and diesel fuel can be produced from abundant U.S. domestic resources, including coal and biomass, to produce large volume of drop-in fuels that are cleaner-burning than petroleum-derived fuel.

The Air Show will take place at the Selfridge Air National Guard Base on August 22 and 23, 2009. More information on the event can be found at www.selfridgeairshow.org.

About Rentech, Inc.

Rentech, Inc. (www.rentechinc.com), incorporated in 1981, provides clean energy solutions. The Company's Rentech-SilvaGas biomass gasification process can convert multiple biomass feedstocks into synthesis gas (syngas) for production of renewable fuels and power. Combining the gasification process with Rentech's unique application of proven syngas conditioning and clean-up technology and the patented Rentech Process based on Fischer-Tropsch chemistry, Rentech offers an integrated solution for production of synthetic fuels from biomass. The Rentech Process can also convert syngas from fossil resources into ultra-clean synthetic jet and diesel fuels, specialty waxes and chemicals. Final product upgrading is provided under an alliance with UOP, a Honeywell company. Rentech develops projects and licenses these technologies for application in synthetic fuels and power facilities worldwide. Rentech Energy Midwest Corporation, the Company's wholly-

Rentech, Inc., 10877 Wilshire Blvd. Suite 710, Los Angeles, California, 90024, 310-571-9800, Fax 310-571-9799
WWW.RENTECHINC.COM

owned subsidiary, manufactures and sells nitrogen fertilizer products including ammonia, urea ammonia nitrate, urea granule, and urea solution in the corn-belt region of the central United States.

About VSE

VSE is a publicly traded (NASDAQ: VSEC), ISO 9001:2000-registered professional services company. VSE has provided more than $2 billion in diversified engineering and technical support services to the U.S. Government. VSE has been ranked among the top 100 defense contractors, top 10 foreign military sales contractors, and top 50 Navy contractors in the nation.

Safe Harbor

This press release contains forward-looking statements as defined in the Private Securities Litigation Reform Act of 1995 about matters such as the performance, emissions and demand of Rentech's jet and diesel synthetic fuels. These statements are based on management's current expectations and actual results may differ materially as a result of various risks and uncertainties. Other factors that could cause actual results to differ from those reflected in the forward-looking statements are set forth in the Company's prior press releases and periodic public filings with the Securities and Exchange Commission, which are available via Rentech's web site at www.rentechinc.com. The forward-looking statements in this press release are made as of the date of this press release and Rentech does not undertake to revise or update these forward-looking statements, except to the extent that it is required to do so under applicable law.

For more information

Please contact: Julie Dawoodjee, Vice President of Investor Relations and Communications, Rentech, Inc. at 310-571-9800, extension 341, or by email at ir@rentk.com.

Appendix C – LASSO® Capabilities Handout

VSE CORPORATION

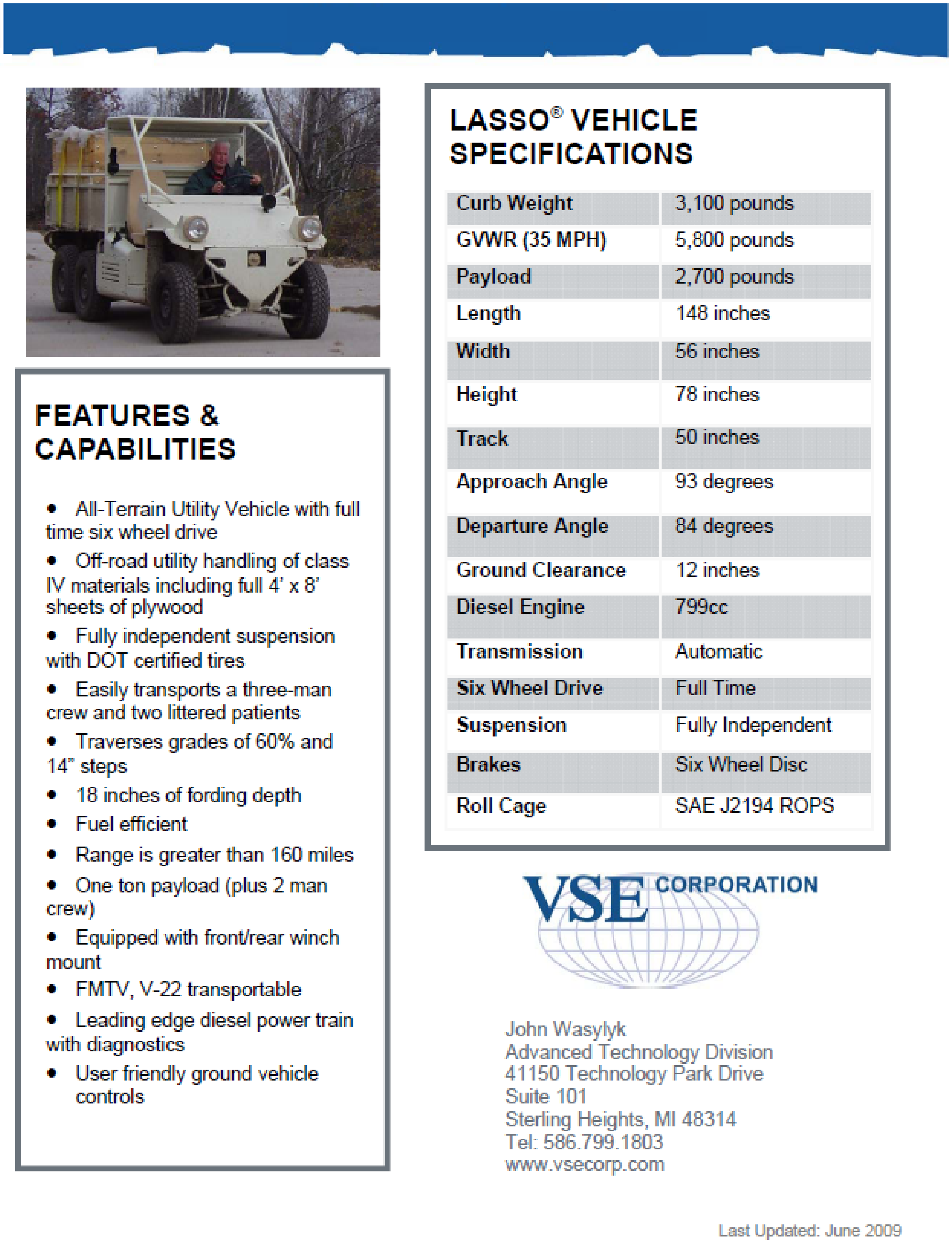
LASSO® Utility Vehicle

A purpose-built all-terrain light combat support and combat service support utility vehicle. The LASSO® vehicle is a high capacity six-wheel drive all-terrain utility vehicle designed with special features which offer significant advantages over current commercial off-the-shelf recreational and commercial UTV's.

Extreme Mud Performance

Desert Terrain Maneuverability

18" Fording Evaluation at 10 MPH



FEATURES & CAPABILITIES

- All-Terrain Utility Vehicle with full time six wheel drive
- Off-road utility handling of class IV materials including full 4' x 8' sheets of plywood
- Fully independent suspension with DOT certified tires
- Easily transports a three-man crew and two littered patients
- Traverses grades of 60% and 14" steps
- 18 inches of fording depth
- Fuel efficient
- Range is greater than 160 miles
- One ton payload (plus 2 man crew)
- Equipped with front/rear winch mount
- FMTV, V-22 transportable
- Leading edge diesel power train with diagnostics
- User friendly ground vehicle controls

LASSO® VEHICLE SPECIFICATIONS

Curb Weight	3,100 pounds
GVWR (35 MPH)	5,800 pounds
Payload	2,700 pounds
Length	148 inches
Width	56 inches
Height	78 inches
Track	50 inches
Approach Angle	93 degrees
Departure Angle	84 degrees
Ground Clearance	12 inches
Diesel Engine	799cc
Transmission	Automatic
Six Wheel Drive	Full Time
Suspension	Fully Independent
Brakes	Six Wheel Disc
Roll Cage	SAE J2194 ROPS

VSE CORPORATION

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Last Updated: June 2009

Appendix D – F-T Ground Support Equipment Certification Poster

Defense Assured Fuels Initiative

Background

Concurrent Technologies Corporation (*CTC*) received an award from the United States Air Force (USAF) Advanced Power Technology Office (APTO) to collaborate with the Air Force, industry representatives, professional societies, academia, original equipment manufacturers (OEMs), demonstration-site personnel, and additional USAF personnel to demonstrate synthetic fuels. *CTC* is partnering with VSE, previously Integrated Concepts and Research Corporation (ICRC), to accomplish this initiative.

Scope

CTC is providing the necessary research, integration, test planning, implementation, and sustainment support to demonstrate synthetic fuels, such as fuel manufactured using the Fischer-Tropsch (FT) process. Government Furnished Equipment (GFE) being demonstrated includes fuel storage systems, distribution systems, ground support equipment (GSE), and vehicles at Selfridge Air National Guard Base (ANGB). More specifically, *CTC* is demonstrating synthetic fuel in one bulk storage tank, two GSE items and three vehicles, all depicted on the right margin.

Objectives

- Improve the Department of Defense's (DoD) knowledge base of synthetic fuels
- Increase USAF capabilities, validating synthetic fuel use in government furnished engines
- Establish conversion procedures for bulk storage tanks
- Identify risks associated with fuel switching in ground power systems
- Develop base level integration of synthetic fuels
- Characterize fuel efficiency using synthetic fuels
- Characterize harmful emissions of GFE vehicles and GSE.

Results

- Five Scientific and Technical Reports researched and authored:
  - Characteristics of FT Fuel
  - State of the US FT Fuel Industry
  - Integration of FT Fuel into USAF Base Storage
  - FT Integration/Conversion Test Plan for Selfridge ANGB
  - FT Fuel Standard Test Plan for GSE and Vehicles
- Fuel Blend Integration Training Plan developed
- Over 465 gallons of synthetic fuel utilized with no problems
  - Vehicles driven over 2,177 miles and GSE operated over 1,252 hours
- Fuel and oil analyses conducted

Oshkosh R-11 Refueler

General Motors Stake-Bed Truck

Ford Flight Line Tow Tractor "Bobtail"

Next Generation Heater

Bomb Loader "Jammer"

Bulk Storage Tank

CTC Concurrent Technologies Corporation

For more information on *CTC*'s Defense Assured Fuels Initiative contact:

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APPENDIX 10
Conversion of US Domestic Industrial Facilities to Produce FT Fuel from Coal

Feasibility of Near-Term Conversion of US Industrial Facilities to Produce Coal-Derived Fischer-Tropsch Liquid Fuel

Report Type: Technical

Submitted to:
National Energy Technology Laboratory (NETL)

Cooperative Agreement DE-FC26-06NT42449

Principal Author:

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Anchorage, Alaska 99515

Report Period Start Date: August 4, 2008
Report Period Ending Date: December 29, 2008
Submitted: December 29, 2008

Submitting Organization:
Integrated Concepts & Research Corp.
41150 Technology Park Dr, Ste 101
Sterling Heights, MI 48314

ACKNOWLEDGEMENT
This work was supported by the U.S. Department of Energy's National Energy Technology Laboratory (NETL) under Cooperative Agreement DE-FC26-06NT42449.

ABSTRACT

This report is focused on the feasibility of establishing, as quickly as possible, but in no more than ten years, the capability of producing Fischer-Tropsch (F-T) liquid hydrocarbon transportation fuels from U.S. domestic coal. The targeted production capacity of coal-derived liquid fuel should initially be at least a few hundred barrels per day, which would be sufficient for validation testing of the fuel. Development of larger production capacity of commercial-scale coal-derived liquid fuel, on the order of at least several thousand barrels per day, would also be of interest, primarily as a means for implementing utilization of the F-T fuel as a follow-on to the initial validation-testing phase.

A key asset under consideration in this feasibility study is the British Petroleum (BP) R&D-scale F-T fuel production facility or pilot-plant currently operating at Nikiski, Alaska, the only operating facility of its kind in North America. The BP pilot plant currently uses natural gas as its feedstock, not coal, to produce approximately 300 barrels per day of F-T liquid products. However, there are several reasonable and technically feasible scenarios by which syngas could be produced from coal and used as feedstock for this R&D scale F-T plant. Some of these scenarios involve building or installing additional equipment at the current location of the BP plant, while others include the possibility of moving the BP plant to other locations that could offer significant advantages such as a readily available supply of coal, and/or the ability to make use of additional specialized equipment.

The BP plant has reportedly accomplished most of the R&D tasks that it was built to complete, so there is a realistic near-term possibility of reconfiguring the plant as required to produce validation-testing quantities of coal-derived F-T fuels for evaluation. The plant was built in Alaska to fulfill a commitment to the state government, so it would almost certainly remain an Alaskan asset, even if it is moved from its current location. Evaluation of the various options for reconfiguring and/or moving the plant, starting with the least disruptive, expensive and time-consuming, and then continuing through other more involved options that offer additional benefits, is the common thread that helps to bind this feasibility study together.

FOREWORD

by: Stephen P. Bergin, Ph.D., P.E., Program Director

This feasibility study has been conducted to evaluate the near-term potential of obtaining commercial quantities of high-hydrogen content, coal-derived transportation and jet fuel (F-T liquids), from U.S. domestic sources, The starting point is an initial broad look across the U.S., then focusing on, and capitalizing on, the potential use and conversion of existing industrial facilities. This broad look considered near term sources (less than 10 years), and on production of fuel quantities sufficient for validation testing at a minimum, with commercial-scale fuel production as a longer-term goal. The report briefly discussed the broad US overview first, and then focused on the potential of converting existing hardware/industrial facilities in Alaska, specifically from natural gas to coal-based feed stocks.

ICRC has done previous extensive studies monitoring developmental FT fuels programs utilizing various feedstocks, including coal. Even tough there are no existing hardware F-t facilities in the lower 48, four coal-to-liquids potential projects, represent the most progressive approaches to date that have the best chance to be operational with the 10 year, near term period that this report focuses upon. Of the four projects being considered, only would produce F-T jet fuel. The projects representing the most promising coal to liquids programs being developed include:

- **Baard Energy's CTL, Wellsville, Ohio**
  Located on the Ohio River, the Wellsville site has access to a supply of coal, close proximity to liquid fuel markets, and strong support provided by the state of Ohio. The unique design and operation of the facility will allow it to use current technology to capture and ultimately sequester at least 85% of all carbon dioxide produced. The plant will be capable of producing synthetic jet fuel, diesel fuel and other valued chemical feedstocks. However, environmental issues and a general resistance to developing coal as an indigenous source of liquid transportation fuels may prove to be significant obstacles that could, at a minimum, cause project delays.
  (Please see http://www.baardenergy.com for more information)
- **Southeast Idaho Energy, Agricultural Products and Energy Facility, Power Country, ID**
  Southeast Idaho Energy plans to construct a \$2 billion agricultural products and energy facility in Power County, ID for producing fertilizers and ultra-low-sulfur diesel fuel. Phase 1, (estimated at \$1 billion) would install one gasifier to turn coal and petroleum coke into more than 4,000 tons of fertilizer and 1,400 barrels of diesel per day. Phase 2, (another \$1 billion estimated), would add two gasifiers to boost diesel output to 8,400 barrels per day.
  (Please see http://www.deq.state.id.us/about/index.cfm for more information.)
- **Waste Management and Processors Inc. (WPMI) CTL, Gilberton, PA**
  The plant, would be located on a 75-acre site near the coal-mining town of Gilberton, PA, in the heart of Pennsylvania's anthracite region, and would produce electricity and steam as well as liquid fuels (~5000 bbl/d of ultra low/no-sulfur diesel) from anthracite waste coal. This waste coal to clean

fuels project has received much interest, since late 2000, and has received local, state and federal permits. The WMPI developer anticipates the release of a $100 million federal loan for the proposed facility.

- **Medicine Bow Fuel & Power LLC, Gasoline, Medicine Bow, WY**
  This plant will use gasified coal to produce electric power and gasoline (using the Exxon Mobil Methane-to-gas-process), though not FT fuels. Additionally, carbon dioxide and chemicals are expected to be dried, liquefied and shipped via a pipeline, and sold to the enhanced oil recovery market in Wyoming.

While the U.S. sits on tremendous reserves of energy in several forms including coal, many of these are likely to continue to remain undeveloped due to a long list of impediments. These impediments will not be discussed in detail in this report, but they have, none-the-less, continued to present tremendous obstacles to financing and building hardware to actually produce liquid fuels in the U.S. and improve national energy security. There are other plants under consideration, but they are still many years from breaking ground. Because of the difficulty in deciding which will go forward at this time, only the above four have been mentioned as examples with strong possibilities of being built. Others have varying likelihoods of success.

TABLE OF CONTENTS

ACRONYMS, ABBREVIATIONS AND NOMENCLATURES

ASRC	Arctic Slope Regional Corporation
AFB	Air Force Base
ANRTL	Alaska Natural Resources to Liquids
b/d	Barrel / day
bbl	Barrel
BP	British Petroleum
BTU	British Thermal Unit
Co.	Company
CO_2	Carbon Dioxide
Corp.	Corporation
cu.	Cubic
DoE	Department of Energy
EOR	Enhanced Oil Recovery
FEDC	Fairbanks Economic Development Corporation
FNSB	Fairbanks North Star Borough
F-T	Fischer-Tropsch
FTA	Federal Transit Authority
ft	feet
GTL	Gas to Liquids
HCCP	Healy Clean Coal Project
IGCC	Integrated Gasification Combined Cycle
Inc.	Incorporated
IRR	Internal Rate of Return
LLC	Limited Liability Corporation
LNG	Liquid Natural Gas
Mmbtu	Million BTU (mbtu = 1000 BTU)
NETL	National Energy Technology Laboratory
NPR-A	Naval Petroleum Reserve - Alaska
RDS	Research and Development Solutions, LLC
SAIC	Science Applications International Corporation
Unocal	Union Oil of California

1.0 OBJECTIVE

The National Energy Technology Laboratory (NETL) has requested an assessment of existing Alaska facilities that could be reconfigured relatively quickly for use in potential coal-to-liquids projects capable of producing large/commercial quantities of coal-derived Fischer-Tropsch liquid fuels within the next few years.

While there are several proposals for large commercial-scale coal-to-liquids projects being advanced in the U.S., the concept explored in this report is for evaluation of a near term, smaller, domestic plant that could be available within a few years. Of interest also is to quickly be capable of producing lesser quantities of fuel to different specifications that could be used for qualification and testing. This report reviews the possibilities for such a plant specifically in Alaska. However, because there is a large-scale coal-to-liquids plant under consideration in Alaska (at Beluga), the status report of that project is also included. The assessment begins with a discussion of why Alaska is far ahead of other initiatives and why it has surfaced as optimal for near term pursuit of coal-based F-T fuel production.

2.0 INTRODUCTION

A Fischer-Tropsch (F-T) plant in Alaska should be considered for several reasons: (1) there is a small gas-based F-T test plant, the only operating plant of this type in North America, in operation at Nikiski, near Kenai, Alaska. This plant could provide the platform for a small production plant that could produce fuels for testing; (2) the state has large coal resources, one producing coal mine, and a second coal mine at an advanced stage of development; (3) There is a large coal-to-liquids project at an advanced stage for consideration in Alaska, therefore it is possible that this project or a smaller project might be developed fairly quickly; (4) hardware already exists which could be easily and economically converted to coal-based FT fuel production; (5) because of unique, harsh locations, higher fuel costs are generally supported, creating a strong market for FT based fuel introduction; (6) new high demands for clean FT coal-based fuel exist to replace the large demand for high sulfur jet fuels (for cold weather diesel engine use).

As mentioned previously, there also are coal-to-liquids plants being proposed for locations outside of Alaska. Although Baard Energy’s proposed 35,000 barrels/day plant at Wellsville, Ohio is one of the better examples, there are also several other smaller projects which plan to produce products other than fuels such as nitrogen fertilizers, from gasified coal.

This report is organized as follows:

- Summary
- Option 1 Near-term option for developing a small production facility for the purpose of producing coal-based F-T fuels for testing: BP Nikiski.

- Option 2 Medium-term option for producing coal-based F-T fuels for testing and commercial sales: Healy.

- Option 3 Longer-term option for producing coal-based F-T fuels for testing and larger quantities for commercial sales: Beluga.

- Fourth Scenario Conversion of Agrium Nikiski fertilizer plant infrastructure to coal-based FT fuel production.

- A fast-paced potential development plan: for near-term Option 1, initially focused on BP Nikiski, is identified.

- Overview of Alaska coal resources and coal extraction.

A note on technology:
The reader is cautioned that many of the scenarios described in this report are based on Fischer-Tropsch technologies at various stages of development. In particular, smaller-scale technologies have not yet been demonstrated in commercial applications and thus represent an additional uncertainty. The technologies discussed in this report that are proven commercially are the Agrium ammonia and urea process that operated at Agrium Corp.'s Nikiski plant for 35 years, and the Sasol and Shell F-T technologies that have been in operation at plants owned by those companies.

The Choren Industries biomass gasifier, suitable for small F-T plants, has several years of operational experience and, thus, can be considered commercially-demonstrated. This gasifier can also be adapted for coal, although that has been done only at a pilot plant scale. A plan by Shell to downsize that company's F-T technology to work with the Choren gasifier with a 500 barrel/day F-T plant is being implemented at this time but is not yet in operation.

A note on CO_2 sequestration:
A premise in this report is that some form of CO_2 sequestration or disposal will be required for any project envisioned. CO_2 sequestration may be possible in the depleted gas fields of the Cook Inlet where three scenarios were examined or in uneconomic coal seams at Healy, where a fourth scenario was examined. Captured CO_2 could be used in enhanced oil recovery in the Beluga plant option and possibly as an aid to coal-bed methane extraction in the Healy plant option as well.

3.0 SUMMARY

3.1. Option 1: Near-term: Use of a 300 b/d Fischer-Tropsch plant at Nikiski, Alaska

A plan involving the existing small Fischer-Tropsch gas-to-liquids plant at Nikiski, near Kenai, Alaska, is the best short-term option for getting a coal-based liquid fuels project underway. The plant exists and the owner, BP, is looking for other uses; although its primary purposes are to test a compact, small reformer that converts natural gas to synthesis gas and to test proprietary catalysts in a Fischer-Tropsch reactor developed by BP with Davy Process Technology. What is attractive about this option is that the BP plant, which is now designed to produce approximately 300 barrels per day of synthetic crude oil, could be expanded to produce at higher volumes.

One plan investigated was for a supply of synthesis gas manufactured from coal to be made available from a fertilizer plant near the BP GTL plant owned by Agrium Corporation. Agrium is far along in consideration of a coal-to-liquids project at the plant, the liquid being ammonia, and the concept considered was for a coal gasifier at the Agrium plant to also supply synthesis gas to the nearby modified BP plant to make F-T jet fuel for testing. Agrium has indicated that this is technically feasible and is possible.

Unfortunately, Agrium announced on March 14, 2008, that the coal gasification project would not be developed because costs had increased to the point where the project became cost prohibitive. The plan had been for a synthesis gas made from coal to replace natural gas as the chemical feedstock for the ammonia plant. However, since this plan will not proceed, an alternative option, involving the build of a coal gasifier at the BP plant to supply synthesis gas, was also considered. This is less attractive however, because of the small scale of the facility. If the gasifier could also serve to generate power for the local electricity market the economics would be improved.

Another option considered the build of a coal gasifier in connection with a large coal-to-liquids project on the west side of Cook Inlet, and supplying that synthesis gas to the BP plant at Nikiski, on the Inlet's east side, by pipeline. This option would require conversion of an existing natural gas pipeline or construction of a new pipeline.

A consideration with this option is that if a large coal-to-liquids plant is built on the Inlet's west side it could supply commercial quantities of coal-derived liquid fuels at more competitive prices than the small BP plant. However, at this early stage of US / domestic interest in F-T liquid fuels, a large and growing base of customers (ie. Department of Defense – Air Force, Department of Transportation – Federal Transit Authority (FTA), automotive engine manufacturers) may wish to engage in long term testing programs with coal derived fuels made to different testing specifications. For this case, it may be desirable to have a pilot plant, wholly dedicated to the production of fuels in smaller batches, for testing.

The key disadvantage of using the Nikiski plant is that, like the Agrium fertilizer plant, it is remote from a supply of coal. If the Agrium coal gasification project were going to proceed, coal would need to be supplied from the Usibelli Mine at Healy via the Alaska

Railroad to the Port of Anchorage and by barges from the Anchorage port to Nikiski. While it is also possible to supply a coal gasifier built near the BP GTL plant in this manner, the lower volumes of coal shipping would make this a very expensive option.

3.2. Option 2: Medium-term: A coal-to-liquids plant at the Usibelli Mine at Healy, in Interior Alaska.

A small or medium-sized coal-to-liquids plant could be built near an existing coal mine that is owned and operated by Usibelli Mines Inc. at Healy, in Interior Alaska. The principle advantage of this option is that the plant would be located at the coal mine, its primary energy source, eliminating the cost of shipping coal to a plant at another location. Another advantage of a plant at Healy is that the Alaska Railroad has tracks and loading facilities near the mine that would allow liquid products to be shipped by rail tank car to Fairbanks, Alaska in the north, or the Anchorage area, in the south.

A plant at Healy could be medium or small-sized. The advantage of a medium-sized plant is that it would enjoy better economies-of-scale in terms of production costs. The disadvantage is that if a dedicated plant to produce batches of fuel to different specifications for testing is desired, it would be more difficult with a medium-sized plant. A small plant, similar to the BP plant at Nikiski, could produce smaller quantities, but would suffer higher unit-costs because of the size. It would also be more difficult for commercial sales to be made from a small plant.

If the option of a smaller, focused plant were desired and BP were to close its Nikiski plant and sell the facility, it could be possible to move the plant units to Healy and reconstruct them there, adding a coal gasification unit.

Second variation for medium-scale coal-to-liquids project:
Another option that could be considered for an Interior Alaska coal-to-liquids project is a proposal by the Fairbanks North Star Borough (FNSB) and the Fairbanks Economic Development Corporation (FEDC) for a Fischer-Tropsch plant using coal from the Usibelli Mine at Healy but built at a location near Fairbanks, the preferred site being Eielson Air Force Base east of Fairbanks, Alaska. The goal is to have the plant and fuel storage facilities on the base so as to best serve the anticipated customer, the U.S. Air Force. Eielson AFB is currently being used to support aerial refueling operations over North America and the polar regions, and the Air Force has openly and significantly taken the lead for the US, both in certification and in use of F-T fuels in it’s air and ground vehicle fleets.

This project is in the conceptual stage and is being advanced by FEDC with the assistance of a consulting company. No company has indicated interest in building such a plant, however.

3.3. Option 3: Long-term: A large 80,000 barrels-per-day coal-to-liquids plant near the Beluga coal fields

A private firm, Alaska Natural-Resources-to-Liquids LLC, is working toward development of a large 80,000 barrels/day coal-to-liquids plant near the undeveloped Beluga coal fields on the west side of Cook Inlet approximately 50 miles from Anchorage. This project could be in operation by 2015 if it proceeds.

An advantage is that a large plant would produce large quantities of liquid products and enjoy economies-of-scale. This project also has the advantage of being located adjacent to a large, but undeveloped, coal deposit. Finally, the plant would be at a tidewater location from which liquid products could be shipped via efficient barge transportation.

The principal product of the plant would be Fischer-Tropsch diesel, sold to the U.S. west coast, as well as naphtha, which would be exported. It would also be possible for this plant to produce Fischer-Tropsch jet fuel as well.

Since this would be a commercial-scale plant it would be difficult to have it dedicated to the production of fuels in batches for testing, such as might be possible with the small BP plant at Nikiski. However, it is always possible to have a small, separate refining unit built within the larger plant that would be dedicated to the production of test fuels. In this context, the refining unit would benefit from the large economies of scale of the gasifier and Fischer-Tropsch plant, as well as support infrastructure and the coal mine. This could partly offset the principal disadvantage of a small plant, the adverse economies-of-scale.

If the “plant within a plant” concept were desirable at Beluga, and BP were to close its Nikiski plant, the facility could be dismantled and its process units, which are modular, moved across Cook Inlet to Beluga and installed within the larger Fischer-Tropsch plant.

Fourth Scenario: Conversion of the Agrium ammonia/urea plant to a Fischer-Tropsch plant:
An additional possibility that could be considered is conversion of the now-closed Agrium Corporation ammonia/urea plant to a Fischer-Tropsch plant. In this report, an earlier study of a Fischer-Tropsch plant built within the then-operating Agrium plant was discussed, which was based on converting natural gas to synthesis gas through a Methane Steam Reformer. Natural gas may no longer be a realistic option, at least for the short-term, but the possibility of the construction of a gasifier using coal could be investigated.

A fast-paced development plan:
The quickest way to begin producing F-T fuels for testing would be to work with BP on a program to purchase F-T synthetic crude, currently produced at the Nikiski GTL test plant, and arrange for the syn-crude to be shipped to a location where custom batch processing to a finished fuel could be produced to given sets of specifications. This could be done almost immediately and BP believes the product price would be in the range of $10 per gallon to $15 per gallon. This is a fast-paced preliminary step in a longer-term plan to produce coal-based F-T fuels in Alaska that could be done either by construction

of a gasifier at the small BP plant or, in the longer-term, a plan to develop a coal-based F-T plant at Beluga or Healy.

Alaska coal resources:
Alaska has very large coal resources. Hypothetical estimates have been made of the state's coal resources and the resource could be in the trillions of tons. However, much of this is in remote locations. There are substantial resources in areas that are accessible, however, such as at Beluga and in the Nenana coal fields of the Interior, where Usibelli Mine Inc. now operates Alaska's only producing coal mine.

4.0 OPTION 1: BIOMASS OR COAL GASIFIER AT THE SMALL BP GTL PLANT

A conceptual study was done in 2005 on the idea of locating a small F-T plant at or near the existing BP GTL plant using a biomass gasifier developed by Choren Industries of Germany. BP's facility is located at Nikiski, Kenai Peninsula, Alaska, 60 miles southwest of Anchorage.

The plant capital cost was estimated at $65 million when this study was conducted in 2005. The estimated cost of production of Fischer-Tropsch diesel with a small Choren gasifier using a biomass feedstock was $3.13 per gallon without consideration of available federal tax credits. We believe a project like this is worthy of further investigation. The Choren gasifier has a commercial operation history with biomass and has been demonstrated to be functional with coal, although this would require process modifications.

BP's test plant is a functioning Fischer-Tropsch plant that is capable of producing small quantities of F-T liquid products or somewhat larger quantities if the plant is expanded. The plant was designed as a research facility and conversion to a production facility would not be particularly efficient, however.

Facilities at the site include a 300 barrels/day capacity Fischer-Tropsch plant with Small Compact Reformer. The plant covers approximately 4 acres of a 23-acre land parcel.

Plant facilities include:

- The main process structure 80 feet wide by 90 feet long by 130 feet high
- An administration building of 4,300 square feet
- A warehouse building of 4,800 square feet
- 3,800 square feet of other buildings are at the site

Other site details: 11.7 acres were cleared for the project, including temporary staging areas and roads. Excavation involved 67,000 cubic yards of material, with 41,000 cubic yards of fill added. The site at Nikiski has highway access and is served by Homer Electric Association, the local electric utility.

The actual capital cost of the plant was $86.3 million, internally funded by BP. The annual operating budget was approximately $10 million in 2005, which includes the cost of natural gas feedstock. If coal were used as a feedstock, costs would be different.

Operations require a staff of approximately 20. The construction workforce was about 350, at peak. If this plant were dismantled and moved to another location, the construction workforce need would be similar.

In terms of environmental issues, the plant emits very small amounts of regulated air emissions but does generate a quantity of briny wastewater, which must be disposed of. The wastewater discharge is a result of the use of natural gas as a feedstock. If a coal gasifier were located on site, a solid waste discharge would result, mainly an inert slag which has commercial value as an aggregate.

4.1. Process description at the BP plant

Three million cubic feet per day of high-pressure natural gas are purchased from Marathon Oil Co. plus 250,000 cubic feet per day of low-pressure gas purchased from Enstar Natural Gas Co. for utilities. Four megawatts of electric power are provided by Homer Electric Association.

The process involves:

- Synthesis gas production in the Small Compact Reformer
- Synthesis gas compression and conversion to paraffins in the F-T converter
- Hydrocracking of paraffins to produce a (liquid) pumpable synthetic crude product at room temperatures.

The GTL product:

- Approximately 200-250 barrels per day of synthetic crude, currently exported by truck to Tesoro refinery, 1 mile away.
- Quality far exceeds specifications for Trans-Alaska Pipeline System.

- No sulfur, aromatics or heavy metals.

4.2. History of the BP project:

BP built its test gas-to-liquids plant to demonstrate a new Small Compact Reformer the company had developed in a partnership with Davy Process Technology. BP developed the small reformer with Davy (formerly Kvaerner) to commercialize the technology. The plant does not produce a finished diesel but rather a liquid, synthetic crude from which diesel, naphtha or other products could be made.

The plant is intended to demonstrate the Small Compact Reformer and to test proprietary catalysts in the F-T reactor. The compact reformer is a modular reactor which allows integration of partial oxidation with catalytic steam reforming. The reformer is about one third of the size of a conventional steam reformer, and works with a fixed-bed F-T synthesis converter. BP and Davy are also testing proprietary catalysts in the F-T converter.

The F-T conversion creates a paraffin wax which, after mild hydrocracking, results in a liquid synthetic crude. The manufacture of finished products like diesel and naphtha from the synthetic crude involves no new technology and since BP and Davy did not need to produce a finished product at the plant the product upgrading facilities were not installed.

Nikiski was chosen as a location because of the availability of skilled labor, the proximity to BP’s technical staff in Anchorage, the availability of natural gas and electricity, the relatively mild weather (compared with the North Slope), and the lower construction and operating costs as compared to the North Slope.

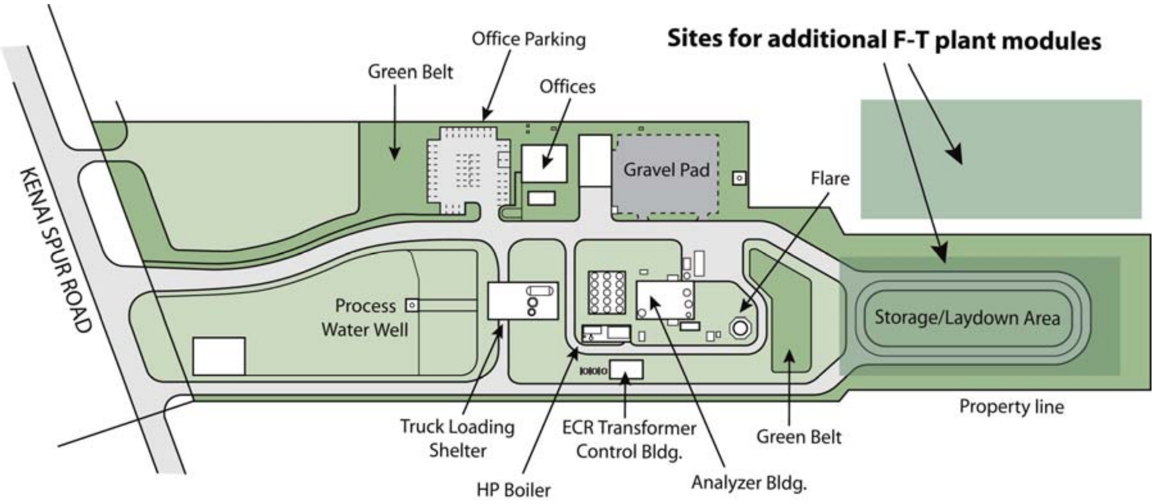
BP could have built the plant in the lower 48 states and within an existing refinery which, the company says, would probably have reduced the $86 million capital cost by approximately 40 percent. However, the company had made a commitment to the state of Alaska to build the demonstration plant in the state as part of an agreement for the state’s approval of BP’s acquisition of Atlantic Richfield Co. The original plan was to build the plant on the North Slope but Nikiski was finally selected because costs would be lower.

4.3. Obtaining GTL fuel products from the plant

From a purely mechanical point of view, a small product makeup unit could be added at this plant in a reasonably short time, and for modest cost. However, the plant is operated as a test plant and is actually producing about 250 barrels per day of synthetic crude, from which perhaps 200 barrels a day or less of F-T diesel could be produced. It is also possible to expand the plant, from a mechanical point of view. The plant capacity could be doubled by adding an additional Small Compact Reformer and an F-T reactor. Most of the infrastructure for the plant, such as the control systems, could support a larger plant. This “duplication” of the existing plant would increase the output to only 400 barrels/day of finished diesel or jet fuel.

Conceptually, the plant could be tripled in size with the addition of a third compact reformer, if gas feedstock were to be used, as well as additional F-T reactors. This would result in production of about 600 barrels/day. The site could easily support a doubling of the plant size but it is somewhat problematic as to whether it could support a tripling of size because of the presence of wetlands on the property adjacent to the existing pad, which would create complications in permitting the expansion. The expansions would also be expensive in that they would probably require nearly as much investment to double the plant capacity as it cost to build the original plant ($86 million) and again as much to triple the plant size.

It is possible that some of the additional cost of a plant expansion could be avoided if a shut-down Steam Methane Reformer at the nearby Agrium plant were reactivated and synthesis gas were brought from Agrium to the BP plant site by pipeline. BP actually looked at this possibility but concluded there are issues with the existing process design at Agrium and the composition of the synthesis gas. In addition, the Agrium steam reformer uses 70 million cubic feet per day of natural gas. It would not be efficient to operate it at 10 percent or 20 percent of its capacity.

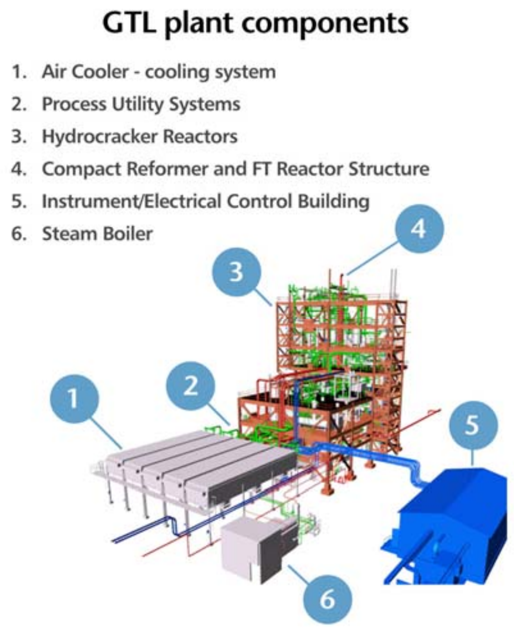


A limitation with the BP plant, as is the case with the present Agrium plant, is the reliance on natural gas as a feedstock. Natural gas is becoming more expensive in Southcentral Alaska, as it is elsewhere in the U.S., and there are concerns within the state and local governments that regional utilities should have priority on the remaining gas supplies for space heating and power generation. Also, preservation of the remaining gas-based industry, such the ConocoPhillips/Marathon liquefied natural gas plant, is important. There are other potential sources of carbon feedstock for an F-T plant, such as coal or biomass, but a gasifier would have to be added to the process.

BP feedback indicates it would be more cost-effective to build a new plant unit sized for the desired output rather than try to build on and modify existing facilities. Also, a new plant could be designed for production rather than the current test/demonstration facility at Nikiski.

4.4. Plant provided valuable experience in building small F-T plant in cold climate

Although it seems unlikely that this particular plant could provide a platform for expansion into a small production plant, BP's experience in building a "greenfield" small, compact F-T plant in a northern climate is valuable. The company has documented many "lessons learned" from its experience in building such a plant, which would be useful for any project of similar scale that might be built in a remote northern location.



5.0 OPTION 2: COAL-TO-LIQUIDS PLANT AT HEALY, ALASKA

Healy represents a good opportunity for a coal-based small F-T plant due to the close proximity of the Usibelli coal mine, which produces about 1.5 million tons of coal yearly. The mine is located in Interior Alaska, 90 miles south of Fairbanks, 242 miles north of Anchorage and about 12 miles north of Denali National Park.

Coal has been mined at Healy by the Usibelli family since 1943, serving power plants at military installations in the Fairbanks area, the University of Alaska Fairbanks campus, Clear Air Force Station and a power plant serving the city of Fairbanks owned by Aurora Energy, a Usibelli company.

Although the mine site is semi-remote, there is infrastructure available as well as highway, rail and utility access. Healy is served by the Parks Highway and the Alaska Railroad. A long-distance electrical transmission system goes through Healy. There are two coal-fired electric power plants, although one is not operating at this time. Healy's location on the main Alaska "railbelt" electrical grid means power is available at the site and any surplus energy from the plant process (through waste heat, for example) could be marketed to the regional grid. The Alaska Railroad could easily move product from a plant at Healy to markets, including military installations near Fairbanks to the north and near Anchorage to the south. From a practical standpoint an F-T plant would have to be a new-build facility.

5.1. Workforce issues in a semi-remote location

For plant construction or modification, a workforce would be imported from Fairbanks and Anchorage and housed in a remote-site construction camp. Maintaining an operations workforce at Healy presents no difficulty. Usibelli Mine Inc. maintains a year-round operations staff as does Golden Valley Electric Association, owner of one of the power plants at Healy.

5.2. Environmental issues mainly in air quality

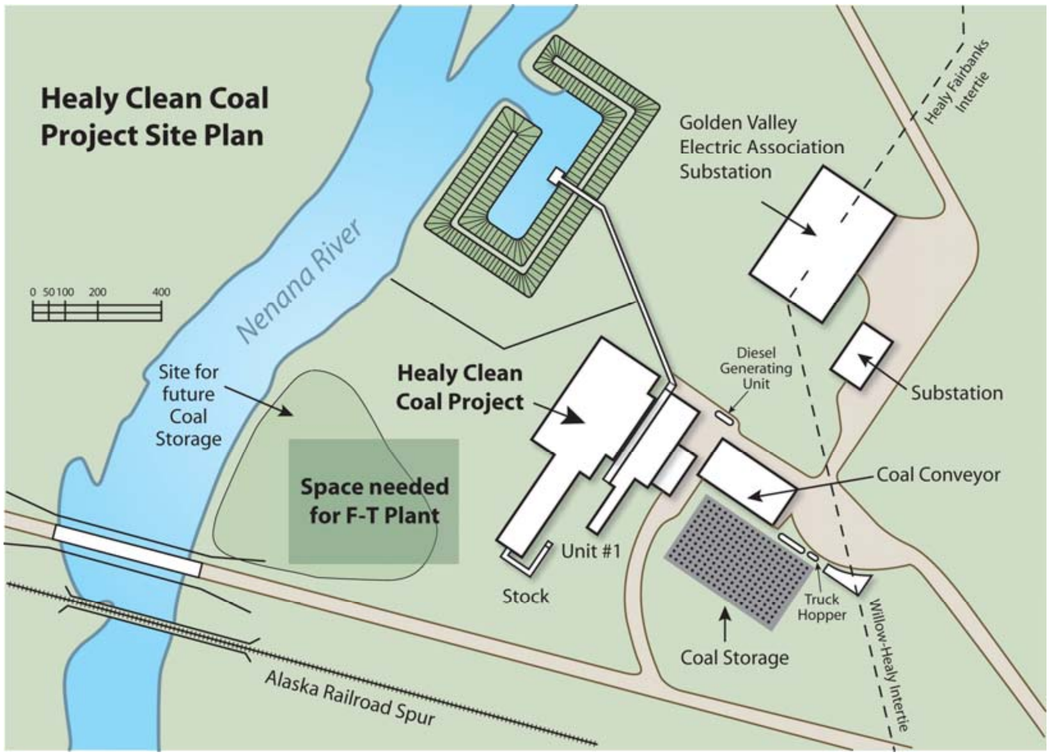
There are sensitive air emissions issues at Healy due to its proximity to the nearby Denali National Park. An F-T plant produces few air pollutants and, therefore, it is likely that the necessary air quality permits can be obtained. However, there will be great sensitivity to this issue with the National Park Service, the U.S. Environmental Protection Agency, the state Department of Environmental Conservation and environmental groups.

The infrastructure present at Healy will be important in supporting an F-T plant. Most important, the presence of the Usibelli coal mine and its support operations would make construction of an F-T plant and its operations more feasible given the remote location. For example, Usibelli maintains a well-equipped machine shop at the mine to support its operating equipment. Arrangements could be made for Usibelli to assist in the support of operations and maintenance of a small F-T plant. Another piece of important infrastructure is a coal-loading tipple built by Usibelli Mine Inc. that crosses the Nenana River. The coal mine is on the east side of the river and the railroad is on the west side. Conceptually, a small liquids line might be built into the tipple so that a separate crossing of the river is avoided. Alternatively, a new-build F-T plant might be located on the west side of the Nenana River so that coal could be carried to the plant on the tipple, avoiding the need to cross the river with the liquids pipeline.

5.3. Possible use of the Healy Clean Coal Project infrastructure:

One concept that has been investigated is whether the 50-Megawatt coal-fired power plant at Healy, which is not currently operating, could be used in a Fischer-Tropsch plant that would make liquid product from coal. In theory, some of the infrastructure for the Healy Clean Coal Project (HCCP) could be used, for example the coal loading facility and some components of the plant itself – the slagging combustor and boiler, etc. – might be used in an F-T plant conversion if a decision were made to dismantle the present HCCP. The plant's emissions and water permits could be important if they could be transferred to a new F-T facility or at least used as the basis for new permits. Permitting an industrial facility in the vicinity of a national park (Denali) always entails uncertainties.

Locating a new F-T plant adjacent to the HCCP to share at least some infrastructure might be possible, but there are complications when other needs are considered. There may not be sufficient room at the site, given the proximity of the plant to the nearby Nenana River, as well as the smaller 25-Megawatt plant owned by Golden Valley Electric Association.



A site investigation and discussions with people familiar with the plant indicate that while some of the components can be used in a conversion, it would be expensive to redesign and rebuild the plant. It would be more cost-efficient to build a new F-T plant designed for the intended purposes. A better location would be away from the existing power plants on lands owned by Usibelli Mine Inc. There is space available for a plant at these locations, as well as utility support. Other investigators have considered the possibility of a Fischer-Tropsch plant built north of Usibelli's present mine operations, where the company intends to do new mining and has also investigated a possible coal-fired power plant.

5.4. Facilities in the plant

The Healy Clean Coal Project process relies on a conventional boiler that produces steam for a conventional turbine to produce the nominal 50 Megawatts of power. The essential elements of the plant involve two precombustor units, a main combustor, a boiler, steam turbine and generator, a spray dryer absorber and a baghouse. Waste products include slag as bottom ash, and middle/fly ash, which are disposed of by truck.

The heart of the new technology in the coal-fired plant is a combustion system that burns coal in stages to minimize the formation of nitrogen oxides. Essentially, the combustion occurs at a slower, multi-staged pace; first at higher temperatures in a fuel-rich environment, followed by the second stage with additional air added at a controlled rate.

The effect is to minimize the buildup of nitrogen oxide and to effect very low carbon monoxide emissions. Sulfur dioxide is controlled with a 3-stage conventional process that includes limestone injection into the boiler. The sulfur dioxide reduction process involves pulverized limestone added to the coal in the combustor and converted by heat in the flue gas to lime, which reacts with the sulfur dioxide in the gas and removes it as a sulfate. A second system catches the unreacted lime and sulfates, which are then recycled to scrub the flue gas, further reducing the sulfur dioxide. The technology also results in approximately 80% of the ash being removed as solid slag material (vs. 20% in a conventional plant) and less of the ash having to be processed as a dry middle ash or fly ash.

In theory, some of the facilities could be used in a retrofit, such as the steam boiler, but the opinion of people knowledgeable with the facility is that it would be more cost-effective to build a new plant if the primary objective were to begin production of F-T fuel.

5.5. Retrofit study of the HCCP to an F-T plant

One conceptual study of a retrofit option to a Fischer-Tropsch plant was done in February, 2004, for the U.S. Department of Energy’s National Energy Technology Laboratory. It was done by Mitretek Systems, who was commissioned by NETL to write a “scoping” paper for internal use.

The Mitretek paper outlined two options for the plant, both involving removal of the coal combustors and their replacement with a coal gasifier.

One option was for the gasifier to produce a synthesis gas with some of the gas used to fire the steam boiler to produce electricity, and some of the gas used in a Fischer-Tropsch reactor to make liquid products.

In the scenario envisioned above, the plant could operate as a power plant producing 55 MW of total power. The plant itself would use 25 MW, leaving 30 MW of net power for sale. When the plant operates the F-T reactor, 500 barrels per day of liquid products could be produced along with 18 MW of power available for sale (net of the plant’s power requirement). Total capital costs of this option are estimated at $147 million with yearly operating and maintenance costs of $24 million.

The second option is similar except that the plant would have the capability of diverting some gas from the boiler to a small shift reactor that would produce hydrogen, with remaining gas sent back to the boiler for power generation. The electricity available for sale in the power-production mode is similar to that of the F-T case (30 MW net) but when the plant is in its hydrogen-production mode, 5 million standard cubic feet of hydrogen is produced along with 22 MW of net power. Total capital costs of this option are estimated at $136 million, with annual operations and maintenance costs estimated at $23 million.

The concept of a plant with dual power and F-T diesel or hydrogen production capability is interesting. The very sketchy concept developed by Mitretek is an illustration of what might be possible. More work would have to be done to refine capital and operating costs. NETL did not pursue these options further. Analysis of the Mitretek conceptual paper indicates that a 500 barrels/day F-T plant could produce F-T diesel for $4.61 per gallon.

5.6. An assessment of a Healy F-T plant

A separate assessment was made for a new, small "grass roots" plant, also 500 barrels/day, in a nearby location but separate from the existing HCCP power plant was conducted. Reference information was provided by Choren Industries of Germany, using information and lessons learned from their existing gasifier/F-T plant.

The initial assumption considered a new-built and separate 500 barrel/day F-T plant with a Choren coal gasifier would have a capital cost estimated in 2005 at $70 million. It was estimated that the plane could produce an F-T diesel for about $2.95 per gallon. The analysis assumed private investor financing 25% in equity investment and 75% with debt, at a 6.5 percent interest rate.

If capital costs are $136 million to $147 million, the per-gallon cost of producing a diesel fuel would rise to $4.61 per gallon under the same 25 percent equity/75 percent debt financing arrangement. However, alternative financing arrangements could reduce the cost of producing the fuel. If, for example, under a scenario that the plant would be dedicated to the production of military F-T fuels for testing and 75% of the capital cost paid through a federal appropriation, and, for commercial sales, the plant benefits from the 50 cents/gallon alternative fuels tax credit now in federal law, the per-gallon cost could drop to 90 cents/gallon. These estimates are for purposes of illustration only and therefore a more comprehensive study would be required to develop realistic capital and operating costs for a Healy site.

5.7. A second assessment of an F-T plant at Healy

A separate assessment of a 14,640 b/d F-T plant at Healy published in July, 2007 (DOE NETL 2007/1251) estimated that with an estimated $2.27 billion capital cost and, under an assumption of an 8 percent cost of capital and 12 percent investor's return on investment, a product gate-price (at the plant) of $64 per barrel or $1.52 per gallon would be required. It must be remembered that there will be more than one product produced, i.e. 70 percent diesel and 30 percent naphtha or a product cut somewhat similar. No federal tax credit or other incentives were included in the analysis. Note the lower price per gallon in this analysis ($1.52/gallon) compared with the two scenarios with a 500 b/d plant ($2.95/gallon (our estimate) and $4.65/gal. (Mitretek). These estimates mainly illustrate the advantages of scale economies in a larger plant.

The analysis assumed $2/bbl to $6/bbl to move the product from Healy to markets, for a total cost-to-market of approximately $70/bbl or $1.75 per gallon. The analysis assumed 2007 product prices of $81.50 per barrel or $1.91 per gallon, which indicates market potential above the projected prices. The 2008 market price for diesel in excess of $4 per gallon would seem to make this even more attractive.

If an F-T plant were to be built at Healy a larger plant would be more economical because of economies-of-scale. The existing coal mine has capacity to expand production without significant new capital investment, up to a point.

A 500 barrels/day plant would require about 82,000 tons of coal per year, well within the capacity of the mine. In comparison, a 6,000 barrels/day plant, which would be more efficient on a per-barrel production cost basis, would require about 1 million tons/year of coal.

Usibelli Mines now produces about 1.2 million tons per year for its current customers and has capacity to produce 1.5 million tons/year. While the coal resource is easily sufficient to supply an additional increment of demand of 1 million tons/year, Usibelli would be required to make significant capital investments in new capacity to meet that need. Those investments would be recovered in the cost of coal supplied to the F-T plant.

5.8. CO_2 sequestration at Healy

In their investigation of a 14,600 bbl/day F-T plant at Healy, Research and Development Solutions LLC (RDS) and Science Applications International Corp. (SAIC) estimated the cost of capture and sequestration of CO_2 at Healy at 42 cents/Mscf (standard cubic feet) or $7/ton. This cost could reduce the investor rate-of-return from 12 percent to 9.7 percent. However, if CO_2 could be commercially sold as an aid to enhanced recovery of coal-bed methane from coal seams, this cost could be reduced or removed.

5.9. Another variation for a medium-size coal-to-liquids project in Interior Alaska, using Healy coal:

Another option that could be considered for an Interior Alaska coal-to-liquids project is a proposal by the Fairbanks North Star Borough and the Fairbanks Economic Development Corp. for a Fischer-Tropsch plant using coal from the Usibelli Mine at Healy but built at a location near Fairbanks, the preferred site being Eielson Air Force Base east of Fairbanks, Alaska. The goal would be to have the plant and fuel storage facilities on the base so as to best serve the anticipated customer, the U.S. Air Force. Eielson AFB is now used to support aerial refueling operations over North America and the polar regions,and, as previously mentioned, the Air force has taken the lead for the US, both in certification and the use of F-T fuels in its Air and ground vehicle fleets.

This project is in the conceptual stage and is being advanced by FEDC with the assistance of a consulting company. No company has indicated interest in building such a plant, however.

FEDC is leading the conceptual planning and promotion of this project and has retained Hatch Corp., a Toronto-based engineering consulting firm, to provide assistance. Hatch has completed an initial screening of technology options and an analysis of possible sites for the plant other than at Eielson AFB, including co-location at the coal mine in Healy. FEDC raised $500,000 to fund this first-stage work from grants provided by the State of Alaska and the Fairbanks North Star Borough.

The conceptual plan is for a 40,000 barrels/day F-T plant to be built at Eielson using coal shipped by rail from the Usibelli mine at Healy (there is an existing rail spur from Fairbanks east to Eielson). FEDC hopes that the plant could also be designed to use biomass as feedstock (providing a market for wastewood from a small Interior forest products industry FEDC hopes to stimulate) and also to use natural gas as additional feedstock if a gas pipeline is built.

Eielson is seen as a preferred location for several reasons. A key objective of FEDC and the Fairbanks North Star Borough is to enhance services the base can provide to the Air Force mission, in this case a secure supply of F-T fuels for the Air Force. If these fuels were available at Eielson it would help improve the efficiency of the base mission. A second advantage of an Eielson location is that the base has an existing coal-fired power plant and coal handling and storage facilities that could possibly be used to support an F-T plant. Finally, an F-T plant could provide waste heat for a central steam-heat distribution system at the base, which would increase the overall efficiency of the plant.

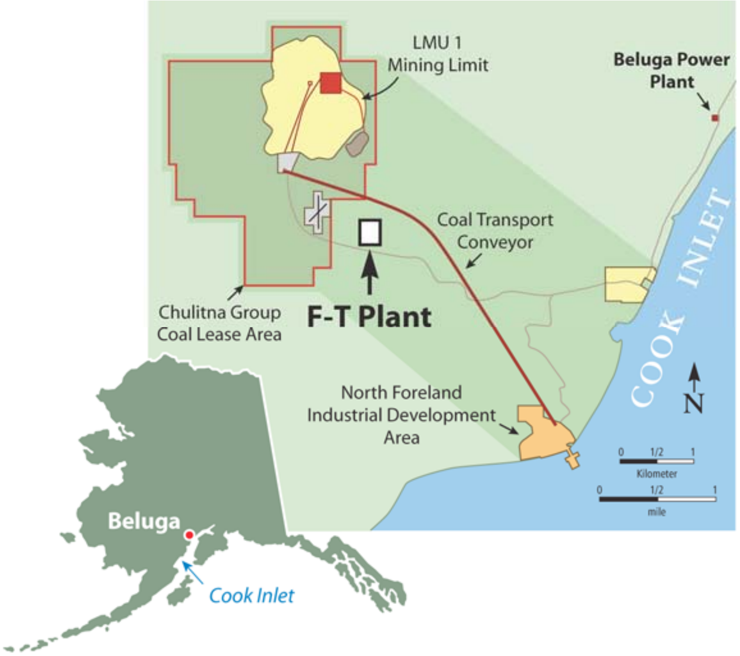
The key disadvantage of an Eielson location is that the coal would have to be shipped from Healy to the plant, raising the cost of the feedstock. What aggravates the shipping cost is that Healy coal is about 25 percent water, which means that one-fourth of the shipping cost is for material that contains no value for the plant.

The alternative is to locate the F-T plant at Healy adjacent to the coal mine, as described earlier in this report, and to ship the liquid fuel products by rail to Eielson. As described earlier, rail track now serves the mine and the Alaska Railroad has equipment and substantial experience in shipping bulk liquids. The shipping of liquid fuels from a plant at Healy would be more efficient than shipping coal to a plant at Eielson. On the other hand, a Healy location would lose the advantage of waste heat use in Eielson’s steam heat system although some other use for waste heat could be found at Healy, such as electricity generation. Construction costs might be somewhat lower at Eielson because the plant is closer to existing infrastructure and services compared with a more remote Healy location.

The initial screening by Hatch Corp. has concluded that such a plant might be feasible if crude oil prices were at the $108/barrel level if the project were developed by a private owner, or about $77 per barrel if the project were developed by a nonprofit entity such as a cooperative or a government agency. FEDC and the Fairbanks North Star Borough are now looking for approximately $7 million in state or federal grants to take this proposal to a second stage, which would involve discussions with technology providers and a more detailed assessment of an Eielson location.

6.0 OPTION 3: LARGE CTL PLANTS AT BELUGA, ALASKA

Two cases are considered, a smaller 6,000 bbl/d coal-based F-T plant and a second case of a larger 80,000 bbl/day coal-based plant.



The Beluga coal fields are located approximately 50 miles west of Anchorage and across the Cook Inlet from the Nikiski industrial site. The Beluga area contains one of the world’s largest surface-mineable reserves of low-sulfur coal close to tidewater and ocean shipping.

There are an estimated 2 billion tons of proven and probable sub-bituminous coal resources but economically recoverable reserves are estimated at 1.2 billion to 1.3 billion tons between two groups of coal leases. The coal’s principal attraction is its low-sulfur content, which make it attractive for power plants in meeting air emission standards. Its principal disadvantage for power plant customers is the relatively low energy content of the coal approximately 7,500 BTU’s per pound, and the high water content, approximately, 25 percent. The high water content means that 25 percent of the material shipped to customers has no economic value.

The current owners of coal leases at Beluga are working on a plan for an export coal mine but the coal deposit is a significant resource that could also supply a coal-to-liquids (CTL) F-T plant. Another company, Barrick Gold., owns additional coal resources nearby and is now assessing the potential for development for this resource.

The owners of the Chuitna coal leases are the Bass-Hunt group of Dallas, Texas with the Hunts designated as operator. The current plan is for a mine capable of producing up to 12 million tons per year and a minimum starting volume of 3 million tons/year. The Chuitna project is now pursuing a Supplemental Draft Environmental Impact Statement, due out in 2009, with plans to be in production by 2011 or 2012.

The coal mine proposed by the Chuitna group is about 12 miles from the Cook Inlet shore. A surface mining operation is proposed with a large dragline for overburden removal and with coal carried to crusher units by large trucks. Three mining areas are proposed, LMU-1 covering 9,650 acres; LMU-2 covering 2,500 acres; and LMU-3 covering 8,350 acres. These would be developed in a sequence.

The mine developers would transport coal by a 48-inch covered conveyor to a new 8,000-foot dock to be built out from shore to a depth of about 15 meters to 18 meters for loading of Cape-Class bulk carriers. The dock would also be designed to accommodate barge loading if customers, such as the project once envisioned by Agrium, are developed in the Alaska region.

The proposed mine, and the possible coal-to-liquids plant location, are also approximately 12 miles from existing electrical infrastructure at the 350 Megawatt simple cycle gas-fired Beluga power plant owned by Chugach Electric Association, the regional electric utility.

The Chugach Electric plant could supply power to the coal mine and to a coal-to-liquids plant under construction. Once the plant is operating, sales of power from waste heat could be made to Chugach. The waste heat from an F-T plant could produce about 300 MW of power. There are possible synergies. The Chugach power plant now has seven gas turbines and one waste heat turbine ranging in age from 25 years to 30 years of age, and the utility needs to plan for replacement or alternative sources of energy.

6.1. Infrastructure available at the site

Outside of the Beluga power plant and its connection to the regional electric grid, there is relatively little infrastructure to support development of the coal mine or an F-T plant, in contrast to sites we have examined at Nikiski and Healy. There are few roads in the area and those that are present are gravel, which would need upgrading. There is an existing 11-mile road in very basic condition from Ladd Landing, on Cook Inlet, to the coal lease boundary. The Chuitna group plans to upgrade this road as a part of the coal mine development.

Natural gas is available through a pipeline in the area. Products from a coal-to-liquids plant could be shipped by pipeline to the existing Drift River crude oil loading terminal 30 miles south of the proposed plant location. Drift River has the capability of loading tankers with 500,000-bbl capacity. A new pipeline would be required, however.

The construction workforce at a Beluga site could be supported by a conventional construction camp and support facility. At the operational stage, the production staff could be housed in a camp facility rotating to homes in Southcentral Alaska, as Chugach Electric now does at its power station in the area. In the long run there will most likely be a road connection with the existing highways in the Matanuska-Susitna Valley, which will enable plant workers to live nearby and commute to work. In addition, Tyonek Native Corp., the landowner in the area, is interested in a long-term community development plan that would include housing.

A major advantage of the Beluga site is that large, heavy gasifier vessels and F-T reactors could be delivered by barge in a fully-assembled state. While Nikiski also has this advantage, that location has no nearby coal deposit. The tidewater location also gives Beluga a distinct advantage over some other proposed U.S. locations for a large coal-to-liquids plant because very large vessels could not be delivered intact to those locations. The vessels and reactors would instead have to be fabricated on site, raising costs substantially.

The sea-level location creates another advantage for Beluga in that it will enhance the performance of air separation, turbine and generation equipment. There are also advantages in being able to use water for cooling instead of air.

6.2. Two plant scenarios considered for Beluga

One case for an F-T plant considered for Beluga is a 6,000 bbl/day project with a capital cost of $650 million. The plant would require approximately 3,000 tons of coal per day, or approximately 1.1 million tons per year. The developers of the proposed coal mine say that a customer requiring 750,000 tons to 1 million tons per year may be sufficient to develop the mine.

This analysis assumed coal prices in the $9 per ton to $13 per ton range. These estimates are for illustration only and do not represent prices the developer might actually charge. There is potential for sales of power generated from waste heat to the local power grid, but this was not considered in the analysis.

The analysis indicated that if coal prices were $13 per ton and that a 6,000 bbl/day plant based on a Choren gasifier could be built for $650 million, a clean diesel product might be sold for $2.55 a gallon. If the existing 50 cents-a-gallon federal energy credit for alternative fuels is applied, the cost is reduced to $2.05 per gallon. This analysis assumed a project financed 25 percent to 30 percent with an equity investment and 75 percent to 70 percent with debt and a private investor earning 20 percent return on the equity investment.

At the other end of the scale is a large project producing 60,000 bbl/day to 80,000 bbl/day, and assuming use of a Sasol or Shell F-T technology. ANRTL LLC, the private developer working on project development, estimated the capital costs at $5.3 billion. The required amount of coal would be much larger, about 50,000 tons per day, or about 17 million tons per year. A coal resource of 850 million tons would be required to supply the plant over 50 years, but that amount appears to be within the 1.3 billion tons of identified coal resources in the area. ANRTL is looking at a plant location on the industrial site offered by Tyonek Native Corp. A 12-mile to 20-mile conveyor would be needed to supply coal to the plant.

The economies of scale with a large project would reduce the threshold price of producing a clean diesel product to an amount just above $1 per gallon. The analysis by ANRTL LLC and its partners is confidential but more details could be made available under special arrangements.

ANRTL would prefer to develop a large plant because of the advantages of economies of scale, and because two major companies that own commercially-proven Fischer-Tropsch technology, Sasol and Shell, might be brought into such a project. However, if a larger project is not possible ANRTL will consider the option of smaller projects.

7.0 FOURTH SCENARIO: CONVERSION OF EXISTING INFRASTRUCTURE – AGRIUM AMMONIA, UREA PLANT TO F-T

Agrium Corp.’s ammonia and urea fertilizer plant, which is now in the process of being closed, is located at Nikiski, approximately 10 miles north of the city of Kenai, on the Kenai Peninsula south of Anchorage, Alaska’s largest city. The plant was shut down in late 2007 due to shortages of natural gas but was maintained and kept in “warm storage” until the company made a decision on whether to proceed with its proposed coal gasification project. Since that project will not proceed, Agrium will complete a “mothball” project that would see major facilities maintained in a state where they could be restarted if a supply of gas became available, but restarted at some expense.

The company owns approximately 180 acres at the site, of which approximately 140 acres are occupied by plant facilities. There are two ammonia plants and two urea plants at the site. One of the ammonia plants and one of the urea plants were initially built in 1967. The second ammonia plant and second urea plant were built in 1977 when the plant was expanded. Union Oil Co. of California (later known as Unocal) first built the plant then sold it to Agrium Corp. in 2000. Unocal itself was purchased by Chevron Corp. in 2005.

At full production, when Agrium was able to get a full supply of natural gas, the company produced approximately 630,000 tons of ammonia and 1 million tons of prilled and granular urea yearly. When it purchased the plant, Agrium had hopes of expanding the plant and its production but began experiencing shortfalls in gas supplies beginning in 2002, the shortages stemming from declining production of gas from Cook Inlet Basin gas fields. By 2005 the shortfalls were serious enough that the plant could no longer operate during the winter months when demand for gas from electric and natural gas utilities in the region were at their peak. In 2007 the company found it could no longer secure enough gas to even operate economically during the summer. Because of that the decision was made to close the plant but to maintain it for a possible restart if the coal gasification project were to go ahead.

7.1. Agrium process description with natural gas feedstock

Agrium’s process with natural gas was in two stages. Natural gas was reformed into a synthesis gas, from which anhydrous ammonia was made as the first step in the process. In the reformer a stream of natural gas was reacted with steam over a catalyst. This resulted in a hydrogen-rich synthesis gas at a high temperature, 1,400 to 1,500 degrees Fahrenheit. Air was added, in stages, to get the nitrogen needed for the ammonia.

Carbon dioxide and carbon monoxide were removed in a series of steps which resulted in a gas stream rich in hydrogen and nitrogen. This stream was compressed and sent to a reactor vessel for ammonia synthesis. The anhydrous ammonia was liquefied and stored at minus 30 degrees F. Carbon dioxide that was extracted during the process was used in the urea manufacturing.

Urea was made by reacting carbon dioxide and ammonia under high pressure and temperatures, 270 degrees to 360 degrees F., resulting in a molten mixture that was processed into solid forms and sold as fertilizer.

7.2. A fit of the Agrium plant with a Fischer-Tropsch facility

In theory, this process would seem to be a good fit with a Fischer-Tropsch process if a plant were built within the Agrium plant complex or near it, because some of the waste gas from ammonia manufacture can be used in an F-T process, and conversely, waste gas from an F-T process can be used in making ammonia. In Agrium's gas-based process the nitrogen is pulled from the air and used and the oxygen is a waste gas. In F-T it is just the opposite, with oxygen pulled from the air and used in the F-T process, leaving the nitrogen as a waste gas. The ammonia process uses the nitrogen and the F-T process the oxygen. Carbon dioxide from the F-T process can be fed into the urea production process. Another advantage of combining the two is that the ammonia process is a large user of waste heat. The F-T process is a large generator of waste heat.

These process combinations would work best if the Fischer-Tropsch plant were built into the existing ammonia and fertilizer plant complex, in which case there would be advantages in combining the utility services for both plants. However, there still might be other advantages if the F-T plant was separated from the fertilizer plant by some distance, which would be the case if the small BP gas-to-liquids plant were expanded and used for production of liquid fuels.

The combination of an F-T plant with the existing Agrium plant was looked at in 2001, although the project involved a scenario in which Agrium would continue to rely on natural gas as feedstock. A study by Dresser Engineering and Agrium looked at three scenarios for building an F-T plant into the existing Agrium plant.

One case involved using the existing Steam Methane Reformer, an estimated capital cost in 2001 of $85 million to $90 million (2001 dollars) in a low estimate ($23,743 to $24,139 capital cost per barrel of installed capacity) and $120 million to $130 million in a high estimate ($33,519 to $36,312 per barrel of installed capacity). It would have produced 3,580 barrels per day of liquid products, including 2,426 barrels per day of diesel and 1,041 barrels of naphtha, and minor volumes of butane, ethanol and methanol. The required gas feed would be 36.7 million cubic feet per day.

A second case involved building a new Steam Methane Reformer that would be more efficient. It would have required $180 million ($25,000 per barrel of installed capacity) to $220 million in capital investment ($30,500 per barrel of installed capacity) and resulted in 8,571 barrels per day of liquids produced from a gas feed of 74 to 75 million cubic feet per day.

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The third case involved a stand-alone F-T plant built adjacent to the fertilizer plant. It would have produced 8,571 barrels of product from 74 to 75 million cu ft. of gas/day, and required a capital investment of $220 million ($30,500 per barrel of installed capacity) to $240 million ($33,333 per barrel of installed capacity).

Dresser's 2001 study showed the potential for profitability. With an assumed market price of $1.50 per gallon for F-T diesel (note: diesel prices are now over $3 per gallon) the plant could pay up to $3.20/mmbtu for natural gas.

The economic circumstances of Cook Inlet have changed since the 2001 study was done. While diesel prices are at least twice what was assumed in the study, natural gas prices in the Cook Inlet region are also about twice the $3.20/mmbtu considered in one case of the study cited above. Also, natural gas is in increasingly short supply in Cook Inlet as reserves in existing fields are depleted. Prices of steel and other construction materials have also increased sharply since 2001.

Even given these facts, however, the Dresser study still points to the potential of a Fischer-Tropsch plant at the Agrium facilitity, albeit one using a synthesis gas made from coal. A partial conversion of the existing plant to incorporate an F-T process could be done in approximately three and a half years. This would include one year for design and engineering, six months for permit modifications, one year for fabrication and procurement and one year for construction.

7.3. Another study of the Agrium plant, but with conversion to coal

Another study, done in 2006, considered coal gasification at the Agrium plant, DOE/NETL-2006/1248. It considered two plant configurations, a system designed entirely as an IGCC that would supply synthesis gas to Agrium as feedstock and have surplus electricity to sell to the regional power grid, and a second case that would entail gasification units supplying the ammonia/urea manufacturing plant and a conventional fluidized bed combustion coal power plant to produce steam and power. The returns estimated were not robust in either case. Case 1, the IGCC plant, had an estimated internal rate of return (IRR) of 11.1 percent. Case 2, involving gasification for the fertilizer plant and a conventional power plant, had an IRR of only 6 percent. It should be pointed out that neither case included a Fischer-Tropsch plant, as considered in the Dresser study. The authors of the 2006 study cited the potential of an F-T plant but did not include one in the assessment.

Agrium's own Kenai coal gasification studies showed an F-T project to be more attractive, although information validating this is still held confidential. There are some differences in the way Agrium approached its own plan for a coal gasification plant than was assumed by the authors of the 2006 DOE/NETL study. The company says that its project could accommodate an F-T plant built near the existing fertilizer plant, and that synthesis gas could also be supplied to the nearby small GTL plant operated by BP. Agrium has decided not to proceed with the project, however.

One of the key questions about a coal gasification project at the Agrium plant is whether coal can be barged economically to the plant site from either the Port of Anchorage, which would receive coal by train from the Usibelli Mine at Healy, or from a new coal mine at Beluga. If the Chuitna group proceeds with its mine, coal could be barged across Cook Inlet from the coal-loading terminal near the mine to the Agrium plant.

Coal could also be barged from the Port of Anchorage. In addition, the Alaska Railroad Corp. and the Matanuska-Susitna Borough are working on a possible rail spur from the mainline track of the Alaska Railroad to the bulk commodities port developed by the borough at Point Mackenzie, on the west side of the Knik Arm of Cook Inlet. If the rail spur is built coal could be shipped from Healy to Point Mackenzie and shipped by barge to the Agrium plant.

The 2006 DOE/NETL study estimated the costs of barging coal from either the Chutina mine terminal at Beluga or from the Port of Anchorage to be similar ($3.43 per ton from Beluga; $3.55 per ton from Anchorage.) The total landed cost of coal at Agrium's plant was estimated by the 2006 DOE/NETL study estimated at $1.96 to $2.11 per mmbtu in the Usibelli/Anchorage case and $1.84 to $1.99 in the Chutina case. The differences were in two scenarios of prices for the coal paid to the mine owners, $18.60 per ton in a low case and $21 per ton in a high case.

7.4. Environmental considerations, Agrium conversion

In terms of currently regulated pollutants, no serious environmental issues are presented with an F-T conversion or expansion at the Agrium plant or the BP plant. A natural gas-based F-T process produces a briny wastewater effluent stream which must be disposed of, which BP does at the GTL plant now operating.

A coal-based F-T process results in an inert solid waste which can be disposed of in a landfill or used as an aggregate in construction of roads. Fischer-Tropsch plants produce minor amounts of regulated air pollutants such as sulfur dioxide, nitrogen oxide and carbon monoxide.

The most significant environmental issue for an Agrium plant conversion, or any Fischer-Tropsch plant in Alaska, is disposal or sequestration of excess carbon dioxide. The Agrium plant, when it operated, was a significant source of CO_2 emissions, about 114 million standard cubic feet per day. A coal gasification plant could increase the CO_2 emissions two-fold or more (the 2006 NETL study estimated 280 million cubic feet per day). Part of the CO_2 will be in a concentrated form that can be captured for use or sequestration, and part will remain as emissions from the turbine flue stack and would be more difficult to capture.

Separate studies have shown that CO_2 could be used in an enhanced oil recovery project in Cook Inlet, and that the five major oil fields in the Inlet have the potential to produce

290 million to 400 million additional barrels of oil. An additional recovery could extend the productive life of the Cook Inlet oil fields by an estimated 20 years.

The best candidate for a CO_2 flood appears to be the McArthur River oil field on the west side of Cook Inlet. However, the 2006 DOE/NETL study considered the capital costs associated with a CO_2 Enhanced Oil Recovery (EOR) project at McArthur River and concluded it was uneconomic, at least for the CO_2 to be supplied from the Agrium plant on the east side of Cook Inlet.

The assumptions for capital costs at a McArthur River CO_2 EOR project included a $15 million new dedicated pipeline for transporting CO_2, a $100 million new platform for CO_2 compression and separation (it was assumed that the current production platforms do not have sufficient space to accommodate facilities for CO_2 compression). In addition, investments of $3.5 million per well for 41 wells and 21 injector wells would be needed to equip the wells for a CO_2 EOR project. The total capital investment was estimated at $308 million. The study authors noted, however, that different configurations of the project, such as locating separation facilities onshore, might lower capital costs and improve the project economics.

7.5. History of the Agrium plant

The plant has an interesting commercial history. It was originally built by Union Oil Co. of California (Unocal) in 1969 as a way of commercializing “stranded” Cook Inlet gas. Unocal, Marathon Oil Co., Phillips Petroleum Co. and others had made significant gas discoveries in the Southcentral Alaska region while exploring for oil in the 1960s, but had no way of marketing the gas. A local gas utility was formed for Anchorage and local electric utilities switched to gas from coal, but local demand did not require significant amounts of gas.

The solution arrived at by Unocal, Marathon, and Phillips was to convert the gas into forms which could be transported. Phillips and Marathon built a liquefied natural gas plant and contracted with utilities in Japan to purchase LNG. It was the world’s first long-distance LNG transportation system. Unocal opted to manufacture agricultural fertilizers from gas and built the ammonia and urea fertilizer plant. The plant was expanded in 1977 by Unocal.

Agrium purchased the plant in 2000 when Unocal sold the facility as part of a plan to divest non-core assets. A critical part of the sales transaction was an agreement for Unocal to supply the plant with gas from the company’s Cook Inlet producing assets for an agreed-on price. The price has never been disclosed but third parties have estimated it at $1.20/million btus and Agrium has not disputed the estimate.

Shortly after Agrium took over the plant the facility began experiencing shortfalls in gas delivered from Unocal. Unocal blamed the shortages on unforeseen production problems in the producing reservoirs on leases dedicated to the supply contract. Agrium sued, asserting a breach in the contract. The litigation was subsequently settled with Unocal making cash payments to Agrium and the long-term contract terminating on Oct. 31,

2005. Without a guaranteed supply of gas after Oct 31, Agrium had announced its decision to begin closing the plant Nov. 1, 2005.

In early 2005, however, Governor Frank Murkowski convened meetings with Cook Inlet gas producers which subsequently resulted in agreements with several to supply the plant until Oct. 31, 2006. Prices and other terms of the one-year contracts were not disclosed, although Agrium had specified a $3/million BTU's (mmbtu) price in its request for proposals. Meanwhile a state regulatory proceeding initiated partly by Agrium resulted in a privately-owned gas pipeline crossing Cook Inlet being made available for use by others to ship gas to Agrium. This allowed Agrium, for the first time, to acquire gas from producers on the west side of Cook Inlet.

All of this is being played out in a situation where Cook Inlet gas prices have been rising. For many years gas in the inlet was "stranded" and therefore inexpensive relative to prices in the continental U.S. However, as reserves have been depleted from existing fields the production has declined. That, coupled with rising demand from regional population growth, has led to higher prices. Average prices for gas in Cook Inlet were near $4/mmbtu at the end of 2005. Enstar Natural Gas Co. paid over $6/mmbtu in 2006, it has reported.

Agrium told the state Legislature in 2005 that it could not pay more than $2/mmbtu for gas. The company said subsequently that it would be able to pay higher prices for gas given rising prices for fertilizer but would not comment further.

There are reasons why Cook Inlet producers continued to sell gas to Agrium for several years at prices lower that those paid by regional utilities. Agrium was a "base supply" customer requiring steady volumes year-around. Utility demand, in contrast, peaks in the winter and is lower in summer. Agrium had been able to negotiate interruptible supply contracts during the peak winter season for prices it could afford. As gas supplies contracted the company closed one urea and one ammonia plant so that it operated at half its former capacity and required half of the natural gas supply. However, the higher fixed costs of the infrastructure and the higher gas prices put the plant at an increasing disadvantage. The plant sold products mainly in Asia where it competed with fertilizer from plants in other nations, some of which have the benefit of less expensive gas.

Although Agrium is in the process of mothballing the plant the company has not decided to dismantle it. The facilities are being prepared for storage in the event that an option for re-use appears, as the plant infrastructure could be important in an F-T application.

7.6. Recommendations for a Fast-Paced Potential Development Plan

Coal-to-liquids Fischer-Tropsch plant for the production of test fuel:
The following recommendations are included to address a near term Fischer-Tropsch pilot plant producing small, but significant quantities of liquid fuels:

- Work with BP on a short-term plan involving the existing GTL plant at Nikiski.
- Work with Alaska Natural-Resources-to-Liquids LLC to help facilitate a larger plant at the Beluga coal fields.

A short-term plant with BP might involve:
Purchase of the synthetic crude now produced at the plant from natural gas. Ship the syn-crude in containers to a plant in the Lower 48 states which can do custom processing of F-T jet fuel, F-T diesel or other products. BP believes this is a viable short-term option that could be done almost immediately, and that F-T fuel batches for testing could be produced and delivered for $10 per gallon to $15 per gallon.

Production of coal-derived fuels at the plant could be done with installation of a Choren gasifier or a gasifier of similar size at the BP GTL plant. Coal could be barged to the site from an existing coal terminal at Seward. An unloading facility and coal storage site would be needed along with a process skid to refine syn-crude into finished F-T products and tankage to store finished product before transport.

8.0 A NOTE ON HOW THIS ANALYSIS WAS CONDUCTED

The analyses involving a Choren gasifier in the Nikiski (BP), Healy and Beluga F-T plant scenarios assumed a private investor providing between 20 percent to 25 percent equity and earning either 20 percent or 30 percent internal rate of return (IRR) before federal tax. A 30 percent rate of return results in approximately a 19 percent rate of return after federal tax depending on the tax status of the investor.

Until several F-T plants, especially small footprint F-T plants, are successfully built and operated, these rates of return are estimated at the levels required to attract a private investor. Debt is assumed to have a 15-year payback at a 7.5 percent interest rate. The analyses have also reserved 18 percent of net cash flow for local and state taxes. In all cases design and construction is estimated at three and a half years except in the case of the BP gas-to-liquids plant conversion to biomass, in which one year is assumed.

Capital costs in the case of coal and biomass were derived from data made available from Choren Industries of Germany and from Sasol, of South Africa, for a larger coal-to-liquids plant at Beluga. The data was provided in 2005 and 2006 and will have to be updated for new estimates.

9.0 OVERVIEW OF ALASKA COAL RESOURCES AND COAL EXTRACTION

It is well-documented that Alaska has very large coal resources, and the bulk of it not explored or adequately assessed. The best known coal deposits are in the Nenana coal fields in the Alaska range where Usibelli Coal Mine Inc. has a producing mine. The Nenana coal field resources are potentially very large. Usibelli itself has several decades of reserves at current production rates on state coal leases it owns and there is substantial potential for reserve additions when the coal is needed.

Another large deposit, or group of deposits, is in the Beluga coal fields west of Anchorage. Private firms have done exploration in the area and a mine is planned by the Chuitna group. There are other nearby deposits, including one owned by Barrick Resources.

The Nenana and Beluga coal deposits are sub-bituminous with a high water content (25 percent) but very low sulfur content. The high moisture is a problem in marketing in export markets but the low sulfur content makes the coal advantageous in terms of a power plant meeting stringent local emission standards.

Another coal deposit where a mine can be developed in the near-term is at Wishbone Hill, in the Matanuska River valley north of Anchorage. Unlike the Nenana or Beluga coals, the Wishbone deposit contains bituminous coal, although the resource quantity appears more limited than at Beluga or the Nenana coal fields. A major Japanese company, Idemitsu Kosan, planned a mine at Wishbone Hill in the early 1990s but the project did not go forward due to litigation over land ownership. The coal leases there are now owned by Usibelli.

Other coal deposits that are relatively less explored include Jarvis Creek in eastern Interior and the Bering River coal fields east of Cordova. Jarvis Creek has been considered as a source of coal for a power plant at Fort Greely, which is in the area.

The largest coal resources in Alaska are on the western Arctic Slope, where large areas of the National Petroleum Reserve-Alaska and private lands west of NPR-A that are owned by Arctic Slope Regional Corporation(ASRC) are underlain by thick bituminous and sub-bituminous coal beds. Arctic Slope has investigated the potential for a coal mine on its lands near Cape Lisburne, on the western Arctic Slope, and now has an exploration program underway with BHP Billiton.

Development scenarios include a mine supplying a coal-fired power plant with a 90-mile electric intertie built to the large producing Red Dog lead-zinc mine, which now uses about 13 million gallons of diesel yearly to generate power. If a mine were built, ASRC believes a road built to the Red Dog Mine could allow coal to be exported using the road and port infrastructure now supporting the lead and zinc mine. A port has also been considered for the Chukchi Sea coast near the mine but shallow waters offshore would require a lightering operation to load large bulk carriers, and ice conditions would present a navigation issue.

Among the possibilities being investigated by ASRC and BHP Billiton is a large coal gasification plant that would produce a synthesis gas for transport by pipeline across the NPR-A to the corridor for a future natural gas pipeline serving the North Slope.

10.0 FINAL ANALYSIS

An analysis of the potential coal to liquids project sites across the country yields several feasible options. Considerations for selecting the appropriate site include an abundant source of coal, the infrastructure to move the raw materials in and the refined product out, and finally complimentary industries to utilize the waste products created during the coal to liquids process. Although there are other areas throughout the nation that may provide some of these components, the State of Alaska is an ideal place to begin coal to liquids production for a variety of reasons. (i.e. the existence of the only operating F-T plant in North America; an abundant coal supply; supporting infrastructures; an existing customer base ideally primed for the technical FT fuels characteristics and projected initial coal based cost comparisons)

The lifestyle of the people of Alaska lends itself toward the use of diesel fuel in everyday life. In Alaska, there is a long standing culture of outdoorsmen braving harsh, cold weather conditions and therefore the use of heavy-duty, diesel-based machinery for everything from snow removal, construction equipment, and personal vehicles to the electrical gensets that support daily activities in remote wilderness areas of the state. This reliance on diesel fuel to support the Alaskan lifestyle, creates a large demand throughout the state. Although the state of Alaska pays the highest diesel fuel price in the country to run their local economy, economic costs for introducing coal-based F-T fuels could be easily offset by high local customer demand.

Compounding the problem even further is the requirement for winter diesel that has special icing inhibitors and a unique cold weather formulation. Throughout the year, the requirement for specially formulated cold weather diesel, due to temperature conditions, is very real. Many Alaskans get around this issue by using jet fuel in their diesel engines. Unfortunately, that jet fuel is formulated with several parts per million of sulfur and other impurities which are being outlawed for use in ground vehicles. Alaska’s small population with a high demand for winter diesel requires a low sulfur option that will allow their vehicles to start reliably in the wintry conditions that dominate their year. F-T fuels, due to their inherent cold weather properties and low sulfur composition, are the natural solution.