LG&E

a PPL company

Jeff DeRouen, Executive Director
Public Service Commission of Kentucky
211 Sower Boulevard
P. O. Box 615
Frankfort, Kentucky 40602

RECEIVED
SEP 01 2011
PUBLIC SERVICE COMMISSION

Louisville Gas and Electric Company
State Regulation and Rates
220 West Main Street
P.O. Box 32010
Louisville, Kentucky 40232
www.lge-ku.com

Robert M. Conroy
Director - Rates
T 502-627-3324
F 502-627-3213
robert.conroy@lge-ku.com

September 1, 2011

RE: ***In the Matter of: The Application of Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Approval of Its 2011 Compliance Plan for Recovery by Environmental Surcharge*** **- Case No. 2011-00162**

Dear Mr. DeRouen:

Enclosed please find and accept for filing the original and fifteen (15) copies of Louisville Gas and Electric Company's Motion to Deviate from Requirement Governing Filing of Copies for certain responses to the Commission Staff's Second Request for Information dated August 18, 2011, in the above-referenced matter.

Please confirm your receipt of this filing by placing the stamp of your Office with the date received on the attached additional copies. Please do not hesitate to contact the undersigned should you have any questions.

Sincerely,

Robert M. Conroy

cc: Parties of Record

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	)))))))	**CASE NO. 2011-00162**

MOTION OF LOUISVILLE GAS AND ELECTRIC COMPANY TO DEVIATE FROM REQUIREMENT GOVERNING FILING OF COPIES

Louisville Gas and Electric Company ("LG&E") by counsel, petitions the Kentucky Public Service Commission ("Commission") to grant LG&E approval pursuant to 807 KAR 5:001 § 14 to deviate from the requirement that parties file an original and fifteen (15) complete copies of all data responses and attachments. LG&E requests that it be excused from filing any paper copies of certain attachments to its responses to the Commission Staff's Second Request for Information because such attachments are voluminous. Similarly, LG&E requests that it be excused from filing all paper copies but one with respect to another response because of the volume of the response. In support of its Motion, LG&E states as follows:

1. Pursuant to Commission's June 28, 2011 Order, LG&E must provide an original and fifteen (15) copies of all data responses and attachments to the Commission, along with a service copy to all parties of record. Certain of LG&E's attachments to its responses to the Commission Staff's Second Request for Information are voluminous. LG&E is therefore requesting permission to file only electronic copies of the attachments on compact disc for LG&E's responses to Request for Information Nos. 3(d) and 11, and to provide only one paper

copy of the attachments to LG&E's response to Request for Information No. 6(c) (the remainder of such copies to be provided electronically on compact disc).

2. LG&E's response to the Commission Staff's Second Request for Information No. 3(d) is voluminous, consisting of over 1,100 pages. To produce a paper original and 15 paper copies for the Commission would consume over 16,000 pages, and service copies would consume even more pages. For that reason, LG&E requests a deviation to produce all copies to the Commission and all service copies in electronic format on compact disc.

3. The Commission Staff's Second Request for Information No. 11 asks for calculations to support two of LG&E's previous responses to the Commission Staff's data requests. The best means to provide the requested information is in an Excel spreadsheet format, where the requested calculations will be apparent as formulae underlying the spreadsheet cells' contents. LG&E therefore requests a deviation from the paper production requirement to produce all copies to the Commission and all service copies of the requested information in an electronic format on compact disc.

4. LG&E's response to the Commission Staff's Second Request for Information No. 6(c) is voluminous, consisting of over 130 pages. To produce a paper original and 15 paper copies for the Commission would consume over 1,700 pages, and service copies would consume even more pages. For that reason, LG&E requests a deviation to produce a single paper copy to the Commission, with 15 additional copies and all service copies to be produced in electronic format on compact disc.

5. LG&E is making all of the above requests to deviate from the paper filing requirement pursuant to 807 KAR 5:001 § 14.

WHEREFORE, LG&E requests the above-described deviations from the requirement that parties provide an original and fifteen (15) paper copies of discovery responses. LG&E requests that it be allowed to instead submit the attachments to responses identified above on compact discs in compliance with this requirement.

Dated: September 1, 2011

Respectfully submitted,

Kendrick R. Riggs
W. Duncan Crosby III
Monica H. Braun
Stoll Keenon Ogden PLLC
2000 PNC Plaza
500 West Jefferson Street
Louisville, Kentucky 40202-2828
Telephone: (502) 333-6000

Allyson K. Sturgeon
Senior Corporate Attorney
LG&E and KU Services Company
220 West Main Street
Louisville, Kentucky 40202
Telephone: (502) 627-2088

Counsel for Louisville Gas and Electric Company

400001.139563/755125.1

<u>**CERTIFICATE OF SERVICE**</u>

I hereby certify that a true copy of the foregoing Motion to Deviate was served via U.S. mail, first-class, postage prepaid; overnight delivery; or hand-delivery, this 1st day of September 2011 upon the following persons:

Dennis G. Howard II
Lawrence W. Cook
Assistant Attorneys General
Office of the Attorney General
Office of Rate Intervention
1024 Capital Center Drive, Suite 200
Frankfort, KY 40601-8204

Michael L. Kurtz
Kurt J. Boehm
Boehm, Kurtz & Lowry
36 East Seventh Street, Suite 1510
Cincinnati, OH 45202

David C. Brown
Stites & Harbison PLLC
400 West Market Street, Suite 1800
Louisville, KY 40202-3352

Tom FitzGerald
Kentucky Resources Council
P.O. Box 1070
Frankfort, KY 40602

Robert A. Ganton
Regulatory Law Office
U.S. Army Legal Services Agency
901 N. Stuart Street, Suite 525
Arlington, VA 22203-1837

Scott E. Handley
Administrative Law Division
Office of the Staff Judge Advocate
50 Third Avenue, Room 215
Fort Knox, KY 40121-5000

Edward George Zuger III
Zuger Law Office PLLC
P.O. Box 728
Corbin, KY 40702

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105

Shannon Fisk
Senior Attorney
Natural Resources Defense Council
2 N. Riverside Plaza, Suite 2250
Chicago, IL 60660

Allyson Sturgeon

Counsel for Louisville Gas and Company

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED

SEP 01 2011

PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	)	**CASE NO. 2011-00162**

PETITION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR CONFIDENTIAL PROTECTION FOR RESPONSES TO CERTAIN DATA REQUESTS OF THE COMMISSION STAFF

Louisville Gas and Electric Company ("LG&E") hereby petitions the Kentucky Public Service Commission ("Commission") pursuant to 807 KAR 5:001, Section 7, and KRS 61.878(1)(c) to grant confidential protection for the items described herein, which LG&E seeks to provide in response to Commission Staff's Second Information Request to LG&E Nos. 3(c), 3(d), 6(a), 11 and 23(b) and (d). In support of this Petition, LG&E states as follows.

Confidential or Proprietary Commercial Information (KRS 61.878(1)(c))

1. The Kentucky Open Records Act exempts from disclosure certain commercial information. KRS 61.878(1)(c). To qualify for the exemption and, therefore, maintain the confidentiality of the information, a party must establish that the material is of a kind generally recognized to be confidential or proprietary, and the disclosure of which would permit an unfair commercial advantage to competitors of the party seeking confidentiality.

2. Staff Request No. 3(c) asks LG&E whether the RFP process undertaken by KU and LG&E has resulted in the selection of self-build options; acquiring existing generation capacity; or purchasing power from a third party. The response to this request is confidential because the response reveals LG&E's plans with regard to additional generation capacity, which

is highly commercially sensitive. Disclosing the information included in the response to Request No. 3(c) would permit a host of third parties to manipulate the costs associated with these options. If LG&E has selected the self-build option, contractors and vendors could manipulate the labor and purchasing costs to the financial detriment of LG&E and its customers. If acquiring existing generation capacity or purchasing power from a third party was selected, those third parties from whom the capacity or power would be acquired or purchased could manipulate the market prices for the energy, again to the financial detriment of LG&E and its customers. Regardless of the option LG&E has selected, the public disclosure of its selection will limit LG&E's ability to secure the energy at the lowest possible cost.

3. Staff Request No. 3(d) asks LG&E to provide the responses received by KU and LG&E to the RFP issued in December 2010 for new capacity and energy. In response to this request, LG&E is providing the responses electronically as an attachment. The responses contain substantial amounts of commercially sensitive and confidential information, including the projected costs of labor, projected fuel costs, and other highly commercial sensitive information. The projected costs are highly commercially sensitive because, if publicly disclosed, fuel suppliers could manipulate fuel prices in order to maximize its revenues based upon the projected costs LG&E anticipates will be required. This would result in a detrimental and undue erosion of LG&E's ability to obtain fuel at competitive prices. This would constitute an unfair disadvantage to LG&E. The projected labor costs are likewise highly commercially sensitive because, if publicly disclosed, vendors and contractors could manipulate the labor prices to force LG&E to contract for labor at higher rates to the detriment of LG&E and its customers.

4. Staff Request No. 6(a) asks LG&E to provide, for each fossil generation unit, a timeline, out to the year 2020, showing the tonnage amount of emission allowances granted by the U.S. Environmental Protection Agency for the Cross-State Air Pollution Rule, the Hazardous Air Pollutants Rule under the Clean Air Act, and the tonnage amount of projected emissions generated by the unit assuming that LG&E's mitigation strategy is implemented as proposed. In response, LG&E is providing the requested allocations as an attachment. The allocations contain highly commercially sensitive information regarding the expected outputs of each of LG&E's generating units. Disclosure of these projections would arm LG&E's competitors with projected information regarding LG&E's tonnage outputs for the remainder of this decade. With this information, competitors could manipulate the market prices for purchased power to maximize the competitors' revenues at LG&E's financial detriment. Consequently, disclosure of this information would erode LG&E's competitive position in the wholesale power market.

5. Staff Request No. 11 asks LG&E to provide the calculations that compare the cost to produce power with market power prices. In response, LG&E is providing as an attachment the calculations computing the average dispatch costs for each unit. The calculations are highly commercially sensitive because the disclosure of LG&E's dispatch costs would permit LG&E's competitors to learn at what cost LG&E generates power, which would permit those competitors to manipulate the market prices for purchased power to maximize the competitors' revenues at LG&E's financial detriment. Consequently, disclosure of this information would erode LG&E's competitive position in the wholesale power market. Also, disclosure of this information would result in a detrimental and undue erosion of LG&E's ability to obtain fuel at competitive prices because fuel suppliers could manipulate fuel prices in order to maximize its revenues based upon

the projected costs LG&E anticipates will be required. This would constitute an unfair disadvantage to LG&E.

6. Staff Request No. 23(b) and (d) asks LG&E to provide various updates to the table LG&E provided in response to the Staff's Initial Data Request No. 45. As with LG&E's initial response, the attachments provided in response to Request No. 23(b) and (d) contain confidential fuel cost data. The projected costs are highly commercially sensitive because, if publicly disclosed, fuel suppliers could manipulate fuel prices in order to maximize its revenues based upon the projected costs LG&E anticipates will be required. Any impairment of its ability to obtain the most advantageous price possible from coal and natural gas suppliers will necessarily erode LG&E's competitive position among other electric utilities with whom LG&E competes for new and relocating industrial customers and for off-system sales. This would constitute an unfair disadvantage to LG&E.

7. If the Commission disagrees with any of these requests for confidential protection, however, it must hold an evidentiary hearing (a) to protect LG&E's due process rights and (b) to supply with the Commission with a complete record to enable it to reach a decision with regard to this matter. Utility Regulatory Commission v. Kentucky Water Service Company, Inc., 642 S.W.2d 591, 592-94 (Ky. App. 1982).

8. The information for which LG&E is seeking confidential treatment is not known outside of LG&E, is not disseminated within LG&E except to those employees with a legitimate business need to know and act upon the information, and is generally recognized as confidential and proprietary information in the energy industry.

9. LG&E will disclose the confidential information, pursuant to a confidentiality agreement, to intervenors and others with a legitimate interest in this information and as required

by the Commission. In accordance with the provisions of 807 KAR 5:001, Section 7 and the Commission's June 28, 2011 Order in this proceeding, LG&E herewith files with the Commission one copy of the above-discussed responses with the confidential information highlighted and fifteen (15) copies of its responses without the confidential information.[1]

WHEREFORE, Louisville Gas and Electric Company respectfully requests that the Commission grant confidential protection for the information at issue, or in the alternative, schedule and evidentiary hearing on all factual issues while maintaining the confidentiality of the information pending the outcome of the hearing.

[1] LG&E, as explained in the Motion to Deviate filed herewith, is requesting a deviation that permits it to only provide electronic copies of the attachments to Staff Request Nos. 3(d) and 11. Thus, no print copies of these attachments are being provided.

Dated: September 1, 2011

Respectfully submitted,

Kendrick R. Riggs
W. Duncan Crosby III
Monica H. Braun
Stoll Keenon Ogden PLLC
2000 PNC Plaza
500 West Jefferson Street
Louisville, Kentucky 40202-2828
Telephone: (502) 333-6000

Allyson K. Sturgeon
Senior Corporate Attorney
LG&E and KU Services Company
220 West Main Street
Louisville, Kentucky 40202
Telephone: (502) 627-2088

Counsel for Louisville Gas and Electric Company

CERTIFICATE OF SERVICE

I hereby certify that a true copy of the foregoing Petition was served via U.S. mail, first-class, postage prepaid; overnight delivery; or hand-delivery, this 1st day of September 2011 upon the following persons:

Dennis G. Howard II
Lawrence W. Cook
Assistant Attorneys General
Office of the Attorney General
Office of Rate Intervention
1024 Capital Center Drive, Suite 200
Frankfort, KY 40601-8204

Scott E. Handley
Administrative Law Division
Office of the Staff Judge Advocate
50 Third Avenue, Room 215
Fort Knox, KY 40121-5000

Michael L. Kurtz
Kurt J. Boehm
Boehm, Kurtz & Lowry
36 East Seventh Street, Suite 1510
Cincinnati, OH 45202

Edward George Zuger III
Zuger Law Office PLLC
P.O. Box 728
Corbin, KY 40702

David C. Brown
Stites & Harbison PLLC
400 West Market Street, Suite 1800
Louisville, KY 40202-3352

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105

Tom FitzGerald
Kentucky Resources Council
P.O. Box 1070
Frankfort, KY 40602

Shannon Fisk
Senior Attorney
Natural Resources Defense Council
2 N. Riverside Plaza, Suite 2250
Chicago, IL 60660

Robert A. Ganton
Regulatory Law Office
U.S. Army Legal Services Agency
901 N. Stuart Street, Suite 525
Arlington, VA 22203-1837

Counsel for Louisville Gas and Electric Company a PPL company

Jeff DeRouen, Executive Director
Public Service Commission of Kentucky
211 Sower Boulevard
P. O. Box 615
Frankfort, Kentucky 40602

RECEIVED
SEP 01 2011
PUBLIC SERVICE COMMISSION

Louisville Gas and Electric Company
State Regulation and Rates
220 West Main Street
P.O. Box 32010
Louisville, Kentucky 40232
www.lge-ku.com

Robert M. Conroy
Director - Rates
T 502-627-3324
F 502-627-3213
robert.conroy@lge-ku.com

September 1, 2011

RE: ***In the Matter of: The Application of Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Approval of Its 2011 Compliance Plan for Recovery by Environmental Surcharge*** **- Case No. 2011-00162**

Dear Mr. DeRouen:

Enclosed please find an original and fifteen (15) copies of Louisville Gas and Electric Company's (LG&E) response to the Commission Staff's Second Request for Information dated August 18, 2011, in the above-referenced matter.

Also enclosed are an original and fifteen (15) copies of a Petition for Confidential Protection regarding certain information contained in response to Question Nos. 3(c-d), 6(a), 11, and 23(b,d).

Should you have any questions regarding the enclosed, please contact me at your convenience.

Sincerely,

Robert M. Conroy

cc: Parties of Record

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	))))))	CASE NO. 2011-00162

LOUISVILLE GAS AND ELECTRIC COMPANY
RESPONSE TO THE
COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION
DATED AUGUST 18, 2011

FILED: SEPTEMBER 1, 2011

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **Lonnie E. Bellar**, being duly sworn, deposes and says that he is Vice President, State Regulation and Rates for Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Lonnie E Bellar

Lonnie E. Bellar

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 31st day of August 2011.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2014

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **Charles R. Schram**, being duly sworn, deposes and says that he is Director – Energy Planning, Analysis and Forecasting for LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Charles R Schram
Charles R. Schram

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 31st day of August 2011.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2014

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Robert M. Conroy**, being duly sworn, deposes and says that he is Director - Rates for LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Robert M. Conroy
Robert M. Conroy

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 31st day of August 2011.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2014

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Gary H. Revlett**, being duly sworn, deposes and says that he is Director – Environmental Affairs for LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Gary H. Revlett

Gary H. Revlett

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 31st day of August 2011.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2014

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **John N. Voyles, Jr.**, being duly sworn, deposes and says that he is Vice President, Transmission and Generation Services for Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

John N. Voyles, Jr.

John N. Voyles, Jr.

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 31st day of August 2011.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2014

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated August 18, 2011

Case No. 2011-00162

Question No. 1

Witness: Charles R. Schram

Q-1. Refer to LG&E's response to Item 18.c. of Commission Staff's First Request for Information ("Staff's First Request") and page 3 of the Direct Testimony of Charles R. Schram.

a. The response to 18.c. states that the two analyses referred to in the Schram Testimony did not consider power purchases, renewable or otherwise. Page 3 of the testimony, at lines 21-24, indicates that the second analysis performed compared whether it would be more cost effective to install the control facilities or to retire the unit and purchase replacement power or generation. Clarify and explain the apparent discrepancy between the testimony and the response.

b. The response states: "Ultimately, market availability of suitable replacement capacity and energy is determined through the RFP process when replacing generation." Explain why LG&E believes there will be available capacity and energy through the Request for Proposals ("RFPs") process when other utilities, who are installing air quality control systems, will be competing for the same available suitable replacement capacity and energy.

A-1. a. There is no discrepancy between the testimony and the data response. The intent of the phrase "buy replacement power or generation" on page 4 of the Direct Testimony of Charles R. Schram was to broadly recognize that the Companies would need to replace the capacity and energy from any retired units. For the 2011 Compliance Plan, the Companies analyzed the replacement generation cost based on the technology costs used in the Companies 2011 Integrated Resource Plan. The Companies believe this approach is consistent with prudent long-term resource planning and avoids the uncertainties of predicting the market availability and price of capacity and energy at this stage of the analysis. However, the Companies recognized that further evaluation of market resources, potentially including existing assets or power purchases, via a RFP process would be required before requesting approval for the replacement plan for any retired capacity.

b. The Companies acknowledge the uncertainties of the marketplace and the potential for competition for available capacity and energy. However, the Companies' timely actions in assessing the need for replacement capacity and energy resulted in numerous responses to the RFP issued in late 2010. Please see the response to Question No. 3d.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated August 18, 2011

Case No. 2011-00162

Question No. 2

Witness: John N. Voyles, Jr.

Q-2. Refer to LG&E's response to Item 3 of Staff's First Request. Due to the nation's electric industry's need to meet more stringent environmental standards, the potential exists for a surge in construction of new gas-fired generating units or conversion of existing coal-fired generating units.

a. State whether the contractors that perform the air quality control system construction described in the response are, for the most part, the same contractors that will be involved in the construction of gas-fired generation units, or conversion of coal-fired generation units. Explain.

b. Identify those contractors known by LG&E to be likely bidders, or industry leaders, in the area of engineering and construction of air quality control systems.

c. The response states that LG&E is concerned about securing the best experienced contractors to install the air quality control systems due to other utilities competing for the same resources. Aside from competing against utilities for the same resources, what other potential barriers may LG&E encounter when installing the air quality control systems? Explain.

A-2. a. The large EPC contractors throughout the U.S. that construct air pollution control equipment for the power industry also engineer and construct new generation projects for the industry. Similarly, the smaller regional contractors that may be asked to bid various scopes on the air compliance projects also perform generation work directly or as a subcontractor to the larger national firms.

b. The final bid list for the engineering and construction of the air quality control systems has not yet been determined. Please see the attached list of contractors that the Companies will consider when choosing bidders for the large primary contracts. Smaller scopes of work will also include regional and local contractors from Kentucky and the Evansville, Louisville and Cincinnati MSAs. The asterisk on the list denotes firms being evaluated by LG&E and KU as prime bidders.

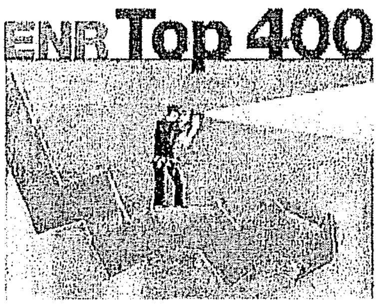
c. The Companies are not only concerned about competing for contractors against coal-fired generating utilities installing air pollution control technologies, but also gas-fired power projects for the same professional and craft labor resources. The Companies are also concerned about the availability of labor and fabrication shops that supply materials and engineered equipment to the industry throughout the world. The very short timeframe allowed by the regulations essentially forces all utility projects to purchase equipment and material, along with the professional and craft labor to design, procure and install the technologies, within a three year window. Please refer to John N. Voyles Jr. testimony page 21 line 10 through page 22, line 23 for further details.

The following is an excerpt from an article published in Engineering News Record (ENR) regarding the Top 400 Contractors. Only the top 100 Contractors are listed below.

The Top 400 Contractors

2011

The table below shows only rankings and firm name. For complete data from the Top 400 Contractors list see the following links.



* Denotes firms being evaluated by LG&E and KU as prime bidders for large environmental and generation contracts.

THE TOP 400 CONTRACTORS

RANK 2011	RANK 2010	FIRM NAME & LOCATION	
1	1	Bechtel, San Francisco, Calif.†	*
2	2	Fluor Corp., Irving, Texas†	*
3	4	Kiewit Corp., Omaha, Neb.†	*
4	3	KBR, Houston, Texas†	*
5	5	The Turner Corp., New York, N.Y.†	
6	8	PCL Construction Enterprises Inc., Denver, Colo.†	*
7	13	The Shaw Group Inc., Baton Rouge, La.	*
8	6	Skanska USA, New York, N.Y.†	
9	11	Clark Group, Bethesda, Md.†	
10	7	Jacobs, Pasadena, Calif.	
11	10	Foster Wheeler AG, Clinton, N.J.†	
12	17	The Walsh Group Ltd., Chicago, Ill.†	
13	14	Balfour Beatty US, Dallas, Texas†	
14	16	The Whiting-Turner Contracting Co., Baltimore, Md.	
15	9	Tutor Perini Corp., Sylmar, Calif.†	
16	15	CB&I, The Woodlands, Texas†	

17	19	Gilbane Building Co., Providence, R.I.†	
18	21	Hensel Phelps Construction Co., Greeley, Colo.	
19	24	Mortenson Construction, Minneapolis, Minn.	
20	20	McCarthy Holdings Inc., St. Louis, Mo.†	
21	18	Lend Lease, New York, N.Y.†	
22	22	Structure Tone, New York, N.Y.†	
23	12	McDermott International Inc., Houston, Texas	
24	23	URS Corp., San Francisco, Calif.†	*
25	25	JE Dunn Construction Group, Kansas City, Mo.†	
26	28	Granite Construction Inc., Watsonville, Calif.†	
27	26	Hunt Construction Group, Scottsdale, Ariz.	
28	27	Brasfield & Gorrie LLC, Birmingham, Ala.	
29	31	Suffolk Construction Co. Inc., Boston, Mass.	
30	30	Turner Industries Group LLC, Baton Rouge, La.†	
31	37	Holder Construction Co., Atlanta, Ga.	
32	29	Austin Industries, Dallas, Texas†	
33	43	DPR Construction Inc., Redwood City, Calif.	
34	33	Manhattan Construction Group, Tulsa, Okla.†	
35	44	Day & Zimmermann, Philadelphia, Pa.†	
36	35	The Yates Cos. Inc., Philadelphia, Miss.†	
37	47	Flatiron Construction Corp., Firestone, Colo.†	
38	38	Barton Malow Co., Southfield, Mich.†	
39	36	Parsons, Pasadena, Calif.†	
40	42	Willbros Group Inc., Houston, Texas†	
41	34	Black & Veatch, Overland Park, Kan.†	*
42	32	Zachry Holdings, San Antonio, Texas†	*
43	45	Michels Corp., Brownsville, Wis.†	
44	101	Primoris Services Corp., Lake Forest, Calif.†	
45	54	Sundt Construction Inc., Tempe, Ariz.	
46	39	Flintco LLC, Tulsa, Okla.	
47	50	Walbridge, Detroit, Mich.†	
48	57	Layne Christensen Co., Mission Woods, Kan.†	
49	40	Swinerton Inc., San Francisco, Calif.†	
50	52	The Lane Construction Corp., Cheshire, Conn.†	

51	46	Pepper Construction Group, Chicago, Ill.†	
52	60	Clayco Inc., St. Louis, Mo.†	
53	41	The Weitz Co., Des Moines, Iowa†	
54	51	ValleyCrest Landscape Cos., Calabasas, Calif.†	
55	48	CH2M HILL, Englewood, Colo.†	*
56	49	Hoffman Corp., Portland, Ore.†	
57	69	The Kokosing Group, Fredericktown, Ohio†	
58	55	Alberici Corp., St. Louis, Mo.†	
59	95	Burns & McDonnell, Kansas City, Mo.	*
60	64	Duke Construction, Indianapolis, Ind.	
61	58	Webcor Builders, San Francisco, Calif.	
62	76	Adolfson & Peterson Construction, Minneapolis, Minn.†	
63	59	HITT Contracting Inc., Falls Church, Va.	
64	63	Layton Construction Co. Inc., Sandy, Utah	
65	67	Ames Construction Inc., Burnsville, Minn.	
66	75	Performance Contractors Inc., Baton Rouge, La.	
67	74	B.L. Harbert International LLC, Birmingham, Ala.	
68	66	Robins & Morton, Birmingham, Ala.	
69	87	Insituform Technologies Inc., Chesterfield, Mo.†	
70	61	David E. Harvey Builders Inc., Houston, Texas	
71	**	Lakeshore TolTest Corp., Detroit, Mich.†	
72	**	Ryan Cos. US Inc., Minneapolis, Minn.†	
73	106	Great Lakes Dredge & Dock Corp. LLC, Oak Brook, Ill.	
74	85	Sellen Construction Co. Inc., Seattle, Wash.	
75	99	Webber LLC, Houston, Texas†	
76	82	American Bridge Co. Inc., Coraopolis, Pa.†	
77	**	OHL USA Inc., Miami, Fla.†	
78	56	Okland Construction Co. Inc., Salt Lake City, Utah†	
79	125	Contrack International Inc., McLean, Va.†	
80	77	Shawmut Design and Construction, Boston, Mass.	
81	100	CORE Construction Group, Phoenix, Ariz.†	
82	71	Matrix Service Co., Tulsa, Okla.†	
83	53	Hunt Building Co. Ltd., El Paso, Texas	
84	81	Kenny Construction, Northbrook, Ill.†	

85	83	PJ Dick-Trumbull-Lindy Paving, Pittsburgh, Pa.
86	89	Weeks Marine Inc., Cranford, N.J.†
87	62	Hunter Roberts Construction Group, New York, N.Y.
88	70	Caddell Construction Co. Inc., Montgomery, Ala.
89	93	The Boldt Co., Appleton, Wis.
90	163	Traylor Bros. Inc., Evansville, Ind.
91	103	LeChase Construction Services LLC, Rochester, N.Y.
92	68	Power Construction Co. LLC, Schaumburg, Ill.†
93	84	F.H. Paschen, S.N. Nielsen, Chicago, Ill.
94	112	Miron Construction Co. Inc., Neenah, Wis.
95	78	Howard S. Wright, Portland, Ore.†
96	**	Zachry Construction Corp., San Antonio, Texas *
97	73	Messer Construction Co., Cincinnati, Ohio
98	94	Chanen Construction Co. Inc., Phoenix, Ariz.
99	**	ECC, Burlingame, Calif.†
100	151	Devcon Construction Inc., Milpitas, Calif.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Commission Staff's Second Request for Information
Dated August 18, 2011**

Case No. 2011-00162

Question No. 3

Witness: Lonnie E. Bellar / Charles R. Schram

Q-3. Refer to LG&E's response to Item 15.d. of Staff's First Request and the response of LG&E and Kentucky Utilities Company ("KU") to Item 6 of Staff's First Request in Case No. 2011-00140. The response to Item 15.d. states that "[t]he RFP for new capacity and energy issued in December 2010 resulted in multiple responses from parties marketing renewable generation resources." The response in Case No. 2011-00140 states: "The Companies completed the RFP analysis in May and anticipate beginning negotiation of an agreement with the selected bidder(s) in June. The Companies expect to file applications for certificates of public convenience and necessity with the Commission later this year."

a. State whether agreements with the selected bidders have been executed by LG&E and KU.

b. State when LG&E and KU plan to file the referenced applications for certificates of public convenience and necessity with the Commission.

c. State whether the RFP process undertaken by KU and LG&E has resulted in the selection of:

(1) Self-build options;

(2) Acquiring existing generation capacity; or

(3) Purchasing power from a third party.

d. Provide the responses received by KU and LG&E to the RFP issued in December 2010 for new capacity and energy.

A-3. a. Agreement(s) are under negotiation, but have not been executed.

b. The Companies anticipate filling the referenced applications in mid-September 2011.

c. Response is being filed under a Petition for Confidential Protection.

d. Please see the attached CD in the folder titled Question No. 3 filed under a Petition for Confidential Protection.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated August 18, 2011

Case No. 2011-00162

Question No. 4

Witness: Charles R. Schram

Q-4. Refer to LG&E's response to Item 19 of Staffs First Request in which LG&E states: "Because the majority of the costs evaluated in the decisions to install controls or retire/ replace capacity are non-ECR costs, the Companies utilized a weighted average cost of capital for non-ECR projects in its analysis."

a. List and describe the non-Environmental Cost Recovery ("ECR") costs that would be incurred related to the installation of controls.

b. List and describe the ECR costs that would be incurred related to the retirement replacement of capacity.

A-4. The statement about the magnitude of non-ECR costs refers to the relatively large dollar amount of production costs and resource expansion capital in the 30-year analysis period compared to the cost of environmental controls. The only difference between the weighted average cost of capital for ECR projects and non-ECR projects is the use of 10.63% ROE vs. 10.50% ROE, respectively. The difference in the resulting weighted average cost of capital is immaterial with respect to its impact on the analysis.

a. None.

b. None.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated August 18, 2011

Case No. 2011-00162

Question No. 5

Witness: Robert M. Conroy

Q-5. Refer to page 12 of LG&E's Supplemental Response to Item 39 of Staff's First Request and the Environmental Cost Recovery Surcharge Summary on page 8 of the Direct Testimony of Robert Conroy. Page 12 of the Supplemental Response states: "Those increases do not take into account the costs associated with retiring generating units with a current book value of over $100 million--units the MACT rule will make uneconomical to run beginning in 2016-nor do they account for the additional costs of replacing the retired units."

a. Provide an update to the Environmental Cost Recovery Surcharge summary by year, through 2020, to include the projected costs associated with the retirement of generating units, the additional costs of replacing the retired units, and any cost savings resulting from the retirement of generating units.

b. Provide the impact the cost in 5.a. above will have on the incremental billing factor and residential customer impact listed in the Summary.

A-5. a. The Environmental Cost Recovery Surcharge Summary on page 8 of the Direct Testimony of Robert Conroy is a summary of Exhibit RMC-5. Exhibit RMC-5 contains the calculation of the ECR mechanism for the compliance plan projects proposed in this proceeding and allowable for recovery through the ECR mechanism pursuant to KRS 278.183. The costs referenced on page 12 of the supplemental response to KPSC-1, Question No. 39 are the net book value of generating assets that may be retired and the cost associated with the construction of replacement generating assets. The referenced costs are not subject to recovery through the ECR mechanism. The cost impact of these decisions will be reviewed in future base rate cases and reflected in base rates. For these reasons, the requested calculations have not been performed. Therefore, the requested information is not available.

b. Please see the response to part a.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated August 18, 2011

Case No. 2011-00162

Question No. 6

Witness: John N. Voyles, Jr. / Gary H. Revlett / Charles R. Schram

Q-6. For each fossil generation unit in the system:

a. Provide a timeline, out to the year 2020, showing the tonnage amount of emission allowances granted by the U.S. Environmental Protection Agency ("EPA") for the Cross-State Air Pollution Rule ("CSAPR'), the Hazardous Air Pollutants ("HAPS") rule under the Clean Air Act, and the tonnage amount of projected emissions generated by the unit assuming that LG&E's mitigation strategy is implemented as proposed.

b. To the extent that surplus allowances exist in any given year, describe how these surplus allowances will be utilized and under what conditions.

c. Indicate whether there is currently, or likely to be, a means of sequestering CO_2 should future regulations require reductions. If there is currently, or likely to be, a means of sequestering CO_2, provide any cost estimates that have been performed.

A-6. a. Known allocations to Existing Units (which does not include TC2) are attached for KU and LG&E individually. For the various jointly-owned combustion turbines, the unit allocation has been distributed to the individual Company by ownership share.

Generating units that do not operate for 2 consecutive years (or ozone seasons) lose their allocation in the fifth year following the non-operation. For example, if a unit ceases to operate in 2016 (and 2017), it will receive allocations for 2018 and 2019, but not for 2020 and beyond. The allocations provided assume Cane Run coal units and Green River coal units cease operation beginning in 2016.

New units (TC2) will receive allocations equal to their previous year's emissions. Therefore, allocations cannot be provided until the projected emissions are known. As an illustration, TC2's 2012 SO_2 and Annual NO_x allocations will equal its 2011 emissions and its 2012 Ozone Season allocation will equal its 2011 Ozone Season emissions. Other new units will not receive an allocation for their first year of operation. For example, if a new unit begins operation in 2016, it will not receive an allocation for 2016. Its 2017 allocations will be equal to its 2016 emissions, and continue as such into the future years.

The forecasted consumption of the allowance allocation is considered confidential commercial information, which would have value in any allowance market that may develop as a result of the CSAPR regulations. Attached are the projected emissions by unit for the 2016-2020 time period, following the construction of recommended controls and the replacement of retired capacity. Emissions for the 2012-2015 time periods are still under review by the Companies, since operation and dispatch of the generating fleet required further review given the more restricted SO2 allowances in the 2012-2015 period under the recently released CSAPR. Certain requested information is considered confidential and is being filed under a Petition for Confidential Protection.

b. Consistent with prior utilization of emission allowances, the Companies would use surplus allowances, if any, within the provisions of the rule to meet its obligations on a least-cost basis for ratepayers.

c. Sequestering CO_2 is currently done for enhanced oil recovery (EOR) in many locations where oil exploration is prevalent. Also, it is technically feasible to inject and store CO_2 into geological formations. The Companies have performed initial studies of the geology near several facilities to assess the available information. See the report *Evaluation of Geologic CO2 Storage Potential at LG&E and Kentucky Utilities Power Plant Locations* prepared by the Kentucky Geological Survey in 2011 and provided on CD in the folder titled Question No. 6. However, it is important to note there is not sufficient specific knowledge of the amount of suitable geologic formations near power generation facilities to provide adequate storage capacity for the CO_2 produced in the Midwest. While there have been some cost estimations developed for sequestration, none have been performed on a per unit basis for the LG&E facilities. Costs are highly dependent on the specific geology where the sequestration will be located.

E. W. Brown Plant: LG&E SO_2 Allocations*			
	BR5	BR6	BR7
	Allocation	Allocation	Allocation
2012	-	2	1
2013	-	2	1
2014	-	2	1
2015	-	2	1
2016	-	2	1
2017	-	2	1
2018	-	2	1
2019	-	2	1
2020	-	2	1

Cane Run Plant: LG&E SO_2 Allocations*			
	CR4	CR5	CR6
	Allocation	Allocation	Allocation
2012	2,540	2,553	3,281
2013	2,540	2,553	3,281
2014	1,093	1,098	1,411
2015	1,093	1,098	1,411
2016	1,093	1,098	1,411
2017	1,093	1,098	1,411
2018	1,093	1,098	1,411
2019	1,093	1,098	1,411
2020	-	-	-

Mill Creek Plant: LG&E SO_2 Allocations*				
	MC1	MC2	MC3	MC4
	Allocation	Allocation	Allocation	Allocation
2012	4,531	4,892	6,769	7,964
2013	4,531	4,892	6,769	7,964
2014	1,950	2,105	2,912	3,427
2015	1,950	2,105	2,912	3,427
2016	1,950	2,105	2,912	3,427
2017	1,950	2,105	2,912	3,427
2018	1,950	2,105	2,912	3,427
2019	1,950	2,105	2,912	3,427
2020	1,950	2,105	2,912	3,427

Paddy's Run Plant: LG&E SO_2 Allocations*		
	PR12	PR13
	Allocation	Allocation
2012	-	-
2013	-	-
2014	-	-
2015	-	-
2016	-	-
2017	-	-
2018	-	-
2019	-	-
2020	-	-

Trimble County Plant: LG&E SO_2 Allocations*								
	TC1	TC2	TC5	TC6	TC7	TC8	TC9	TC10
	Alloc.	Alloc.	Alloc.	Alloc.	Alloc.	Alloc.	Alloc.	Alloc.
2012	4,459		-	-	-	0	0	0
2013	4,459		-	-	-	0	0	0
2014	2,807		-	-	-	0	0	0
2015	2,807		-	-	-	0	0	0
2016	2,807		-	-	-	0	0	0
2017	2,807		-	-	-	0	0	0
2018	2,807		-	-	-	0	0	0
2019	2,807		-	-	-	0	0	0
2020	2,807		-	-	-	0	0	0

NOTES:

Known allocations to Existing Units (which does not included TC2) are included for each company individually. For jointly-owned units (various combustion turbines), the unit allocation has been distributed to the individual companies by ownership share.

The allocations provided assume Cane Run and Green River coal units cease operation beginning in 2016.

Units that do not operated for 2 consecutive years (or ozone seasons) lose their allocation in the fifth

New units (TC2) will receive allocations equal to their previous year's emissions. Therefore,

E. W. Brown Plant: LG&E Annual NOx Allocations*			
	BR5	BR6	BR7
	Allocation	Allocation	Allocation
2012	12	19	24
2013	12	19	24
2014	11	19	22
2015	11	19	22
2016	11	19	22
2017	11	19	22
2018	11	19	22
2019	11	19	22
2020	11	19	22

Cane Run Plant: LG&E Annual NOx Allocations*			
	CR4	CR5	CR6
	Allocation	Allocation	Allocation
2012	882	887	1,140
2013	882	887	1,140
2014	800	804	1,033
2015	800	804	1,033
2016	800	804	1,033
2017	800	804	1,033
2018	800	804	1,033
2019	800	804	1,033
2020	-	-	-

Mill Creek Plant: LG&E Annual NOx Allocations*				
	MC1	MC2	MC3	MC4
	Allocation	Allocation	Allocation	Allocation
2012	1,574	1,699	2,351	2,766
2013	1,574	1,699	2,351	2,766
2014	1,427	1,540	2,131	2,508
2015	1,427	1,540	2,131	2,508
2016	1,427	1,540	2,131	2,508
2017	1,427	1,540	2,131	2,508
2018	1,427	1,540	2,131	2,508
2019	1,427	1,540	2,131	2,508
2020	1,427	1,540	2,131	2,508

Paddy's Run Plant: LG&E Annual Nox Allocations*		
	PR12	PR13
	Allocation	Allocation
2012	2	21
2013	2	21
2014	2	19
2015	2	19
2016	2	19
2017	2	19
2018	2	19
2019	2	19
2020	2	19

Trimble County Plant: LG&E Annual NOx Allocations*								
	TC1	TC2	TC5	TC6	TC7	TC8	TC9	TC10
	Alloc.	Alloc.	Alloc.	Alloc.	Alloc.	Alloc.	Alloc.	Alloc.
2012	2,267		6	5	8	9	8	9
2013	2,267		6	5	8	9	8	9
2014	2,054		6	5	8	9	8	9
2015	2,054		6	5	8	9	8	9
2016	2,054		6	5	8	9	8	9
2017	2,054		6	5	8	9	8	9
2018	2,054		6	5	8	9	8	9
2019	2,054		6	5	8	9	8	9
2020	2,054		6	5	8	9	8	9

<u>NOTES</u>:

Known allocations to Existing Units (which does not included TC2) are included for each company individually. For jointly-owned units (various combustion turbines), the unit allocation has been distributed to the individual companies by ownership share.

The allocations provided assume Cane Run and Green River coal units cease operation beginning in 2016.

Units that do not operated for 2 consecutive years (or ozone seasons) lose their allocation in the fifth year following the non-operation. For example, if a unit ceases to operate in 2016 (and 2017), it will receive allocations for 2018 and 2019, but not for 2020 and beyond.

New units (TC2) will receive allocations equal to their previous year's emissions. Therefore, allocations cannot be provided until the projected emissions are known. As an illustration, TC2's 2012 SO2 and Annual NOx allocations will equal its 2011 emissions and its 2012 Ozone Season allocation will equal its 2011 Ozone Season emissions.

E. W. Brown Plant: LG&E Ozone NOx Allocations*			
	BR5	BR6	BR7
	Allocation	Allocation	Allocation
2012	10	14	9
2013	10	14	9
2014	8	14	9
2015	8	14	9
2016	8	14	9
2017	8	14	9
2018	8	14	9
2019	8	14	9
2020	8	14	9

Cane Run Plant: LG&E Ozone NOx Allocations*			
	CR4	CR5	CR6
	Allocation	Allocation	Allocation
2012	404	384	481
2013	404	384	481
2014	358	340	426
2015	358	340	426
2016	358	340	426
2017	358	340	426
2018	358	340	426
2019	358	340	426
2020	-	-	-

Mill Creek Plant: LG&E Ozone NOx Allocations*				
	MC1	MC2	MC3	MC4
	Allocation	Allocation	Allocation	Allocation
2012	674	731	1,098	1,282
2013	674	731	1,098	1,282
2014	597	648	973	1,135
2015	597	648	973	1,135
2016	597	648	973	1,135
2017	597	648	973	1,135
2018	597	648	973	1,135
2019	597	648	973	1,135
2020	597	648	973	1,135

Paddy's Run Plant: LG&E Ozone NOx Allocations*		
	PR12	PR13
	Allocation	Allocation
2012	3	18
2013	2	18
2014	2	16
2015	2	16
2016	2	16
2017	2	16
2018	2	16
2019	2	16
2020	2	16

Trimble County Plant: LG&E Ozone NOx Allocations*								
	TC1	TC2	TC5	TC6	TC7	TC8	TC9	TC10
	Alloc.	Alloc.	Alloc.	Alloc.	Alloc.	Alloc.	Alloc.	Alloc.
2012	542		4	4	6	5	5	6
2013	542		4	4	6	5	5	6
2014	542		4	4	6	5	5	6
2015	542		4	4	6	5	5	6
2016	542		4	4	6	5	5	6
2017	542		4	4	6	5	5	6
2018	542		4	4	6	5	5	6
2019	542		4	4	6	5	5	6
2020	542		4	4	6	5	5	6

NOTES:

Known allocations to Existing Units (which does not included TC2) are included for each company individually. For jointly-owned units (various combustion turbines), the unit allocation has been distributed to the individual companies by ownership share.

The allocations provided assume Cane Run and Green River coal units cease operation beginning in 2016.

Units that do not operated for 2 consecutive years (or ozone seasons) lose their allocation in the fifth year following the non-operation. For example, if a unit ceases to operate in 2016 (and 2017), it will receive allocations for 2018 and 2019, but not for 2020 and beyond.

New units (TC2) will receive allocations equal to their previous year's emissions. Therefore, allocations cannot be provided until the projected emissions are known. As an illustration, TC2's 2012 SO2 and Annual NOx allocations will equal its 2011 emissions and its 2012 Ozone Season allocation will equal its 2011 Ozone Season emissions.

CONFIDENTIAL INFORMATION REDACTED

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated August 18, 2011

Case No. 2011-00162

Question No. 7

Witness: Lonnie E. Bellar

Q-7. Indicate if LG&E has performed any preliminary research on meeting future CO_2 reduction goals in the proposed cap and trade regulations or other, more restrictive, regulations.

A-7. Please see the responses to KPSC-1 Question No. 2 and MHC-1 Question No. 6.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated August 18, 2011

Case No. 2011-00162

Question No. 8

Witness: John N. Voyles, Jr.

Q-8. Refer to LG&E's response to Item 22.f. of Staff's First Request. The response states that no Black and Veatch expenses have been assigned to Projects 26 and 27. Identify the specific accounts in which the Black and Veatch expenses have been recorded.

A-8. The Black and Veatch expenses have been recorded to FERC Account 107 – Construction in Progress – Electric.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated August 18, 2011

Case No. 2011-00162

Question No. 9

Witness: Lonnie E. Bellar

Q-9. Refer to LG&E's response to Item 26 of Staff's First Request. Provide a revenue allocation that LG&E believes would "balance the interests of all customers" and explain why the allocation would do so.

A-9. A revenue allocation that more closely follows the methodology used to allocate production-related environmental costs in the Company's cost of service is an alternative method to balance the interests of all customers.

Possible methodologies for allocating ECR revenues that would more reflect the cost of service would include: (1) to use the modified Base-Intermediate-Peak (BIP) methodology to allocate ECR revenue requirements to the rate classes; (2) to use the effective allocation factors for the applicable production cost components (either demand or energy, as applicable) from the cost of service study submitted by the Company in its last rate case to allocate ECR revenues to the rate classes.

A third approach would be to calculate and apply the ECR factor on the basis of average monthly net revenue (revenue less fuel cost revenues) rather than "average monthly base revenues" which includes fuel cost revenues. Currently, the ECR factors is calculated by dividing (i) ECR revenue requirement E(m) by (ii) revenue R(m), where R(m) is calculated as follows:

> The revenue R(m) is the average monthly base revenue for the Company for the 12 months ending with the current expense month. Base revenue includes the customer, energy and demand charge for each rate schedule to which this mechanism is applicable and automatic adjustment clause revenues for the Fuel Adjustment Clause and the Demand-Side Management Cost Recovery Mechanism as applicable for each rate schedule.

By excluding base fuel cost revenues and Fuel Adjustment Clause revenues from the determination of R(m), the ECR factor would be calculated in a manner that more closely reflects an allocation on the basis of demand-related costs. Because the preponderance of ECR costs are demand-related, removing base fuel and Fuel Adjustment Clause revenues, which are strictly energy related, from revenues will result in the remaining net revenues more properly reflecting the demand-related component of revenue.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated August 18, 2011

Case No. 2011-00162

Question No. 10

Witness: Charles R. Schram

Q-10. Refer to LG&E's response to Item 35 of Staff's First Request. The response states: "Relying on purchased power as a compliance measure would create market risk that could have a detrimental impact on customers.'' Once LG&E is compliant after the installation of the air quality control systems, does LG&E anticipate having excess generation for off systems sales to utilities who are not compliant? Explain.

A-10. Depending on the development of market prices for power it could, in some hours be economic for the Companies to make off-system sales. It is not possible to predict the counterparties for these hourly transactions and whether or not these parties would be purchasing power to become compliant.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated August 18, 2011

Case No. 2011-00162

Question No. 11

Witness: Charles R. Schram

Q-11. Refer to LG&E's response to Items 37 and 46 of Staff's First Request. The response to 37 states that LG&E expects that its coal units that will be fitted with pollution control equipment will continue to produce power at a lower cost than market power prices. The response also refers to market power prices provided in response to Item 46. For each LG&E unit to be fitted with pollution control equipment, provide the calculations that compare the cost to produce power with market power prices.

A-11. The Companies' expectation that the coal units to be fitted with pollution control equipment will continue to produce power at a lower cost than market prices is based on the comparison of the average annual dispatch costs on pages 7-8 of the Companies' response to Question No. 37 versus the market prices for electricity contained in the Companies response to Question No. 46.

Please see the attachment on CD in the folder titled Question No. 11 for the calculations computing the average dispatch costs for each unit. The requested information is provided under a Petition for Confidential Protection.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated August 18, 2011

Case No. 2011-00162

Question No. 12

Witness: John N. Voyles, Jr.

Q-12. Refer to LG&E's response to Item 58 of Staff's First Request. State whether LG&E has any concern about or is aware of any reports by other utilities of excessive corrosion in using lime injection methodologies.

A-12. No. Lime injection is generally used to prevent corrosion. LG&E is not aware of any reporting by other utilities regarding excessive corrosion caused by lime injection methodologies.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated August 18, 2011

Case No. 2011-00162

Question No. 13

Witness: Robert M. Conroy / Charles R. Schram

Q-13. a. For the Cane Run units that have been mentioned as potential candidates for retirement, explain whether environmental remediation costs resulting from decommissioning have been included in any cost/benefit analysis performed in the formulation of the compliance plan. If the remediation costs are known, or can be estimated, provide those costs by unit.

b. If environmental remediation costs for retired units occur, state whether LG&E believes any or all of the costs would be recovered through the environmental surcharge. Explain.

A-13. a. A cost of $2.1 million per unit (in $2016) has been included in the cost/benefit analysis for capping and reinforcing the stack.

b. LG&E's current ECR application in this case does not propose to recover any environmental remediation costs resulting from the possible de-commissioning of the Cane Run generation units. If LG&E incurs such environmental remediation costs for these retired units, LG&E will undertake an analysis of whether such costs are recoverable under KRS 278.183 and a business analysis of whether to pursue the recovery of the costs through the ECR. The reasons supporting LG&E's position would be presented in a subsequent ECR application.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated August 18, 2011

Case No. 2011-00162

Question No. 14

Witness: Charles R. Schram

Q-14. Describe how possible price volatility of natural gas, due to increased demand for electric generation or from possible increased regulation due to environmental concerns, was considered in modeling for the 2011 Compliance Plan.

A-14. Consultant PIRA's natural gas outlook forms the basis for the Companies' longer-term projections for natural gas prices. PIRA develops forecasts for energy prices, including natural gas, based on supply and demand considerations. PIRA includes the impacts from projected changes in coal-fired and gas-fired generation capacity in their models.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information Dated August 18, 2011

Case No. 2011-00162

Question No. 15

Witness: John N. Voyles, Jr.

Q-15. Refer to the LG&E's response to Item 17 of Drew Foley, Janet Overman, Gregg Wagner, Sierra Club, and the Natural Resource Defense Council's Request for Production of Documents. The response states that LG&E's Transmission group examined the impact on the transmission system of potential power plant retirements.

a. State whether the examination included the effect of power purchases necessary to replace retired generation upon the transmission system. State whether the effect upon the transmission system is considered significant. Explain.

b. State whether LG&E has studied, or is aware of any studies concerning, the possible effect on the regional electric grid of the retirement of a sizeable portion of the country's coal-fired electric generation. Provide a copy of each article, or study, on this subject, that LG&E has examined, reviewed, or otherwise considered.

c. Describe the possible effect of the redirection of power flows upon the regional power grid if the existing grid was engineered in part to deliver loads from existing units that are to be retired.

A-15. a. The impact of potential power plant retirements was examined. Power purchases to replace the potential power plant retirements were not within the scope of the work completed as it was assumed that the retired generation would be replaced internal to the LGE/KU Balancing Authority area. (Please see response to Question No. 3(c).) If all of the generation were to be replaced by imports, there could be a significant reliability impact on the transmission system depending on the location of the imports, which would require specific transmission system reliability studies. This reliability impact could also extend beyond the LGE/KU transmission system.

b. Yes, the Companies would be concerned about the impact of significant retirements on the reliability of the bulk electric system. Without knowledge of specific generating units to be retired in the region, it is not possible for LG&E to study the possible transmission impacts on the regional electric grid. LG&E is aware that MISO analyzed impacts from EPA regulations in August 2011. The draft report, dated August 2011, is attached and is available on MISO's website.

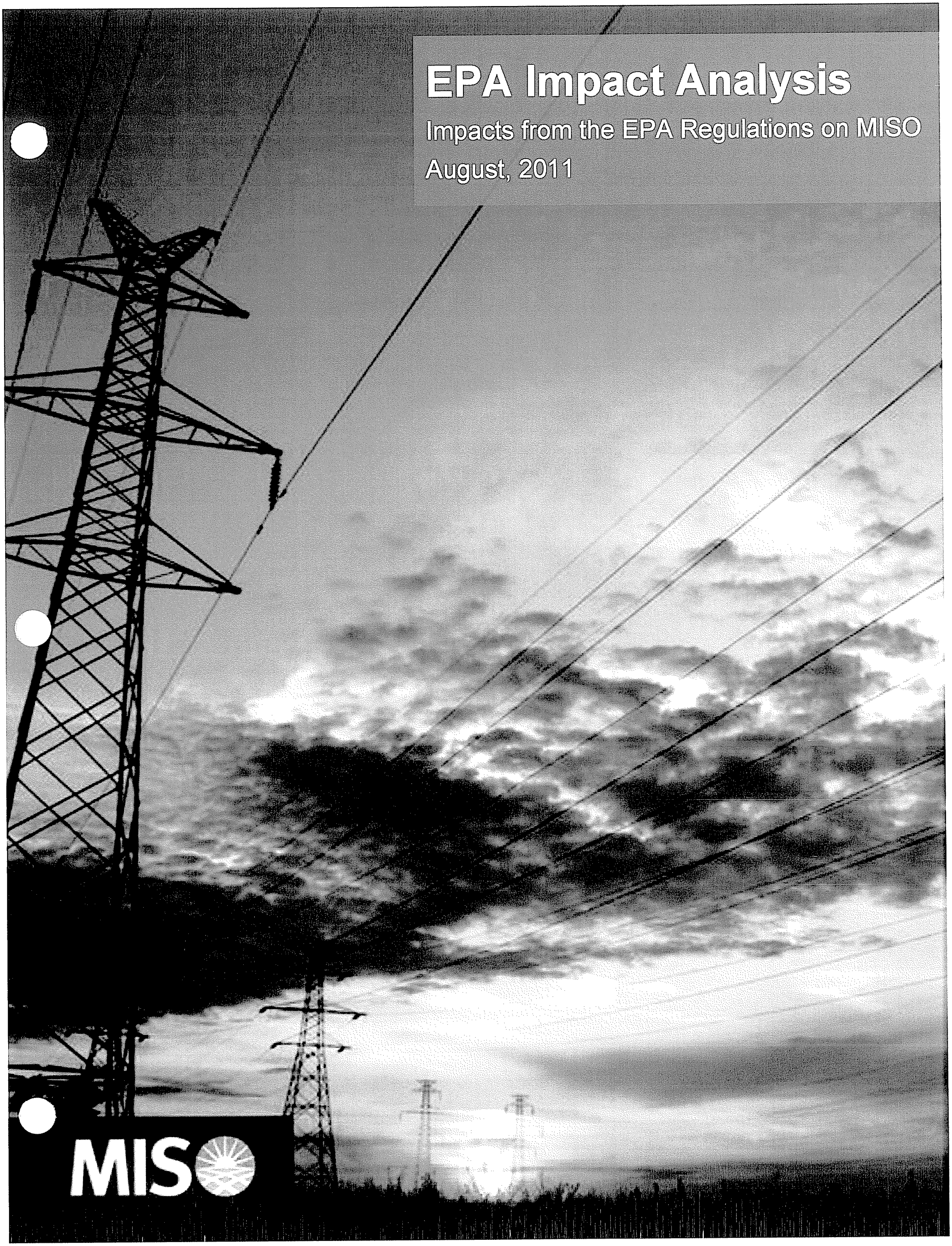
www.midwestiso.org/Library/Pages/Results.aspx?q=EPA%20Impacts

c. As noted in answer "b." above, LG&E has not performed a study of possible impacts on the regional electric grid that may occur if a sizeable number of coal plants are retired. However, based on the transmission impacts identified on the LGE/KU system, including low voltage and thermal overloads, it would be anticipated that similar issues would be identified in other areas that are retiring significant generation assets.

EPA Impact Analysis

Impacts from the EPA Regulations on MISO

August, 2011



Contents

1 Study Disclaimer

The objective of the MISO EPA Impact Analysis is to inform stakeholders. MISO does not intend nor has the authority to direct generation unit strategies. That authority belongs to the individual asset owners, only. The MISO analysis attempts to provide an overview of the impacts from the MISO regional perspective. Any subregional evaluation of the data would be an incorrect interpretation and application of the results.

The detailed results of the analysis were derived from a limited set of economic assumptions that included low demand and energy growth, low gas prices, and variation of carbon prices with sensitivities performed on gas and carbon prices. It should be expected that retirement impacts can change with different assumptions for these variables. The study also assumes that the natural gas transmission system is sufficient to accommodate the increased dependence on the natural gas fleet. This report attempts to address some of those issues, but is not able to capture all potential future outcomes. To get a better understanding of impacts associated with changing inputs and risks associated with the uncertainty of carbon, additional analysis would need to be performed.

2 Executive Summary

The United States Environmental Protection Agency (EPA) is finalizing four proposed regulations that will affect the MISO system. They require utilities to choose between retrofitting their generators with environmental controls and retiring them. At the direction of its members, stakeholders and Board of Directors, MISO evaluated the potential impacts of the new regulations including potential impact of carbon requirements. This study evaluated the impacts on capacity cost, resource adequacy, cost of energy and transmission reliability.

The 4 proposed EPA regulations are:

- Cooling Water Intake Structures (CWIS) – section 316(b) of the Clean Water Act (CWA)
- Coal Combustion Residuals (CCR)
- Cross State Air Pollution Rule (CSAPR) formerly known as Clean Air Transport Rule (CATR)
- Mercury and Air Toxics Standards (MATS) formerly known as EGU Maximum Achievable Control Technology (MACT)

2.1 EPA Impact Results Summary

A survey of the current fleet within MISO revealed a number of generation units will be affected. Impacts ranged from the installation of control equipment and expected redispatch to meet emission budgets, to potential retirement of units where the costs to comply outweigh the benefits of continued operation. Figure 2-1 shows that there are 355 units affected by these four proposed regulations and that the majority of the units (55 percent) are affected by three or all four regulations.

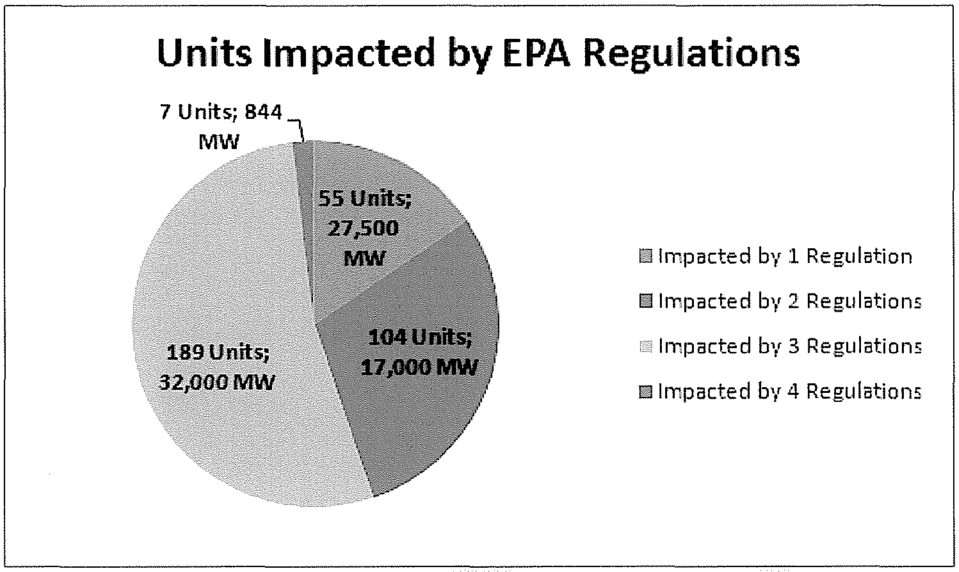


Figure 2-1: Number of Units Affected by EPA Regulations

The studies were conducted with the Electric Generation Expansion Analysis System (EGEAS) software package developed by the Electric Power Research Institute (EPRI) which is commonly used by utility generation planners. MISO performed over 400 sensitivity screens using with the EGEAS capacity expansion model to identify the units most at-risk for potential retirement. The sensitivities consisted of variation in gas costs, carbon costs and retrofit compliance costs. From those sensitivities, MISO identified nearly 13,000 MW of units at risk for retirement. Those units were offered to the EGEAS model as an economic choice to retrofit for compliance or retirement. The model makes this decision by comparing alternatives and selecting an expansion forecast that minimizes costs, including capital investment, production including emissions, and annual fixed operations and maintenance.

MISO ran two economic alternatives. The first evaluated a $4.50 natural gas cost, $0 cost for carbon, compliance for all the identified regulations and an expected cost for compliance with the regulations based on MISO stakeholder feedback through the study process. The second analysis provided the same assumptions but increasing costs of up to $50/ton for carbon production. The analysis on carbon costs was evaluated because judging the risk around the uncertainty of future carbon reduction requirements may cause asset owners to change their approach.

The results of the EGEAS analysis produced:

- **2,919 MW** at-risk for retirement at $4.50/MMBtu natural gas price and $0/ton carbon cost.
- **12,652 MW** at-risk for retirement with a $4.50/MMBtu natural gas cost and $50/ton carbon cost.

Using a suite of planning products, MISO's evaluation on the range of potential impacts indicates the following:

- Total 20-year net present value capital cost of compliance may range from **$31.6 billion** for 2,919 MW of retirement to **$33.0 billion** for 12,652 MW of retirement. Both values are in 2011 dollars and include the cost of retrofits on the system, the cost of replacement capacity, the cost of fixed O&M and the cost of transmission upgrades.
    - Capital costs for retrofits are **$28.2 billion and $22.5 billion**, respectively.

- Maintenance of the Planning Reserve Margin (PRM) is obligated under the MISO tariff. So it is expected that any capacity retirements would eventually be matched with replacement capacity to support PRM requirements. To maintain this requirement, it is estimated that the replacement costs would **$1.7 billion and $9.6 billion.**

- The annual fixed O&M impacts the total cost impact by **$1.1 billion and $0.0**, respectively.

- Retirement of units will have an impact on localized transmission system reliability. To ensure voltage and transmission thermal support on the system, an estimated **$580 million and $880 million**, respectively, of additional transmission upgrades could be necessary to maintain system reliability due to the identified potential unit retirements. The transmission numbers depend on location and any change from the study assumptions could result in different costs. Also, this assumes that any replacement capacity is not located at the retired unit locations. If replacement capacity is located at retired unit sites, it is likely the transmission upgrade costs will decrease.

- By replacing traditionally less reliable capacity with new resources, there is a potential that Planning Reserve Margin (PRM) requirements could decrease by having a more reliable fleet. Loss of Load Expectation (LOLE) analysis showed reductions of **0.2 to 1.0 percent**. However, if no replacement capacity is identified for resource adequacy purposes, then Loss of Load Expectation (LOLE) analysis shows that the LOLE on the system could be on the order of **0.21 to 1.028 days/year**. The current target is 0.1 days/year.

- There will also be an increase in the MISO load-weighted LMP of between **$1.2/MWh-$4.8/MWh** (2011$). This is driven by two key factors: (1) newly retrofitted units are less efficient because of the emission controls, and (2) retired coal facilities are replaced with natural gas fired capacity resulting in a greater dependence on the higher cost energy. These numbers exclude impacts of carbon costs on energy prices.

- Identifying all the costs to maintain regulation compliance and system reliability, a **7.0 to 7.6 percent** increase in current retail rates could be realized excluding the impacts of carbon on energy prices. If carbon costs are included in the generation production costs, the rate impact increases to a range of **37.2 to 37.7 percent**.

There is compliance risk associated with meeting the proposed regulations. As identified previously, additional investment in the generation fleet and the transmission system will maintain bulk power system reliability – at a cost. However, another risk that is not addressed directly within this analysis but should be mentioned is the time frame in which units must be compliant. Figure 2-2 demonstrates a high level time table of rule implementation and compliance deadlines. If it is determined that capacity should be retired, it would take at least two to three years to build a combustion turbine to replace that capacity. Also, if transmission system reliability requires bulk transmission upgrades, a minimum of five years could be required for a transmission line to become operational. The time frame from final regulation to compliance may be difficult to meet for some situations throughout the system.

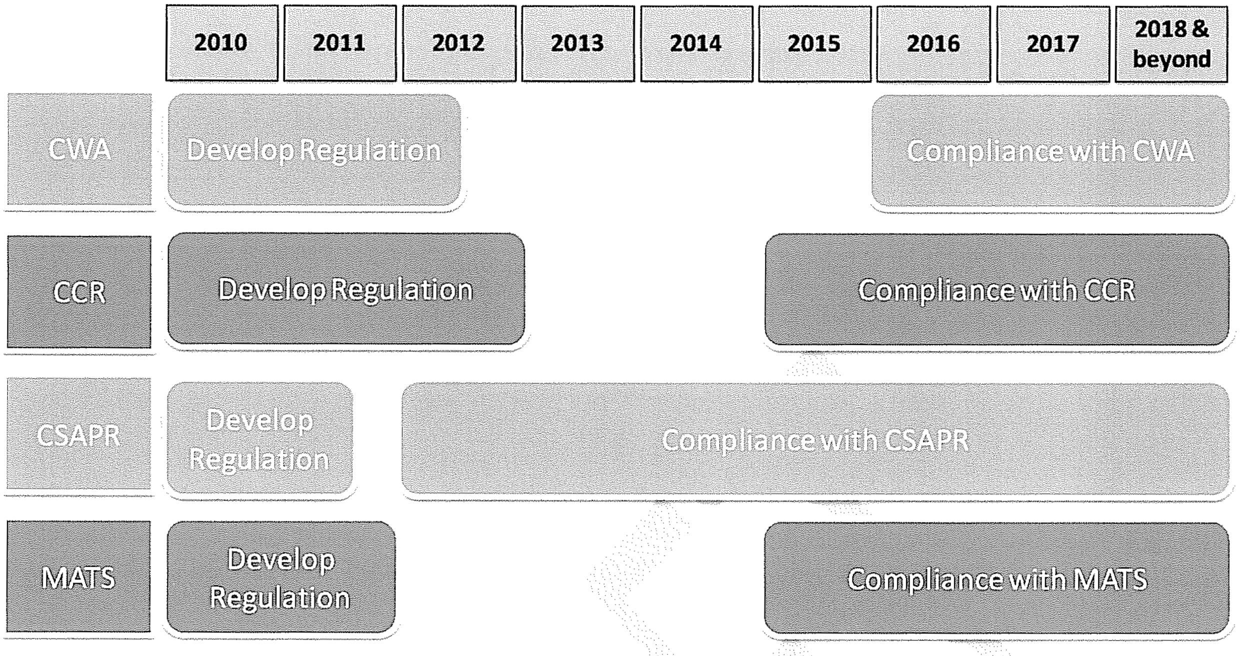


Figure 2-2: Estimated timeline for regulation development and implementation

2.2 Sensitivities Impact

Just as in the MISO Transmission Expansion Plan (MTEP), MISO uses a scenario planning process in the analysis and evaluation of these EPA regulations. Evaluating the impact over the EPA regulations requires that many conditions be considered separately and in combination with each other. MISO evaluated six scenarios with 77 sensitivities for each of the scenarios. The scenarios are:

- Base conditions, no new regulations
- Cooling Water Intake Structures section – 316(b) of the Clean Water Act (CWA)
- Coal Combustion Residuals (CCR)
- Cross State Air Pollution Rule (CSAPR) formerly known as Clean Air Transport Rule (CATR)
- Mercury and Air Toxics Standards (MATS) formerly known as EGU Maximum Achievable Control Technology (MACT)
- Combination of all 4 regulations

Figure 2-3 demonstrates the sensitivities evaluated for each regulation analysis. As there are 6 regulation scenarios there would be 6 branches to this decision tree, only the first branch is shown in Figure 2-3.

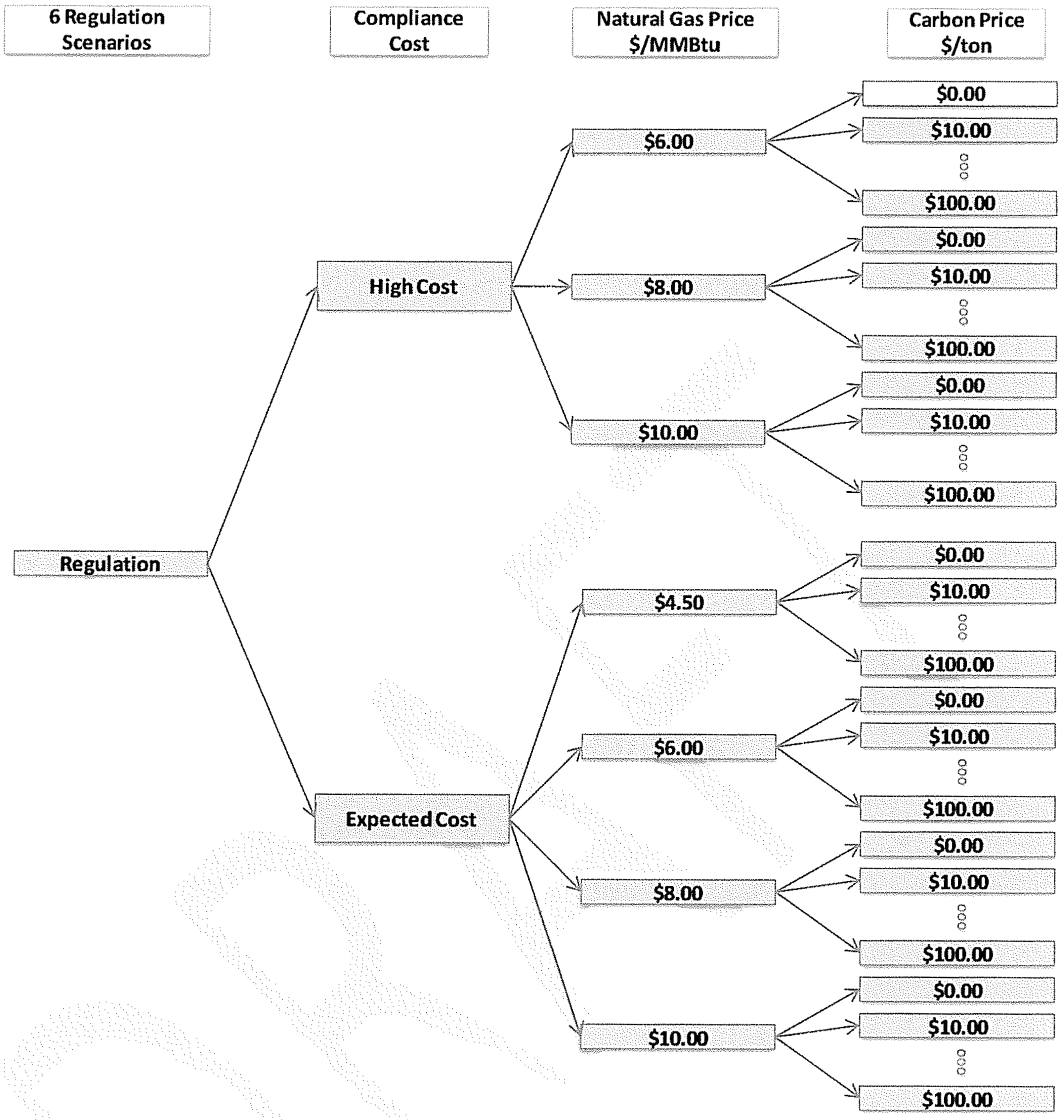


Figure 2-3: Decision Tree of EPA Cases

For each of the scenarios, 77 sensitivity cases consisting of two variations in compliance costs, natural gas costs and carbon price levels were modeled to produce a combined total of more than 400 sensitivity cases. The results indicated that up to 23,000 MW of coal capacity could be at-risk because of regulation compliance.

From these sensitivity cases, a few general conclusions can be made.

- **EPA Regulation impacts:** Compliance associated with the Mercury and Air Toxics Standards (MATS) produces the most at-risk units as its compliance costs and emission reductions have the greatest impact of the proposed regulations.

- **Compliance costs:** Higher compliance costs result in more at risk units. Evaluating all natural gas and carbon sensitivities for the high compliance cost cases resulted in up to 23,000 MW of at-risk capacity. However, running the same sensitivities at the more expected compliance costs as recommended and reviewed through the MISO stakeholder process, up to 13,000 MW of capacity was considered to be at risk.

- **Natural gas prices:** Lower natural gas prices produced more at-risk capacity than higher gas prices. The lower natural gas prices provide more incentive to retire capacity as the alternative resources provide competitive energy costs for the system. Conversely, when gas prices are high, the coal units find enough revenue on the system to cover compliance costs and keep general energy prices lower.

- **Carbon prices:** Adding cost to carbon puts economic pressure on units with higher carbon production rates. Because of this, higher carbon prices put more economic pressure on the coal units within the system, and the economics favor natural gas and carbon neutral capacity. So more coal units are at-risk for retirement with the higher carbon prices applied.

The units at-risk for retirement range from 0 MW to 23,000 MW based on the economic assumptions within the sensitivities. Cases where no units were identified to be at-risk for retirement include low compliance costs, higher gas prices and no carbon costs applied. This occurs because it minimizes cost for compliance while increasing potential revenue within the energy market through higher natural gas prices. Cases that produce at-risk generation up to 23,000 MW include high compliance costs, low gas prices and varying levels of carbon costs.

Figure 2-4 depicts an example of the impacts of the compliance costs, gas costs, and carbon costs from the identified potential retirements of 2,919 MW.

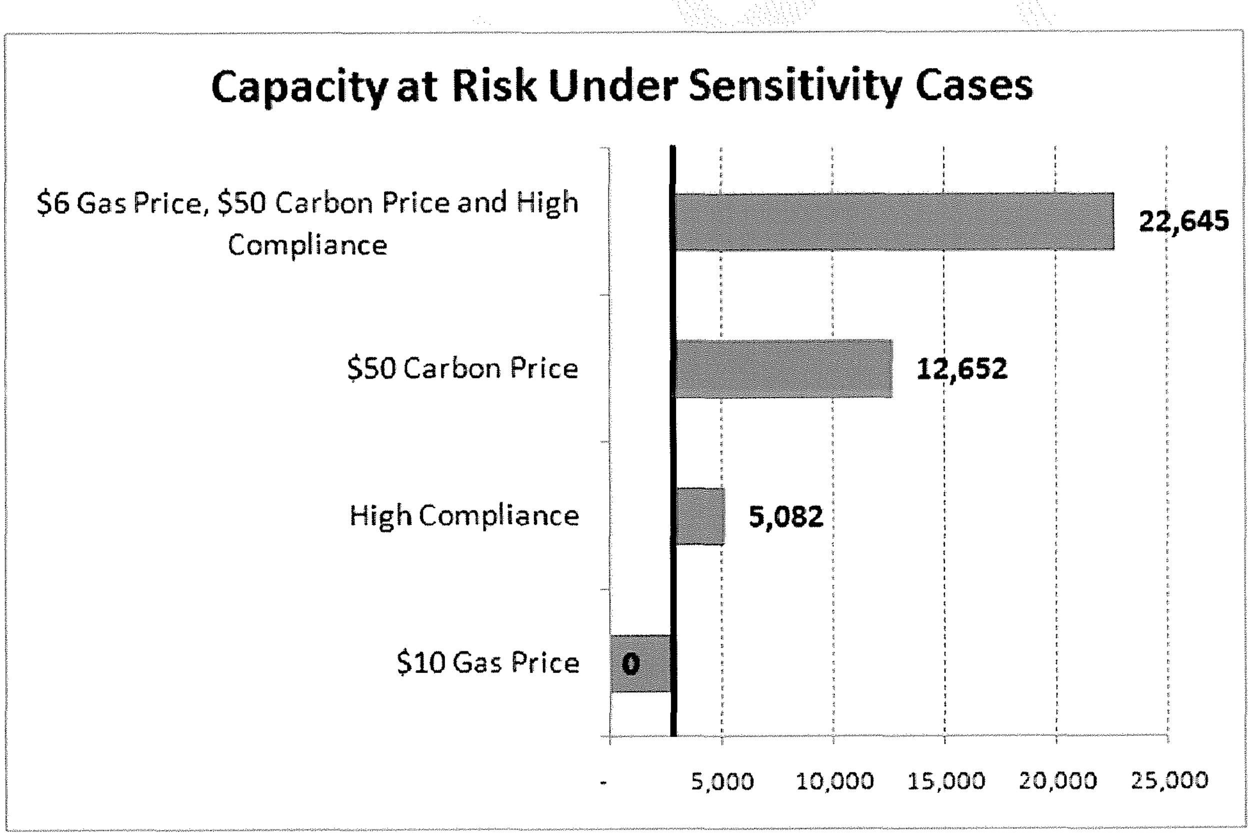


Figure 2-4: Tornado chart demonstrating the impacts of sensitivities on potential capacity retirements

2.3 Potential Carbon Regulation

At the end of 2010, the EPA issued a proposed schedule for establishing greenhouse gas (GHG) standards under the Clean Air Act for fossil fuel fired power plants and petroleum refineries. This is the first step the EPA is taking to address carbon. How that will unfold is not known. One of the ways for MISO to evaluate the impacts of carbon compliance is to add a cost to carbon that can represent either a carbon production tax or the effective costs to comply through reduction in carbon output by technology applications. This increases the dispatch cost in $/MWh for all units that produce carbon. Higher carbon emitting units receive a greater cost penalty that will change the order that all units in MISO are dispatched.

Figure 2-5, illustrates how the at-risk for retirement units increase because of the application of a cost for carbon. As the cost of carbon is increased to $50/ton, 12,652 MW's of units become at risk for retirement. This should be compared to the 2,919 MW identified without the carbon costs applied. This illustrates the importance of assessing the impact of future carbon in the analysis. If a unit would have spent money to retrofit for the EPA regulations, based on the assumption of no new carbon requirements, and carbon regulations materialize in the $35-$50/ton range, the investment becomes at risk at that later date.

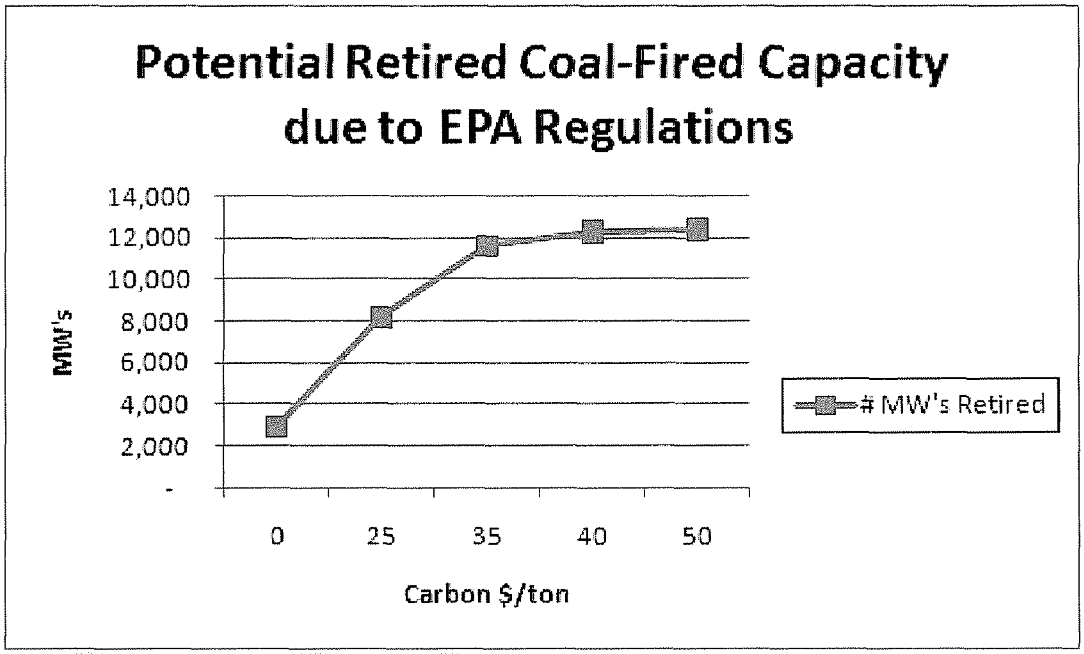


Figure 2-5: Carbon Impacts on Retrofit/Retirement Decision

2.4 Rate Impact

In general, the retail rates on the system are driven by the costs of generation production, generation capital costs, transmission capital costs and distribution capital costs. The MISO EPA regulation analysis identifies costs that impact three of the four components of the rates.

When the impact of carbon cost is excluded from the rate increase calculation, the greatest impact on the rates comes from the capital cost component. The capital cost increase comes in two forms, the EPA capital compliance cost and the capital cost for replacement capacity. Figure 2-6 demonstrates the comparison of the rate impact of the two retirement scenarios with the current average system rate. The overall increase in the rates because of compliance with the EPA regulations is approximately 7.0 to 7.6 percent.

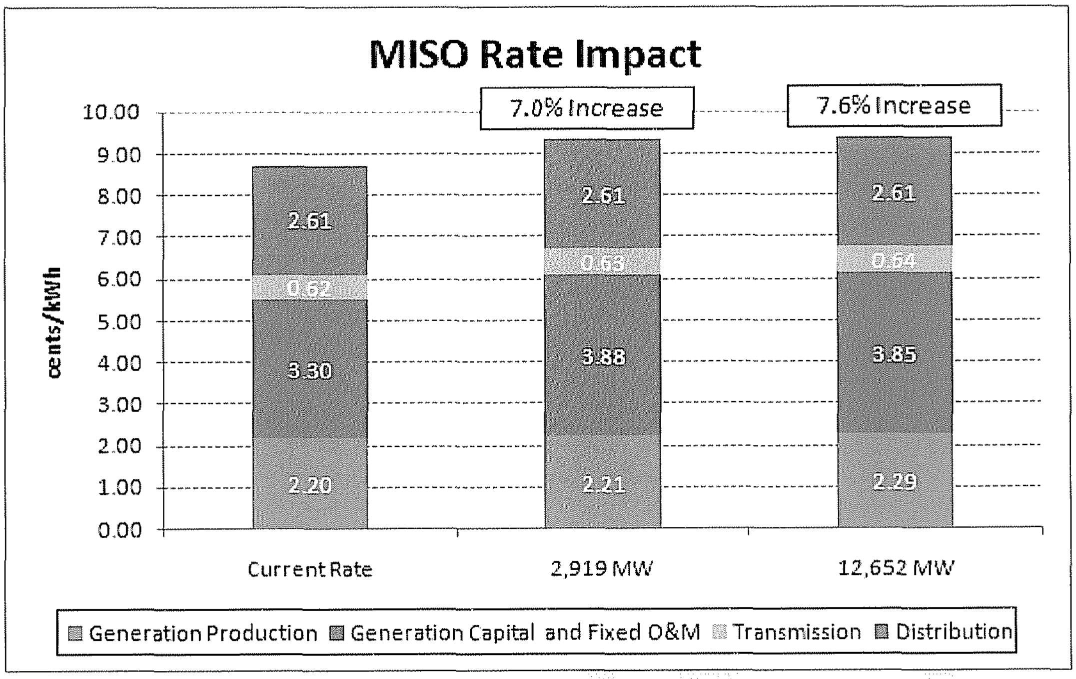


Figure 2-6: MISO Rate Impact excluding the cost of carbon in the production costs

Figure 2-7 demonstrates the rate impacts when a cost for carbon compliance is included in the generation production costs. In this comparison, the production costs are the primary driver for the rate increases that are 37.2 to 37.7 percent. The cost of carbon drives the retirements of 12,652 MW in this analysis. Applying the carbon cost to both scenarios demonstrates the total impact that carbon has on both capital investment and production costs.

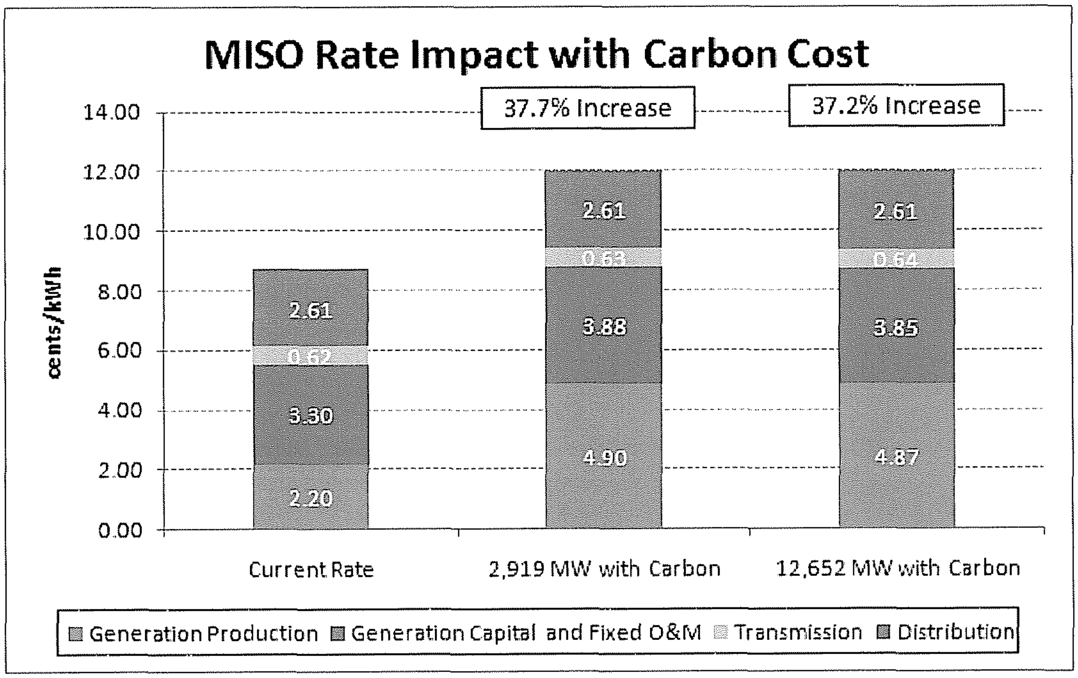


Figure 2-7: MISO Rate Impact including the cost of carbon in the production costs

3 EPA Regulations

The EPA is in the process of finalizing the following four proposed regulations that impact the electric industry:

- Cooling Water Intake Structures – section 316(b) of the Clean Water Act (CWA), final rule expected at the end of 2012
- Coal Combustion Residuals (CCR) , final rule expected at the end of 2011
- Cross State Air Pollution Rule (CSAPR) formerly known as Clean Air Transport Rule (CATR) , rule finalized July 2011
- Mercury and Air Toxics Standards (MATS) formerly known as Electric Generating Unit (EGU) Maximum Achievable Control Technology (MACT) , final rule expected at the end of 2011

Each regulation is unique and has specific goals and as such MISO evaluated the impacts on its system for each regulation separately and also all four combined. The MISO study centered on determining the capacity cost impact, resource adequacy impact, energy cost impact and the transmission reliability cost impact on the MISO system.

3.1 Clean Water Act, Section 316(b)

Section 316(b) of the Clean Water Act (CWA) will establish the Best Technology Available (BTA) for Cooling Water Intake Structures to minimize impingement and entrainment of aquatic organisms. Currently it is a possibility that BTA could be defined as re-circulating cooling system retrofits for all units employing once-through cooling systems. This is likely a worst case scenario. In the MISO analysis BTA is defined as retrofits to re-circulating cooling systems only if the retrofit is drawing its cooling source from an ocean, tidal river or estuary.

3.2 Coal Combustion Residuals

The purpose of the CCR is to regulate the coal fly ash under one of two methodologies. The first methodology is to treat the ash as a special waste under subtitle C (hazardous waste) of the Resource Conservation and Recovery Act (RCRA). Under this option, facilities would need to close their surface ash impoundments within five years and dispose of the ash (past and future) in a regulated landfill with groundwater monitoring.

The second methodology is to regulate ash disposal as a non-hazardous waste under subtitle D of RCRA. This alternative would require the facility to remove the solids and retrofit the impoundment pond with a liner to protect against groundwater contamination and landfill coal combustion residuals disposal would require liners for new landfill and groundwater monitoring of existing landfills.

The second methodology is evaluated in this study.

3.3 Cross State Air Pollution Rule

The transport proposal reduces emissions that contribute to fine particle (PM2.5) and ozone non attainment that often travel across state lines, sulfur dioxide ($SO2$) and nitrogen oxides (NOx) contribute to PM2.5 and ozone transport. The 28 states plus the District of Columbia are affected by transport rule and illustrated in Figure 3-1. The rule allows units in each state to meet the emissions targets in any way the state sees fit, including unlimited trading of emissions allowances between power plants within the same state with interstate trading permitted.

To assure emissions reductions happen quickly, EPA is proposing federal implementation plans, or FIPs, for each of the states covered by this rule. A state, however, may choose to develop a state plan to achieve the required reductions, replacing its federal plan, and may choose which types of sources to control.

Emission budget schedule implementation:

- Annual SO_2
  - Phase 1 group - 2012 cap that lowers in 2014
  - Phase 2 group - 2012 cap
  - Set emissions budget for each state
- Annual NO_x
  - 2012 state specific cap
- Ozone Season NO_x
  - 2012 state specific cap

The final CSAPR regulation came out just prior to the conclusion of this study. The analysis and results presented in the study are from previous proposals of what was known as the Clean Air Transport Rule (CATR).

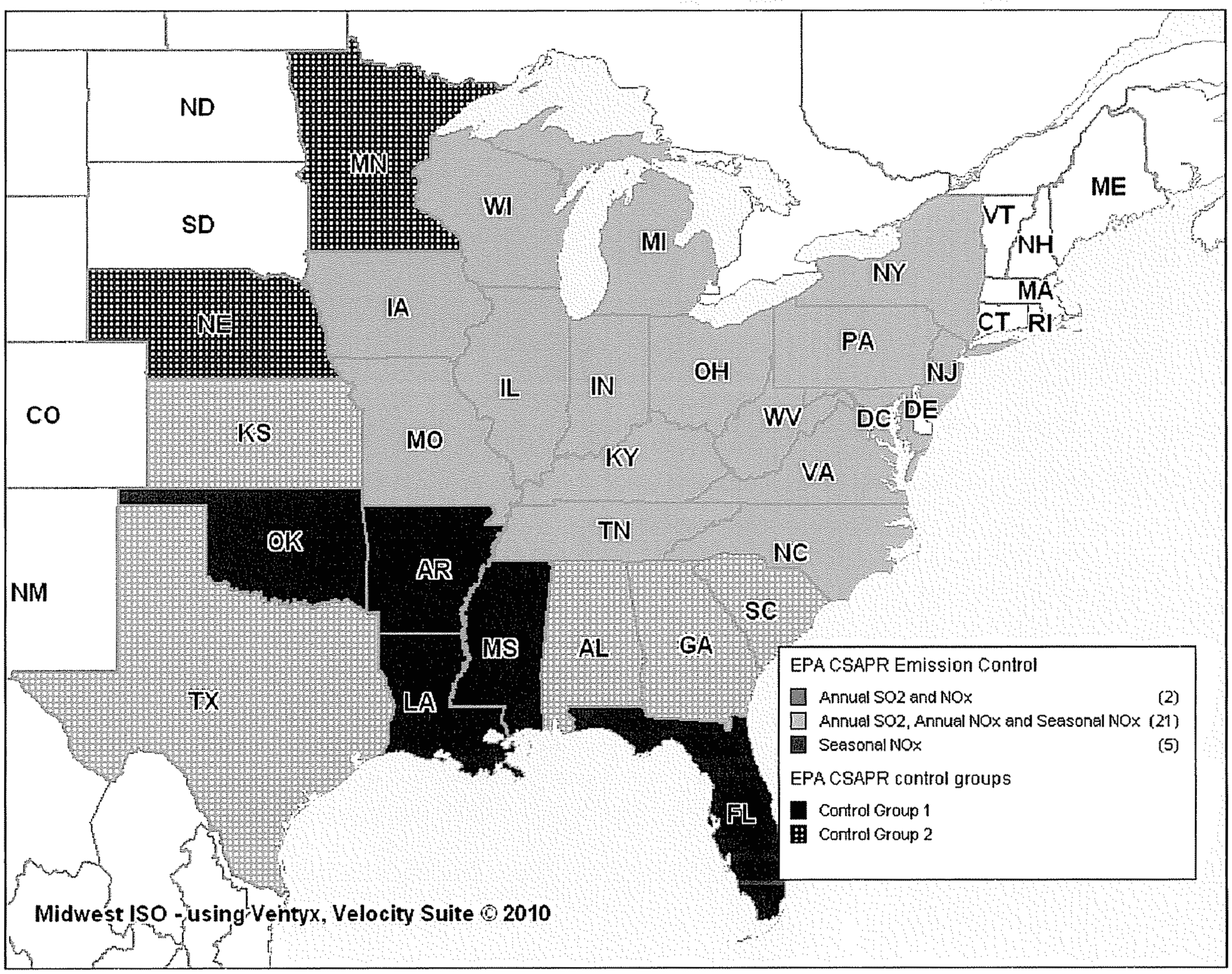


Figure 3-1: Cross State Air Pollution Rule Implementation

3.4 Mercury and Air Toxics Standards

The primary focus of the Mercury and Air Toxics Standards is the reduction of emissions from heavy metals and acid gases. The heavy metals include mercury (Hg), arsenic, chromium and nickel; and, the acid gases include hydrogen chloride (HCl) and hydrogen fluoride (HF). A final rule will be expected towards the end of 2011. The following represent a few key highlights of the proposal:

- For all existing and new coal-fired Electric Generating Units (EGUs), the proposed MATS regulations would set numerical standards for mercury, Particulate Matter (PM), and HCl
- For all existing and new oil-fired EGUs, the proposed toxics rule would establish numerical emission limits for total metals, HCl, and HF. Compliance with the metals standards is through fuel testing.
- For new units, proposed revisions to the New Source Performance Standards (NSPS) would include revised numerical EGU emission limits for PM, SO_2, and NOX.

There are many technologies available to power plants to meet the emission limits, including wet and dry scrubbers, dry sorbent injection systems, activated carbon injection systems, and baghouses.

3.5 Regulation Timing

Figure 3-2 demonstrates a high level time table of rule implementation and compliance deadlines. If it is determined that capacity should be retired, it would take a minimum of two to three years to build a combustion turbine to replace that capacity. Also, if transmission system reliability requires bulk transmission upgrades, a minimum of five years could be required for a transmission line to come into service. The time frame from final regulation to compliance may be difficult to meet for some situations throughout the system.

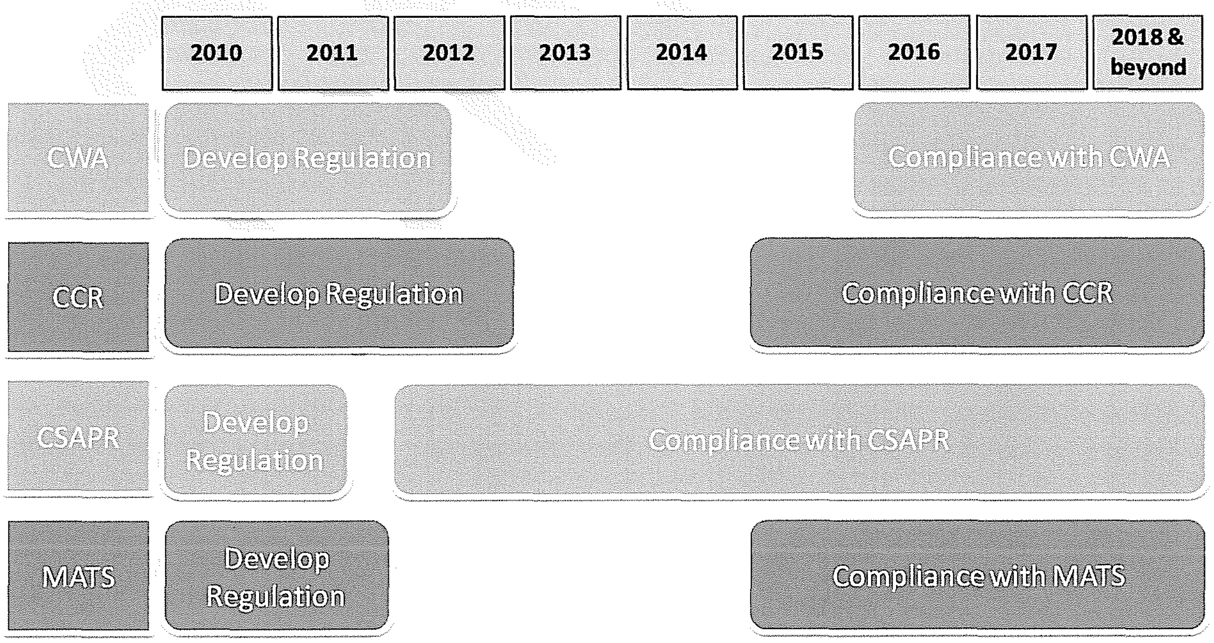


Figure 3-2: Estimated timeline for regulation development and implementation

3.6 Carbon Restrictions

There are currently no existing rules that regulate and reduce the amount of carbon being produced from the existing fleet. However, recent classification of carbon as a hazardous air pollutant obligates the EPA to regulate its production. There have also been proposals through the legislative process that have produced certain targets for the reduction of carbon. One of those proposals requires that the output of carbon should reduce by 40% from 2005 levels by 2030 and 83% by 2050.

4 Models

4.1 EGEAS

The Electric Generation Expansion Analysis System (EGEAS) software from the Electric Power Research Institute (EPRI) is used for long-term regional resource forecasting. EGEAS performs capacity expansions based on long-term, least-cost optimizations with multiple input variables and alternatives. Optimizations can be performed on a variety of constraints such as resource adequacy (loss-of-load hours), reserve margins, or emissions constraints. The EPA study optimization is based on minimizing the 20-year capital and production costs, with a reserve margin requirement indicating when new capacity is required.

4.2 PROMOD IV®

PROMOD IV® is an integrated electric generation and transmission market simulation system that incorporates extensive details of generating unit operating characteristics and constraints, transmission constraints, generation analysis, unit commitment/operating conditions, and market system operations. It performs an 8,760-hour commitment and dispatch recognizing both generation and transmission impacts at the bus-bar (nodal) level. PROMOD IV® forecasts hourly energy prices, unit generation, fuel consumption, bus-bar energy market prices, regional energy interchange, transmission flows, and congestion prices. It uses an hourly chronological dispatch algorithm that minimizes costs while simultaneously adhering to a variety of operating constraints, including generating unit characteristics, transmission limits, fuel and environmental considerations, spinning reserve requirements, and customer demand.

4.3 PSS®E

PSS®E is an integrated, interactive program simulating, analyzing, and optimizing power system performance. PSS®E allows for detailed analysis of single hour operation based on defined system conditions such as system topology, demand and generation dispatch. This tool will allow the user to evaluate system reliability requirements in terms of both the transmission thermal limitations and required voltage levels at different points of the system.

4.4 GE-MARS

GE Energy's Multi-Area Reliability Simulation (GE-MARS) is a transportation-style model based on a sequential Monte Carlo simulation that steps through time chronologically and produces a detailed representation of the hourly loads and hourly wind profiles in comparison with the available generation, in addition to interfacing between the interconnected areas.

GE-MARS calculates, by area or area group, the standard reliability indices of daily or hourly loss of load expectation (LOLE, in days per year or hours per year) and expected unserved energy (EUE, in megawatt-hours per year).

The basic calculations are done at the area level, which is how much of the data are specified and aggregated. Loads, wind profiles, and generation are assigned to areas, and transfer limits are specified between areas.

5 Scope

The objective of the EPA Impact Analysis is to identify potential aggregate impacts of the EPA proposed regulations on the fleet within the MISO footprint. Specific key questions that are answered by the study are:

- Are there resource adequacy risks?
- Are there transmission adequacy risks?
- What are the impacts on the energy markets?
- What are the impacts on capital costs to the system?

Evaluation of study questions and results will be expressed at the MISO level, only. It is understood that retrofit/retirement decisions are the responsibility of the asset owners. MISO will not share unit specific information with any entity outside of the asset owner at their request.

Figure 5-1 shows the study scope. The study was comprised of 3 phases. The first phase screened the approximate 2,000 units in the MISO system to determine which of those units would be most at risk for retirement. The second phase used the results of the screening process to determine the energy and congestion impacts on the system. The third phase developed the compliance and capital cost requirements. The third phase also evaluated the impact of resource adequacy, system reliability and customer rates.

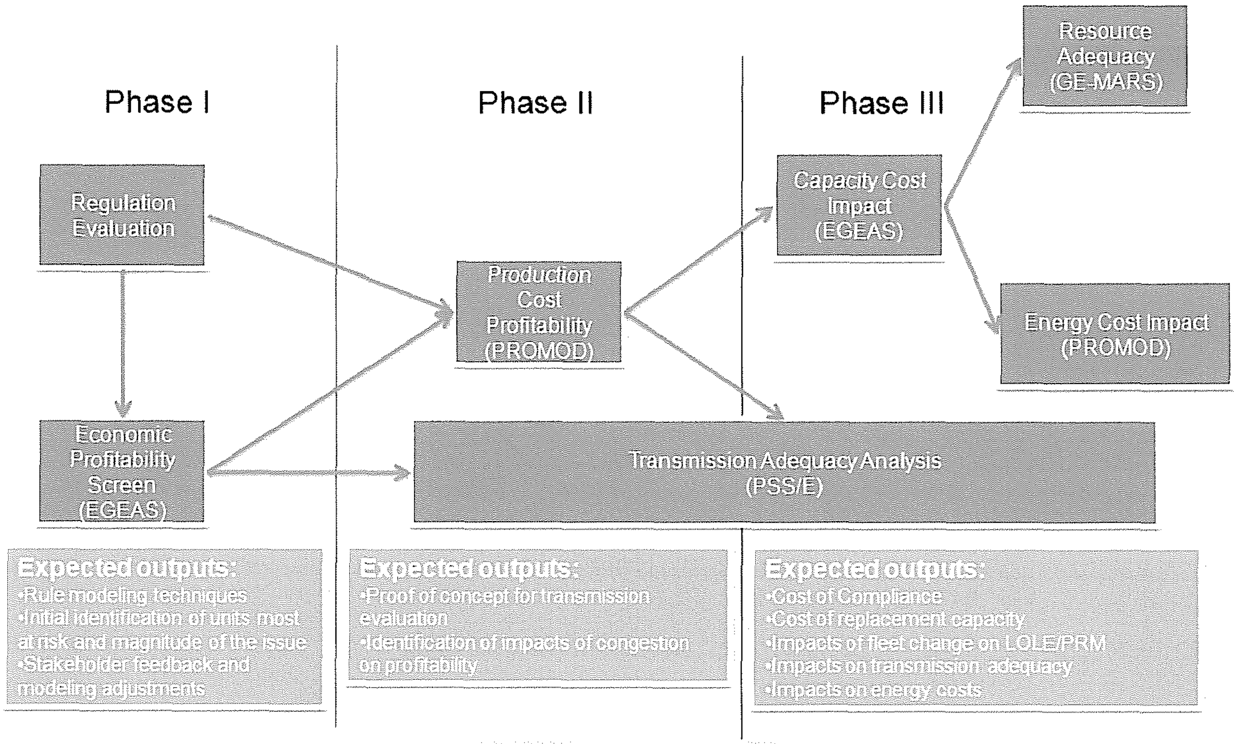


Figure 5-1: Flow Diagram of EPA Impact Analysis

6 Phase I

Phase I of the process consisted of three primary tasks: modeling techniques, profitability screening, and MISO stakeholder interaction. MISO researched the proposed regulations and recent evaluations of the regulations. The research focused on the development of the modeling techniques to be used within the various models. This included looking at various compliance technologies and their impacts on the operation and costs of units that may need to be retrofitted. MISO also surveyed asset owners on the control equipment already installed on the units.

The profitability screening utilized the EGEAS model. Existing system characteristics, compliance assumptions, and sensitivities on gas prices and costs for carbon regulation were applied. This resulted in over 400 screening cases to be run to identify potential at-risk for retirement units on the system.

Through the MISO Planning Advisory Committee, stakeholders were given the opportunity to comment on inputs and outputs from the screening runs. Through this feedback process, stakeholders provided suggestions on compliance technologies and costs that further enhanced the MISO analysis.

6.1 Phase I Assumptions

The MTEP 11 Business as Usual with Low Demand and Energy Growth Rate future was used as the base model in the regulation impact analysis. The demand growth rate was 0.78 percent and the energy growth rate was 0.79 percent. Both values are the effective growth rates determined through the MTEP process that include the impacts of projected demand response and energy efficiency resources. Detailed assumptions of the MTEP 11 futures can be found in Appendix E2 of the 2011 MTEP report.

The EGEAS model is used in Phase I because of the ability to run 20-year study cases in a quick and efficient manner. For the EPA Impact Analysis study MISO ran more than 400 EGEAS cases, representing sensitivities on combinations of the proposed regulations:

- Base conditions, no new regulations
- Cooling Water Intake Structures – section 316(b) of the Clean Water Act (CWA)
- Coal Combustion Residuals (CCR)
- Cross State Air Pollution Rule (CSAPR) formerly known as Clean Air Transport Rule (CATR)
- Mercury and Air Toxics Standards (MATS) formerly known as EGU Maximum Achievable Control Technology (MACT)
- Combination of all 4 regulations

Figure 6-1 demonstrates the sensitivities evaluated for each regulation analysis. As there are 6 regulation scenarios there would be 6 branches to this decision tree, only the first branch is shown in this graphic.

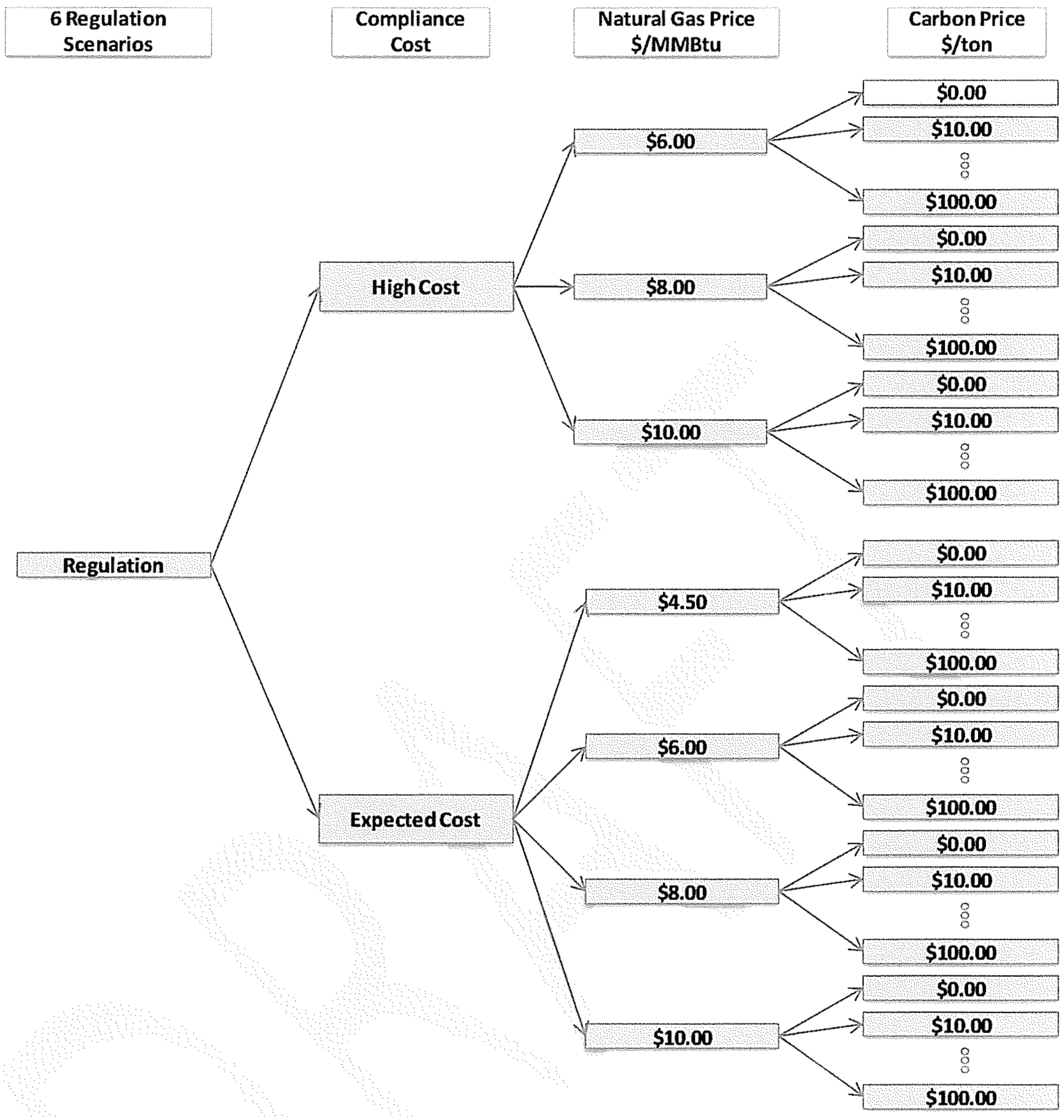


Figure 6-1: Decision Tree of EPA Cases (total of 77 sensitivities per regulation evaluated)

6.1.1 MATS, CWIS and CCR Assumptions

To increase the efficiency of the EGEAS analysis, a rule set was developed for which control technologies to model based on unit characteristics. This allows MISO to model the entire system and provide a reasonable set of alternatives for the retrofit versus retire comparisons. Table 6-1 demonstrates the rule set that was created.

The Great Lakes were considered as "oceans" for this analysis. This provided some impact of the intake structure regulation on the land locked footprint of MISO.

EPA Rule	Unit Type	Dry Scrubber	Dry Sorbent Injection	Activated Carbon Injection	Fabric Filter/Bag House	Recirculating Cooling	Fine Mesh Screens	Ash Conversion
MATS	Coal Units <=200MW		Yes	Yes	Yes			
	Coal Units >200 MW	Yes if no Wet Scrubber			Yes			
CWIS	Oceans, Estuaries or Tidal rivers					Yes		
	Not on Oceans, Estuaries or Tidal rivers						Yes	
CCR	Coal Units							Yes

Table 6-1: Retrofit Rule Set for EPA Regulations

Generating unit operating impacts due to installation of various control technologies were also introduced into the EGEAS model. Data was gathered from public sources and stakeholder feedback. Ultimately the values used in this EPA Impact Analysis were provided and agreed to by the stakeholders. Table 6-2 shows the generating unit operating impacts due to the installation of various control technologies.

Control Technology	Capital Cost ($/kw)	Fixed O&M ($/kw-year)	Variable O&M ($/MWh)	Heat Rate (%)	Max Capacity (%)	Removal Rate (%)
Wet Scrubber	525 @ 500 MW	+10	+1	+1.5	-1	95% SO2 with .08 lbs/MMBtu floor
Dry Scrubber	450 @ 500 MW	+8	+1.5	+1.5	-0.7	90% SO2 with .08 lbs/MMBtu floor
Dry Sorbent Injection	40.6 @ 200 MW	+3.40	+9.7 Bituminous Coal +4.4 Lignite and Sub-Bituminous Coal	+.02	-.02	70% SO2 with .08 lbs/MMBtu floor
Activated Carbon Injection	275 @ 500 MW	+4	+1	N/A	N/A	90% Mercury
Fabric Filter/Bag House	150 @ 500 MW	N/A	N/A	N/A	N/A	90% PM
Recirculating cooling conversion	150 @ 500 MW	+1.5	N/A	+1.5	-1	N/A
Fine Mesh Screens	90 @ 500 MW	N/A	N/A	N/A	N/A	N/A
Wet to Dry Ash conversion	$30 Million + $80 w/ FGD or $200 w/o FGD	N/A	+1	N/A	N/A	N/A

Table 6-2: Unit Impacts due to Control Technologies

6.1.2 CSAPR Assumptions

The Cross State Air Pollution Rule (CSAPR) assumptions used within this report are from the preliminary numbers provided in the draft Clean Air Transport Rule (CATR). The recent CSAPR limits are more stringent than the limits applied in this study. There is a possibility that with the newer limits the impact is greater than seen in this report. The CSAPR *regulation sets state wide emission limits for* SO_2, NO_x, *and* NO_x Ozone. MISO is able to model state limitations within the EGEAS model. EGEAS will take those limits and dispatch the units in each state to meet the state limits. This closely models the unlimited intrastate trading with no interstate trading.

For this study EGEAS is run at an RTO/ISO level and as such some states might span across multiple RTO/ISO's. Just applying the state limit would cause the limit to be too high in some cases. An example would be a state that has 10 units but only 1 of the units is in MISO. That would mean one unit would have a limit set intended for 10 units. To accommodate multi-regional states, the emission limits were prorated by the capacity of the units in each RTO/ISO.

Table 6-3 demonstrates the state and region emission budgets under the draft CATR. These were the numbers applied to the impact analysis. The CSAPR was finalized in July 2011 and as such the numbers in the table below are not from the finalized rule. Initial analysis seems to suggest that the emission budgets are reduced for some states and re-categorized for other states.

State	RTO/ISO	GRP	2012-2013 SO2 Annual Limit (Tons)	2014+ SO2 Annual Limit (Tons)	2014+ NOX Annual Limit (Tons)	2014+ NOX Ozone Annual Limit (Tons)
Alabama	SERC	II	115,285	115,285	49,262	21,179
Alabama	TVA	II	46,586	46,586	19,907	8,559
Arkansas	Entergy	II	-	-	-	14,876
Arkansas	SPP	II	-	-	-	1,784
Connecticut	ISONE	II	3,059	3,059	2,775	1,315
Delaware	PJM	II	7,784	7,784	6,206	2,450
District of Columbia	PJM	II	337	337	170	105
Florida	Florida	II	161,739	161,739	120,001	56,939
Georgia	SERC	I	233,260	85,717	73,801	32,144
Illinois	MISO	I	126,795	91,948	34,005	14,302
Illinois	PJM	I	82,162	59,582	22,035	9,268
Indiana	MISO	I	287,231	144,493	82,994	35,861
Indiana	PJM	I	113,147	56,919	32,693	14,126
Iowa	MISO	I	93,488	85,571	45,792	-
Iowa	MRO	I	564	517	276	-
Kansas	SPP	II	57,275	57,275	51,321	21,433
Kentucky	TVA	I	174,871	90,677	59,034	24,618
Kentucky	PJM	I	20,286	10,519	6,848	2,856
Kentucky	MISO	I	24,392	12,648	8,234	3,434
Louisiana	Entergy	II	67,125	67,125	32,604	15,743
Louisiana	Cleco	II	20,176	20,176	9,800	4,732
Louisiana	SPP	II	3,176	3,176	1,543	745
Maryland	PJM	II	39,665	39,665	17,044	7,232
Massachusetts	ISONE	II	7,902	7,902	5,960	-
Michigan	MISO	I	232,261	143,859	60,004	26,109
Michigan	PJM	I	19,076	11,816	4,928	2,144
Minnesota	MISO	II	47,101	47,101	41,322	-
Mississippi	SERC	II	-	-	-	5,108
Mississippi	TVA	II	-	-	-	4,870
Mississippi	Entergy	II	-	-	-	6,552
Missouri	MISO	I	85,651	66,760	24,255	-
Missouri	SPP	I	82,413	64,236	23,338	-
Missouri	TVA	I	35,625	27,768	10,088	-
Nebraska	SPP	II	71,598	71,598	43,228	-
New Jersey	PJM	II	11,291	11,291	11,826	5,269
New York	New York ISO	I	66,542	42,041	23,341	11,090
North Carolina	SERC	I	108,731	79,837	50,521	22,958
North Carolina	PJM	I	2,754	2,022	1,279	581
Ohio	PJM	I	386,571	148,244	80,906	33,806
Ohio	MISO	I	78,393	30,063	16,407	6,855
Oklahoma	SPP	II	-	-	-	36,108
Oklahoma	TVA	II	-	-	-	979
Pennsylvania	PJM	I	388,612	141,693	113,903	48,271
South Carolina	SERC	II	116,483	116,483	33,882	15,222
Tennessee	TVA	I	100,007	100,007	28,362	11,575
Texas	SPP	II	-	-	-	52,040
Texas	Entergy	II	-	-	-	23,534
Virginia	PJM	I	72,595	40,785	29,581	12,608
West Virginia	PJM	I	205,422	119,016	51,990	22,234
Wisconsin	MISO	I	96,439	66,683	44,846	-
Total			3,117,288	2,500,003	1,376,312	641,614

Table 6-3: State Emission Budget for draft CATR as used within the analysis

6.2 Phase I Results

To identify at-risk capacity on the system, MISO had to develop a methodology to evaluate the profitability of the units on the system. This was achieved through calculating the annual revenues and costs for each generating unit within MISO and determining the net margins for the units. The units with a net margin less than $0/kW were deemed to be either Tier I at-risk units or Tier II potentially at-risk units.

The net margin for each generating unit is calculated by subtracting annual costs from annual revenues. The next step is to list all the generating units in order of decreasing net margin for each year of the study period. From this ordered list of generating units, the marginal unit can be determined. The marginal unit is the unit at which the cumulative capacity equals the capacity requirements to meet the planning reserve margin (PRM) criterion. The offset adder expressed in $/kW is the required amount of net margin adder that will make the marginal unit whole. For example, as shown in Table 6-4, the net margin of the marginal unit, U_n, is -$450/kW, and the offset adder would be $450/kW to make the marginal unit whole. This offset adder is then applied to all units in the ordered list.

Unit	Net Margin	Capacity	Cumulative Capacity	Reserve Margin
U_1	$200/kW	400 MW	400 MW	
U_2	$175/kW	650 MW	1050 MW	
U_3	$130/kW	160 MW	1210 MW	
...	...	...	...	
...	...	...	...	
U_{898}	$0/kW	330 MW	100,000 MW	
U_{1000}	-$45/kW	80 MW	110,000 MW	
U_n	-$450/kW	125 MW	118,000 MW	17.40%
U_{n+1}	-$550/kW	30 MW	118,030 MW	17.4%+

Table 6-4: Pictorial Representation of Tier I and Tier II units

Two different sets of offset adders were calculated and used to determine which generating units are to be classified as Tier I and Tier II units. The Tier I offset adders are based on the EGEAS cases for each specific EPA Regulation, whereas the Tier II offset adders are based on the results of the EGEAS Base Case assuming no EPA Regulations, By definition, the Tier I offset adders are greater than the Tier II offset adders, since the Tier II offset adders do not include the added costs for the various EPA control systems needed to meet compliance. Table 6-5 provides an example of the Tiers. Units at risk are those at the bottom of the dispatch order where the revenue in-take may or may not cover the costs of compliance. Since MISO does not capture all revenue for a unit, this methodology provides reasonable cut-offs based on the PRM system reliability objective.

Unit	Net Margin from Regulation Case	Net Margin with EPA Regulation Offset Adder ($200/kW)	Net Margin with Base Conditions Offset Adder ($100/kW)	At-Risk Status
U1	$200/kW	$400/kW	$300/kW	Not at-risk
U2	$100/kW	$300/kW	$200/kW	Not at-risk
U3	$50/kW	$250/kW	$150/kW	Not at-risk
U4	$0/kW	$200/kW	$100/kW	Not at-risk
U5	-$50/kW	$150/kW	$50/kW	Not at-risk
U6	-$100/kW	$100/kW	$0/kW	Not at-risk
U7	-$150/kW	$50/kW	-$50/kW	Tier II
U8	-$200/kW	$0/kW	-$100/kW	Tier II
U9	-$250/kW	-$50/kW	-$150/kW	Tier I
U10	-$300/kW	-$100/kW	-$200/kW	Tier I

Table 6-5: Example of Tier I and Tier II identification

If a unit is identified as a Tier I unit in any of the sensitivity cases, it is classified as Tier I for the entire set of runs. Therefore, not any one scenario will result in the total identified Tier I list, but it is a combination of the unique units from all of the sensitivity cases.

6.2.1 High Compliance Cost Applications

MISO *ran over four hundred* sensitivities on the EPA regulations where Tier I and Tier II units were identified. Most of the sensitivities focused on combinations of gas and carbon prices. Those gas and carbon sensitivities were run on two variations of compliance with the EPA rules. Compliance with the rules was modeled at a high cost application and a more expected cost application. The differences in the two methods of modeling can be seen in Table 6-6.

High Cost Application	Expected Cost Application
Compliance costs applied in 2011 with 10 year recovery period	Compliance costs applied in 2015 with 20 year recovery period
SCR required to meet MATS	SCR **NOT** required to meet MATS
Closed loop cooling applied to all steam units	closed loop cooling applied to oceans, tidal rivers and estuaries
FGD applied to all units <=200MW	DSI applied to all units <=200MW
Carbon prices applied in 2011	Carbon prices applied in 2015
No $4.5/MMBtu gas price in sensitivities	$4.5/MMBtu gas price in sensitivities

Table 6-6: Modeling Differences between compliance modeling methodologies

Modeling of the compliance high cost application resulted in the identification of 102 Tier I coal units amounting to 5,082 MW of capacity and an additional 116 Tier II coal units amounting to 22,645 MW of capacity. Figure 6-2 provides a histogram of the units identified by Tier. As can be seen, the most at-risk units identified in Tier I are less than 200 MW while the Tier II units can get up to larger sizes. The modeling runs identify that the most at-risk units are a result of the application of compliance costs combined with lower gas prices where the higher values of those units in the Tier II list tend to show up as potentially at-risk because of the application of costs to carbon. It was also found through the sensitivity analysis that the MATS regulation is the primary driver in placing units at risk for retirement.

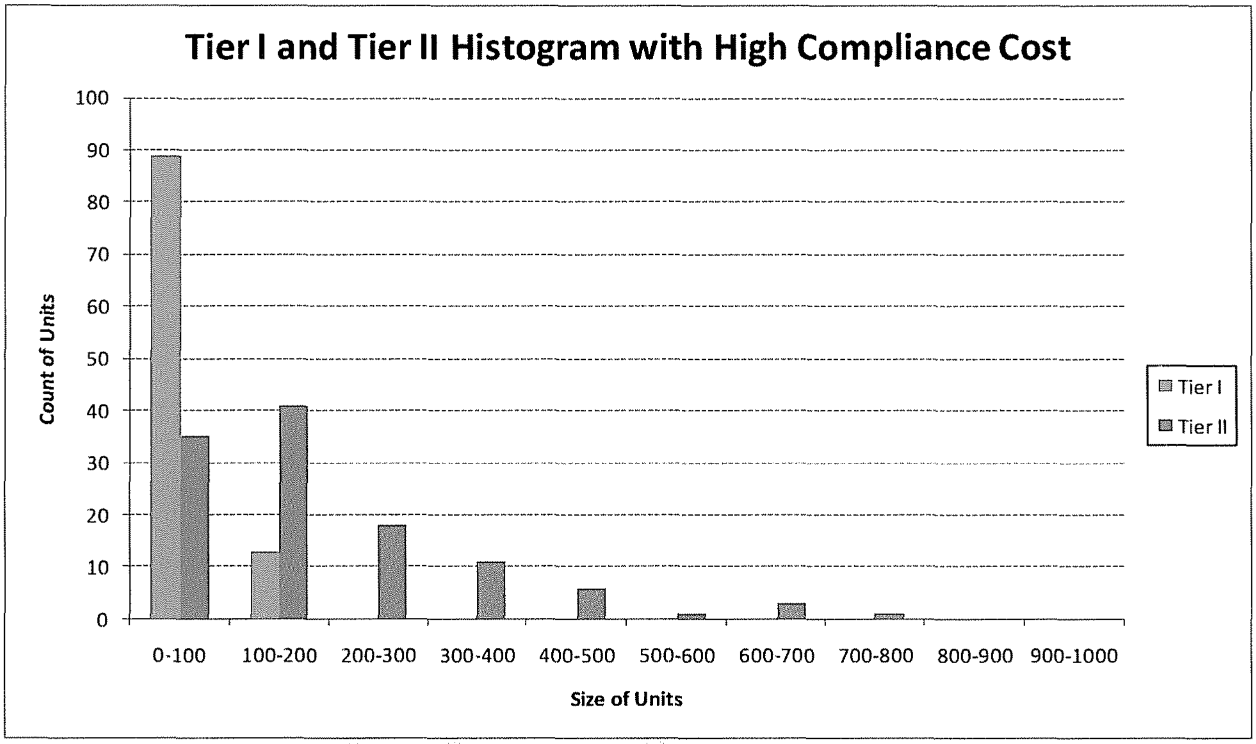


Figure 6-2: Tier I and Tier II Histogram high compliance cost application

6.2.2 Expected Compliance Cost Application

The modeling of the lower, more realistic compliance application reduced impacted generation on the Tier I and Tier II lists. In this set of sensitivity cases, Tier I accounts for 53 coal units amounting to 2,764 MW of capacity and Tier II accounts for an additional 98 coal units amounting to 9,885 MW of capacity. The adjustment in capacity cost modeling identifies more of the smaller coal units on the system as Tier II rather than Tier I as seen in the compliance cost application cases, Figure 6-2 and Figure 6-3. The expected compliance cost application also identifies no units greater than 300 MW in either of the Tiers. The average age of the units identified is 52 years.

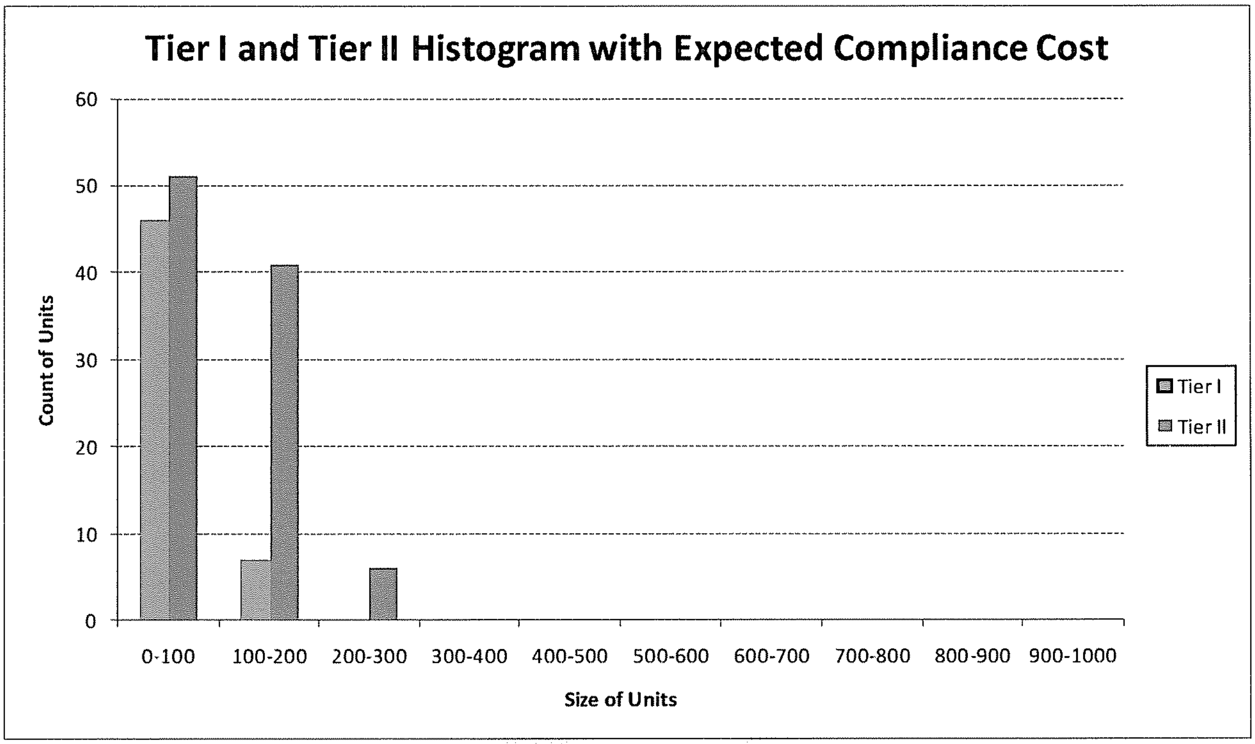


Figure 6-3: Tier I and Tier II Histogram for expected compliance cost application

6.3 General Observations of Sensitivity Screens in Phase I

The sensitivity cases have given information to what variables have impacts on what units are identified as at-risk.

- A greater cost for compliance will result in more coal units to be at risk.
- Lower gas prices result in a greater amount of at-risk coal capacity. This is due to lowered revenue on the system as the clearing energy price for peaking capacity is lower. Higher gas costs provide more revenue on the system for coal units and lower the risk for retirement on the system.
- Carbon costs drive more coal units to be at risk. However, carbon costs combined with higher gas prices could mitigate the amount of at-risk capacity.

7 Phase II

Because EGEAS does not include the detailed transmission system within the modeling capability, it was determined that PROMOD IV® would be utilized to identify if congestion on the transmission system could provide additional revenue to generators to remove them from the list of Tier I and Tier II units identified in Phase I.

7.1 Phase II Assumptions

Four sets of sensitivities were modeled within the PROMOD IV® model, as shown in Table 7-1. These cases represent results from Phase I that maximized and minimized retirements under the MATS only cases and the cases representing a combination of all the studied regulations. The years evaluated included 2016, 2021, and 2026.

Phase II PROMOD IV® Cases
MATS Regulation, Expected Compliance Costs, $4.50 Gas and $100 Carbon
MATS Regulation, Expected Compliance Costs, $10 Gas and $0 Carbon
Combined Regulations, Expected Compliance Costs, $4.50 Gas and $100 Carbon
Combined Regulations, Expected Compliance Costs, $10 Gas and $0 Carbon

Table 7-1: Phase II analysis assumptions

Because MISO models the Eastern Interconnect within the PROMOD IV® models, high level EPA evaluation and EGEAS runs had to be made for the entire model footprint. This is done to maintain appropriate cost balances between MISO and the other regions.

Each PROMOD IV® case was run under copper sheet (no transmission limitations) and constrained conditions. The difference between the generation revenue and generation cost for those cases provides the transmission impact on the revenue and cost, or net margin, for each unit on the MISO system. Comparing these results from the Phase I results will show the transmission impact on the Tier I and II list.

7.2 Phase II Results

Phase II results indicate that some of the units on the Tier I and II lists are in locations where greater revenues can be received due to congestion. Of the Tier I units identified in the expected compliance cost set of sensitivities, 12 units amounting to 594 MW result in a positive net margin with the addition of transmission congestion revenue. In Tier II, 28 units amounting to 2,957 MW become profitable.

The congestion revenue information is important because it shows that congestion on the system may provide additional revenue opportunities for some generating units. However, the following Phase III analysis does not include the additional congestion revenue because the revenue number identified is a one year representation from the production cost model runs where the capacity expansion looks at the interaction of retirement and retrofit decisions over a 20 year time frame. Additional analysis will be needed to include a transmission congestion component in the future.

7.3 General Observations of PROMOD IV® Analysis

The Phase II provided analysis shows the following results.

- A total of 3,551 MW could possibly be in transmission sensitive areas.
- Transmission congestion could provide additional revenue that is not captured in the MISO EGEAS analysis of the retirements of at-risk capacity.

8 Phase III

Phase III of the analysis focused on answering the four questions posed at the beginning of the study.

- What are the impacts on capital costs to the system?
- Are there resource adequacy risks?
- What are the impacts on the energy markets?
- Are there transmission adequacy risks?

These questions are answered utilizing four different models. EGEAS was used to evaluate the capital investment costs. These costs include both compliance retrofit costs and replacement capacity costs for retired capacity. The GE-MARS model was used to evaluate the impacts of retirements and retrofits on the Loss of Load Expectation (LOLE) analysis. The PROMOD IV® was used to determine energy cost impacts. Finally, the PSS®E model was used to evaluate transmission system adequacy for the retirement of units on the system.

8.1 Phase III Assumptions

The EGEAS retirement versus retrofit analysis was performed on the case that included expected compliance cost application, a gas cost of $4.50/MMBtu and $0/ton carbon cost. Additionally, increasing levels of carbon costs were also modeled to capture the impacts of the uncertainty of future carbon regulation on the retirement decision.

To perform the EGEAS analysis, two model runs were made for each unit from the expected compliance cost application Tier I and II list. One modeled the unit and its retrofit controls and one modeled the retirement of the unit with replacement capacity. The output with the lowest overall system cost determined the strategy of the unit tested.

The outputs of the EGEAS analysis are passed to the other models. The inputs to those models will include the retirement versus retrofit decision as well as compliance technology impacts and future replacement capacity.

8.2 Phase III Results

The EGEAS analysis identified 46 coal units amounting to 2,919 MW as at-risk units to retire. Increasing the carbon cost increases the amount of retirements of coal units. Figure 8-1 shows the increasing amount of capacity that should be considered for retirement for carbon costs from $0/ton to $50/ton. At the $50/ton cost for carbon, 12,652 MW are at-risk to retire.

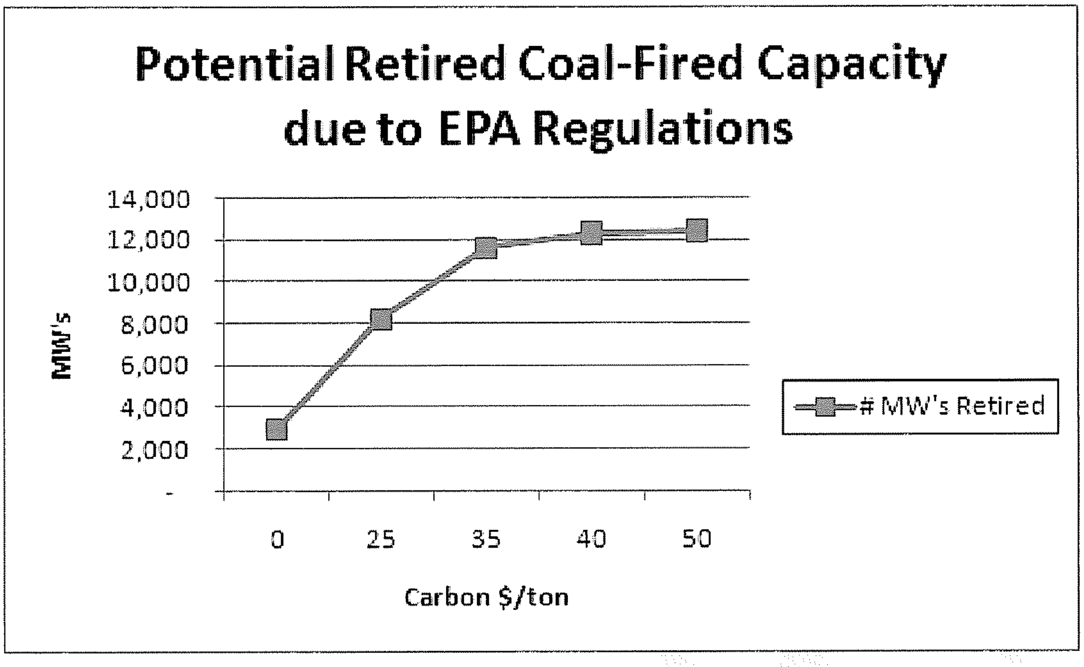


Figure 8-1: Carbon Impacts on Retrofit/Retirement Decision

8.2.1 Capacity Cost Impact

Figure 8-2 demonstrates the 20-year net present value of capital cost impacts of the EPA regulations from the EGEAS modeling runs in 2011 dollars. The comparison of the costs are based on the retirement impacts of 2,919 MW from the non-carbon analysis and 12,652 MW from the carbon analysis compared to the non-carbon, no EPA regulation compliance base case. As can be seen, compliance capital costs are in the range of $22.5 billion to $28.2 billion. Capacity capital fixed charges increases by $1.7 billion to $9.6 billion and Fixed O&M costs range from no increase to $1.1 billion. The total capital cost impacts for compliance with the EPA regulations ranges from $31.0 billion to $32.1 billion.

	No Regulation Case	2,919 MW of Retirements	12,652 MW of Retirements
EPA Compliance Retrofit Capital Costs	$0.0B	$28.2B	$22.5B
New Capacity Capital Fixed Charges	$68.8B	$70.5B	$78.4B
Fixed O&M Costs	$45.7B	$46.8B	$45.7B

Figure 8-2: 20-year NPV capital cost impact of EPA regulations (2011$)

8.2.2 Resource Adequacy Impact

The impact of EPA regulations on the resource adequacy of the MISO system is dependent on the manner in which the system is maintained during the retirement or replacement of affected units. Assuming a controlled replacement of capacity as it is retired, system reliability is actually improved. As the older and less reliable units identified within this study are removed the system average forced outage rate decreases marginally. This decrease in outage rates (less than 1% in both cases) when applied to the entire system results in Planning Reserve Margin decreases of up to 1% from 17.4% with the current system to 16.4% in a system where 12,652 MW of capacity is replaced with system average units.

As an analysis of the base reliability of the MISO system, if all units within the footprint were assumed committed to resource adequacy the Loss of Load Expectation (LOLE) would be roughly 0.088 days/year. If the capacity flagged for retirement in this section was removed and not replaced, the loss of 2,919 MW would decrease the base reliability to the point where the LOLE would be 0.21 days/year, twice the current target of 0.1 days per year or one day in ten years. If all 12,652 MW of capacity were removed from the system and not replaced the resulting LOLE would yield a system with 10 times the probability for outage as the current benchmark or 1.028 days/year.

Removal of capacity without replacement is an unlikely scenario and maintenance of the Planning Reserve Margin is obligated under the MISO tariff. In order to analyze the impacts of a system where the reserve margin was maintained all removed capacity was replaced by theoretical new units which had an outage rate equivalent to the system average after unit removal. In this case when 2,919 MW of capacity was retired and the reserve margin maintained the LOLE improved from the target of 0.1 to 0.093 days/year. When 12,652 MW was retired and replaced in the same fashion the reliability improved even more to 0.068 days/year.

This is indicative of the improved average forced outage rates experienced when less reliable units are removed and replaced with more reliable units. The starting system average forced outage rate was 8.0248% where the removal of 2,919 MW improved average forced outage rate to 7.9983% and 12,652 MW of retirements resulted in a 7.9864%.

As a final analysis of the impact of unit retirement and replacement with system average units a hypothetical reserve margin was established. Since the system average forced outage rates declined after the retirements it can be assumed that Planning Reserve Margins would drop. This was indeed the case as starting from the 17.4% reserve margin established in the base case, 2,919 MW of retirements lowered the reserve margin to 17.2%. Likewise the retirement of 12,652 MW resulted in a decrease in reserve margin to 16.4%. In either case it was assumed that retired units would be replaced by units that matched the system average forced outage rates. The reliability of the system is ultimately dependant on many factors including the availability of the units. If the units identified as at risk for retirement are all replaced with units that have better availability, system reliability will improve.

8.2.3 Energy Cost Impact

The EPA regulations have two primary impacts on the cost of energy on the system. First, all coal units that require retrofits for compliance will have a negative impact on their production of energy. For example, the impacts on heat rates and variable O&M costs will make many units less efficient and more expensive in the production of energy. Second, units that are selected for retirement will remove the lower cost coal capacity from the system and will eventually be replaced by the higher cost natural gas capacity replacement units. This will put a greater dependence on the natural gas units to meet the system energy requirements at higher production costs.

Both identified retirement scenarios were modeled within PROMOD. Figure 8-3 shows that both scenarios increase the average cost of energy on the MISO system. The retirement of 2,919 MW of capacity will result in a slightly less than $1/MWh average cost increase in 2011 dollars. The retirement of 12,652 MW of capacity on the system results in average cost of energy increase near $5/MWh in 2011 dollars.

When carbon costs are added to the cost of energy, the average LMPs on the system increase by approximately $30/MWh. In Figure 8-3, it can be seen that the 2,919 MW of retirement case results in greater energy costs than the 12,652 MW retirement case. This occurs because the higher retirement case was optimized with carbon costs considered and the higher retirements reduce carbon emissions by replacing coal capacity with natural gas capacity.

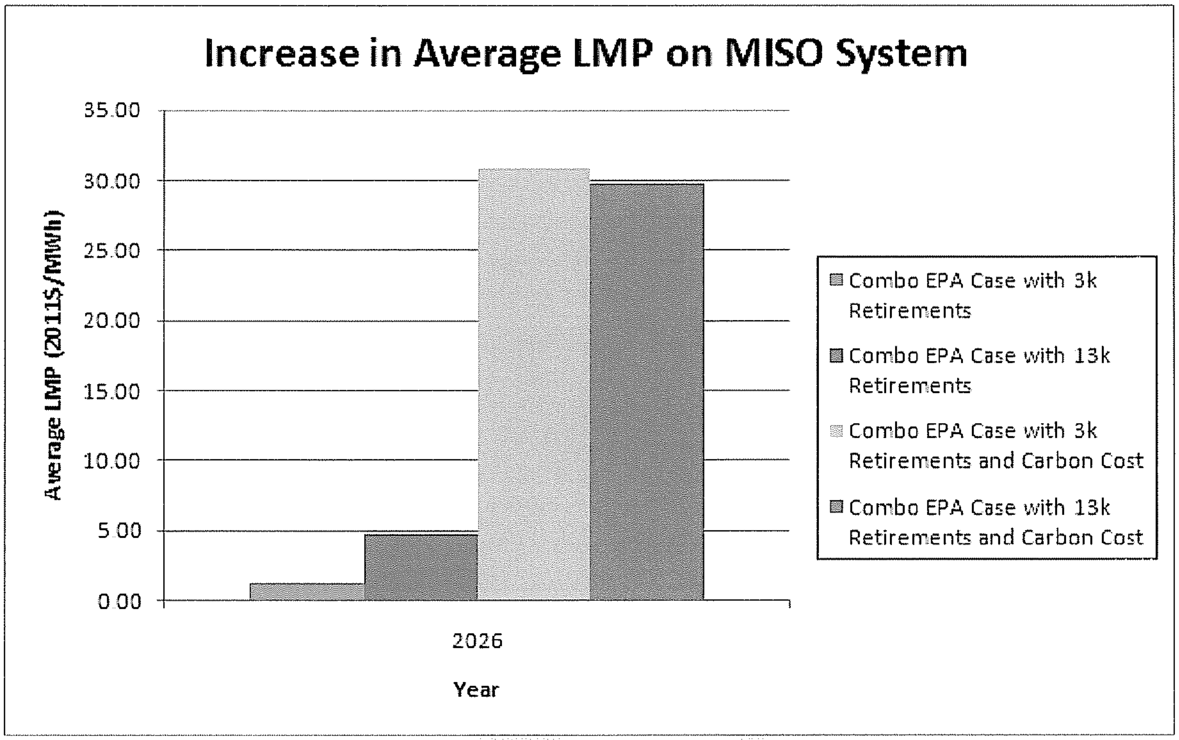


Figure 8-3: MISO Average LMP Impact

8.2.4 Transmission Reliability Cost Impact

Transmission investment that would be needed to meet applicable reliability criteria after the retirement of 2,919 MW and 12,652 MW were studied as two separate scenarios, based on the system configuration in 2015 at summer peak load forecast. Replacement generation dispatch was assumed to be sourced within the MISO footprint.

Transmission investment requirements were minimal in most cases. The total expected transmission investment under the 2,919 MW retirement scenario is $580 million.

The 12,652 MW scenario could require an estimated additional $300 million in transmission upgrades, for a total of about $880 million in transmission investment.

This analysis assumed that none of the retired units that caused transmission problems was replaced with new generation. Although it is a viable option to repower a retirement site, the purpose of this analysis is to identify transmission costs under no replacement.

Potential retirements in neighboring entities that are sufficiently close to MISO to potentially cause reliability impacts were represented in the models. Expected and potential unit retirements in PJM were modeled based on the publically posted PJM unit retirement request list and on application of the EPA impact risk assessment criteria. None of these potential unit retirements impacted expected MISO transmission needs.

9 Conclusion

The proposed EPA regulations will have an impact on the MISO system. It is up to the individual utilities to make the decisions on the retrofit or retirement decision. Many factors will need to be considered for this decision. They will include the cost of retrofit compliance, the cost of replacement capacity to meet resource adequacy requirements and the cost of energy on the system. Asset owners will also consider the cost of needed transmission upgrades, transmission congestion, timelines for compliance, and future regulatory uncertainties such as carbon. MISO addressed these issues, but the results should be considered indicative to what could happen throughout the system. Asset owners will have to take all the aforementioned factors into consideration when making a decision.

This study identified a set of retirements based on a low natural gas price and various levels of carbon costs. Future natural gas prices and carbon price have a direct correlation to the amount of retirements that will occur. Low gas prices encourage retirement of coal units because the replacement energy costs are not significantly higher. However, as gas costs increase, the decision for retirement may become less. Increase of costs for carbon compliance could increase coal unit retirement. Uncertainty around the future economic and regulatory conditions makes the retirement decisions difficult for the asset owners.

This analysis identified impacts on the resource fleet, system energy costs and the transmission system. Under tariff reliability requirements, it is required that the bulk power system will maintain generation and transmission reliability. The EPA regulations add a constraint to the system that must be mitigated. Because of this, the risk of implementing the EPA regulations is not reliability, but the cost to maintain that reliability. Table 9-1 shows those costs identified within the MISO analysis.

	2,919 MW of Retirements	12,652 MW of Retirements
Energy Cost Impacts without Carbon	$1.0/MWh	$5/MWh
Energy Cost Impacts with Carbon	$31.0/MWh	$30/MWh
EPA Compliance Retrofit Capital Costs	$28.2B	$22.5B
New Capacity Capital Fixed Charges	$1.7B	$9.6B
Fixed O&M Capital Costs	$1.1B	$0.0B
Transmission Capital Costs	$0.6B	$0.9B
Total Capital Costs	**$31.6B**	**$33.0B**

Table 9-1: System Costs because of implementation of EPA regulations (2011$)

The costs for both sets of retirement scenarios are less than 10% different in this analysis. The primary difference in the outputs is where the costs are allocated. It is difficult to judge which plan is "better." This analysis reviewed the uncertainty around carbon regulation. However, to determine a more likely scenario between the two would require additional iterations of analysis around gas, carbon, and other sensitivity evaluation. The cost of energy within the system contains feedbacks that the models used can't capture. For example, higher dependence on the natural gas fleet could result in higher natural gas prices. At some point, equilibrium will exist at a point with a proper balance of new natural gas resources and gas prices.

10 Next Steps

This analysis did not take into account sensitivities around demand and energy growth or wind penetration. Higher demand and energy growth may result in greater impacts around the cost of system compliance as new resources to replace any retirement selection would impact the system capital investment and energy costs at an earlier time frame. Increase wind resources could suppress energy costs on the system making coal retirements more likely. Both conditions could impact the amount of retirements further.

Additionally, further iterations around the cost of natural gas and carbon need to be evaluated with the identified retirements from this analysis. This would provide additional information on the robustness of the results provided for the uncertainties of what the future may hold for costs on the system.

Finally, this analysis also assumes that the natural gas transmission system is sufficient for the increased dependence on natural gas. This may or may not be true. This question needs to be pursued further to determine if there are costs being left out of the analysis.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated August 18, 2011

Case No. 2011-00162

Question No. 16

Witness: Charles R. Schram

Q-16. a. For each unit in the system for which new technology is being added in the current Compliance Plan, state whether any analysis has been conducted to determine if there would be stranded costs should the unit be forced to retire prior to its newly projected life.

b. For each unit in the system for which new technology is being added in the current Compliance Plan, indicate what the stranded costs would be if the unit is forced to retire for any reason after:

(1) ten years;
(2) 20 years.

c. Provide the length of time each unit would need to operate to achieve a breakeven Net Present Value ("NPV").

A-16. a. While there is no determination of any potential stranded costs, the remaining book value of the recommended controls after a specified period of time can be obtained from the current analysis.

b. (1) Please see the table below for the remaining book value of the new controls after 10 years.

	10 yr Remaining Book Value ($000)
Mill Creek 1	201,700
Mill Creek 2	179,528
Mill Creek 3	146,367
Mill Creek 4	257,050
Trimble County 1	84,115

(2) Please see the table below for the remaining book value of the new controls after 20 years.

	20 yr Remaining Book Value ($000)
Mill Creek 1	61,792
Mill Creek 2	21,121
Mill Creek 3	57,210
Mill Creek 4	105,258
Trimble County 1	39,749

c. The table below indicates the breakeven year on a NPVRR basis for each unit where controls are constructed as proposed in the 2011 Compliance Plan.

Unit(s)	Breakeven Year
Brown 1-2	2021
Brown 3	2019
Ghent 1	2021
Ghent 2	2018
Ghent 3	2020
Ghent 4	2018
Mill Creek 1-2	2024
Mill Creek 3	2021
Mill Creek 4	2023
Trimble County1	2018

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated August 18, 2011

Case No. 2011-00162

Question No. 17

Witness: Gary H. Revlett

Q-17. Since the development of LG&E's 2011 Compliance Plan, state whether the EPA or other federal agencies have indicated a willingness to relax implementation schedules for the new regulations.

A-17. No. The LG&E 2011 Compliance Plan addresses compliance with four existing and proposed regulations. Of these there are air related regulations. The three air regulations are: 1) new 1-hour SO_2 National Ambient Air Quality Standard (NAAQS) which is final, 2) recently finalized Cross State Air Pollution Rule (CSAPR), and 3) proposed electric generating unit (EGU) hazardous air pollution (HAP) rule. EPA finalized the 1-hour SO_2 NAAQS and the new CSAPR rule within their scheduled regulatory planning dates. In addition, with respect to the final requirements of these two regulations, EPA's final version had the same implementation schedule as their proposal with no delays in the implementation schedule. Therefore, based on EPA's finalization of these two regulations they have shown no indication of delay in their implementation schedule.

As described on page 13 of Mr. Revlett's testimony, it is unlikely EPA will delay the final version of the EGU HAP rule past the scheduled November 16, 2011 date, since this date is a court ordered requirement pursuant to a signed consent decree. EPA issued the proposed HAP rule on schedule with the consent decree and they have given no indication that they will the delay the issuance of the final rule. Also as mentioned in Mr. Revlett's testimony, EPA cannot legally delay the HAP rule implementation schedule since the 3-year implementation schedule is fixed in the Clean Air Act. There is only the ability to obtain a 1-year extension for the HAP rule schedule, which LG&E considered in developing the 2011 Compliance Plan.

LOUISVILLE GAS AND ELECTRIC COMPANY

**Response to Commission Staff's Second Request for Information
Dated August 18, 2011**

Case No. 2011-00162

Question No. 18

Witness: John N. Voyles, Jr.

Q-18. Refer to the Black & Veatch Due Diligence Report provided in LG&E's response to Staff's First Request, at Item 32.h.

a. For each unit, provide, yearly, the following 2008 thru 2010 historical performance data including:

(1) Net generation;

(2) Net heat rate;

(3) Capacity factor;

(4) Equivalent Availability Factor; and

(5) Equivalent Forced Outage Rate.

b. Refer to page 2-10 of the Black & Veatch Due Diligence Report. State whether the replacement of the Trimble County 1 boiler slope tube was implemented. If yes, state whether the station experienced a reduction in boiler tube leaks.

c. Refer to page 2-11 of the Black & Veatch Due Diligence Report. State whether modifications were made to the Trimble County 1 turbine to enable the unit output to reach the design gross output of 546.7 MW. State the current gross and net output of the unit. Describe the modifications that were completed during the 2009 turbine overall outage.

d. Refer to page 2-20 of the Black & Veatch Due Diligence Report. State whether the Mill Creek 3 & 4 GE Mark II, EHC turbine control system has been upgraded. If the upgrade has been made, state whether the project met expectations.

e. Refer to page 2-25 of the Black & Veatch Due Diligence Report. What is the status of the planned Preventative Maintenance and root cause analysis programs for Mill Creek?

f. Refer to page 2-27 of the Black & Veatch Due Diligence Report. What is the status of the boiler tube replacement and overlay projects?

g. Refer to page 2-28 of the Black & Veatch Due Diligence Report. What is the status of the high vibration on the Unit 2 turbine, as noted in the post 2003 outage findings?

h. Refer to page 2-28 of the Black & Veatch Due Diligence Report. What is the status of the high vibration on the Unit 4 generator bearings, as noted in the post 2006 outage finding?

i. Refer to page 2-29 of the Black & Veatch Due Diligence Report. Provide the status of the condenser leak issues on all four units. Explain why erosion is an issue on a closed-loop circulating water system.

A-18. a. Please see the attached.

b. Yes. The Trimble County Unit 1 (TC1) 2009 fall outage boiler scope included replacement of the west lower slope water wall tubing and replacement of the supporting structural steel. There have been no west rear lower slope tube leaks since this work was performed.

c. Yes, modifications and repairs were made to the TC1 turbine as planned. The current gross output of TC1 is 547 megawatts and the net output is 514 megawatts. During the 2009 TC 1 turbine outage, some steam path components were replaced or repaired including sealing strips, steam packing, spill strips and inlet steam seal rings. In addition to resealing the steam path, efficiency improvements were made such as replacement of the 7th stage turbine blades. The high pressure (HP) and intermediate pressure (IP) stationary and rotating turbine blades were reworked to re-establish design contours, surface condition and trailing edges.

d. The Mill Creek 3 work to upgrade the GE Mark II, EHC turbine control system was completed in the Spring of 2011 and has met expectations. The upgrades to the Mill Creek 4 turbine control system is scheduled for the Fall of 2014 during the turbine overhaul of that unit.

e. The Predictive Maintenance Program at Mill Creek is performed as planned on a regular basis. The root cause analysis is conducted as needed to investigate issues when they occur.

f. The boiler tube weld overlay project has been completed on Mill Creek Unit 2. Mill Creek Unit 1 is approximately 40% complete with the remainder scheduled for completion during that unit's 2013 turbine overhaul planned outage. A test area using thermal spray overlay techniques was applied to Mill Creek Unit 3 during a planned outage in 2009. The area was expanded during the planned 2011 Spring outage and results have been satisfactory. Further installation is scheduled for the 2013 planned outage. Plans for applying the thermal spray overly to Mill Creek Unit 4 will occur during the planned 2014 turbine overhaul outage.

g. As of this date, Mill Creek Unit 2 vibration levels remain within an acceptable range. Final work scopes are developed from the outage inspections and could be changed if the need for a low speed balance is determined.

h. Through analysis and inspection, the bulk of the generator bearing vibration issues on Mill Creek Unit 4 is attributed to the Alterex rotor. The Alterex rotor is scheduled to be rewound by the OEM using new copper windings in the planned 2014 outage.

i. The leaks in the Mill Creek Unit 1 condenser were primarily caused by issues with steam seal pipe discharges in the condenser and that piping has been replaced. Condenser tubing has been procured and is on-site to re-tube the Mill Creek Unit 2 condenser during the Spring 2012 planned outage. The Mill Creed Unit 4 condenser is scheduled for re-tubing in 2014 during the planned turbine overhaul outage. Mill Creek Unit 3 is scheduled for tube inserts in 2013 and a condenser re-tubing during the next turbine overhaul outage scheduled for 2019.

   Erosion in closed-loop and once-through condensers is not uncommon for the industry and has basically the same root cause over time; high water velocities from the cooling water that is ladened with silt from the river which impinges on the tubing at the sharp turns near the condenser inlets and outlets. Also, the tubes experience vibration at the tube sheet connections.

(1) Net Generation;

	2008	2009	2010
BR 1	513,921	217,008	411,311
BR 2	1,074,881	547,458	763,280
BR 3	2,534,659	1,740,829	1,828,361
GH 1	3,598,899	2,867,588	3,295,876
GH 2	2,804,097	2,413,738	3,201,480
GH 3	3,262,152	3,182,388	3,431,840
GH 4	2,840,532	2,881,867	2,667,176
MC 1	1,985,134	2,106,620	2,009,037
MC 2	2,073,872	1,847,309	2,101,040
MC 3	2,989,529	2,786,525	2,914,876
MC 4	3,321,419	3,562,608	3,348,610
TC 1	4,065,036	3,063,559	3,629,757

(2) Net heat rate;

	2008	2009	2010
BR 1	11,010	11,589	11,072
BR 2	10,261	10,383	10,282
BR 3	10,315	10,521	11,090
GH 1	10,652	10,436	10,459
GH 2	10,323	10,464	10,502
GH 3	10,997	11,131	10,935
GH 4	10,829	10,988	11,013
MC 1	10,646	10,639	10,683
MC 2	10,820	10,929	10,845
MC 3	10,619	10,602	10,738
MC 4	10,466	10,410	10,520
TC 1	10,368	10,565	10,805

(3) Capacity factor;

	2008	2009	2010
BR 1	57.4%	24.3%	46.0%
BR 2	72.4%	37.0%	51.9%
BR 3	66.6%	45.9%	48.4%
GH 1	87.6%	70.0%	79.7%
GH 2	68.5%	59.1%	76.9%
GH 3	77.1%	75.4%	81.5%
GH 4	65.3%	68.4%	63.4%
MC 1	74.6%	79.4%	75.7%
MC 2	79.0%	70.5%	80.0%
MC 3	85.7%	80.1%	84.5%
MC 4	76.9%	82.7%	78.8%
TC 1	89.9%	67.9%	80.8%

(4) Equivalent Availability Factor;

	2008	2009	2010
BR 1	74.8%	84.1%	85.3%
BR 2	94.2%	78.1%	84.9%
BR 3	87.5%	78.9%	79.3%
GH 1	89.9%	79.4%	87.0%
GH 2	78.4%	76.3%	94.5%
GH 3	85.5%	88.3%	90.6%
GH 4	75.1%	89.9%	75.4%
MC 1	85.9%	92.0%	84.3%
MC 2	92.2%	83.9%	88.7%
MC 3	93.0%	87.1%	89.3%
MC 4	85.1%	91.8%	83.2%
TC 1	95.2%	73.5%	87.4%

(5) Equivalent Forced Outage Rate;

	2008	2009	2010
BR 1	16.4%	13.5%	2.6%
BR 2	3.5%	5.5%	7.9%
BR 3	6.3%	6.6%	1.1%
GH 1	6.3%	12.0%	2.6%
GH 2	12.4%	3.9%	1.2%
GH 3	8.3%	4.3%	7.4%
GH 4	4.0%	3.8%	3.2%
MC 1	6.0%	4.7%	4.9%
MC 2	4.6%	5.3%	2.1%
MC 3	3.0%	5.1%	5.8%
MC 4	6.2%	3.0%	5.0%
TC 1	2.7%	8.7%	11.8%

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated August 18, 2011

Case No. 2011-00162

Question No. 19

Witness: Charles R. Schram / Gary H. Revlett

Q-19. Refer to LG&E's 2011 Air Compliance Plan, Table 1, "Capital Costs for Environmental Controls". Provide an explanation of why Sulfuric Acid Mist, sorbent injection, and powdered activated carbon systems are not included for Mill Creek 1 & 2.

A-19. The Companies have not identified additional needs at Mill Creek 1 & 2 for further SAM mitigation and sorbent injection beyond that which is already part of the baghouse system. Powdered activated carbon systems are an integral part of each baghouse systems proposed in the 2011 Compliance Plan. SAM controls are not needed on Units 1 and 2 based on the Best Available Retrofit Technology (BART) analysis developed by LG&E and incorporated by KDAQ into Kentucky's SIP. Units 1 and 2 do not have SCRs, therefore, it is not cost effective to install dedicated SAM equipment beyond the lime injection systems installed as part of the fabric filter technology.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated August 18, 2011

Case No. 2011-00162

Question No. 20

Witness: Charles R. Schram

Q-20. Refer to LG&E's Response to Staff's First Request, Item 6.b.(2). Provide an update to the RFP process to replace the capacity and energy due to retirements of Cane Run 4-6 units.

A-20. See the response to Question No. 3(c).

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated August 18, 2011

Case No. 2011-00162

Question No. 21

Witness: John N. Voyles, Jr.

Q-21. Refer to LG&E's Response to Staff's First Request, Item 31.

a. Have any of the cost estimates for Projects 26 or 27 been updated since the original filing? If so, provide all of the updated cost estimates.

b. If LG&E cannot provide a probable range of cost estimates at this time, at what stage of the construction process will LG&E be able to provide a more definitive range of cost estimates?

A-21. a. The base estimates, which were developed from Level 1 Engineering standards, have not changed; however, outage timing has changed on several units which changes the escalation estimates on the affected units. The escalation estimates will increase or decrease depending on whether the outages are moving out to later years in the plan or advancing to earlier years than previously thought.

b. The Companies believe the estimates are reasonable for the scope identified. As the Companies receive bids over the next 8-12 months for the primary technologies and the prime EPC contracts, overall cost projections will be refined. The current estimates that have been provided are the best estimates available at this time. Consistent with past practices, the Companies will keep the Commission informed as the projects progress.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated August 18, 2011

Case No. 2011-00162

Question No. 22

Witness: Gary H. Revlett

Q-22. Refer to LG&E's response to Staff's First Request, Item 39. If not already filed, provide a copy of the comments filed by the PPL entities on EPA's HAPS proposed rulemaking.

A-22. Please see the Supplemental Response to KPSC-1 Question No. 39 filed on August 9, 2011.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated August 18, 2011

Case No. 2011-00162

Question No. 23

Witness: Charles R. Schram

Q-23. Refer to LG&E's response to Staff's First Request, Item 45. The footnotes to the table refer to the 2010 Wood-MacKenzie forecast for coal and PIRA's Spring 2010 natural gas forecast.

a. Provide the 2010 Wood-MacKenzie price forecast.

b. Provide an update to the table using the most recent Wood-MacKenzie forecasts. Provide the range of the price forecasts (e.g., high-low).

c. Provide the PIRA Spring 2010 natural gas forecast.

d. Provide an update to the table using the most recent PIRA forecasts. Also, provide the range of the price forecasts (e.g., high-low).

e. Provide any additional studies, other than the Wood-MacKenzie 2010 price forecast and the PIRA Spring 2010 natural gas forecast, used to develop natural gas and coal prices for modeling purposes.

f. Provide the description, and results, of any methodology used to adjust the forecasts for coal or natural gas modeling prices to be Kentucky-specific. If such adjustments were made, provide the underlying data.

A-23. a. Please see the Response to SC-NRDC Production of Documents Question No. 11. The Company provided the requested information under a Petition for Confidential Protection filed with the Commission.

b. Please see attached information.

c. The Companies requested from PIRA Energy Group ("PIRA") authorization to disclose the information provided to the Companies under the subscription service; however, PIRA did not consent to the request. Please also see the Response to SC-NRDC Production of Documents Question No. 10.

d. Please see attached information.

e. The Companies also reviewed energy forecasts from consultant IHS CERA. The Companies requested from IHS CERA authorization to disclose the information provided to the Companies under the subscription service; however, IHS CERA did not consent to the request. Please also see the Response to SC-NRDC Production of Documents Question No. 10.

f. Coal price forecasts are developed initially by coal quality (e.g., high sulfur, compliance, powder river basin). The delivered cost of coal for each station was computed by adding an estimate for transportation, barge fleeting, and rail car maintenance costs to the appropriate coal quality forecast.

   The LG&E and KU gas forecasts are identical. Each forecast is computed as the average of two regional forecasts. Each regional forecast is computed by summing a monthly gas transportation cost with the product of the monthly Henry Hub gas price and a monthly loss factor. The table below contains the regional loss factors and gas transportation costs by month. The Haefling gas forecast is computed by adding $0.75/mmBtu to the LGE (or KU) gas forecast.

Gas loss factors and transportation costs				
	LGE		KU	
Month	Loss Factor	Transport ($/mmBtu)	Loss Factor	Transport ($/mmBtu)
1	1.03	0.63	1.04	0.38
2	1.03	0.63	1.04	0.38
3	1.03	0.63	1.04	0.38
4	1.02	0.03	1.04	0.38
5	1.02	0.03	1.04	0.38
6	1.02	0.03	1.04	0.38
7	1.02	0.03	1.04	0.38
8	1.02	0.03	1.04	0.38
9	1.02	0.03	1.04	0.38
10	1.02	0.03	1.04	0.38
11	1.03	0.63	1.04	0.38
12	1.03	0.63	1.04	0.38

Fuel Costs ($/MBtu) **CONFIDENTIAL INFORMATION REDACTED**

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
2011 WoodMac Coal	[redacted]														
Brown Coal															
Cane Run Coal															
Ghent Coal															
Green River Coal															
Mill Creek Coal															
Trimble County Coal															
Trimble County PRB Coal															
Tyrone Coal															
2011 PIRA Gas															
KU Gas															
LGE Gas															
Haefling Gas															

Note: Values above as well as values provided in response to Question 44 are reported from Strategist. The price from Strategist for each year is the maximum monthly price for that year.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated August 18, 2011

Case No. 2011-00162

Question No. 24

Witness: John N. Voyles, Jr.

Q-24. Project 26 in the LG&E 2011 Environmental Compliance Plan is estimated to have a capital cost of $1,268 million. From this total, provide the dollar estimate and the percent of total needed to comply with:

a. The recently finalized CSAPR; and

b. The proposed HAPs rules.

A-24. Please see table below for the allocations to parts a. and b. above.

$ in Millions
Summary

Plan	Unit	CSAPR $	CSAPR %	HAPS $	HAPS %	Total
26	**Mill Creek 1**	$176.9	53%	$154.6	47%	$331.4
26	**Mill Creek 2**	$176.9	54%	$151.1	46%	$328.0
26	**Mill Creek 3**	$80.7	36%	$142.4	64%	$223.1
26	**Mill Creek 4**	$232.0	60%	$153.8	40%	$385.7
		$666.5	53%	$601.8	47%	$1,268.2

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated August 18, 2011

Case No. 2011-00162

Question No. 25

Witness: John N. Voyles, Jr.

Q-25. Project 27 in the LG&E 2011 Environmental Compliance Plan is estimated to have a capital cost of $124 million. From this total, provide the dollar estimate and the percent of total needed to comply with:

a. The recently finalized CSAPR; and

b. The proposed HAPs rules.

A-25. Please see the table below:

$ in Millions
Summary

Plan	Unit	CSAPR $	CSAPR %	HAPS $	HAPS %	Total
27	Trimble 1	$0	0%	$124	100%	$124

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information Dated August 18, 2011

Case No. 2011-00162

Question No. 26

Witness: John N. Voyles, Jr.

Q-26. Refer to the Appendix to this request, which consists of Vantage Energy Consultant's ("Vantage") preliminary analysis of the LG&E/KU cost estimates versus an industry benchmark. The estimated costs of the Fabric Filters appear to consistently exceed the industry benchmark. Provide an explanation.

A-26. LG&E respectfully disagrees with the premise of the question. Although the charts contained in the Appendix attached to this data request appear to contain "industry benchmarks" for numerous kinds of costs, they do not; rather, they contain rough, largely undifferentiated estimates of control costs created for government agencies to use in macro-level forecasting of regulatory cost impacts and overall energy production activity. They certainly do not address any of the specifics needed to estimate the costs of installing controls on LG&E's generating units. Therefore, the proposed comparison between the KU/LG&E costs estimates versus the "industry benchmark" is not meaningful because the values are not comparable.

In response to an inquiry by KU/LG&E seeking the sources for the information in the Appendix, Vantage Consultants through KPSC Staff provided to KU/LG&E and the other parties in this case a written presentation by NERA Economic Consulting titled, "Proposed CATR + MACT," prepared for American Coalition for Clean Coal Electricity, as well as the text of an entry from the "Next Big Future" blog. The NERA study appears to be the actual source of the data described in note 1, and the "Next Big Future" blog entry appears to the source of most of the data described in note 3. Concerning the NERA study, it is true that the study purports (and LG&E does not dispute) that much of the input data in the study were taken from EPA and EIA sources. But the EPA and EIA reports from which NERA, and thus Vantage, drew its information were not provided to or otherwise identified for LG&E. Concerning the "Next Big Future" blog, such a blog is not a reliable "industry source."

The analysis in the Appendix is also flawed by making a fundamentally apples-to-oranges comparison between macro-level government estimates (which the Appendix inaccurately refers to the data as "industry benchmarks") and LG&E's engineering estimates for the total costs to install fabric filters (and other controls) on individual generating units, each of which sits on a unique site that presents a unique set of challenges. As page 3 of the supplied NERA presentation shows, the purpose of the study was to evaluate impacts of EPA's Clean Air Transport Rule and the proposed Utility Maximum Achievable Control Technology rule on the electric industry and the national economy, not to provide unit-by-unit environmental control costs or retirement recommendations. Because the study's purpose was to make macro-level projections, and in particular to compare national-level modeling results with those EPA used to support its new environmental regulations, the NERA study explicitly relied on EPA, not industry, data for control costs. (See NERA presentation pages 4, 7, 14, and 18.) (Although the NERA study also shows purported EIA macro-level control cost data on page 10, it does not appear that NERA used that data in its analysis. (See NERA presentation pages 4, 7, 14, and 18.))

Because the actual EPA or EIA data to support the figures contained in the Appendix was not supplied, LG&E researched the EPA and EIA websites to verify the data in the NERA report. Though it appears that the NERA data do indeed reflect EPA and EIA (not industry) data adjusted to 2010 dollars, the EPA and EIA documents LG&E found give additional reasons not to use such data in comparison to LG&E's engineering estimates for site- and unit-specific costs. First, the EIA fabric filter data are based on a 1998 cost projection model, and as such are significantly outdated.[1] Second, although the tables below show that EIA projected dramatically increasing control costs for FGDs and SCRs between its 2010 Annual Energy Outlook and its 2011 Annual Energy Outlook, it nevertheless maintained that fabric filter costs did not change during the same period, remaining an inexplicably stable $77/kW (again, basing both years' fabric filter costs on a 1998-vintage cost model).[2]

[1] *See* Electricity Market Module of the EIA's 2011 Annual Energy Outlook at 105 ("[T]he cost of a supplemental fabric filter with activated carbon injection (often referred as a COPAC unit) is approximately $77 per kilowatt of capacity") (available at http://www.eia.gov/forecasts/aeo/assumptions/pdf/electricity.pdf); *id.* at note 2 ("These costs were developed using the National Energy Technology Laboratory Mercury Control Performance and Cost Model, 1998."); Electricity Market Module of the EIA's 2010 Annual Energy Outlook available at http://www.eia.gov/oiaf/aeo/assumption/electricity.html ("[T]he cost of a supplemental fabric filter with activated carbon injection (often referred as a COPAC unit) is approximately $77 per kilowatt of capacity."); *id.* at note 1 ("These costs were developed using the National Energy Technology Laboratory Mercury Control Performance and Cost Model, 1998.") (available at http://www.eia.gov/oiaf/aeo/assumption/electricity_footnotes.html).
[2] *See* EIA's 2011 Annual Energy Outlook Table 8.8: Coal Plant Retrofit Costs; EIA's 2010 Annual Energy Outlook Table 8.8: Coal Plant Retrofit Costs.

From the EIA's 2010 Annual Energy Outlook:

Table 8.8. Coal Plant Retrofit Costs
(2008 Dollars)

Coal Plant Size (MW)	FGD Capital Costs ($/KW)	SCR Capital Costs ($/KW)
300	384	150
500	278	131
700	229	118

Note: The model was run for each individual plant assuming a 1.3 retrofit factor for FGDs and 1.6 factor for SCRs.

Source: CUECOST3.xls model (as updated 2/8/2000) developed for the Environmental Protection Agency by Raytheon Engineers and Constructors, Inc. EPA Contract number 68-D7-0001.

From the EIA's 2011 Annual Energy Outlook:

Table 8.8. Coal plant retrofit costs
2009 dollars

Coal Plant Size (MW)	FGD Capital Costs ($/KW)	SCR Capital Costs ($/KW)
300	556	179
500	464	161
700	428	159

Documentation for EPA Base Case v4.10 using the Integrated Planning Model, August 2010, EPA Contract EP-W-08-018

Third, the EIA control cost data is markedly different from EPA's data, particularly concerning fabric filter costs; according to NERA, the EIA projects fabric filter costs of $78/kW for all generating units, whereas the EPA's data is $170/kW for 500 MW units, $187/kW for 300 kW units, and $230/kW for 100 MW units. (See NERA presentation page 10.) Fourth and finally, the EIA's all-purpose $78/kW cost for fabric filters ignores the large differences in costs for such facilities due to size, configuration, number of filter bags, and bag materials, as well as fuel type, flue gas volume, fan capacity, and many other site based specifics (differences the EPA has acknowledged, though not obviously included in the cost estimates in the NERA report).[3] For these reasons, LG&E believes the EIA control cost data shown in the NERA report should be rejected for all purposes, as NERA itself appeared to do in running its analysis.

Turning to the EPA control cost numbers shown in the NERA presentation, there are multiple reasons why such numbers, particularly as used in the Appendix, are not appropriate to compare to LG&E's engineering cost estimates. First, as was true of the EIA data, the purpose of EPA's data is to make macro-level projections to attempt to predict national phenomena, not to determine the reasonableness of the cost of a fabric filter on a specific generating unit at a unique site. Second, as noted in the Appendix a single value was listed as EPA's cost projection for each kind of control technology for each of three sizes of generating units, whereas NERA, understanding the inherent inaccuracy in using any single global average, more appropriately bounded the average

[3] EPA AIR POLLUTION CONTROL COST MANUAL, Sixth Edition, EPA/452/B-02-001, January 2002 at Section 6, Particulate Matter Controls, page 1-42, Table 1.8 (available at http://www.epa.gov/oaqps001/lead/pdfs/2002_01_cost_control_%20manual.pdf).

for various 500 MW control costs within a 95% confidence interval (see page 14). Thus, for fabric filters, NERA used a 95% confidence interval of \$127/kW - \$227/kW for the average cost, not a single value of \$170; for FGDs, NERA used a 95% confidence interval of \$403/kW - \$718/kW for the average cost. Third, EPA itself recognizes significant limits to its control cost projection methodologies, and in particular limitations concerning the use of such data to predict the cost of retrofitting individual facilities, as stated in its Air Pollution Control Cost Manual:

> Certain control systems, such as those used for flue gas desulfurization (FGD) or selective catalytic reduction (SCR), require larger quantities of land for the equipment, chemicals storage, and waste disposal. In these cases, especially when performing a retrofit installation, space constraints can significantly influence the cost of installation....[4]
>
> ...
>
> For some controls, no amount of vendor data would have made our cost numbers more accurate because the control in question is either so large or so site-specific in design that suppliers design, fabricate, and construct each control according to the specific needs of the facility. For these devices (specifically, SCR reactors and FGD units), the Manual deviates from its standard approach of providing study level costs and, instead, provides a detailed description of the factors that influence the TCI for the analyst to consider when dealing with a vendor quotation.[5]
>
> ...
>
> **2.5.4.2 Retrofit Cost Considerations**
>
> Probably the most subjective part of a cost estimate occurs when the control system is to be installed on an existing facility. Unless the original designers had the foresight to include additional floor space and room between components for new equipment, the installation of retrofitted pollution control devices can impose an additional expense to "shoe-horn" the equipment into the right locations. For example, an SCR reactor can occupy tens of thousands of square feet and must be installed directly behind a boiler's combustion chamber to offer the best environment for NO_x removal. Many of the utility boilers currently considering an SCR reactor to meet the new federal NO_x limits are over thirty years old - designed and constructed before SCR was a proven technology in the United States. For these boilers, there is generally little room for the reactor to fit in the existing space and additional ductwork, fans, and flue gas heaters may be needed to make the system work properly.

---

[4] *Id.* at Section 1, page 2-7.
[5] *Id.* at Section 1, page 2-27.

To quantify the unanticipated additional costs of installation not directly related to the capital cost of the controls themselves, engineers and cost analysts typically multiply the cost of the system by a retrofit factor. The proper application of a retrofit factor is as much an art as it is a science, in that it requires a good deal of insight, experience, and intuition on the part of the analyst. The key behind a good cost estimate using a retrofit factor is to make the factor no larger than is necessary to cover the occurrence of unexpected (but reasonable) costs for demolition and installation. Such unexpected costs include - but are certainly not limited to - the unexpected magnitude of anticipated cost elements; the costs of unexpected delays; the cost of re-engineering and re-fabrication; and the cost of correcting design errors.

The magnitude of the retrofit factor varies across the kinds of estimates made as well as across the spectrum of control devices. At the study level, analysts do not have sufficient information to fully assess the potential hidden costs of an installation. At this level, a retrofit factor of as much as 50 percent can be justified. ... In complicated systems requiring many pieces of auxiliary equipment, it is not uncommon to see retrofit factors of much greater magnitude can be used.

Since each retrofit installation is unique, no general factors can be developed. A general rule of thumb as a starting point for developing an appropriate retrofit factor is: The larger the system, the more complex (more auxiliary equipment needed), and the lower the cost level (e.g. study level, rather than detailed), the greater the magnitude of the retrofit factor. Nonetheless, some general information can be given concerning the kinds of system modifications one might expect in a retrofit:

1. Auxiliary equipment. The most common source of retrofit-related costs among auxiliary equipment types comes from the ductwork related costs. In addition, to requiring very long duct runs, some retrofits require extra tees, elbows, dampers, and other fittings. Furthermore, longer ducts and additional bends in the duct cause greater pressure drop, which necessitates the upgrading or addition of fans and blowers.

2. Handling and erection. Because of a "tight fit," special care may need to be taken when unloading, transporting, and placing the equipment. This cost could increase significantly if special means (e.g., helicopters) are needed to get the equipment on roofs or to other inaccessible places.

3. Piping, Insulation, and Painting. Like ductwork, large amounts of piping may be needed to tie in the control device to sources of process and cooling water, steam, etc. Of course, the more piping

> and ductwork required, the more insulation and painting will be needed.
>
> 4. Site Preparation. Site preparation includes the surveying, clearing, leveling, grading, and other civil engineering tasks involved in preparing the site for construction. Unlike the other categories, this cost may be very low or zero, since most of this work would have been done when the original facility was built. However, if the site is crowded and the control device is large, the size of the site may need to be increased and then site preparation may prove to be a major source of retrofit related costs.
>
> 5. Off-Site Facilities. Off-site facilities should not be a major source of retrofit costs, since they are typically used for well-planned activities, such as the delivery of utilities, transportation, or storage.
>
> 6. Engineering. Designing a control system to fit into an existing plant normally requires extra engineering, especially when the system is exceptionally large, heavy, or utility-consumptive. For the same reasons, extra supervision may be needed when the installation work is being done.[6]

It is clear the EPA recognizes the complications of site-specific conditions in determining quality estimating of large air pollution control projects. For these reasons, LG&E believes it is inappropriate to compare the EPA's macro-level control cost projections to the unit-specific engineering studies performed for LG&E.

The charts in the Appendix do not take into account any of these data infirmities or nuances. Instead, for each kind of control technology LG&E proposes to install, including fabric filters, a simple average of two government-created control cost estimates that were never intended to be used to evaluate the reasonableness of particular facility costs is displayed in the charts contained in the Appendix and identified as an "industry benchmark." Because the figures in the Appendix are neither "industry" nor "benchmark," and were created from cost estimates not intended to be used for the purpose indicated by the comparison in the Appendix, LG&E respectfully submits that the comparison charts in the Appendix be given no evidentiary weight as bases for analyzing the reasonableness of LG&E's proposed fabric filter or other control costs.

In contrast, the Black and Veatch studies provided in LG&E's applications provide extensive detail on the calculation of the proposed fabric filters' costs, as well as the costs of other proposed controls, including the proposed Mill Creek FGDs (using actual cost data from the recently completed KU WFGD projects). These studies also reflect Black and Veatch's in-depth knowledge of the market. They are based on site-specific reviews

---

[6] *Id.* at Section 1, pages 2-28 – 2-29.

of the generating stations, the available footprint for controls, knowledge of the Companies' engineering and operating staff on the systems that would be impacted by the installation and integration of new control systems, and the engagement of B&V design and construction engineering resources. Many of the same factors are recognized in the EPA's Air Pollution Control Cost Manual, as quoted above. Such information simply is not comparable to the information provided in the Appendix.

If, however, a comparison were to be made between the Appendix information and LG&E's engineering estimates, a number of matters must be taken into account (in addition to those discussed above).

First, there are errors in the Appendix charts, such as the Brown Unit 2 MW rating, which is shown as 110 MW instead of the correct 180 MW. This error would equate to approximately 63% overstatement of the $/kW cost. There is also an error in the "industry benchmark" given for the Trimble County fabric filter, which, using the simple averaging method contained in the Appendix should be $124/kW, not $154/kW. And included in the Appendix were $/kW values for Tyrone Unit 3 that the Companies did not estimate in its report from B&V.

Another significant error in the Appendix concerns the Mill Creek 1 and 2 FGD. LG&E's application in this proceeding provided an estimated capital cost for the FGD of $354 million. Dividing this amount by the units' combined 660 MW capacity results in a cost-per-kilowatt figure of $536/kW, not the $544/kW shown in the Appendix. This error is significant because the $536/kW amount is less than the EPA "industry benchmark" of $538/kW for FGDs on units of 500 MW or more. It is also important to note that the Appendix does not provide "industry benchmarks" for single controls to be installed on multiple units, which typically require more engineering and ductwork (but still can provide a better value than multiple controls in some cases, such as is true for the FGD for Mill Creek Units 1 and 2). This is yet another reason it is inappropriate to compare the Appendix's "industry benchmark" to the engineering estimate for the Mill Creek Units 1 and 2 FGD.

Second, the Appendix contains individual $/kW from the EPA for PAC and Dry Sorbent Injection with "n/a" listed for all LG&E units except for Mill Creek 3 and 4 and the Dry Sorbent costs for the Cane Run units. These scopes are included in the Companies' fabric filter scopes as subsets of the estimate, just like the other items listed below such as instrument air, fans, insurances, sales tax, etc. LG&E was not supplied information to determine whether the EPA or EIA included all or some of such considerations (although LG&E's research indicates that the EPA's data may include some, but not all, of the relevant items).[7]

[7] *See, e.g.*, Documentation Supplement for EPA Base Case v.4.10_FTransport – Updates for Final Transport Rule, EPA 430-K-11-004, June 2011 at 61-63 (available at http://www.epa.gov/airmarkets/progsregs/epa-ipm/CSAPR/docs/DocSuppv410_FTransport.pdf). Although the EPA's approach appears to address some of the items contained in LG&E's engineering estimates, the way such items are addressed is questionable. For examples, the EPA's ductwork assumptions likely do not include the length of ductwork necessary to erect fabric filters far

The Companies' control cost estimates include consideration of such items. Listed below are considerations required to integrate a new large air pollution control technology into an existing, operating coal-fired unit. Categories of components of the B&V estimates are:

Balance of Plant System Modifications

- Fan, Motors and Drives
- Instrument Air
- Instrumentation & Controls (i.e., DCS interfaces with existing station control systems)
- Ductwork and Breeching geometries and routings
- Electrical Auxiliary System Upgrades
  - Transformers
  - Motor Control Centers
  - Switchgear
- PAC and Sorbent Injection systems integrated with the fabric filter designs

Other Project Cost

- Contingency (10%)
- Insurances
- Sales Taxes (6%)
- Escalation (4% annually from 2011 estimates)
- 3.5% Owner Project Management Cost
- Contract Performance Securities
- Engineering/Construction Management Cost

To show the significance of these items on the "total" installed cost, and referencing the B&V estimate sheets, the estimates for the Mill Creek and Trimble County units (i.e., the units on which LG&E proposes to add fabric filters) are broken down in summary form below. These breakdowns show that using only the fabric filter cost would yield a much lower value than the total estimate cost to retrofit the fabric filter and balance of plant impacts into an existing thirty-plus-year-old unit that is in operation during construction.

(This space intentionally left blank.)

---

away from current facilities due to lack of available space. Also, the EPA's fabric filter costs are homogenized into unit-size categories, which should be increased to match LG&E's unit sizes. Further, EPA does not appear to add cost associated with plant electrical auxiliary system upgrades; electrical upgrades are listed, but the extent of modifications to upgrade plant aux systems is not. Finally, the EPA does not appear to add cost for ash handling system upgrades, which can be significant.

Mill Creek 1 - Baghouse

x $1m	
$154.5	Gross Fabric Filter Cost
$4.7	Overheads
$16.3	Escalation
	Purchase Contracts
$11.2	Mechanical and Electrical Balance of Plant
$3.2	Fan VFDs and Motors
$2.2	Switchgear and MCCs
$1.0	Transformers
$0.3	Air Compressors, dryers, and air receivers
$1.8	ID fans
$19.6	Total Purchase Contracts
	Construction Costs
$31.2	% of construction costs based off % of total purchase contracts
	Indirect Costs
$2.3	Project insurance
$1.0	Performance Bond
$0.1	6% Sales tax
$15.2	Contingency
$18.5	Total indirect Costs
$64.3	Net Fabric Filter Cost **($195/Kw)**

Mill Creek 2 - Baghouse

x $1m	
$151.1	Gross Fabric Filter Cost
$4.6	Overheads
$16.0	Escalation
	Purchase Contracts
$11.2	Mechanical and Electrical Balance of Plant
$3.2	Fan VFDs and Motors
$2.2	Switchgear and MCCs
$1.0	Transformers
$0.3	Air Compressors, dryers, and air receivers
$1.8	ID fans
$19.6	Total Purchase Contracts
	Construction Costs
$28.1	% of construction costs based off % of total purchase contracts
	Indirect Costs
$2.3	Project insurance
$1.0	Performance Bond
$0.1	6% Sales tax
$14.8	Contingency
$18.2	Total indirect Costs
$64.6	Net Fabric Filter Cost **($196/Kw)**

Mill Creek 3 - Baghouse

x $1m	
$140.2	Gross Fabric Filter Cost
$4.2	Overheads
$16.1	Escalation
	Purchase Contracts
$1.4	Mechanical and Electrical Balance of Plant
$2.9	Fan VFDs and Motors
$1.5	Switchgear and MCCs
$0.8	Transformers
$0.3	Air Compressors, dryers, and air receivers
$1.9	ID fans
$8.8	Total Purchase Contracts
	Construction Costs
$18.1	% of construction costs based off % of total purchase contracts
	Indirect Costs
$2.4	Project insurance
$1.0	Performance Bond
$0.0	6% Sales tax
$14.8	Contingency
$18.2	Total indirect Costs
$74.6	Net Fabric Filter Cost **($176/Kw)**

Mill Creek 4 - Baghouse

x $1m	
$151.2	Gross Fabric Filter Cost
$4.7	Overheads
$11.1	Escalation
	Purchase Contracts
$3.6	Mechanical and Electrical Balance of Plant
$3.1	Fan VFDs and Motors
$3.1	Switchgear and MCCs
$1.9	Transformers
$0.3	Air Compressors, dryers, and air receivers
$2.1	ID fans
$14.0	Total Purchase Contracts
	Construction Costs
$14.6	% of construction costs based off % of total purchase contracts
	Indirect Costs
$4.0	Project insurance
$1.7	Performance Bond
$0.1	6% Sales tax
$27.3	Contingency
$33.1	Total indirect Costs
$73.7	Net Fabric Filter Cost **($140/kW)**

Trimble County 1 - Baghouse

x $1m	
$123.8	Gross Fabric Filter Cost
$3.5	Overheads
$19.4	Escalation
	Purchase Contracts
$13.2	Mechanical and Electrical Balance of Plant
$0.0	Fan VFDs and Motors
$0.0	Switchgear and MCCs
$0.0	Transformers
$0.0	Air Compressors, dryers, and air receivers
$1.9	ID fans
$15.1	Total Purchase Contracts
	Construction Costs
$21.6	% of construction costs based off % of total purchase contracts
	Indirect Costs
$0.5	Project insurance
$0.0	Performance Bond
$0.2	6% Sales tax
$2.0	Contingency
$2.7	Total indirect Costs
$61.5	Net Fabric Filter Cost **($150/Kw)**

Third, consistent with observations in the EPA cost manual, each unit estimate included a review of constructability by B&V and the Companies on categories such as:

- Interferences to plant operations through the closures of plant roadways and access points.
- Crane layouts and the effects on structural steel erection with regards to "picks" of trusses or the need to make numerous smaller lifts and elevated erection of more, smaller structural members.
- Evaluation of the limited site lay down areas and the effects on cost for site fabrication and equipment storage.

The EPA and EIA data used in the Appendix does not appear to take into account such factors.

If these factors and the others used to develop LG&E's engineering estimates are taken into account, LG&E believes its total installed control cost estimates are reasonable and within the industry ranges for units of similar size, age, and complexity of construction for large retrofit projects.

It is important to note that a number of LG&E's proposed facilities are projected to cost less than the Appendix's "industry benchmark," such as the dry sorbent injection facilities at Mill Creek Units 3 and 4, and for the reasons previously stated, cannot be given any weight as well.

Also, in line with NERA's projection on page 3 of its presentation, the Companies' coal-fired generation will decrease by about 13% in 2016, and LG&E's anticipated retail electric rate impact is projected to be less than NERA's projected average retail price increase of 23.5% for Kentucky and Tennessee by 2016.

For these reasons, LG&E believes the comparison charts in the Appendix should not be considered for purposes of determining the reasonableness of the costs of LG&E's proposed control facilities' costs, and that analysis of LG&E's proposed control costs, the engineering work that produced them, and related retail price increases shows such costs to be reasonable.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated August 18, 2011

Case No. 2011-00162

Question No. 27

Witness: John N. Voyles, Jr.

Q-27. Identify and describe all other differences in the Vantage analysis and LG&E/KU values.

A-27. Please see response to Question No. 26.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated August 18, 2011

Case No. 2011-00162

Question No. 28

Witness: John N. Voyles, Jr. / Charles R. Schram

Q-28. Refer to LG&E's 2011 Air Compliance Plan, Table 1, "Capital Costs for Environmental Controls" and the Black & Veatch Capital Cost Estimates, included in JNV-2, Appendix B, which detail the summarized direct, indirect, and overall capital costs for each unit.

a. Describe how the Black & Veatch Capital Costs roll up to the capital costs in the Compliance Plan.

b. Include a cost breakdown for each of the units in the Air Compliance Table in $/kW.

A-28. a. In general, Black and Veatch cost estimates were in 2011 dollars and included 3.5% to cover owner's costs, plus an annual escalation rate of 4% based on the planned installation dates and future outage schedules. If there were projects in progress that were comparable, an estimate was made using those projects (i.e. Mill Creek 1 and 2 FGD were based on current information from the Brown FGD Program).

b. Please reference information below:

Plan	Description	Capital Cost ($ Millions)	$/KW
26	Mill Creek 1	$331	$1,004
26	Mill Creek 2	$328	$994
26	Mill Creek 3	$223	$527
26	Mill Creek 4	$386	$735
27	Trimble 1 (Net)	$124	$302

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated August 18, 2011

Case No. 2011-00162

Question No. 29

Witness: Charles R. Schram

Q-29. Refer to pages 5 and 6 of the Direct Testimony of John N. Voyles, Jr. Explain, based on now having more specific information on the sources and cost of the power that will substitute for the generation of the units planned for retirement, whether LG&E and KU have updated their NPV analysis of the "add controls" and "retire" alternatives. If an updated NPV analysis has been performed, provide the results therefrom. If such an analysis has not yet been performed, explain when it will be performed.

A-29. There is not a need to update the NPV analysis. Based upon the results of the analysis referenced in response to Question No. 3(c) the Companies confirm that this information further validates and supports the assumptions and recommendations in the Companies' 2011 Compliance Plan.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPROVAL OF ITS 2011 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE	))))))	CASE NO. 2011-00162

LOUISVILLE GAS AND ELECTRIC COMPANY
RESPONSE TO THE
COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION
DATED AUGUST 18, 2011

ONE PAPER COPY
QUESTION NO. 6

FILED: SEPTEMBER 1, 2011

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's Second Request for Information
Dated August 18, 2011

Case No. 2011-00162

Question No. 6

Witness: John N. Voyles, Jr. / Gary H. Revlett / Charles R. Schram

Q-6. For each fossil generation unit in the system:

a. Provide a timeline, out to the year 2020, showing the tonnage amount of emission allowances granted by the U.S. Environmental Protection Agency ("EPA") for the Cross-State Air Pollution Rule ("CSAPR'), the Hazardous Air Pollutants ("HAPS") rule under the Clean Air Act, and the tonnage amount of projected emissions generated by the unit assuming that LG&E's mitigation strategy is implemented as proposed.

b. To the extent that surplus allowances exist in any given year, describe how these surplus allowances will be utilized and under what conditions.

c. Indicate whether there is currently, or likely to be, a means of sequestering CO_2 should future regulations require reductions. If there is currently, or likely to be, a means of sequestering CO_2, provide any cost estimates that have been performed.

A-6. a. Known allocations to Existing Units (which does not include TC2) are attached for KU and LG&E individually. For the various jointly-owned combustion turbines, the unit allocation has been distributed to the individual Company by ownership share.

Generating units that do not operate for 2 consecutive years (or ozone seasons) lose their allocation in the fifth year following the non-operation. For example, if a unit ceases to operate in 2016 (and 2017), it will receive allocations for 2018 and 2019, but not for 2020 and beyond. The allocations provided assume Cane Run coal units and Green River coal units cease operation beginning in 2016.

New units (TC2) will receive allocations equal to their previous year's emissions. Therefore, allocations cannot be provided until the projected emissions are known. As an illustration, TC2's 2012 SO_2 and Annual NO_x allocations will equal its 2011 emissions and its 2012 Ozone Season allocation will equal its 2011 Ozone Season emissions. Other new units will not receive an allocation for their first year of operation. For example, if a new unit begins operation in 2016, it will not receive an allocation for 2016. Its 2017 allocations will be equal to its 2016 emissions, and continue as such into the future years.

The forecasted consumption of the allowance allocation is considered confidential commercial information, which would have value in any allowance market that may develop as a result of the CSAPR regulations. Attached are the projected emissions by unit for the 2016-2020 time period, following the construction of recommended controls and the replacement of retired capacity. Emissions for the 2012-2015 time periods are still under review by the Companies, since operation and dispatch of the generating fleet required further review given the more restricted SO2 allowances in the 2012-2015 period under the recently released CSAPR. Certain requested information is considered confidential and is being filed under a Petition for Confidential Protection.

b. Consistent with prior utilization of emission allowances, the Companies would use surplus allowances, if any, within the provisions of the rule to meet its obligations on a least-cost basis for ratepayers.

c. Sequestering CO_2 is currently done for enhanced oil recovery (EOR) in many locations where oil exploration is prevalent. Also, it is technically feasible to inject and store CO_2 into geological formations. The Companies have performed initial studies of the geology near several facilities to assess the available information. See the report *Evaluation of Geologic CO2 Storage Potential at LG&E and Kentucky Utilities Power Plant Locations* prepared by the Kentucky Geological Survey in 2011 and provided on CD in the folder titled Question No. 6. However, it is important to note there is not sufficient specific knowledge of the amount of suitable geologic formations near power generation facilities to provide adequate storage capacity for the CO_2 produced in the Midwest. While there have been some cost estimations developed for sequestration, none have been performed on a per unit basis for the LG&E facilities. Costs are highly dependent on the specific geology where the sequestration will be located.

Attachment to Question No. 6(c)

1 of 1

Voyles

Evaluation of Geologic CO2 Storage Potential at LG&E and Kentucky Utilities Power Plant Locations, Central & Western Kentucky

University of Kentucky Research Foundation Contract #47713
Final Report

David C. Harris and John B. Hickman

May 25, 2011

Kentucky Geological Survey
University of Kentucky

UNIVERSITY OF KENTUCKY®

Kentucky Geological Survey

Evaluation of Geologic CO_2 Storage Potential at LG&E-KU Power Plant Locations, Central & Western Kentucky

Executive Summary

As part of a larger carbon capture feasibility study, the Kentucky Geological Survey, University of Kentucky (KGS) evaluated five Kentucky coal burning power generation stations owned and operated by Louisville Gas and Electric-Kentucky Utilities (LG&E-KU), a subsidiary of PPL Corporation. This work was undertaken to determine which generation station had the best potential for geologic CO_2 storage in order to select, design, and seek funding for an integrated carbon capture and storage demonstration project.

The sites evaluated included the following: E.W. Brown Station (Mercer Co.), Ghent Station (Carroll Co.), Green River Station (Muhlenberg Co.), Mill Creek Station (Jefferson Co.), and Trimble County Station (Trimble Co.). Detailed geologic studies, including interpretation of seismic reflection data were completed to estimate CO_2 storage options, feasibility, and capacity. Various subsurface geologic maps and cross-sections were made for each site and are included in the chapters that follow. The Trimble County and Ghent stations were evaluated separately, but are discussed together in Chapter One due to their close proximity and similar geology. Following the chapters on the individual locations, a list of site-selection criteria is included for comparison of the relative merits of these sites. The relative values used for each criteria type are somewhat subjective and are intended to be used as a guide for decision making. Therefore, the specific needs of LG&E-KU may make the values of some criteria types a different priority what is listed here.

Additional reflection seismic data was purchased by LG&E-KU around the Green River Station to improve mapping of faults near the site which could impact containment of injected CO_2. This new data was interpreted and incorporated into the Green River evaluation. The rest of the data used for the study consisted of geophysical well logs, seismic data, and core data from databases maintained by KGS.

Figure 1 illustrates the storage capacity calculated, and the ranking score totals for each site. The ranking criteria and scores are included after the four chapters describing the geology at each site. All of the sites with the exception of E.W. Brown Station have potential to inject and store CO_2 on-site to some degree. The geology at Brown is not favorable for on-site storage, however, an area six to ten miles east of the site has the largest sequestration capacity of the five sites examined. Use of this area for CO_2 injection would require building a pipeline to transport CO_2, and securing the rights to use the subsurface pore space under private property. The potential storage reservoir for the E.W. Brown Station is the only site that has sufficient geologic structure ("closure") to trap injected CO_2 and limit lateral migration. Unfortunately, there are potentially economic accumulations of natural gas in parts of this area that could be adversely affected by contamination with injected CO_2. More detailed studies may be able to identify areas that could be used for sequestration without impacting other economic minerals.

The Ghent Station has the second-highest storage capacity of the sites studied, and injection wells could be drilled on-site using land and pore space owned by LG&E-KU. This avoids the need to lease rights to pore space from other property owners. The Ghent Station parcel is among the largest of the five sites, resulting in a large on-site storage volume. In addition,

drilling depths at Ghent are shallower compared to the other sites, which would reduce drilling costs. The CO_2 injected at Ghent would probably migrate slowly to the northeast, and possibly under the Ohio River into Switzerland County, Indiana.

The storage reservoir formation at Trimble County is the same as at Ghent, but the formation is deeper, and porosity (and thus storage capacity) is predicted to be lower. Well data is scarce near the Trimble County Station, making precise predictions of the geology under the site difficult. Estimated storage capacities are lower than at Brown or Ghent, and drilling depths would be greater. The CO_2 injected at Trimble County would probably also migrate slowly to the northeast, but because of the geometry of the Ohio River, it would remain in Kentucky for at least 14 miles.

The lowest CO_2 storage capacities estimated were at the Mill Creek and Green River Stations. Mill Creek Station is near an older hazardous waste disposal well in Louisville that found poor injectivity in the deep Mt. Simon Sandstone. This suggests limited porosity and storage capacity within the Mt. Simon at Mill Creek Station. The Green River Station lies above a deep geologic basin where the only suitable injection zone is in carbonate rocks of the Knox Group. While good injectivity was demonstrated in the Knox in a KGS research well in Hancock County, the limited deep well data in Muhlenberg County indicates lower porosity values for this unit. Seismic data around Green River shows that faulting (and possible leakage pathways) does not appear to be present near the site.

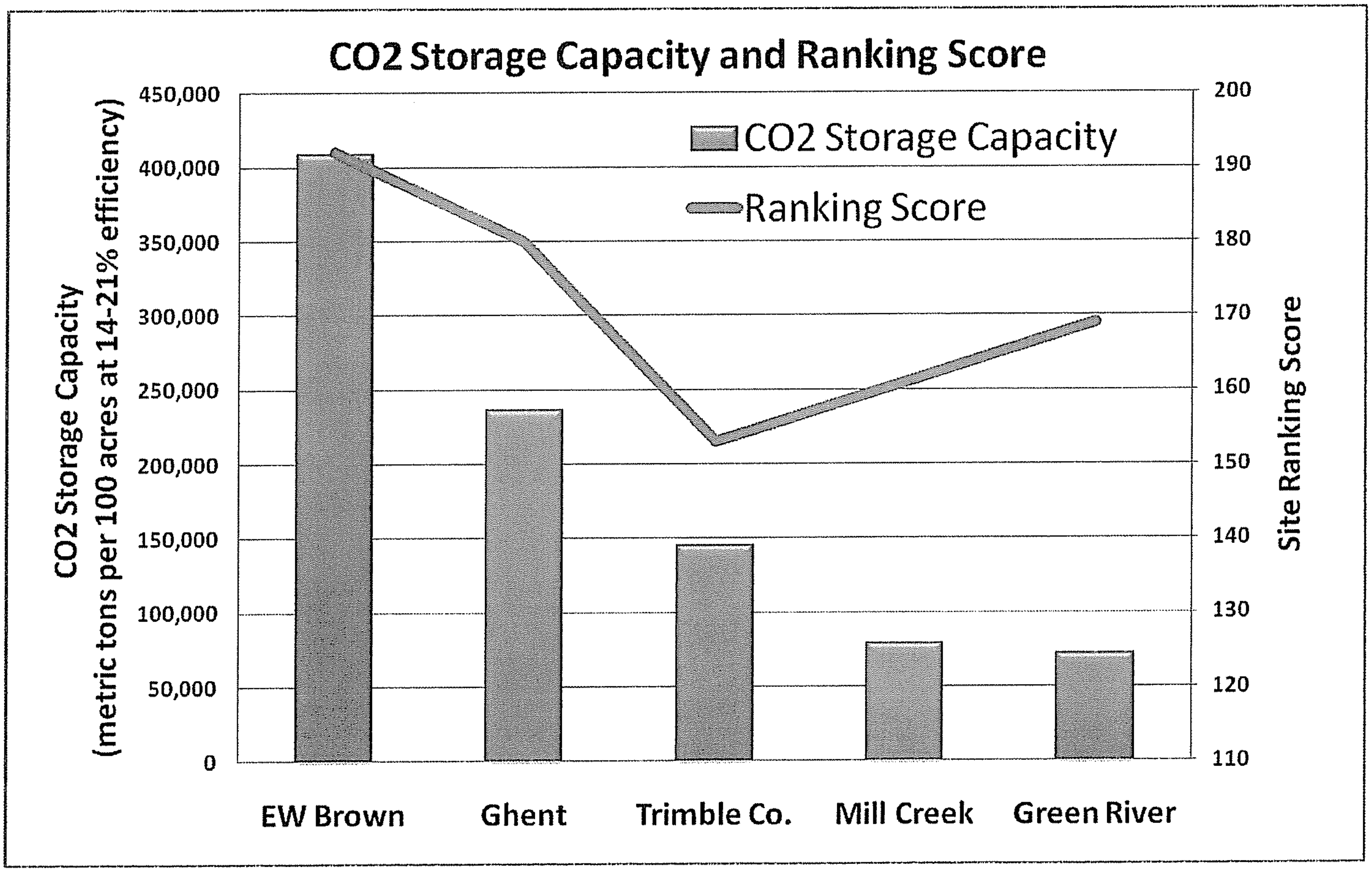
Calculated CO_2 storage volumes at all sites were scaled by published efficiency factors, which reduce total storage capacity due to various displacement factors that limit the pore space actually occupied by CO_2. Efficiency factors used range from 14 to 21 percent of the total pore space within the reservoirs.

Public perception regarding a CCS (carbon capture and storage) project at each of the five sites was not scientifically-evaluated as part of this project. The authors' personal opinions on possible public acceptance or resistance to a CCS project were included in the ranking criteria. This was based primarily on the plant location and current land use in the area. We felt a demonstration project would be most acceptable in Muhlenberg County (Green River Station) because of the rural plant location, number of local coal mining jobs, and long history of mining in the area. Ghent and Trimble County Stations are located in more developed, non-coal producing areas, and have residential areas within a mile of the plant sites. This could lead to public opposition to a CCS project due to the proximity of homes to the sequestration site. Mill Creek Station is located in an even more developed area, where concern about nearby homes could be a problem. E.W. Brown's off-site sequestration area is a primarily rural area and site selection could focus on areas away from residences to avoid potential opposition.

In summary, the E.W. Brown Station has the highest CO_2 storage capacity, and a known trap in which to contain migration of the CO_2. However the sequestration area is not located on-site, and will require a pipeline and access to privately-held pore space. In addition, injection zones will have to be chosen carefully to avoid contamination of existing natural gas deposits.

The Ghent Station has a lower storage capacity, but should be more than adequate for a demonstration project located on-site. It has the shallowest depth of the five sites evaluated, which will significantly reduce drilling costs. Ghent appears to have the lowest geologic storage cost of any of the sites evaluated. Although deeper than Ghent and having lower porosity, the Trimble County Station should also have adequate storage volumes on-site for a demonstration project.

Figure 1. Summary chart showing calculated CO_2 storage capacities and site ranking scores for the sites evaluated in this study. Capacities are metric tons of CO2 for 100 acres, Storage efficiency factors of 14% (sandstone) and 21% (carbonate) of total pore volume have been used.



Chapter One

Geologic CO_2 Sequestration Potential of the LG&E-KU Trimble County and Ghent Stations, Northern Kentucky

Dave Harris and John Hickman
Kentucky Geological Survey

LG&E-KU CO_2 Sequestration Geologic Summary Sheet

Power Plant: GHENT **County:** CARROLL **Geologic Basin:** Cincinnati Arch

Data Quality

Distance to nearest well control in reservoir: 4.7 mi.
Wells to primary injection zone within 15-mi. radius: 3
Distance to nearest core in injection zone: 14.7 mi.
Distance to nearest good quality seismic control: 14.5 mi.

Reservoirs

Primary injection zone: Cambrian Mt. Simon Sandstone
Rock type: sandstone (quartz arenite)
Drilling depth at plant site: 3,423 ft
Trapping mechanism: *regional dip (capillary and solution trapping)*
Max. reservoir pressure: 1,635 psi (hydrostatic)
Reservoir temperature: 100°F
Salinity of reservoir fluid: 200,000 ppm (est.)
Reservoir thickness (gross/net): 301/160 ft
Average porosity: 12%
Average permeability: 200md
Secondary injection zone: None at this site

Confinement and Integrity

Primary confining zone: Cambrian Eau Claire Shale
Rock type: shale and dolomite
Thickness of primary confining zone: 560 ft
Height above primary injection zone: 0 (overlies injection zone)
Well penetrations of primary seal within 15-mi. radius: 4
Secondary confining zone: Ordovician Black River Ls (High Bridge)
Rock type: Limestone
Thickness of secondary confining zone: 500 ft
Height above primary injection zone: 2,600 ft
Well penetrations of secondary seal within 15-mi. radius: 16

Number of faults cutting primary seal within 15-mi. radius: 0
Distance to nearest mapped fault: 15.6 mi

Storage Capacity

Calculated CO_2 storage capacity, primary injection zone:
1,688,924 metric tons/100 acres (assuming 100% efficiency)
236,449 metric tons/100 acres (at 14% efficiency)

LG&E-KU CO_2 Sequestration Geologic Summary Sheet

Power Plant: TRIMBLE COUNTY **County:** TRIMBLE **Geologic Basin:** Cincinnati Arch

Data Quality

Distance to nearest well control in injection zone:	26.6 mi.
Wells to primary injection zone within 15-mi. radius:	0
Distance to nearest core from injection zone:	34.3 mi.
Distance to nearest good quality seismic control:	35 mi.

Reservoirs

Primary injection zone:	Cambrian Mt. Simon Sandstone
Rock type:	sandstone (quartz arenite)
Drilling depth at plant site:	3,900 ft
Trapping mechanism:	regional dip (capillary and dissolution trapping)
Max. reservoir pressure:	1,888 psi (hydrostatic)
Reservoir temperature:	110°F
Salinity of reservoir fluid:	200,000 ppm (est.)
Reservoir thickness (gross/net):	366/121 ft
Average porosity:	10%
Average permeability:	150 md
Secondary injection zone:	None at this site

Confinement and Integrity

Primary confining zone:	Cambrian Eau Claire Shale
Rock type:	shale and dolomite
Thickness of primary confining zone:	560 ft
Height above primary injection zone:	0 (overlies injection zone)
Number of well penetrations of primary seal within 15-mi. radius:	0
Secondary confining zone:	Ordovician Black River Ls (High Bridge)
Rock type:	Limestone
Thickness of secondary confining zone:	500 ft
Height above primary injection zone:	2,800 ft
Number of well penetrations of secondary seal within 15-mi. radius:	5

Number of faults cutting primary confining zone within 15-mi. radius:	1
Distance to nearest mapped fault:	13.2 mi.

Storage Capacity

Calculated CO_2 storage capacity, primary injection zone:
1,035,206 metric tons/100 acres (assuming 100% efficiency)
144,929 metric tons/100 acres (at 14% efficiency)

Introduction

An evaluation of geologic CO_2 sequestration potential was performed for an area surrounding the LG&E-KU Trimble County and Ghent Stations in Trimble and Carroll Counties, Kentucky. These plants are approximately 23 mi apart, and due their proximity and similar geology, they have been evaluated together. Circular areas with a 15-mi. radius around each plant were defined as the primary focus of the evaluation, but data from beyond 15-mi. was also used because of limited data within the primary areas. The 15-mi. radius circles around the Trimble County and Ghent stations overlap, as seen in Figure 1-1, supporting their combined evaluation.

The following data were compiled for the evaluation:

1. 7.5 minute topographic and geologic quadrangle maps for the Bethlehem (Trimble County) and Vevay South (Ghent) quads
2. Locations of all petroleum exploration and waste disposal wells penetrating the Cambro-Ordovician Knox Group or deeper (Kentucky and Indiana Geological Surveys)
3. Formation tops for geologic units from the top of the Ordovician to Precambrian (Kentucky, and Indiana Geological Surveys)
4. Available digital geophysical logs for Knox and deeper wells (Kentucky and Indiana Geological Surveys)
5. Core analyses (porosity and permeability) for Mt. Simon Sandstone and Eau Claire Fm.
6. Reflection seismic data (2 lines in Boone County, Kentucky at the Duke East Bend Station)

Within the 15-mi. radius around the Ghent Station 3 wells have been drilled that penetrate the entire Paleozoic sequence, ending in Precambrian rocks. These wells provide the key geologic data used in this assessment. Two wells were drilled in Switzerland County, Indiana by Ashland Oil, and well logs are available for these wells. In 2009, a CO_2 injection test well was drilled by Battelle Memorial Institute at the Duke Energy East Bend Station in Boone County, Kentucky as part of the U.S. DOE-funded Midwest Regional Carbon Sequestration Partnership (MRCSP, www.mrcsp.org). This well was drilled to test the Cambrian Mt. Simon Sandstone, the same reservoir zone that underlies Ghent and Trimble County. Data from this well was available for this evaluation, including core analyses, formation image logs, and injection data. All of these wells penetrated the primary injection zone and overlying seal.

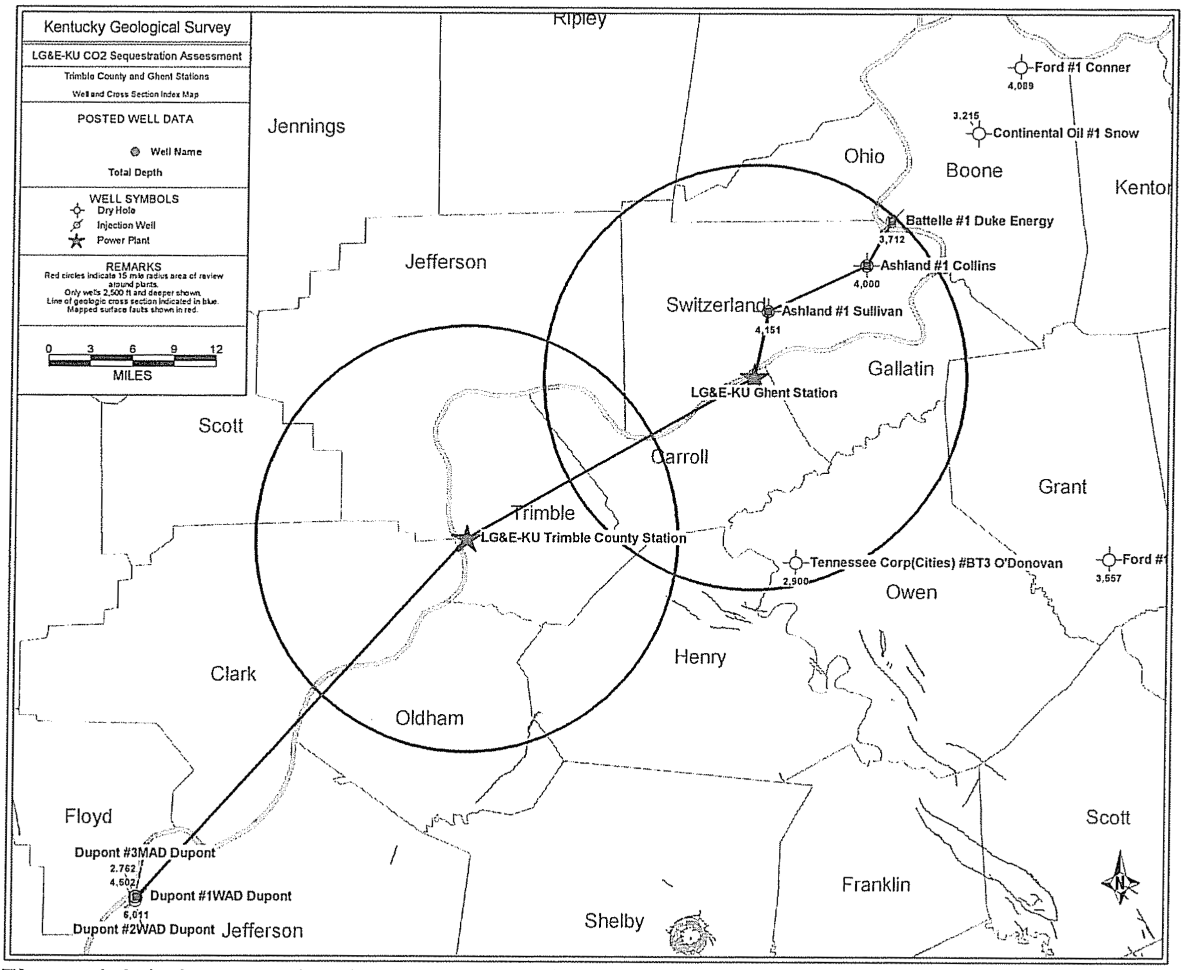


Figure 1-1. Index map showing location of Trimble County and Ghent Stations in northern Kentucky. Heavy gray line is the Ohio River, separating Indiana from Kentucky. Red circles are 15-mi. radius around each station. Wells deeper than 2,500 ft are shown. Blue line is the location of the southwest to northeast cross section shown in Figure 1-12.

The 15-mi. area around the Trimble County Station lacks any wells below 2,500 ft., the depth required for dense phase CO_2 storage. The deepest well in the area went to 2,496 ft. (Oldham County), ending in the Knox Supergroup. There are no other wells greater than 2,500 ft. to the southwest of Trimble County until the DuPont waste disposal wells in Louisville (Jefferson County). DuPont drilled 3 deep wells at their Louisville neoprene plant for hazardous waste disposal. Data from the DuPont wells has been included in the Trimble County/Ghent evaluation.

Geologic Setting and Surface Geology

Trimble and Carroll Counties lie on the west flank of the Cincinnati Arch, a broad anticline (arch) that separates the deeper sedimentary basins in western Kentucky (Illinois Basin) and eastern Kentucky (Appalachian Basin). The arch developed in Middle Ordovician time, and rock units deposited prior to this time have been tilted to the west toward the Illinois Basin. Rocks deposited from the Middle Ordovician and younger were influenced to some extent by the growing arch, but for the interval of interest in this study the arch had no effect on thickness or lithology.

The Ghent station is located on the Vevay South 7.5 minute topographic quadrangle, and a geologic map for this quadrangle was published by Swadley (1973). The Trimble County station is located on the Bethlehem topographic quadrangle, and the geologic map was published by Swadley (1977).

The Ghent and Trimble County power plants are located on unconsolidated sediments deposited along the Ohio River (Figs. 1-2a and 1-2b). These sediments are Quaternary (Pleistocene) age, and interpreted as glacial outwash deposits. Bedrock is exposed in the hills and bluffs to the east of each station. Rocks near the Ghent station in Carroll County consist of Ordovician-age shales and limestones assigned to the Kope, Fairview, and Grant Lake, and Bull Fork Formations as mapped by the USGS (Figure 1-2a). For the Trimble County station, slightly younger Ordovician rocks are exposed, including the Drakes Formation and Lower and Middle Silurian Osgood Formation, Brassfield Formation, and Laurel Dolomite are exposed on hilltops (Figure 1-2b).

Surface geology does not have a direct impact on carbon sequestration potential, since CO_2 injection will occur at much deeper depths. However, the abundance of low permeability shales in the near-surface Upper Ordovician rocks would serve as a secondary confining layer in the unlikely event CO_2 were to migrate through the deeper primary seals.

The surface geology will impact the design and implementation of shallow groundwater monitoring wells that will be required by U.S. EPA for an underground injection (UIC) permit. The presence of unconsolidated glacial outwash along the Ohio River at both sites allows relatively inexpensive construction of monitoring wells. The EPA UIC permit will likely require monitoring down to the base of the underground source of drinking water (USDW), which may require drilling into bedrock. However, the Upper Ordovician interval below the unconsolidated sediments may not be suitable for groundwater monitoring due to low porosity and permeability. Both geologic maps (Swadley, 1973; 1977) cite very hard groundwater with some salt occurrence, and the lack of groundwater in wells drilled on ridges and hillsides. Monitoring wells would likely be confined to the Ohio River alluvium and glacial deposits, larger creek valleys, and the Kentucky River valley.

Stratigraphy and Structure

Geologic storage of carbon dioxide (CO_2) is confined to depths greater than 2,500 ft below the surface so that CO_2 exists in the supercritical, or dense phase. Supercritical CO_2 has properties of both a liquid and gas, but much higher density. In the Trimble and Carroll County area, this 2,500 ft depth falls within the Cambrian-Ordovician Knox Supergroup. Geologic formations below the 2,500 ft depth in this area include basal part of the Knox, the Upper/Middle Cambrian Eau Claire Formation and Middle Cambrian Mt. Simon Sandstone, and Precambrian Middle Run Formation (see Figure 1-3). These formations are briefly described below, from oldest to youngest.

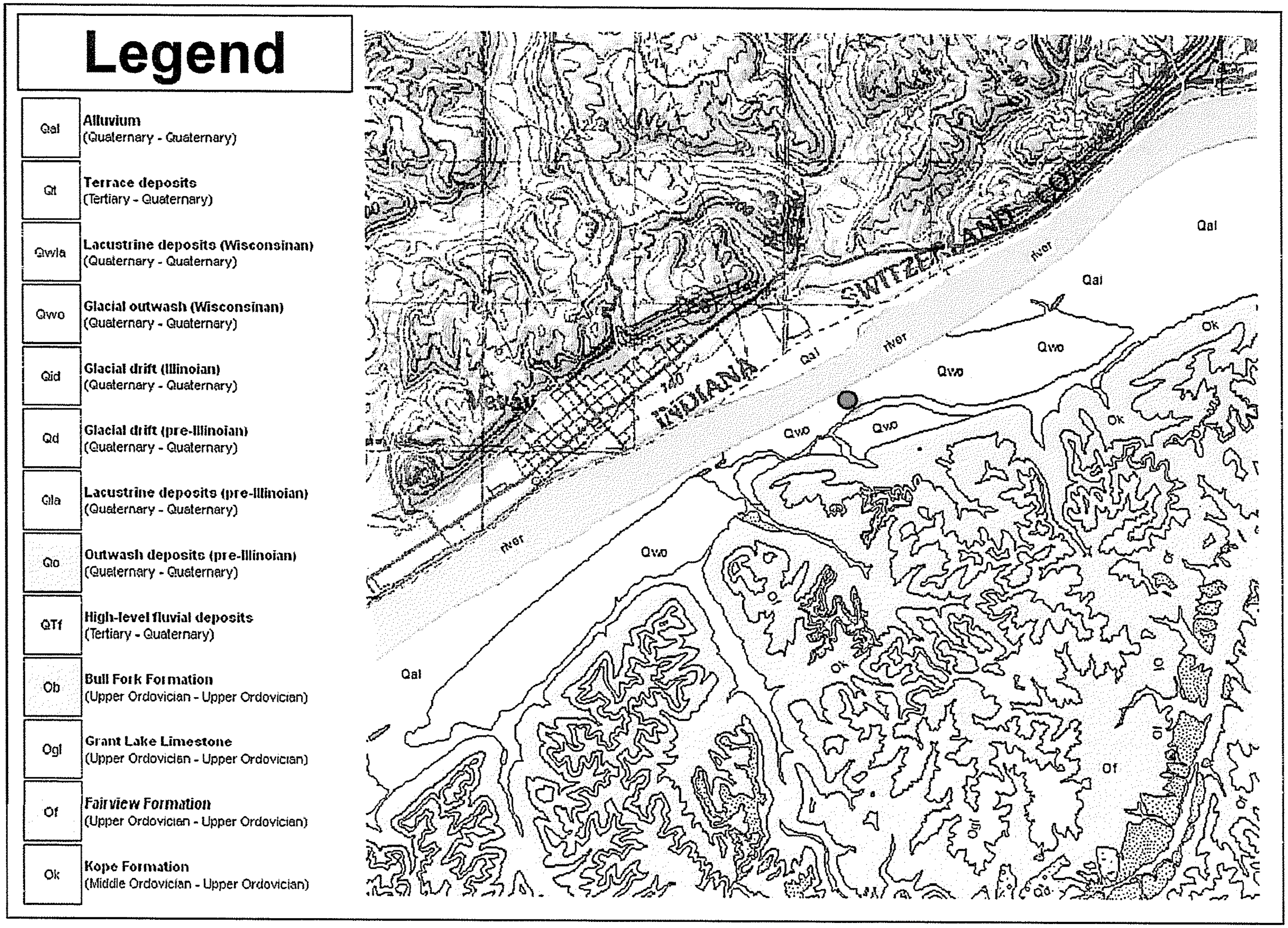


Figure 1-2a. Geologic map of a portion of the Vevay South and Vevay North 7.5 minute quadrangles (Swadley, 1973). The Ghent Station (red dot) is located on unconsolidated Pleistocene-age glacial outwash (Owo). Hills to the south of the station are underlain by Upper Ordovician shales and limestone.

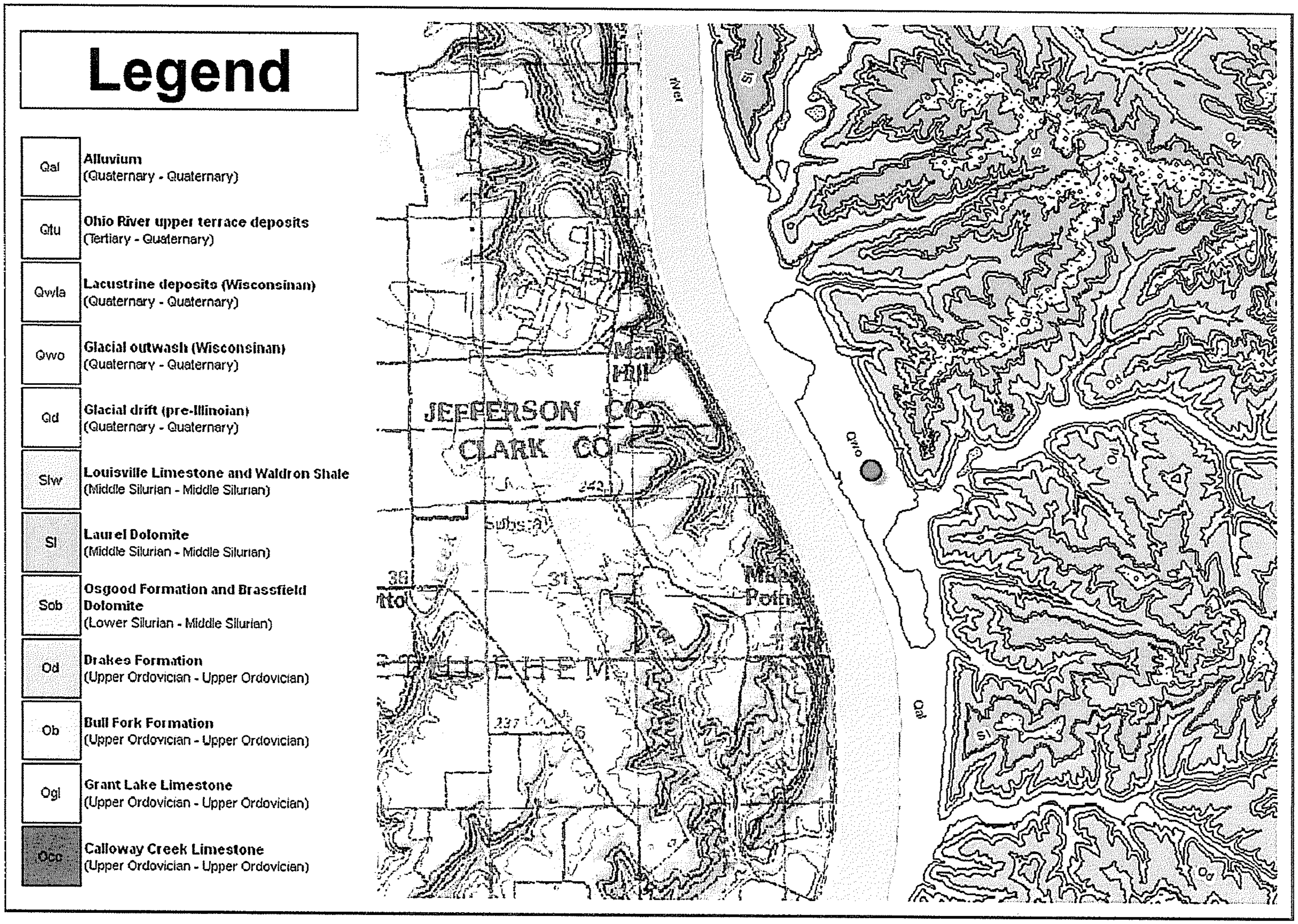


Figure 1-2b. Geologic map of a portion of the Bethlehem 7.5 minute quadrangle showing the location of the Trimble County Station (red dot) (Swadley, 1977). The station is located on unconsolidated Pleistocene-age sediments, mapped as glacial outwash (Owo). Hills to the east of the station are underlain by Upper Ordovician shales and limestone, and Silurian dolomite and shale.

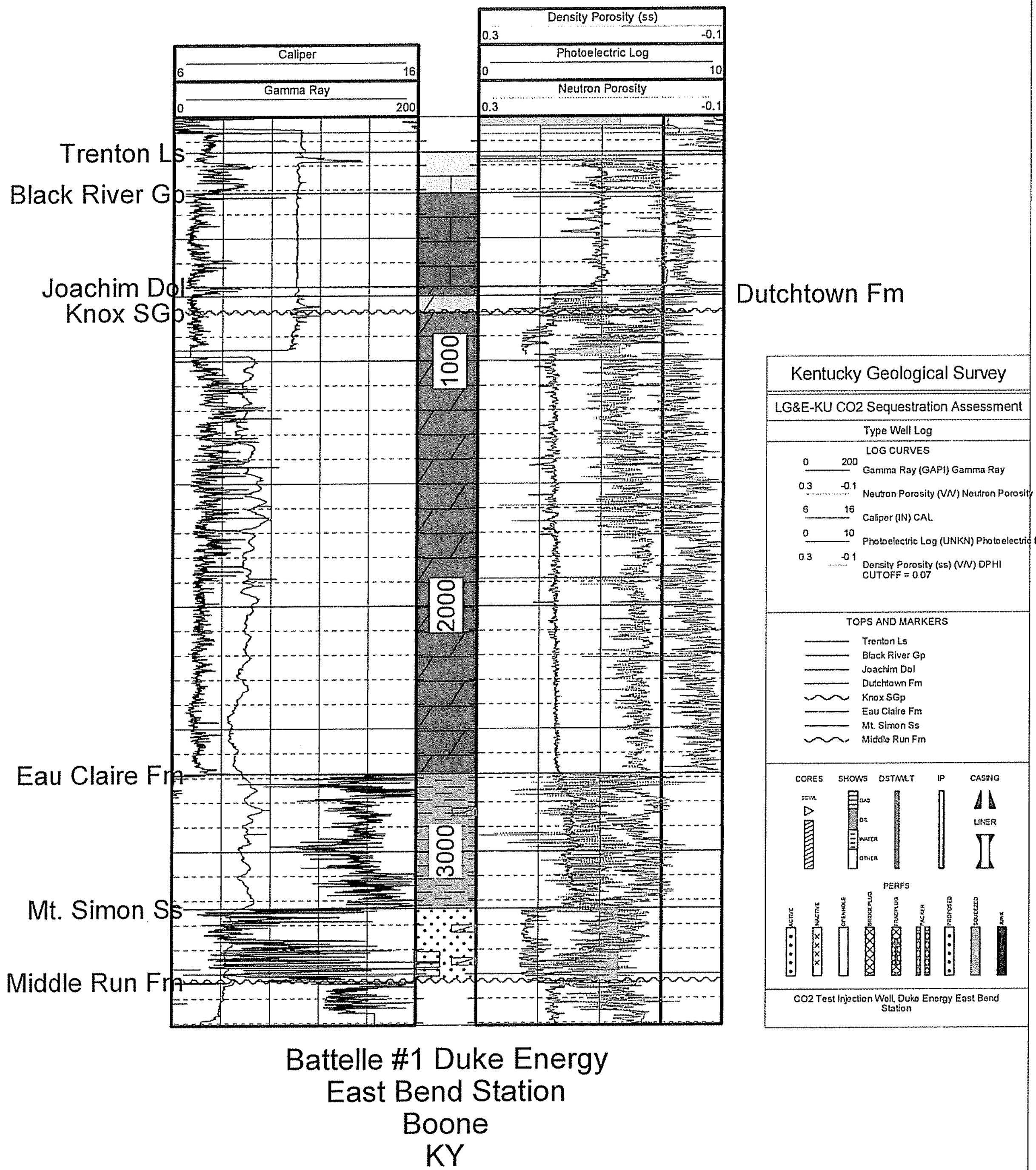


Figure 1-3. Geophysical log for the Battelle #1 Duke Energy well at the East Bend station in Boone County, Ky. Stratigraphic units are labeled. Cored intervals are marked on the right edge of the depth column, and the CO_2 injection zone is marked on the left side of the depth column in the Mt. Simon Sandstone. The density porosity log is shaded blue in the Mt. Simon interval where porosity is greater than 7%.

Precambrian Middle Run Formation

The Precambrian basement in the study area consists of sedimentary rocks assigned to the Middle Run Formation, in contrast to the igneous and metamorphic rocks typically encountered in the basement in other parts of Kentucky. The Middle Run consists of fine-grained red lithic sandstones and minor siltstone and shale. It was deposited in non-marine fluvial environments in a fault-bounded rift basin (Drahovzal and others, 1994). The top of the Middle Run is an erosional unconformity, formed during a long period of exposure and non-deposition between the Precambrian and Paleozoic Eras.The Middle Run has been penetrated in 5 wells in northern Kentucky and adjacent Indiana. The sandstone is well-cemented and lacks porosity and permeability in all of these wells. It has no potential for carbon sequestration in the study area, but forms the lower confining layer for the overlying Mt. Simon Sandstone.

Precambrian rocks dip to the west in the study area, consistent with the trend of the Cincinnati Arch (Figure 1-4). This structure map is based on the few wells that penetrate the Precambrian surface in the area. As such, it should be considered a general representation of the structure of the area. This map indicates that the depth to basement is about 4,361 ft (-3,888 subsea) at the Trimble County Station, and 3,777 ft (-3,289 subsea) at the Ghent Station. This would be the maximum depth required for an injection well, with Ghent lying about 600 ft updip (shallower) from Trimble County at the Precambrian level.

Cambrian Mt. Simon Sandstone

The Cambrian Mt. Simon Sandstone unconformably overlies the Precambrian Middle Run Formation in most of the study area. Farther to the southwest in Louisville, the Mt. Simon overlies Precambrian igneous rocks. The Mt. Simon Sandstone is predominantly quartz-rich, and because of its depth and porosity, is the primary CO_2 injection zone in the study area. The Mt. Simon has been encountered in 5 wells in the study area. Cores from the Mt. Simon Sandstone are available from 2 of these wells, the Battelle Duke Energy well and in the DuPont waste injection well in Louisville. Porosity and permeability data derived from these cores is described further in the reservoir quality section.

Using available well data in the area, structure and thickness maps for the Mt. Simon were constructed. Other studies have used data from seismic lines outside this study area to map the extent of the Mt. Simon Sandstone across Kentucky. The broader regional data show the Mt. Simon thickens to the north and northwest, and pinches out toward the south, Figure 1-5 (Greb and Drahovzal, 2011). The zero thickness line from this map has been used in the Trimble/Ghent maps made for this study. The zero thickness line runs across the southeast corner of the map area, and has been used to constrain the structure and thickness maps for this study. Please note this zero thickness line has been interpreted from limited data, and should be considered approximate. The Mt. Simon is known to be absent in several wells in central Kentucky, but the mapped pinchout should be considered a preliminary limit that may be revised with new data.

The top of the Mt. Simon is at 3,233 ft in the Battelle #1 Duke Energy well, and deepens to the southwest to 5,098 ft in the DuPont well in Louisville (Figure 1-6). The Mt. Simon Sandstone ranges in thickness from 297 ft in to 748 ft across the same area (Figure 1-7). The Mt. Simon should have suitable porosity and permeability at both stations to allow injection and storage of CO_2. 1000 tons of CO_2 were successfully injected in the Duke Energy well in 2009.

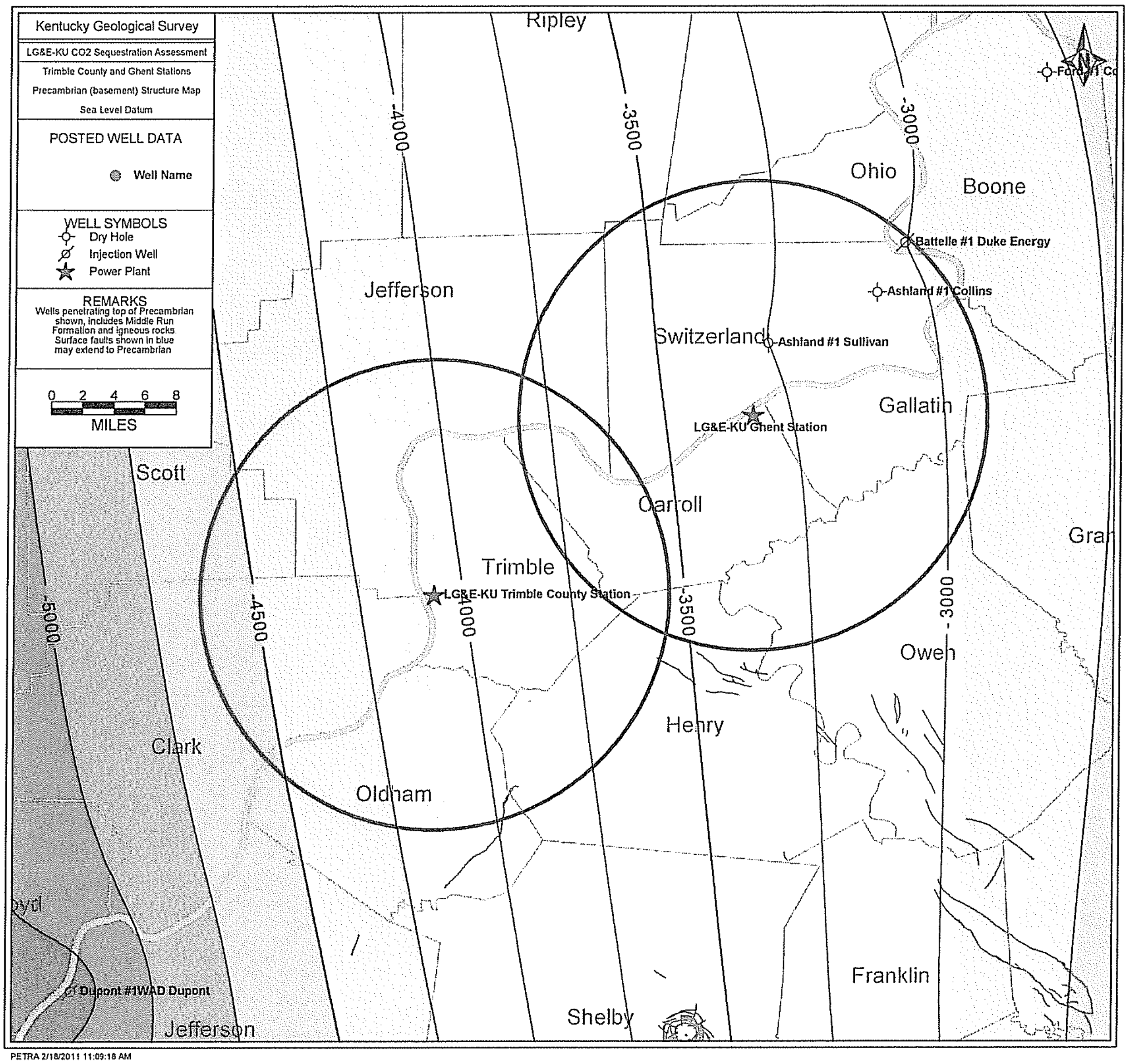


Figure 1-4. Structure map on top of Precambrian basement surface. In this area this is the top of the Middle Run Sandstone, or igneous rocks. The Precambrian surface deepens to the west-southwest. Blue lines are faults mapped at the surface, which may extend to Precambrian level.

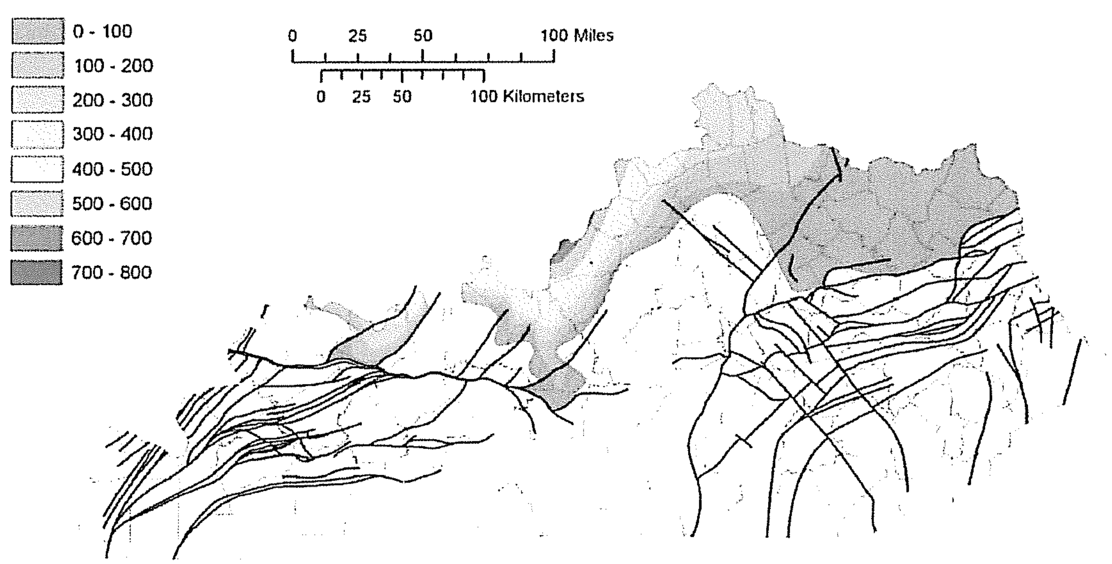


Figure 1-5. Thickness (isopach) map of the Mt. Simon Sandstone in Kentucky. Interpretation based on seismic and well data. Contours in feet. From Greb and Drahovzal, 2011.

The Trimble County and Ghent sites lie intermediate in depth between the DuPont waste disposal well to the southwest and the Duke Energy East Bend well to the northeast. Interpolating depth and thickness data from wells, the top of the Mt. Simon is estimated to be 3,898 ft (-3,425 subsea) at Trimble, and 3,423 ft (-2,935 subsea) at Ghent (Figure 1-6). The inferred pinchout line for the Mt. Simon was used to clip the structure contours at the zero edge. The isopach (thickness) map (Figure 1-7) shows thinning of the Mt. Simon Sandstone toward the southeast. Its thickness is estimated to be 366 ft at Trimble and 301 ft at Ghent. The isopach map was interpreted from the nearby well data, and the zero thickness line drawn on the regional map. The greater projected thickness at the Trimble Station is due to its closer proximity to the DuPont waste disposal well in Louisville, where the Mt. Simon is 748 ft thick.

Cambrian Eau Claire Formation

The Eau Claire Formation directly overlies the Mt. Simon Sandstone and is predominantly composed of green and gray marine shale, with some interbedded dolomite. In the Duke Energy East Bend well the Eau Claire Formation is 549 ft thick, and was cored from 2,825 to 2855 ft. The Eau Claire Formation was also cored in the DuPont #1WAD waste disposal well in Louisville, from 4,409 to 4,459 and 4,842 to 4,871 ft. The Eau Claire has very low porosity and permeability and is the primary confining layer (seal) for CO_2 injected into the Mt. Simon below.

Figure 1-8 is a structure map on the top of the Eau Claire. The Eau Claire deepens to the southwest into the deeper parts of the Illinois Basin. The top is projected to be at 2,870 ft (-2,382 ft subsea) at Ghent, and 3,423 ft (-2,950 subsea) at Trimble County. The top of this confining layer is deeper than the minimum depth for supercritical CO_2 at both sites.

Fig 1-9 is an isopach (thickness) map of the Eau Claire. The Eau Claire Formation thickens slightly to the southwest, reaching a thickness of 589 ft in the DuPont well in Louisville. Thickness contours parallel the Ohio River, and both Ghent and Trimble County have projected Eau Claire thicknesses of about 560 ft. This map indicates there is an adequate thickness of impermeable rocks immediately above the Mt. Simon injection zone.

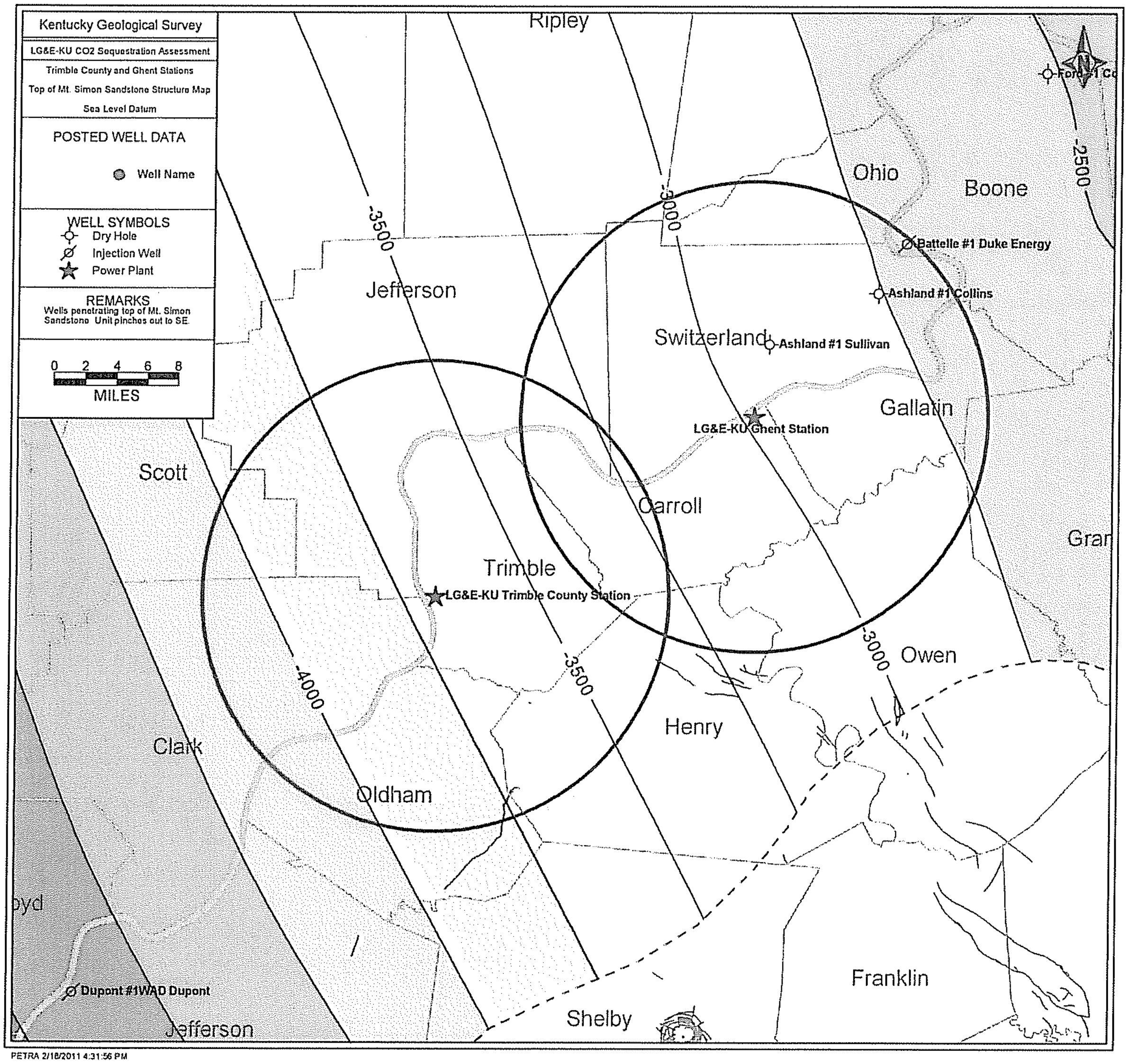


Figure 1-6. Structure map on top of Cambrian Mt. Simon Sandstone. Contour interval is 250 ft. The dashed line in the southeast part of the map is the inferred pinchout of the Mt. Simon to the south (Greb and Drahovzal, 2011).

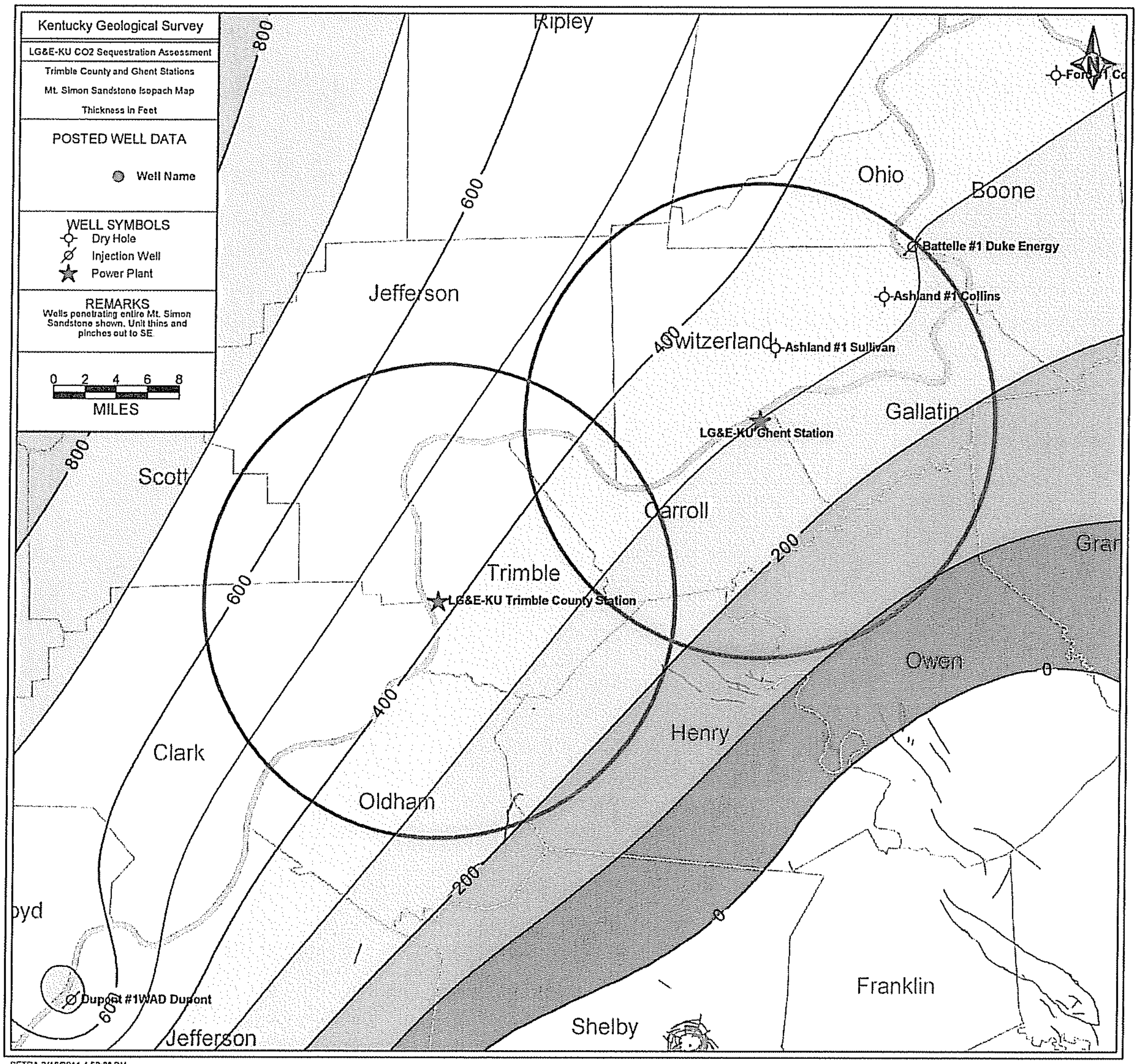


Figure. 1-7. Isopach (thickness) map of the Cambrian Mt. Simon Sandstone. Contour interval is 100 ft. The Mt. Simon thins to the southeast, and thickens to the west into the Illinois Basin. The Mt. Simon is interpreted to pinch out at the zero contour line. This interpretation is based on data from several older seismic lines, and should be regarded as an approximate location.

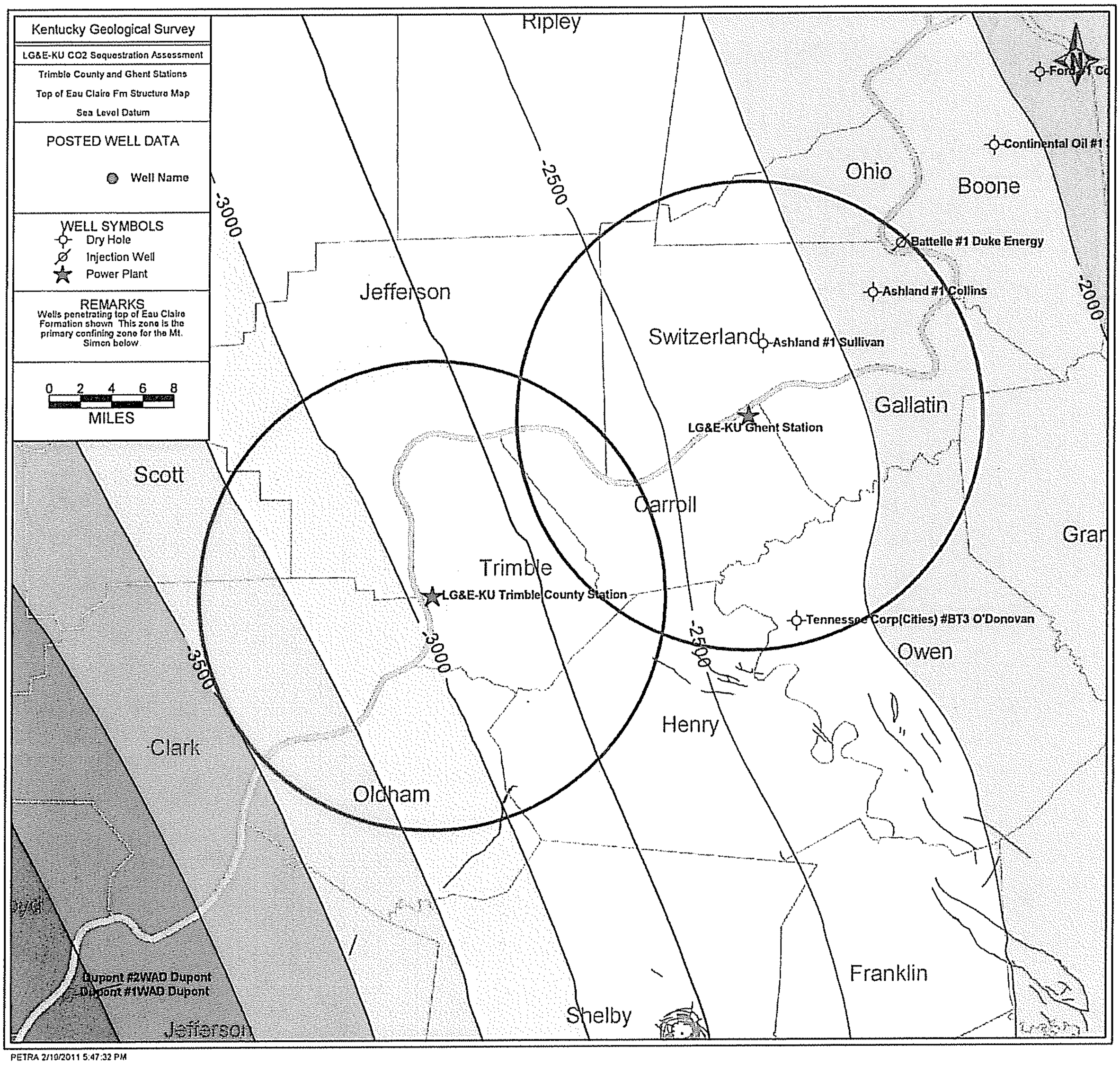


Figure 1-8. Structure map on top of the Cambrian Eau Claire Formation. Contour interval is 250 ft. The structure deepens to the southwest.

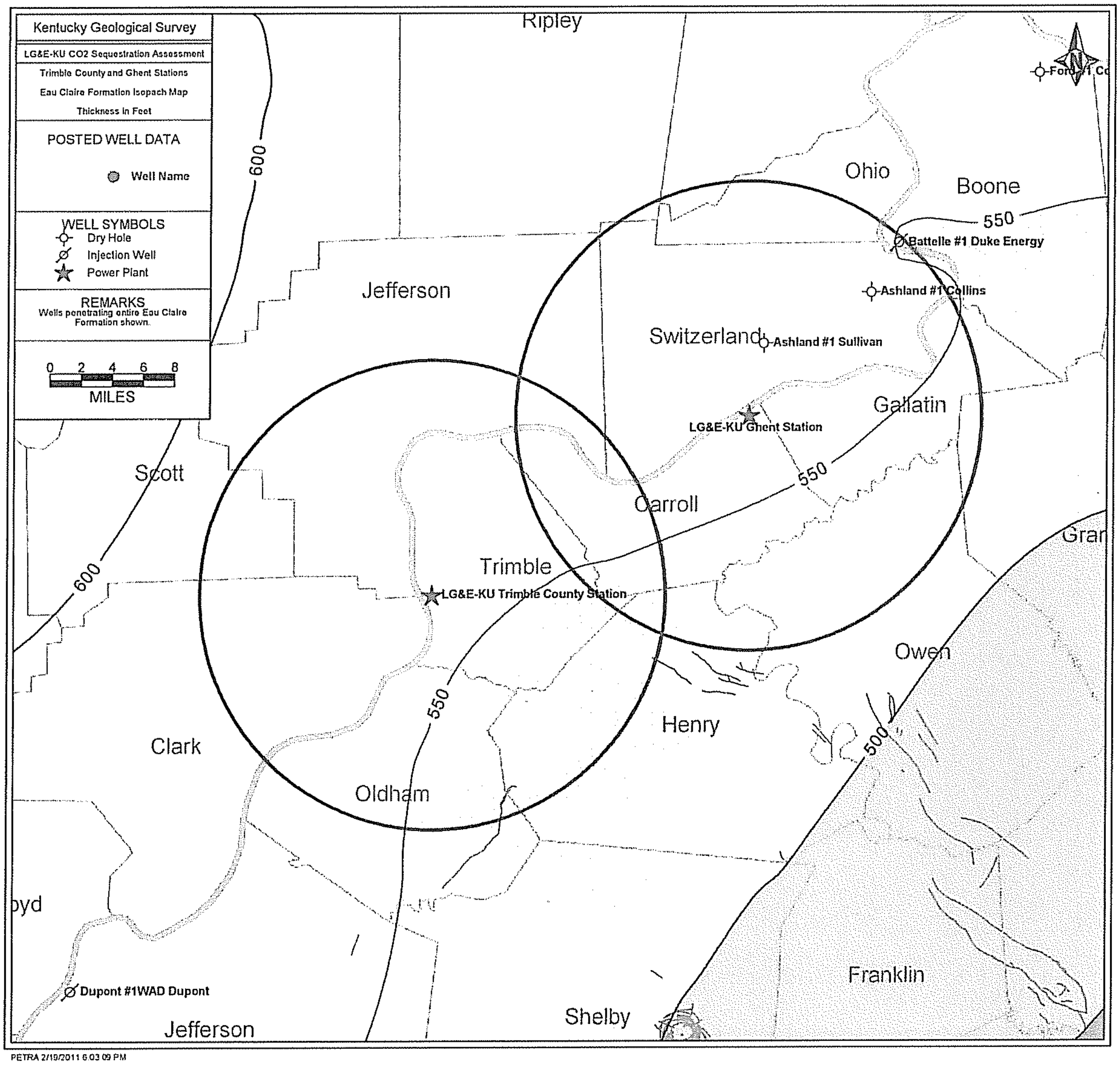


Figure 1-9. Isopach (thickness) map of the Eau Claire Formation. Shale and minor dolomite in this formation are over 550 ft thick at both sites, providing an excellent seal for CO_2 injected into the underlying Mt. Simon Sandstone.

Cambrian-Ordovician Knox Supergroup

The Knox Supergroup is divided into an upper dolomite unit, the Beekmantown Dolomite, and the lower Copper Ridge Dolomite, separated by sandstone or quartzose dolomite unit (Rose Run Sandstone) that is poorly developed in this area. The top of the Knox is a regional erosional unconformity that formed when the Knox was uplifted above sea level during the early Ordovician. The Knox is approximately 2,000 ft thick in the study area. The Knox contains scattered porous and permeable intervals separated by impermeable dolomite. It has injection potential in deeper parts of Kentucky (such as the KGS #1 Marvin Blan research well in

Hancock County), and was used as a hazardous waste injection zone at the DuPont chemical plant in Louisville. Porous zones in the Knox have also been used for natural gas storage by LG&E near the study area, in Grant and Oldham Counties (Ballardsville and Eagle Creek storage fields). These storage fields are now abandoned, and the porous zones used in these fields are too shallow for CO_2 storage.

In the study area, much of the Knox lies above the 2,500 ft depth limit for CO_2 to be in a supercritical phase. The lower part of the Knox (below 2,500 ft depth) is also not a viable injection target, since the primary seal (containment zone) above the top of the Knox is well above 2,500 ft. depth required to keep CO_2 in a supercritical phase.

The Knox is the shallowest interval mapped in this evaluation. Figure 1-10 is a structure map on the top of the Knox. Many more wells have been drilled to the top of the Knox than the deeper horizons, and thus more well data is available for the Knox structure map. The Knox deepens to the west, with the projected top of the Knox at about 1,077 ft (-604 ft subsea) at Trimble County and 849 ft (-361 ft subsea) at Ghent.

The Knox isopach map (Figure 1-11) shows the unit thins by over 1,000 ft from southwest to northeast across the study area. This thinning is primarily due to erosional truncation at the top of the Knox during exposure after Knox deposition. This thinning is also illustrated on the regional cross section, Figure 1-12. The Knox is interpreted to be 2,300 ft thick at Trimble County and 2,034 ft thick at Ghent.

Ordovician Dutchtown Formation and Joachim Dolomite

The Dutchtown Formation and Joachim Dolomite are dolomite intervals that contain variable amounts of shale, and overlie the Knox unconformity. They are equivalent to the Wells Creek Dolomite in Ohio, and are partly gradational with the St. Peter Sandstone. They generally have low porosity and permeability. They would provide additional confinement for CO_2 injected in deeper zones. The formations were not mapped in detail.

Ordovician Black River Group and Trenton Limestone

The Trenton Limestone and Black River Group together form a shallow secondary confining zone (seal) for CO_2 injected into the deeper Mt. Simon Sandstone. These rocks are composed of limestone, minor dolomite, and interbedded shale. The interval typically has very low porosity and permeability unless fractured. In the Battelle #1 Duke Energy well these formations have a combined thickness of 550 ft., with the top of the Trenton Limestone at 145 ft and the top of the Black River at 313 ft. (depths below surface). On surface geologic maps in the area the Trenton is named the Lexington Limestone (Swadley, 1973).

Near-Surface Formations

Formations at and near the surface in the study area include several Upper Ordovician units above the Trenton. Around Ghent these include the Point Pleasant (Calloway Creek), Kope, Fairview Fm, Grant Lake Limestone, and Bull Fork Formation. Near the Trimble site, in addition to these formations, younger rocks are present, including the Upper Ordovician Drakes, and Lower and Middel Silurian Osgood and Brassfield Formations, and Laurel Dolomite. Due to their shallow depth these units were not mapped in detail, but most will provide additional confining zones.

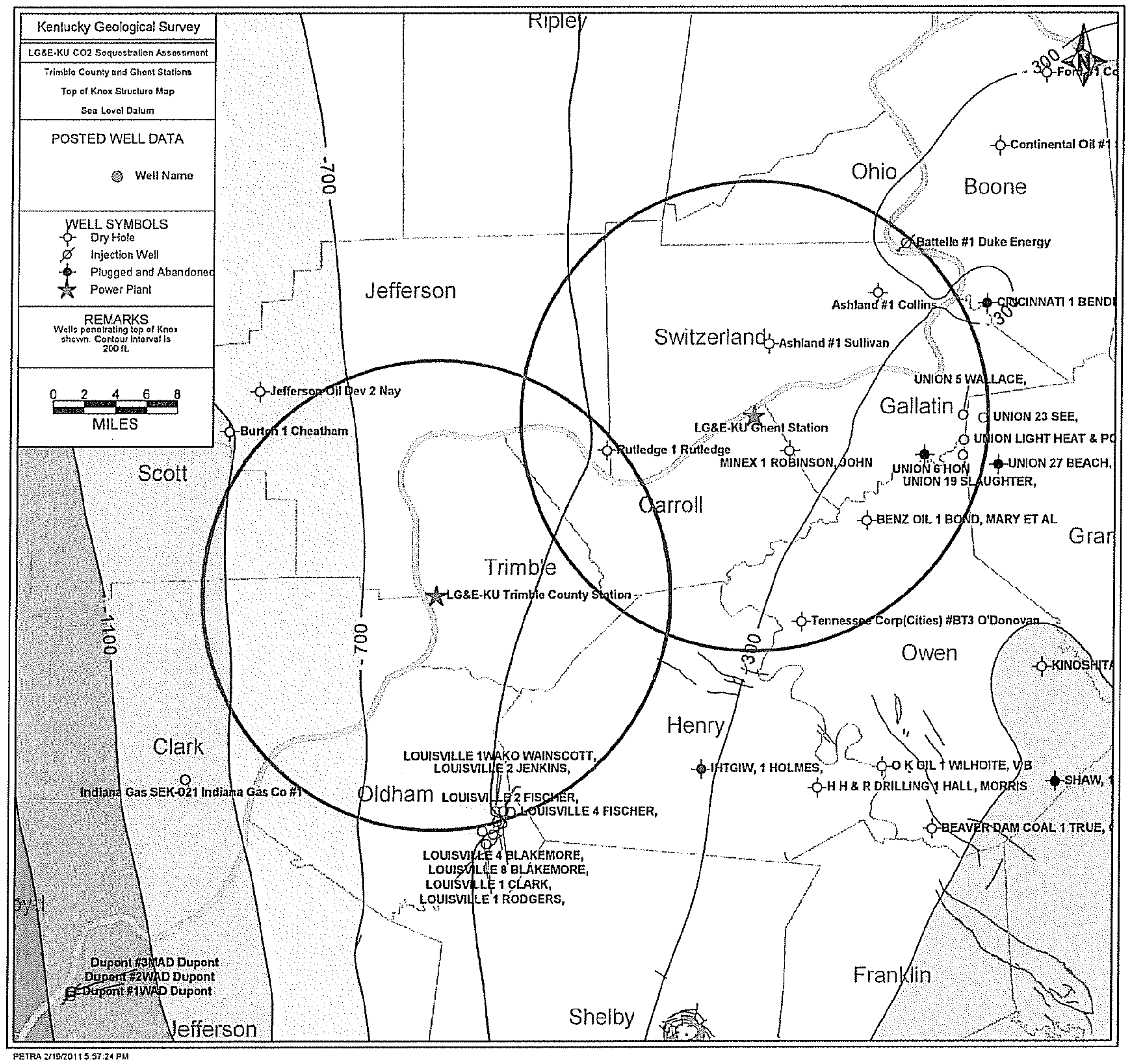


Figure 1-10. Structure map on the top of the Knox Supergroup. Contour interval is 100 ft. The top of the Knox is a regional erosional surface, and the structure dips more westerly than in underlying formations. The upper part of the Knox is too shallow for carbon storage in this area.

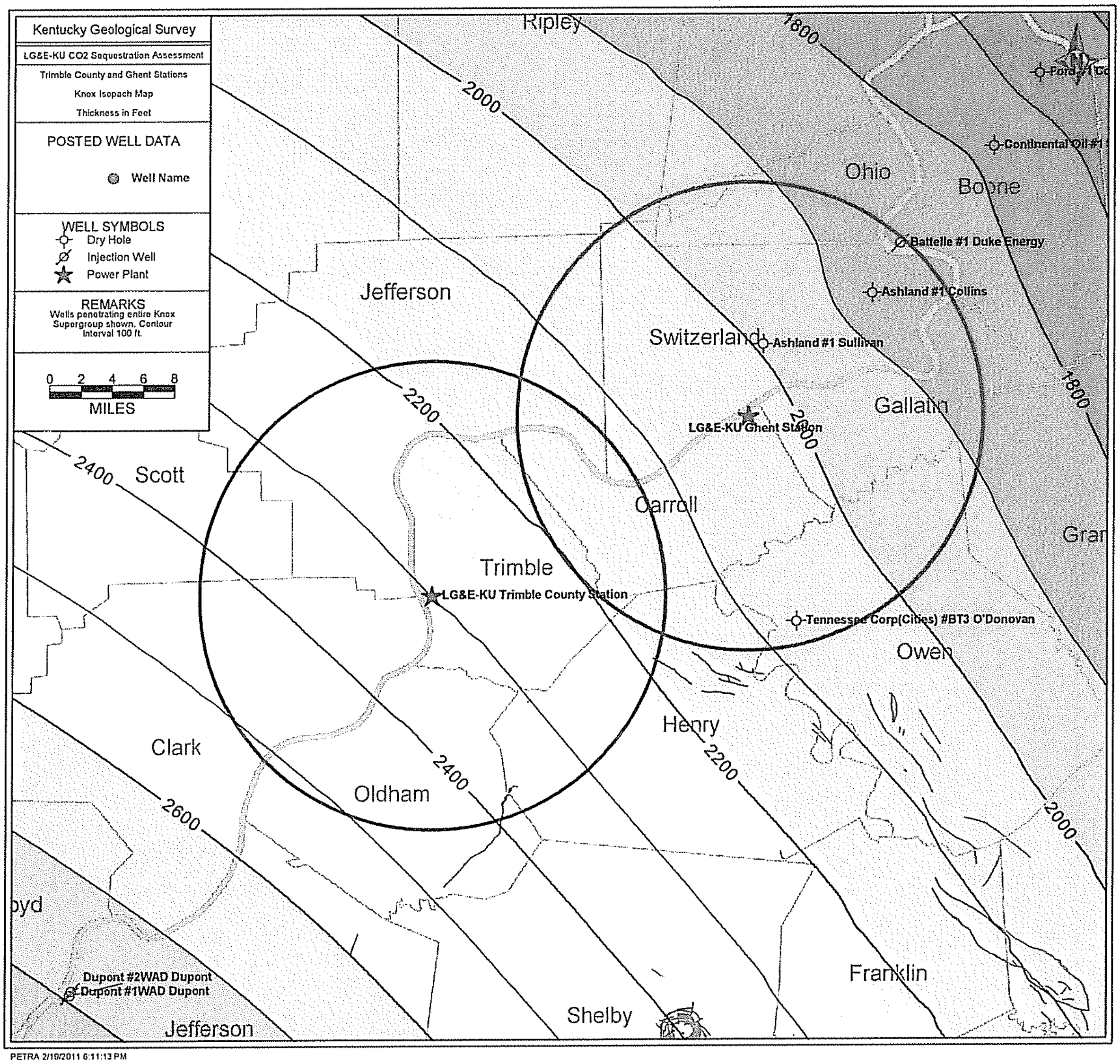


Figure 1-11. Isopach (thickness) map of the Knox Supergroup. The Knox thins to the NE due to erosion on the post-Knox unconformity

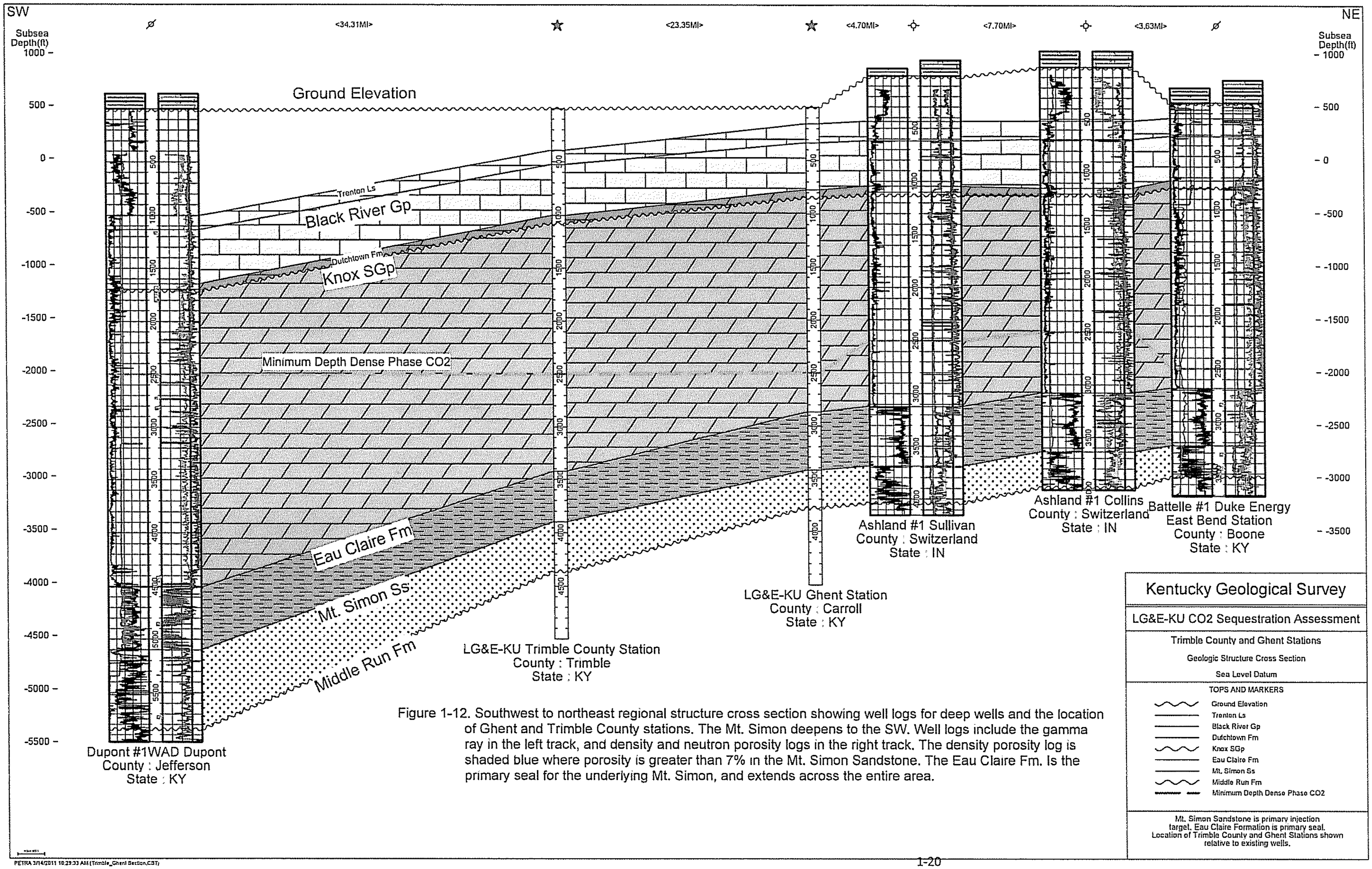


Figure 1-12. Southwest to northeast regional structure cross section showing well logs for deep wells and the location of Ghent and Trimble County stations. The Mt. Simon deepens to the SW. Well logs include the gamma ray in the left track, and density and neutron porosity logs in the right track. The density porosity log is shaded blue where porosity is greater than 7% in the Mt. Simon Sandstone. The Eau Claire Fm. Is the primary seal for the underlying Mt. Simon, and extends across the entire area.

Deep Faults and Available Seismic Data

The only seismic data in the area are two short lines acquired at the Duke Energy East Bend Station prior to drilling of the CO_2 injection well in 2009. These lines show no faults near the East Bend site. Faults have been mapped at the surface near the study area, and are shown in blue on Figs. 1-1 and 1-4. Only two of these faults are located within 15-mi. of a plant site. The Ballardsville Fault crosses the southern edge of the 15-mi. radius around the Trimble County site. This fault is in Oldham County, and forms the trap and southeastern boundary of the former Ballardsville gas storage field, operated by LG&E. This natural gas field was discovered in 1931 and later converted to gas storage in 1964 (Luft, 1977). Gas was stored in porous dolomite in the Knox Supergroup at depths around 1,250 ft. The fact that the Ballardsville fault forms the southeastern boundary of the gas storage field indicates it is a seal, at least at shallow depths. Kepferle (1977) reported gas bubbles rising out of a stream bed about a mi. southeast of the fault, but due to the distance, this seems to be unrelated to the fault or gas storage field.

There is also a NW-SE trend of faults that occur to the southeast of the plant sites. These faults define a graben, or down-dropped fault block in Franklin County on the Switzer quadrangle, and this has been named the Switzer graben. The faults continue the northwest into Owen and Henry Counties, but are more discontinuous. As mapped at the surface, one fault extends 0.2 mi.s across the SE edge of the 15-mi. radius around the the Trimble County site. The fault trend could extend farther to the northwest in the subsurface, but there is no seismic or well data to suggest this.

Reservoir Quality and Injection Zone Thickness

In order to calculate carbon sequestration capacity, the average porosity and thickness of the storage zone is required. Since there are no wells drilled to the Mt. Simon Sandstone at the Ghent and Trimble County plant sites, exact porosity data are not available. As such, reasonable estimates for porosity and net injection zone thickness were calculated from nearby well control. Data from the Duke Energy East Bend CO_2 injection test well is especially helpful, since high-quality well logs and core data are available from this well drilled in 2009.

Regional Porosity Trends

Like many sandstones, porosity in the Mt. Simon Sandstone decreases with increasing burial depth. This is primarily due to cementation and compaction, and is a result of increased temperature, pressure, and the amount of time the rocks have been buried. A substantial set of Mt. Simon porosity and permeability data from across the midwest has been published by Medina and others (2011). Cross-plots of porosity vs. depth in this paper establish a general correlation between porosity and depth. The authors found a dramatic decrease in porosity at depths below 7,000 feet. This depth generally corresponds to a porosity value of 7%, although significant variability exist in the data.

Significant variations in porosity are observed in the Mt. Simon within the current study area, and correlate with burial depth (Figure 1-13). The DuPont #1WAD well in Louisville was drilled to over 6,000 ft to test the Mt. Simon for hazardous waste injection. Initial injection tests in the Mt. Simon determined it lacked sufficient porosity and permeability for commercial waste disposal. An alternate zone in the shallower Knox dolomite was eventually used as the injection zone. The average depth of the Mt. Simon in the DuPont well is 5,600 ft, and the average log-derived sandstone porosity is 6.5%. The regional depth/porosity correlation proposed by Medina and others (2011) suggests the Mt. Simon should have about 8.4% porosity at 5,600 ft. This means that the DuPont well has lower porosity than predicted for its depth. The reason for this is not known, but the DuPont well provides a deep control point that must be considered for prediction of porosity at the Trimble County and Ghent sites.

To the northeast of Trimble County and Ghent are three wells where the Mt. Simon is much shallower than in Louisville. In the two Ashland Oil wells in Switzerland County, Indiana and the Duke Energy East Bend well in Boone County, Kentucky the Mt. Simon occurs at depths of 3,400 to 3,900 ft. In these three wells the average log-derived sandstone porosity is 13%, double that at Louisville. The Ghent and Trimble County sites lie intermediate between the poor porosity at Louisville and the much higher porosity in Boone and Switzerland Counties (Figure 1-13). The methodology for estimating porosity and reservoir thickness at the 2 sites is discussed below.

Site-specific Porosity Estimates

Both well log and core porosity data were used to estimate porosity at Ghent and Trimble County. Core measurements are the most accurate method of determining porosity and permeability. Core-derived porosity and permeability data for the Mt. Simon is available from cores at the Duke Energy East Bend well and the DuPont #1WAD waste disposal well in Louisville.

Core data is not available for all wells, and cores typically are cut for a limited interval within the Mt. Simon. Thus the best zones are not always cored. Porosity (but not permeability) data is also derived from downhole well logs, especially the bulk density log. Logs provide a continuous dataset for the entire formation, but are not as accurate as core data. A total of 4 wells with density logs were used to estimate sandstone porosity at the plant sites (the DuPont and Duke Energy wells, and the two Ashland Oil wells in Switzerland County, Indiana).

Core data from the Duke Energy East Bend and the DuPont #1WAD well (Louisville) are presented in Figs. 1-14, 1-15. The porosity and permeability vs. depth plots (Figs. 1-14a and 1-14b) also include data from the overlying Eau Claire Shale core from East Bend. The Mt. Simon core data help to illustrate the range of porosity and permeability in the area. There is considerable variation in porosity and permeability within the limited depth range of the cores. Despite this, the DuPont core data shows overall lower porosity and permeability than the cores at East Bend. As discussed previously, this is related to the greater burial depth.

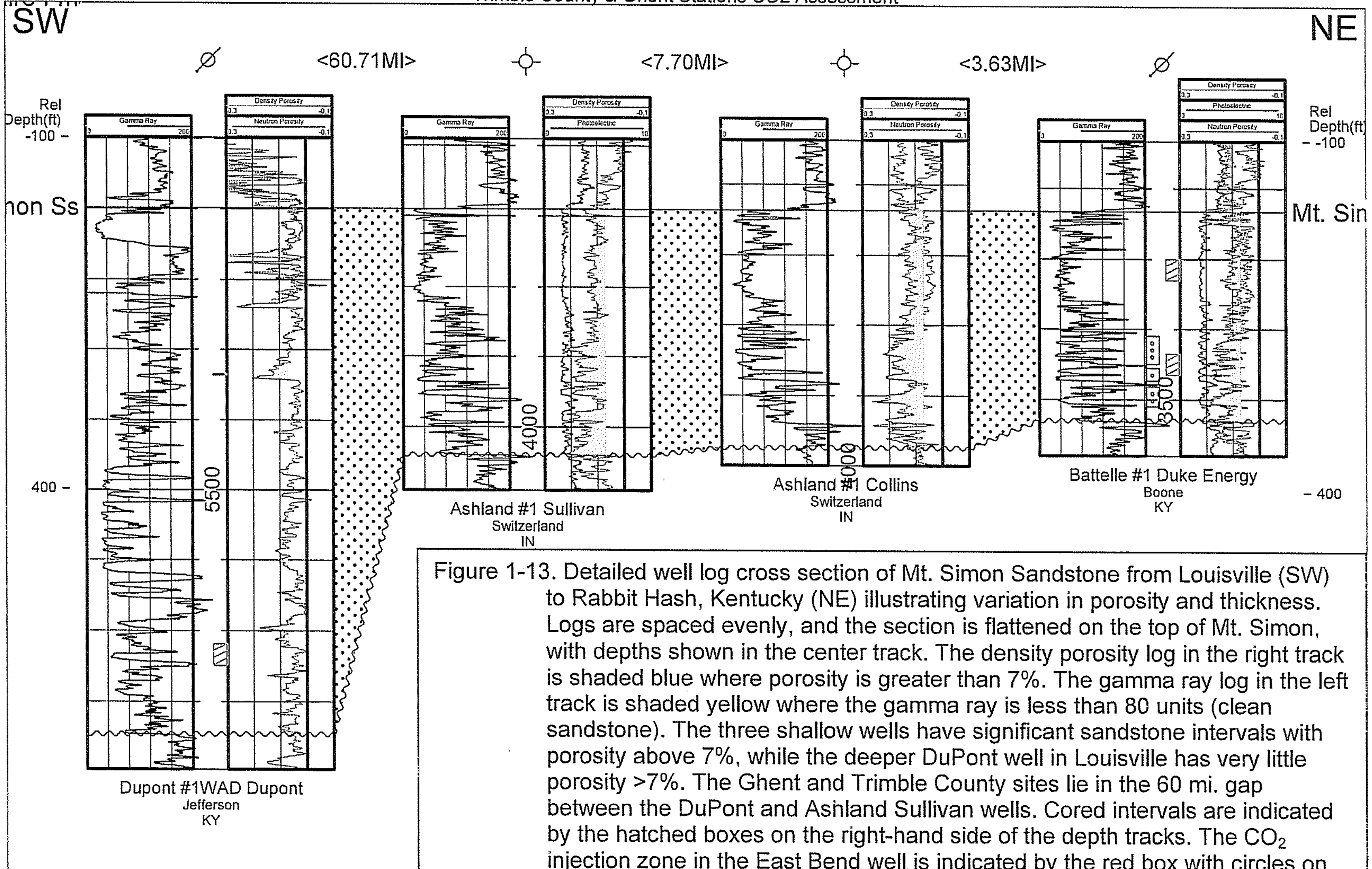


Figure 1-13. Detailed well log cross section of Mt. Simon Sandstone from Louisville (SW) to Rabbit Hash, Kentucky (NE) illustrating variation in porosity and thickness. Logs are spaced evenly, and the section is flattened on the top of Mt. Simon, with depths shown in the center track. The density porosity log in the right track is shaded blue where porosity is greater than 7%. The gamma ray log in the left track is shaded yellow where the gamma ray is less than 80 units (clean sandstone). The three shallow wells have significant sandstone intervals with porosity above 7%, while the deeper DuPont well in Louisville has very little porosity >7%. The Ghent and Trimble County sites lie in the 60 mi. gap between the DuPont and Ashland Sullivan wells. Cored intervals are indicated by the hatched boxes on the right-hand side of the depth tracks. The CO_2 injection zone in the East Bend well is indicated by the red box with circles on the left-hand side of the depth track.

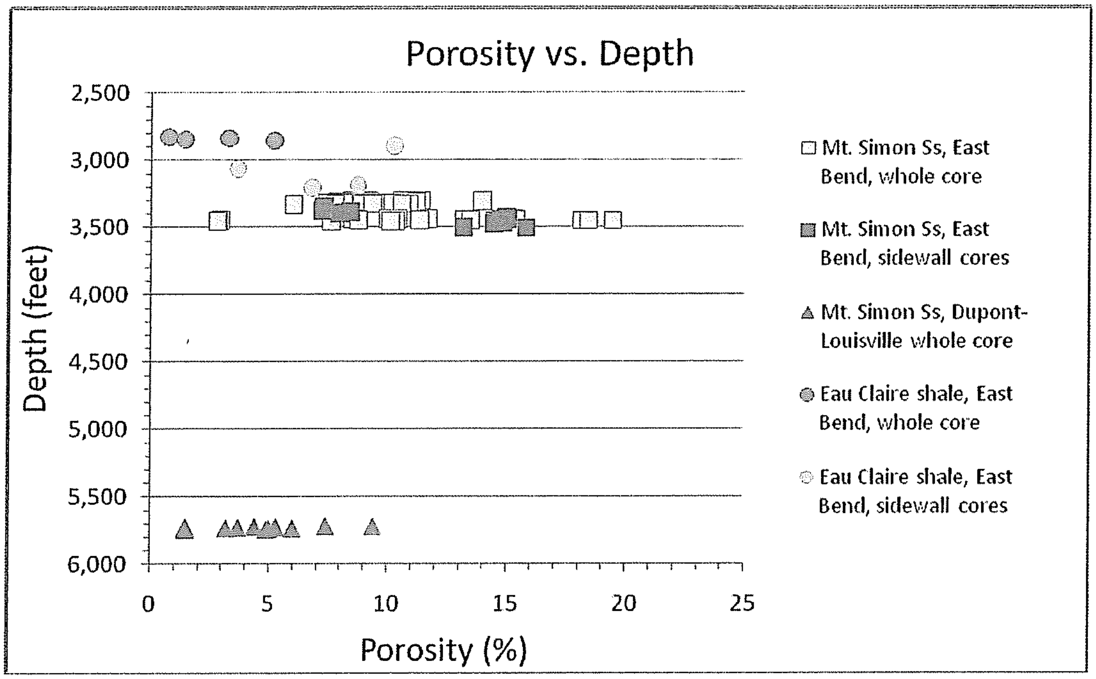


Figure 1-14a. Plot of core porosity vs. depth below surface for Mt. Simon Sandstone (reservoir) and Eau Claire Formation (seal) core from the Duke East Bend and DuPont #1WAD wells. Note significantly lower Mt. Simon porosity in the DuPont cores due to deeper burial depth. Average porosity for East Bend sidewall cores is 11.9%, for East Bend whole core plugs, 10.4%, and for the DuPont core plugs, 4.3%.

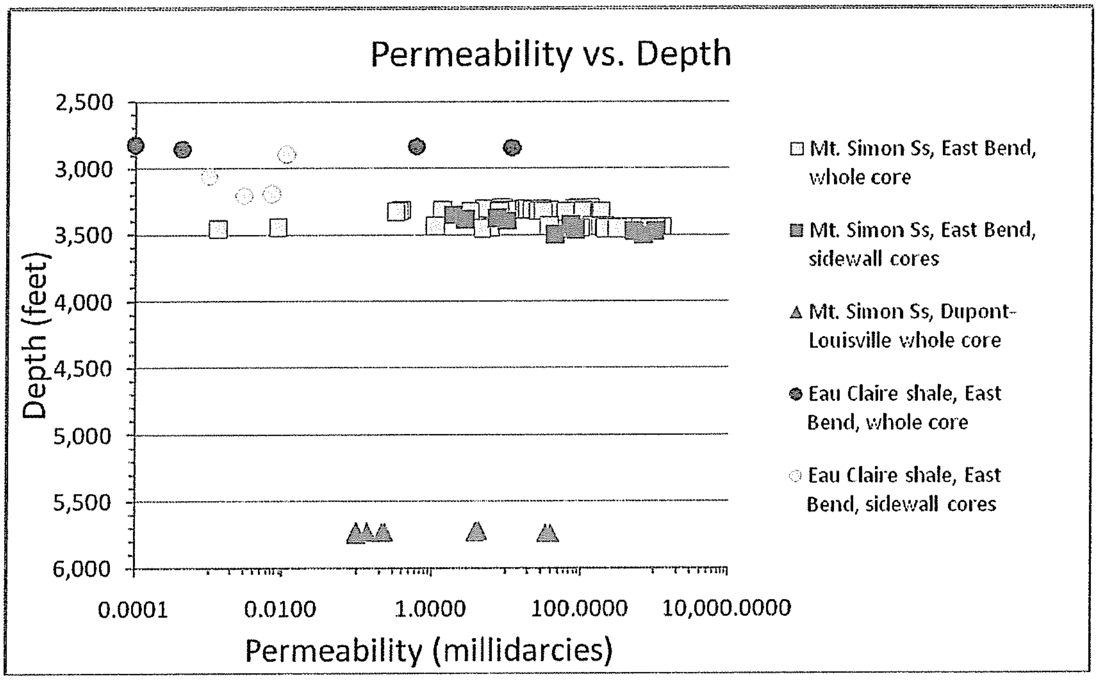


Figure 1-14b. Plot of core permeability vs. depth below surface for Mt. Simon Sandstone and Eau Claire Formation. Permeability is quite variable, but is lower in the DuPont cores and in the Eau Claire shales. Average permeability for the East Bend sidewall cores is 246 millidarcies, for East Bend whole core plugs, 143.4 md, and for the DuPont core plugs, 6.1 md.

Plotting porosity vs. permeability illustrates the positive correlation between the two measurements (Figure 1-15). This plot allows a minimum porosity to be interpreted for sandstone with acceptable permeability for injection. Because porosity can be measured with downhole logs and permeability cannot, this cutoff allows the thickness of rock with suitable porosity and permeability for injection to be summed from porosity log data alone.

Based on the core data in Figure 1-15, a minimum porosity of 7% was chosen as the porosity cutoff in this area. The 7% porosity line separates the majority of the East Bend data (permeability >10 md) from the DuPont core data, where injection was not successful. Medina and others (2011) also used a 7% porosity cutoff for the Mt. Simon across the Midwest in their calculation of CO_2 sequestration capacities. Their cutoff, based on a much larger dataset is supported by the core data used in this study.

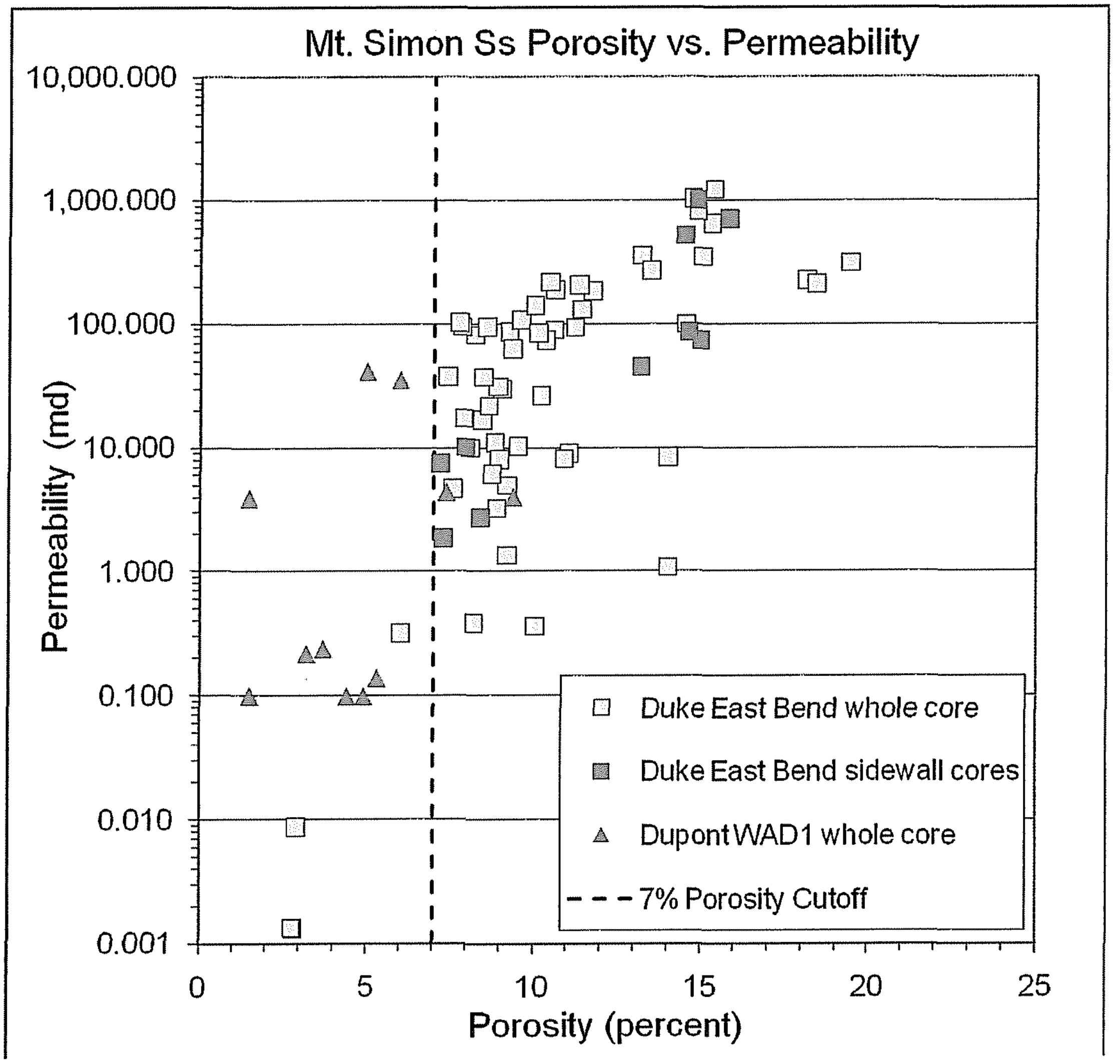


Figure 1-15. Mt. Simon Sandstone core porosity vs. permeability plot for the Duke East Bend and DuPont #1WAD wells. In general, permeability decreases rapidly below 7% porosity, and this trend was the basis for the 7% porosity cutoff used to calculate net reservoir thickness.

Calculation of Net Porous Sandstone

Once a porosity cutoff was chosen, the footage of net porous sandstone, and average porosity of sandstones above the cutoff was determined for use in CO_2 capacity calculations. Because the Mt. Simon Sandstone contains thin shales and some argillaceous sandstones with poor reservoir quality, only clean sandstone was included in the net sandstone calculation. The gamma ray log is the best discriminator of clay and shale, and a cutoff of 80 API gamma ray units was used to identify clean sandstone. Intervals with 80 or less API gamma ray were classified as sandstone. This 80 API unit cutoff is very close to the 75 API cutoff used by Media and others (2011) in their Mt. Simon study.

A log analysis program (Petra) was used to calculate the number of feet of Mt. Simon in each well with a gamma ray reading of less than 80 API units, and density porosity (calculated using a sandstone matrix) greater than or equal to 7%. The results of the net sandstone calculation are shown in Table 1-1. Average log porosity and total porosity feet (thickness of void space) were also calculated. Gross thickness is the total Mt. Simon thickness. A net to gross sandstone ratio was calculated for each well to allow a similar thickness to be calculated at the Trimble County and Ghent sites using the total mapped thickness. The net to gross ratio ranges from 0.57 at East Bend to 0.15 in the Louisville DuPont well, reflecting the decrease in porous sandstones with increasing depth. Average log-derived porosity of the net sandstone interval ranges from 14.4% in the Ashland Collins to 8.7% in the DuPont well.

Table 1-1. Mt. Simon reservoir data

Mt. Simon Sandstone Well Log Data	Average Depth (below surface, ft)	Gross Thickness (ft)	Net Porous Sandstone <80 GR and >7% porosity (ft)	Net to Gross Ratio	Average Log Porosity of Net Porous Sandstone	Porosity Feet
Duke Energy East Bend	3400	297	170	0.57	11.90%	20.3
Ashland Collins	3800	338	178	0.53	14.40%	25.6
Ashland Sullivan	3900	350	186	0.53	13.40%	25.0
DuPont #1WAD	5600	748	111.5	0.15	8.70%	9.6
Calculated Data						
Ghent Station	3650	301	160	0.53	12%	19.2
Trimble County Station	4200	366	121	0.33	10%	12.1

Table 1-1 also includes calculated data for the Ghent and Trimble County sites. The gross thickness was taken from the thickness map of the Mt. Simon at each location (Figure 1-7). Then a net sandstone footage was calculated using the net-to-gross ratios determined from the 4 analog wells. For the Ghent site, a ratio of 0.53 was used, because the site is very close to the Ashland Sullivan well. This yields a net sandstone estimate for Ghent of 160 ft. The Ghent site is slightly deeper than the Sullivan well (see cross section, Figure 1-12), so a slightly lower average porosity of 12% was assigned. This is essentially the same average porosity as at the Duke East bend well.

Estimates for the Trimble County site are more difficult because there are no wells to the Mt. Simon within a 15-mi. radius of the plant. Trimble is intermediate in depth between the DuPont well in Louisville (34 mi.s SW) and the three shallower wells about 35 mi.s to the northeast. The predicted gross thickness of the Mt. Simon at Trimble is 366 ft (Figure 1-7). A net-to-gross ratio of 0.33 was used for Trimble, intermediate between 0.53 in the Ashland wells and 0.15 in the DuPont well. This yields a predicted net sandstone thickness of 121 ft. Average porosity at Trimble is estimated to be 10%, again chosen as an intermediate value between DuPont to the southwest and the three shallower wells. The porosity predicted for Trimble County is reduced due to the poor porosity at the DuPont well. Comparison with regional data suggests the DuPont well has lower porosity than it should for its depth (Medina and others, 2011). If this is a local anomaly, Trimble County may have better porosity than the conservative number used here.

CO_2 Capacity Calculations

Using data compiled and calculated, CO_2 storage volume calculations have been made. CO_2 storage capacity is based on the porosity, thickness and acreage of the injection zone, and density of the injected CO_2. CO_2 density is a function of reservoir pressure and temperature. The Mt. Simon interval is deep enough for supercritical (dense) phase CO_2 injection at both Ghent and Trimble County. CO_2 density calculations were made using the CO_2 properties calculator at the MidCarb project web site: http://www.midcarb.org/calculators.shtml. The Midcontinent Interactive Digital Carbon Atlas and Relational dataBase (MIDCARB) was a research consortium composed of the State Geological Surveys of Illinois, Indiana, Kansas, Kentucky, and Ohio, funded by the US Department of Energy.

Calculated CO_2 densities are shown in Table 1-2. CO_2 density is higher at Ghent than at Trimble County despite the shallower depth. This is due to the lower reservoir temperature.

Table 1-2. Calculated CO_2 density at reservoir conditions.

CO_2 Density	Reservoir Pressure (psi)	Reservoir Temperature (F)	CO_2 Density lbs/ft^3	CO_2 Density kg/m^3
Ghent	1600	100	44.5	713.14
Trimble County	1800	110	43.3	693.60

The following parameters are required inputs to calculate CO_2 storage capacity:

Reservoir pressure: assumed hydrostatic, and calculated at 0.433psi/ft for the reservoir depth
Temperature: taken from well log data in Boone and Jefferson Counties.
Reservoir thickness: the net porous sandstone thickness as calculated above.
Reservoir area: a standard area of 100 acres was used for these calculations.
Reservoir porosity: the average porosity for the net reservoir footage.

The equation for CO_2 storage capacity is (modified from Medina and others, 2011):

$$SC = A_n * h_n * \Phi_n * \rho_{CO2} * \acute{\varepsilon} / 1000$$

Where SC is the storage capacity in metric tons, A_n is the area in square meters, h_n is the net reservoir thickness, Φ_n is the average porosity of the net reservoir, ρ_{CO2} is the density of CO_2 at the reservoir conditions, and $\acute{\varepsilon}$ is the storage efficiency factor (discussed below).

The Ghent Station has a higher storage capacity than Trimble County due the greater reservoir thickness, higher porosity, and higher CO_2 density. The reservoir parameters used and CO_2 capacities calculated are shown in the table below:

Table 1-3. Input parameters and calculated CO_2 storage capacity for a 100 acre area at 100% and 14% storage efficiency.

Site	Net Reservoir Thickness (ft)	Net Reservoir Thickness (m)	Porosity	CO_2 Density (kg/m^3)	CO_2 Capacity @ 100% Efficiency (metric tons)	Storage Efficiency Factor	CO_2 Capacity @ 14% Efficiency (metric tons)
Ghent	160	48.8	0.12	713.14	1,688,924	0.14	**236,449**
Trimble County	121	36.9	0.10	693.60	1,035,206	0.14	**144,929**

Efficiency of CO_2 Storage

The storage capacity equation used above includes an efficiency factor which reduces the CO_2 storage capacity. This factor is applied because 100% of the available pore volume is never completely saturated with CO_2 due to fluid characteristics and geologic variability within the reservoir.

Litynski and others (2010) calculated efficiency factors for carbon storage in various reservoir types that account for factors which reduce the volume of CO_2 that can be stored. These factors include:

Geologic Factors

- Net to total area of a basin suitable for sequestration
- Net to gross thickness of a reservoir that meets minimum porosity and permeability requirements
- Ratio of effective to total porosity (fraction of connected pores)

Displacement Factors

- Areal displacement efficiency- area around a well that can be contacted by CO_2
- Vertical displacement efficiency- fraction of vertical thickness that will be contacted by CO_2
- Gravity- fraction of reservoir not contacted by CO_2 due to buoyancy effects
- Displacement efficiency- portion of pore volume that can be filled by CO_2 due to irreducible water saturation

Combining all of these factors using a Monte Carlo simulation results in a probability range of total efficiency factors of 0.51% to 5.4% (P_{10} to P_{90} range) (Litynski and others, 2010). For the purposed of this assessment, we can assume the *geologic* factors are equal to 1. In our 100-acre unit the net to total area is the same, the net to gross thickness has already been calculated and used in the calculation, and for clastic reservoirs (sandstones) we can assume that the porosity is well-connected with a ratio of effective (connected) porosity to total porosity equal to 1. Litynski and others (2010) calculated efficiency factors for just the *displacement* factors separately, and for sandstone reservoirs they range from 7.4% to 24%, with a P_{50} (most likely) efficiency factor of 14%. This means the most likely case is that 14% of the pore space can be filled with CO_2. The range of storage volumes using the probabilistic efficiency factors for each site is shown in Table 1-4.

Table 1-4. Range of probabilistic storage volumes using U.S. DOE displacement efficiency factors for clastic reservoirs (Litynski and others, 2010).

Site	Minimum Volume (metric tons/100 ac.) ε = 7.4% (P_{10})	Most Likely Volume (metric tons/100 ac.) ε = 14% (P_{50})	Maximum Volume (metric tons/100 ac.) ε = 24% (P_{90})
Ghent	124,980	**236,449**	405,342
Trimble County	76,605	**144,929**	248,449

The application of an efficiency factor significantly reduces the storage capacities but is necessary to determine reasonable volume estimates.

Summary

Both Ghent and Trimble County Stations have good potential for geologic storage of CO_2 beneath the site property. The Mt. Simon Sandstone is the only formation with suitable porosity and permeability at depths required for dense phase sequestration. Excellent confinement for injected CO_2 is provided by the 500+ ft thick Eau Claire Formation.

Geologic data control for Ghent is good with several wells to the reservoir within a 15-mi. radius, including the Duke Energy East Bend CO_2 injection well. The proximity of the East Bend well to Ghent lowers the risk of finding a suitable reservoir, and excellent core, log and engineering data are available from this research project. Two short seismic lines were acquired at the East Bend site, almost 15-mi. from Ghent. While helpful in mapping, these lines are not close enough to characterize the Ghent site. There are no surface faults mapped within a 15-mi. radius. Ghent has a higher calculated CO_2 storage volume per acre than Trimble County due to its shallower depth and higher porosity, which results in a higher net reservoir thickness. The Mt. Simon structure map (Figure 1-6) indicates that injected CO_2 would migrate slowly to the northeast, parallel to the Ohio River. Migration of some CO_2 under the river into Indiana is possible, but this would depend on the volume of CO_2 injected and the length of time. If this is a concern, an injection simulation could be run to predict the CO_2 plume size and direction over time. KGS does not currently have this modeling capability, but it may be available in the near future.

The Trimble County site has very similar geology to Ghent, but geologic data are scarcer. There are no wells to the Mt. Simon within a 15-mi. radius of the site. The Mt. Simon Sandstone is likely to be thicker at Trimble than at Ghent, but it lies about 500 ft deeper, resulting in less porosity, and thinner net reservoir thickness. The Trimble County site is closer to Louisville, where a waste disposal well was unable to establish commercial rate injection in the Mt. Simon. Reservoir quality is thought to be adequate for injection at Trimble County, but with lower storage volumes predicted than at Ghent, and with a higher level of risk due to the lack of nearby data. The Eau Claire Formation seal is good and similar to Ghent, but there are mapped surface faults that just cross the 15-mi. buffer to the east and south of the site. These faults do not appear to continue toward the site, but seismic data would be necessary to confirm their extent in the subsurface. The dip of the Mt. Simon is similar to that at Ghent, but due to the location of the Ohio River, injected CO_2 migrating northeast (updip) from Trimble County would remain in Kentucky for at least 14 miles. Depending on volumes and rates of injection, part of the CO_2 plume could grow to the southwest (downdip) of the plant site, under the river. As at Ghent, injection simulations could be run to predict the size and shape of the CO_2 plume over time.

Using the most likely storage volumes at each site, the following volume of CO_2 could be stored on at each site, using property owned by LG&E-KU (Table 1-5).

Table 1-5. Total storage volume on-site assuming 100% use of LG&E-KU property

Site	CO_2 Storage Volume (metric tons per acre)	Total Property Size (acres)	Total On-site Storage Volume
Ghent	2,364	2,178	5,149,866
Trimble County	1,449	2,192	3,176,841

References Cited

Drahovzal, J.A., Harris, D.C., Wickstrom, L.H., Walker, D., Baranoski, M.T., Keith, B.D., and Furer, L.C., 1992, The East Continent Rift Basin: a new discovery: Spec. Pub. 18, Ser. XI, Kentucky Geological Survey, 25 p

Greb, S. and Drahovzal, J.A., 2011, unpublished report for Midwest Regional Carbon Sequestration Partnership (MRCSP).

Kepferle, R.C., 1977, Geologic map of the Ballardsville quadrangle,north-central Kentucky: U.S. Geological Survey Geologic Quadrangle Map GQ-1389, scale 1:24,000

Litynski, J., Deel, D., Rodosta, T., Guthrie, G., Goodman, A, Hakala, A., Bromhal, G., and Frailey, S., 2010, Appendix B, Summary of the Methodology for Development of Geologic Storage Estimates for Carbon Dioxide, 2010 Carbon Sequestration Atlas of the United States and Canada, U.S. Department of Energy, National Energy Technology Laboratory, http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlasIII/.

Luft, S. J., 1977, Geologic map of the Smithfield quadrangle, north-central Kentucky, U.S. Geological Survey Geologic Quadrangle Map GQ-1371, scale 1:24,000

Medina, C. R., Rupp, J. A., Barnes, D. A. 2011, Effects of reduction in porosity and permeability with depth on storage capacity and injectivity in deep saline aquifers: A case study from the Mount Simon Sandstone aquifer. International Journal of Greenhouse Gas Control 5: 146-156.

Swadley, W.C., 1977, Geologic map of part of the Bethlehem quadrangle, Trimble and Oldham Counties, Kentucky: U.S. Geological Survey Geologic Quadrangle Map GQ-1436, scale 1:24,000.

Swadley, W.C., 1973, Geologic map of parts of the Vevay South and Vevay North quadrangles, north-central Kentucky: U.S. Geological Survey Geologic Quadrangle Map GQ-1123, scale 1:24,000.

Chapter Two

Geologic CO_2 Sequestration Potential of the LG&E-KU Green River Station, Western Kentucky

John Hickman and Dave Harris
Kentucky Geological Survey

Geologic Summary Sheet for LG&E-KU CO2 Storage

Power Plant: Green River **County:** Muhlenberg **Geologic Basin:** Illinois Basin

Data Quality

Distance to nearest well control in reservoir: 3.0 miles (partial penetration)

Wells to primary injection zone within 15 mile radius: 4

Distance to nearest core in injection zone: 10.7 miles

Distance to nearest high-resolution seismic control: 3.6 miles

Reservoirs

Primary injection zone: Cambrian-Ordovician Knox Group

Rock type: dolomite with interbedded sandstones

Drilling depth at plant site: 6,421 - 8,000 ft

Trapping mechanism: regional dip (capillary and solution trapping)

Avg. reservoir pressure: 3,300 psi (assuming 100,000ppm TDS)

Reservoir temperature: 130°F

Salinity of reservoir fluid: 100,000 ppm

Reservoir thickness (gross/net): 36/11.1 ft

Average porosity: 9.7%

Average permeability: 1.2 md (calculated)

Secondary injection zone: None at this site

Confinement and Integrity

Primary confining zone: Maquoketa Shale

Rock type: shale and siltstone

Thickness of primary confining zone: 545 ft

Height above primary injection zone: 875 ft

Well penetrations of primary seal within 15 mile radius: 6

Secondary confining zone: Devonian New Albany Shale

Rock type:	black shale
Thickness of secondary confining zone:	225 ft
Height above primary injection zone:	2,690 ft

Well penetrations of secondary seal within 15 mile radius: 43

Number of faults cutting primary seal within 15 mile radius:	7 (fault zone segments)
Distance to nearest mapped fault:	6.8 mi

Storage Capacity

Calculated CO_2 storage capacity, primary injection zone:

345,515 million metric tons/100 acres (assuming 100% efficiency)

72,558 metric tons/100 acres (at 21% efficiency)

Introduction

An evaluation of geologic carbon dioxide (CO_2) sequestration potential was performed for an area surrounding the LG&E-KU Green River power generation station in Muhlenberg County, Kentucky. A circular area with a 15-mi radius around the plant was defined as the primary focus of the evaluation, but data from beyond 15 mi was also used because of limited data within the primary area (Figure 2-1).

The following data were compiled for the evaluation:

- 7.5 minute topographic and geologic quadrangle maps for the Central City East, Central City West, Equality, and Livermore quads;
- Locations of all petroleum exploration and waste disposal wells penetrating the Upper Ordovician Maquoketa Shale or deeper formations;
- Depths of formation tops for geologic units from the top of the Ordovician to the Middle Cambrian strata;
- Digital geophysical logs for Knox and deeper wells; and
- Reflection seismic data, including the purchase and interpretation of 3 new profiles in Ohio, Muhlenberg, and Hopkins Counties, Kentucky.

Within the 15 mile radius around the Green River Station, four wells have been drilled that penetrate the target reservoir (Knox Group), including one well (Conoco #1 Turner) that penetrated entire Paleozoic section, ending in Precambrian rocks. These wells provide the key geologic data used in this assessment. Even though the well is 23 miles outside of the project radius, geological data relating to the injection zone was also used from the Kentucky Geological Survey #1 Marvin Blan well in Hancock, County, Ky. The data from this more distant well were added to the review because of the quality and quantity of the subsurface data acquired at this research well. Data from this well included core analyses, formation image logs, and injection data. All of these wells penetrated the primary injection zone (Knox Group) and overlying seal (Maquoketa Shale).

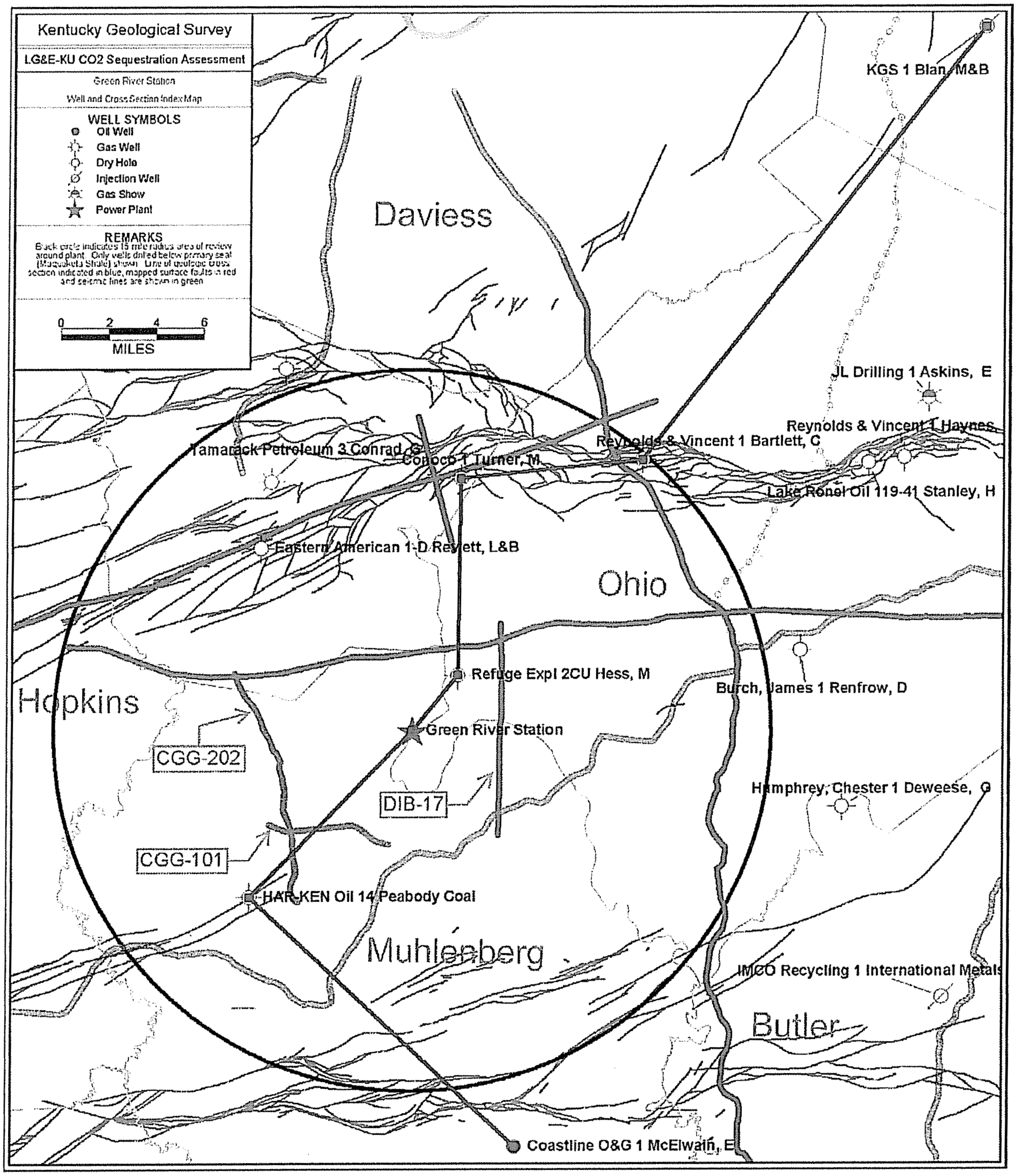


Figure 2-1 - Index map showing the location of Green River Station in western Kentucky. The study area is enclosed by the black circle. Red lines are faults mapped at the surface and green lines are the locations of seismic profiles used in the study. Wells drilled deeper than Maquoketa Shale are shown. See Figure 2 for surface geology. Blue line is the location of the north-to-south cross section shown in Figure 2-3.

Geologic Setting and Surface Geology

The Green River Station is located in southernmost Illinois Basin, within the Moorman Syncline. This east-west trending syncline (concave upward fold structure) within Mississippian, Pennsylvanian, and Quaternary strata is a sag feature that formed above the Cambrian-aged Rough Creek Graben. The borders of the Rough Creek Graben are formed by basement-rooted fault systems; the Rough Creek Fault System to the north (exposed in McLean and Ohio Counties; Figure 2-1), and by the Pennyrile Fault System to the south (Christian, Muhlenberg, and Butler Counties; Figure 2-1). Despite the numerous exposed faults in the study area, no evidence has been found to suggest that any of these faults have been active since the Permian (more than 250 million years ago).

The Green River Station is located on the western edge of the Central City East 7.5 minute topographic quadrangle, and a geologic map for this quadrangle was published by Palmer (1972). The station is located on unconsolidated Quaternary alluvium sediments (Figure 2-2). The hills northwest of the station are underlain by Middle-Upper Pennsylvanian sandstones, siltstones, shales, limestones, and coal of the Patoka Formation (Pp in Figure 2-2). The hills colored in green to the south of the station are formed by sandstone, shale, coal of the Lower-Middle Pennsylvanian Shelburn Formation (Psh in Figure 2-2). The change in colors in the map area northwest of the station (Livermore Quad) in Figure 2-2 represents a slightly different stratigraphic classification system, and not an abrupt change in surface geology. Surface geology does not have a direct impact on carbon sequestration potential, since carbon dioxide (CO_2) injection will occur at much deeper depths. More information about these quadrangle maps and units is available online at: http://kgs.uky.edu/kgsmap/KGSGeology/viewer.asp

The surface geology will impact the design and implementation of shallow groundwater monitoring wells that will be required by U.S. EPA for an underground injection control (UIC) permit. The presence of unconsolidated alluvium along the Green River should reduce the overall expense of the construction of monitoring wells. The EPA UIC permit will likely require monitoring down to the base of the underground source of drinking water (USDW), defined as having water with less than 10,000 ppm of total dissolved solids, which will require drilling into bedrock.

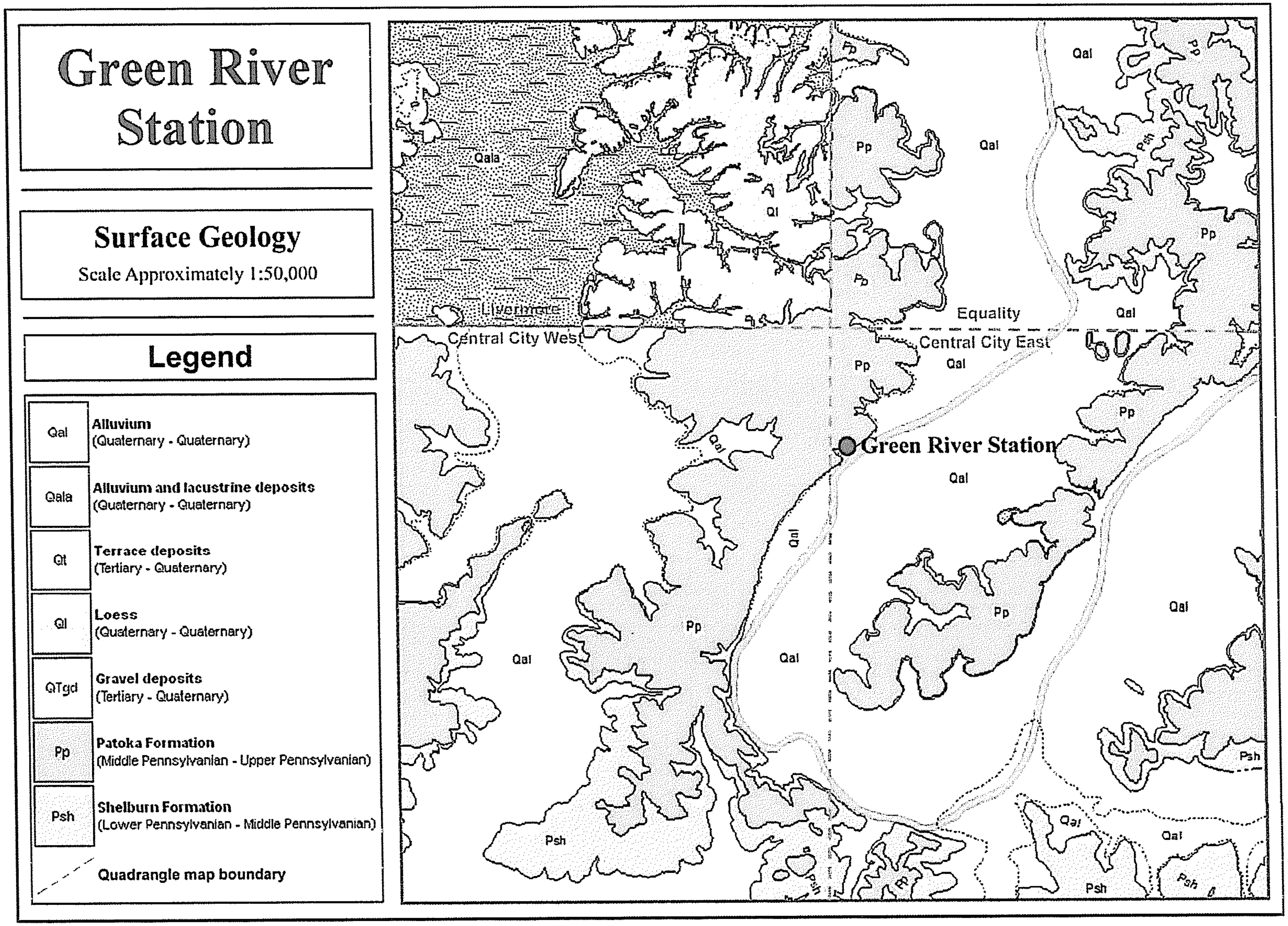


Figure 2-2 - Geologic map of parts of the Central City East (Palmer, 1972), Central City West (Palmer, 1969), Equality (Goudarzi, 1969), and Livermore (Hanson and Smith, 1978) 7.5 minute USGS Geologic Quadrangle maps surrounding the Green River Station. Note that Hanson and Smith (1978) used slightly different classifications for unlithified surficial units compared to the other quadrangles in this view.

Stratigraphy and Structure

In areas with normal subsurace temperature and pressure gradients, geologic storage of CO_2 is confined to depths greater than 2,500 ft below the surface so that CO_2 exists in a supercritical, or dense phase. Supercritical CO_2 has properties of both a liquid and gas, but much higher density than gaseous CO_2. This results in significant increases in storage capacity within the same storage reservoir. In the Green River Station area, this 2,500 ft depth falls within Upper Mississippian strata (primarily limestones and siltstones). Although these formations can be porous, the lack of a adequate confining unit or stratigraphic seal make these units unsuitable for the storage of CO_2.

The two formations below 2,500 ft that are considered appropriate for use as confining layers within this area are the Upper Devonian New Albany Shale (around 3,500 ft depth), and the Upper Ordovician Maquoketa Shale (at around 5,000 ft). The Silurian Laurel Dolomite is the only porous unit that lies between the New Albany and Maquoketa Shales, but its limited thickness in this area (about 10 ft thick) makes it unsuitable as a commercial-scale injection target. For these reasons, the Maquoketa Shale will be considered the Primary Confining Unit, with the stratigraphically higher New Albany Shale acting as a Secondary Confining Unit. At shallower locations, the Middle Ordovician Black River Limestone is also considered as a Secondary Confining Unit because of its low porosity and permeability. However, the deeper burial at the Green River site has produced extensive fracturing within this unit, which therefore limits its sealing capacity.

The only unit evaluated for storage capacity at this site is the Late Cambrian to Early Ordovician Knox Group. Reservoir zones within the Knox include dolostones with both primary (intergranular) and secondary (vuggular) porosity, as well as interbedded porous sandstones.

Unlike at other LGE-KU study sites, the base of the proposed injection zone at the Green River Station is defined by depth-related porosity loss within the Knox Group, and not by the base of a stratigraphic unit (Figure 2-3). The depth at which porosity within the Knox is insufficient for storage of CO_2 (less than seven percent porosity) is around 8,000 ft depth in the Green River Station area.

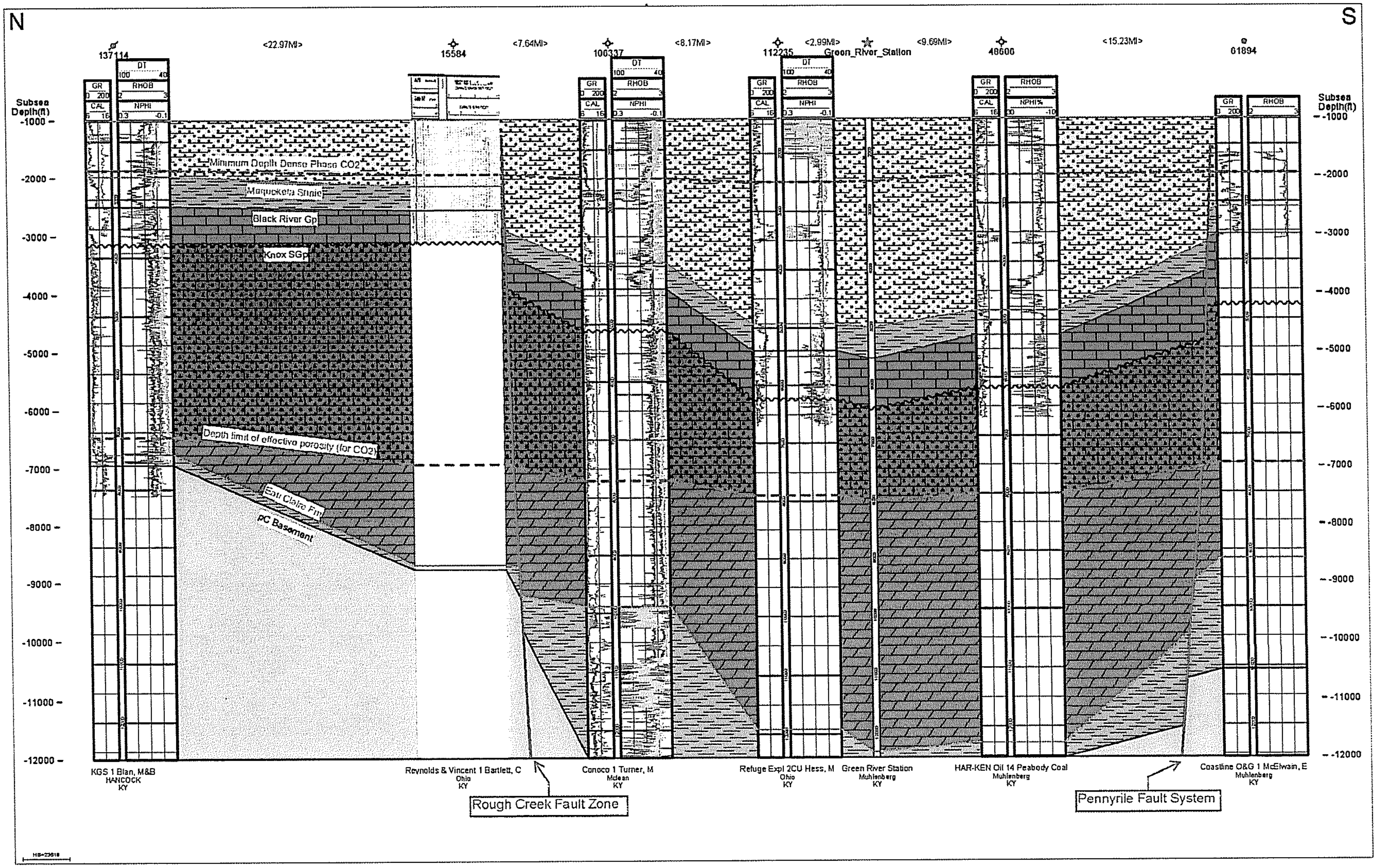


Figure 2-3 - North to south regional structure cross section showing well logs for deep wells and the location of the Green River Station. Basement offsets along faults (near edge of 15 mi study radius) are not to scale. Well logs include the gamma ray and caliper in the left track, and bulk density, neutron porosity, and sonic logs in the right track. Stratigraphic tops below logged intervals (and well total depth) interpreted from regional seismic data. The Maquoketa Shale is the primary seal for the underlying Knox, and extends across the entire area.

Middle Cambrian Eau Claire Formation

The deepest unit evaluated in this study is the Eau Claire Formation. The Eau Claire directly underlies the Knox Group and is predominantly composed of green and gray marine shale, with some interbedded dolomite. The Eau Claire has very low porosity and permeability. Figure 2-4 is a structure map contoured on the top of the Eau Claire. The Eau Claire deepens to the west into the deeper parts of the Rough Creek Graben. The drilling depth to the top of the Eau Claire at the Green River Station is estimated to be 12,300 ft, based on regional seismic interpretation. No units with porosity suitable for CO_2 storage are expected or interpreted below the top of the Eau Claire Formation. Unlike at the Ghent, Trimble, and Mill Creek Station sites, the Mt. Simon Sandstone is not present at this location.

Late Cambrian-Early Ordovician Knox Group

Within the Illinois Basin, the Knox Group is divided into two dolomite units; the Beekmantown Dolomite and the Copper Ridge Dolomite, separated by sandstone or dolomitic sandstone unit of the Gunter Sandstone. Because the Gunter is poorly developed in this area, this study analyzes the Knox Group as a whole without differentiation. The top of the Knox is a regional erosional unconformity that formed when the Knox Group rocks were uplifted above sea level during the early Ordovician. The Knox Group lies at a subsurface elevation of about 6,010 ft below sea level (Figure 2-5), and is approximately 5,900 ft thick at the Green River Station site (Figure 2-6). The Knox contains scattered porous and permeable intervals separated by impermeable dolomite. It has injection potential in other parts of Kentucky (such as the Kentucky Geological Survey #1 Marvin Blan research well in Hancock County), and was used as a hazardous waste injection zone at the DuPont chemical plant in Louisville. Porous zones in the Knox have also been used for natural gas storage by LG&E in Grant and Oldham Counties (Ballardsville and Eagle Creek storage fields). These storage fields are now abandoned, and the porous zones in these fields are too shallow for CO_2 storage.

Within the Rough Creek Graben, the Knox Group deepens and thickens to the west. All of the Knox in the study area lies below the 2,500 ft depth limit for CO_2 to be in a supercritical phase. However, the lower part of the Knox (below 7,500-8,000 ft depth) is not an injection target, because the primary porosity (and therefore permeability) has been destroyed by the compaction of burial. Only units with seven percent or more porosity are suitable for sequestration, so the compaction alters the effective reservoir thickness of the Knox to about 1,575 ft at the Green River Station (Figure 2-7). This depth limitation reverses the trend of the overall thickness map (Figure 2-6), so that the target interval thickens to the east (Figure 2-7), and towards the northern and southern boundaries of the Rough Creek Graben (Figure 2-8). Thus, within the 15 mi radius, the useable thickness of the Knox varies from around 700 ft in eastern Hopkins County to around 4,200 ft thick in central Ohio County, Kentucky.

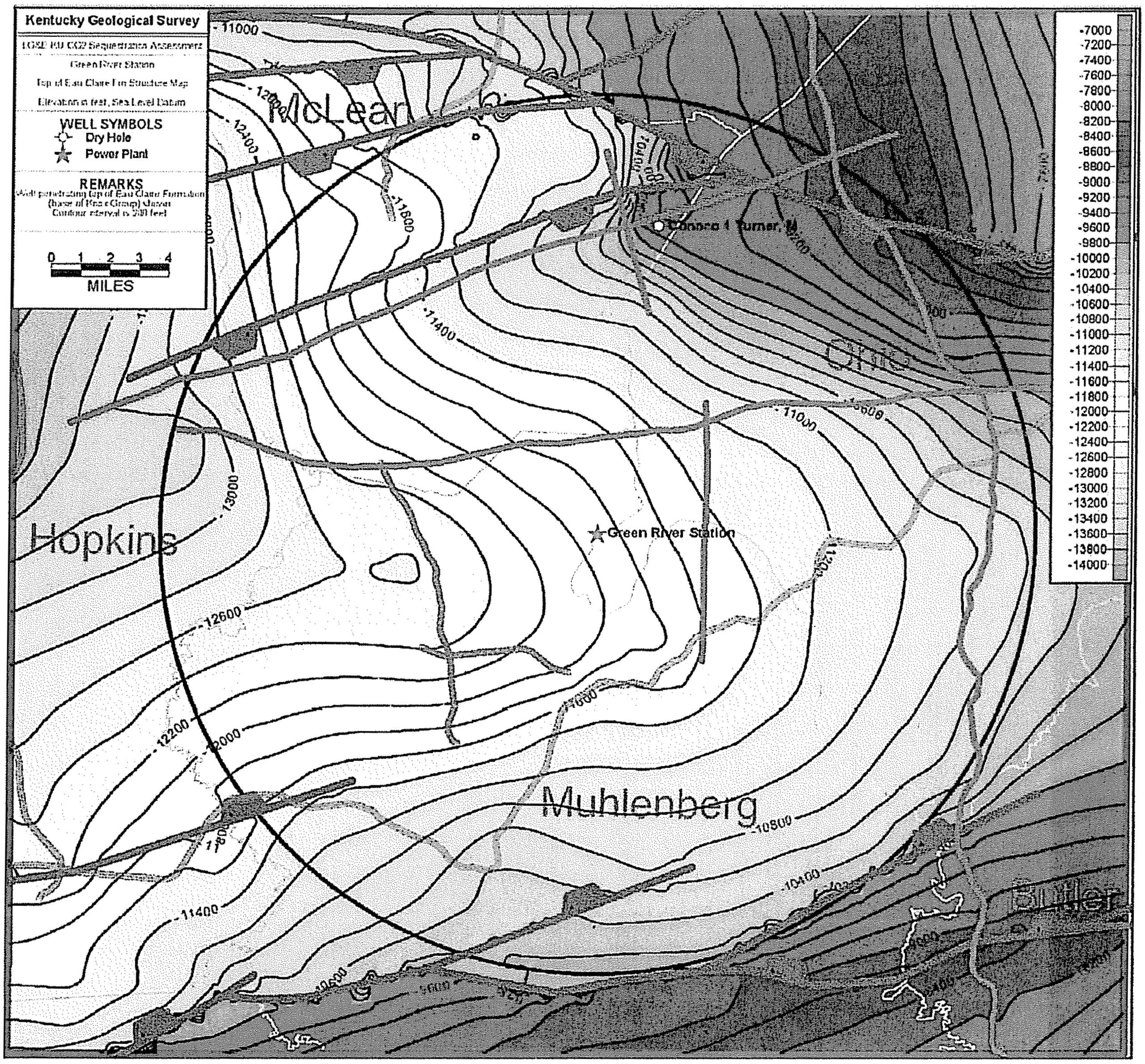


Figure 2-4 - Structure map on top of the Cambrian Eau Claire Formation. The structure deepens to the west. Regional fault systems marked in dark grey, seismic profiles in green. The contour interval is 200 ft.

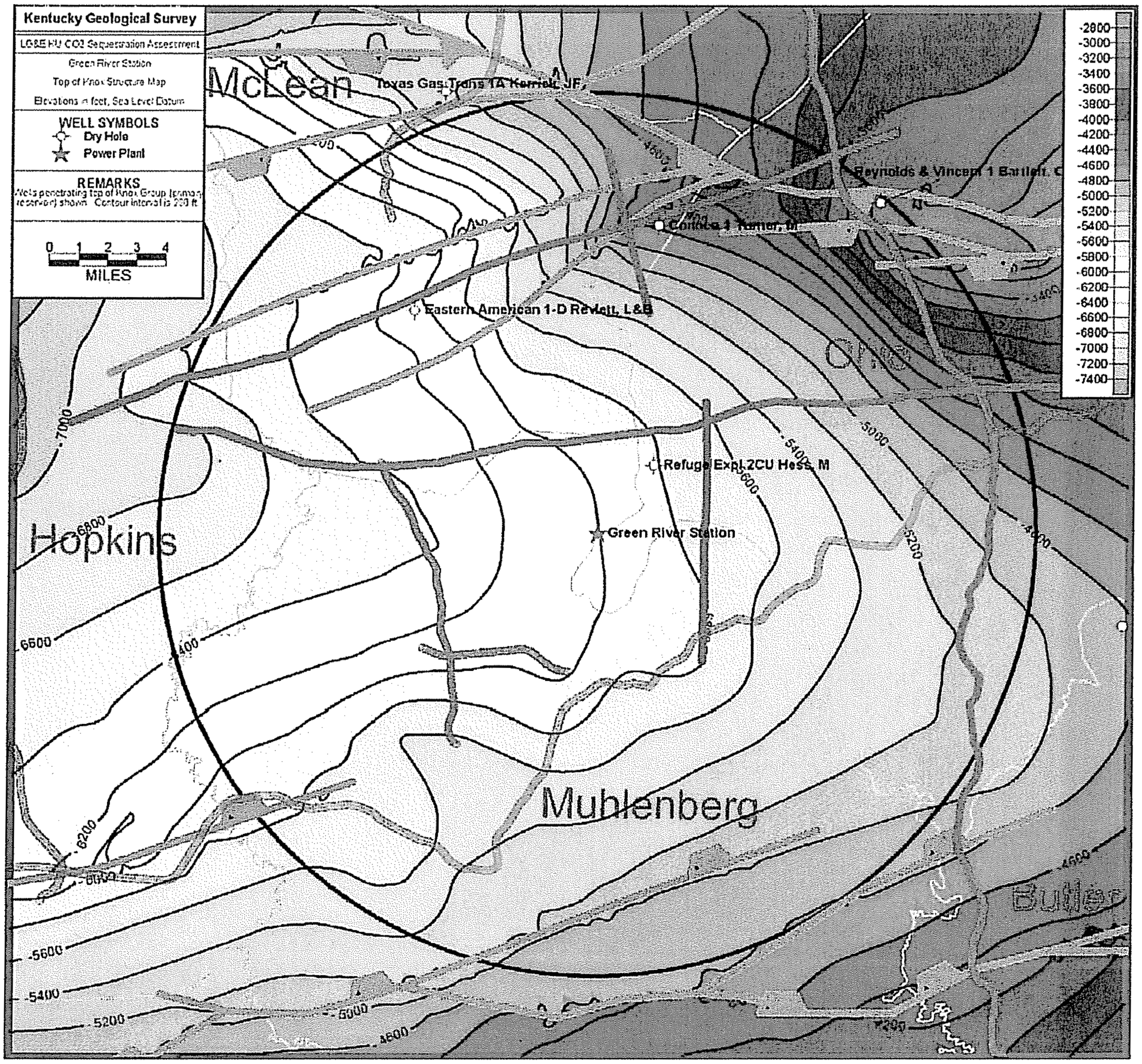


Figure 2-5 - Structure map on the top of the Knox Group. Regional fault systems marked in dark grey, seismic profile data locations in green. Contour interval is 200 ft. The top of the Knox dips to the west at the site location.

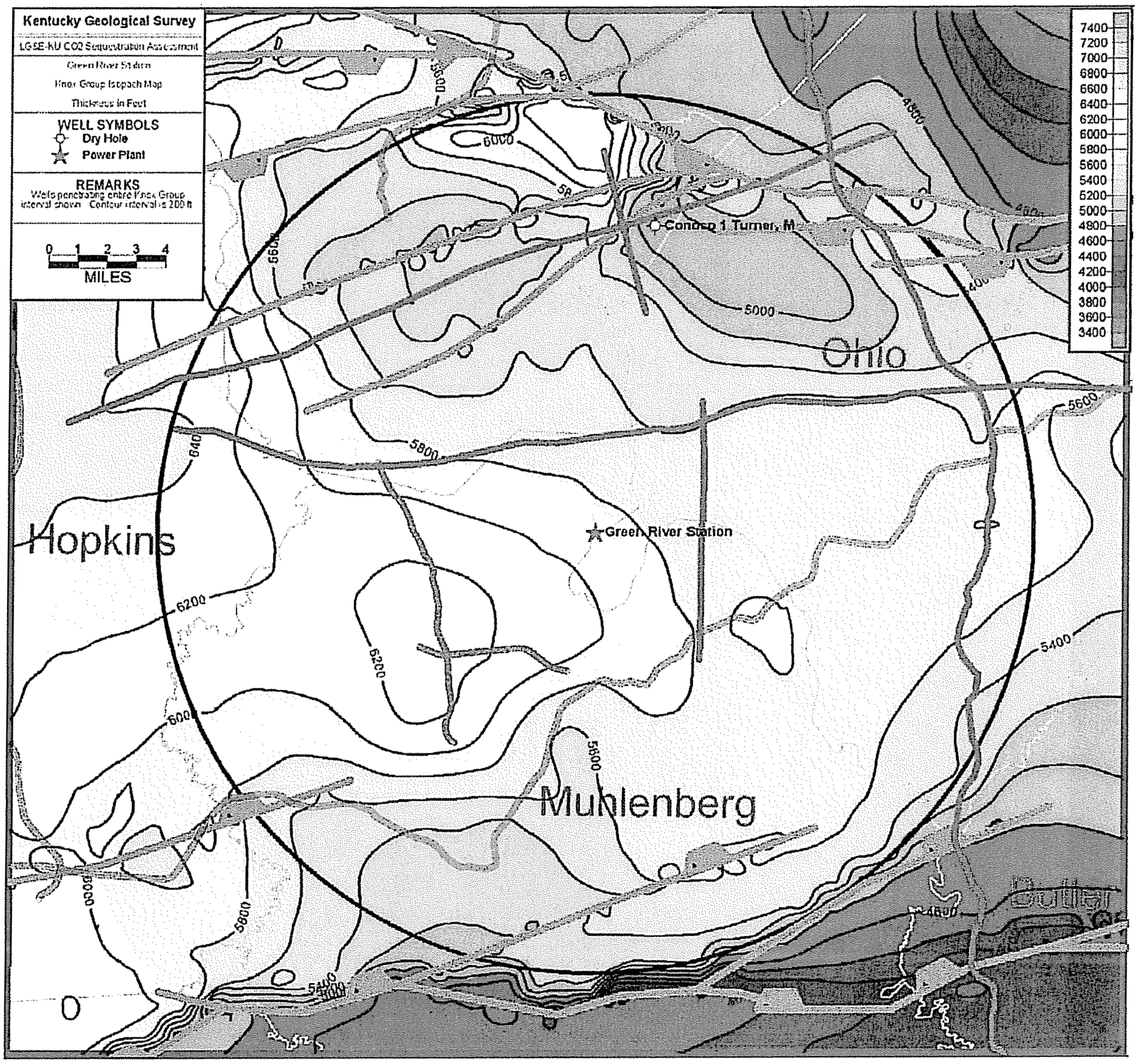


Figure 2-6 - Isopach (thickness) map of the entire Knox Group interval.

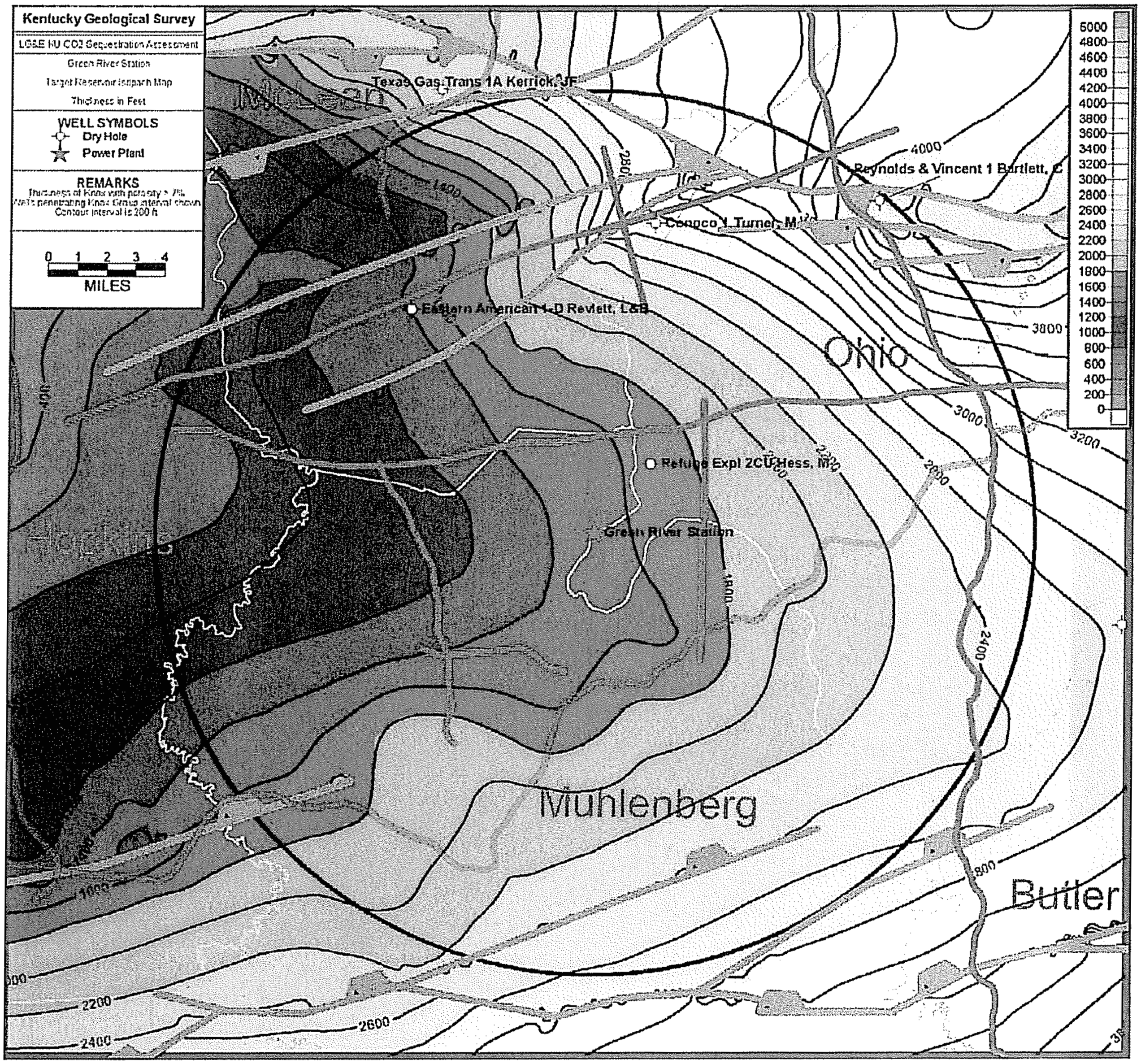


Figure 2-7 - Isopach thickness map of upper porous zone of Knox Group above -7,600 ft in elevation (about 8,000 ft depth).

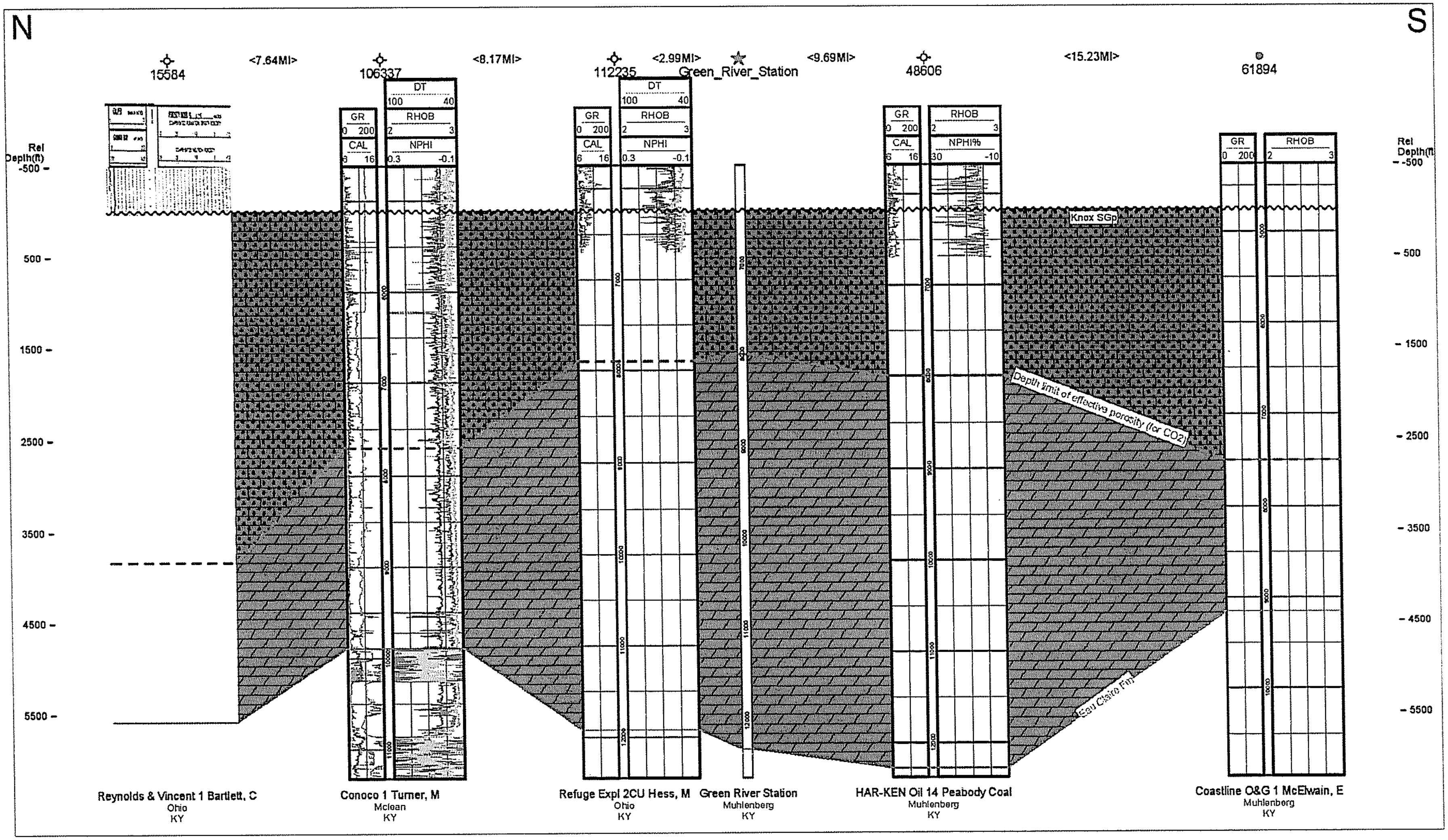


Figure 2-8 - Stratigraphic north to south cross-sectional profile across 15 mile radius around the Green River Station. Depth datum is the top of the Knox Group. Stratigraphic tops below logged intervals (and well total depth) interpreted from regional seismic data.

Ordovician Ancell Group - Dutchtown Formation and Joachim Dolomite

The Dutchtown Formation and Joachim Dolomite are dolomite intervals that contain variable amounts of shale, and immediately overlie the Knox unconformity. They are equivalent to the Wells Creek Dolomite in Ohio, and are partly gradational with the St. Peter Sandstone. They generally have low porosity and permeability, and may provide additional confinement for CO_2 injected in deeper zones. The formations were not mapped in detail.

Ordovician Black River Group

In shallower areas, the Black River Group forms a secondary confining zone (seal) for CO_2 injected into the deeper Knox Group. The top of the Black River is at about 5,545 ft depth below the Green River Station (Figure 2-9), where the interval is about 875 ft thick. These rocks are composed of limestone, with minor amounts of dolomite. The interval typically has very low porosity and permeability unless fractured from faulting or burial. Unfortunately, the Black River Group in the area surrounding the Green River Station appears to be extensively fractured, making it unsuitable as a seal.

Upper Ordovician Maquoketa Shale

The Maquoketa Shale is the primary confining unit for the Knox Group at the Green River site. The Maquoketa Shale does not directly overlie the Knox injection target, but instead lies roughly 875 ft above the top of the Knox Group (separated by the rocks of the Ancell and Black River Groups). The Maquoketa Shale is composed of mudstone and siltstones with sufficient clay content to reduce the effective porosity and permeability to almost zero. At the Green River site, the top of the Maquoketa is around 5,000 ft deep (-4,590 ft subsea), and dips gently to the west-northwest (Figure 2-10). The thickness of the Maquoketa Shale appears to lack the large basinal trends of other units (Figure 2-11), and is about 545 ft thick at the station.

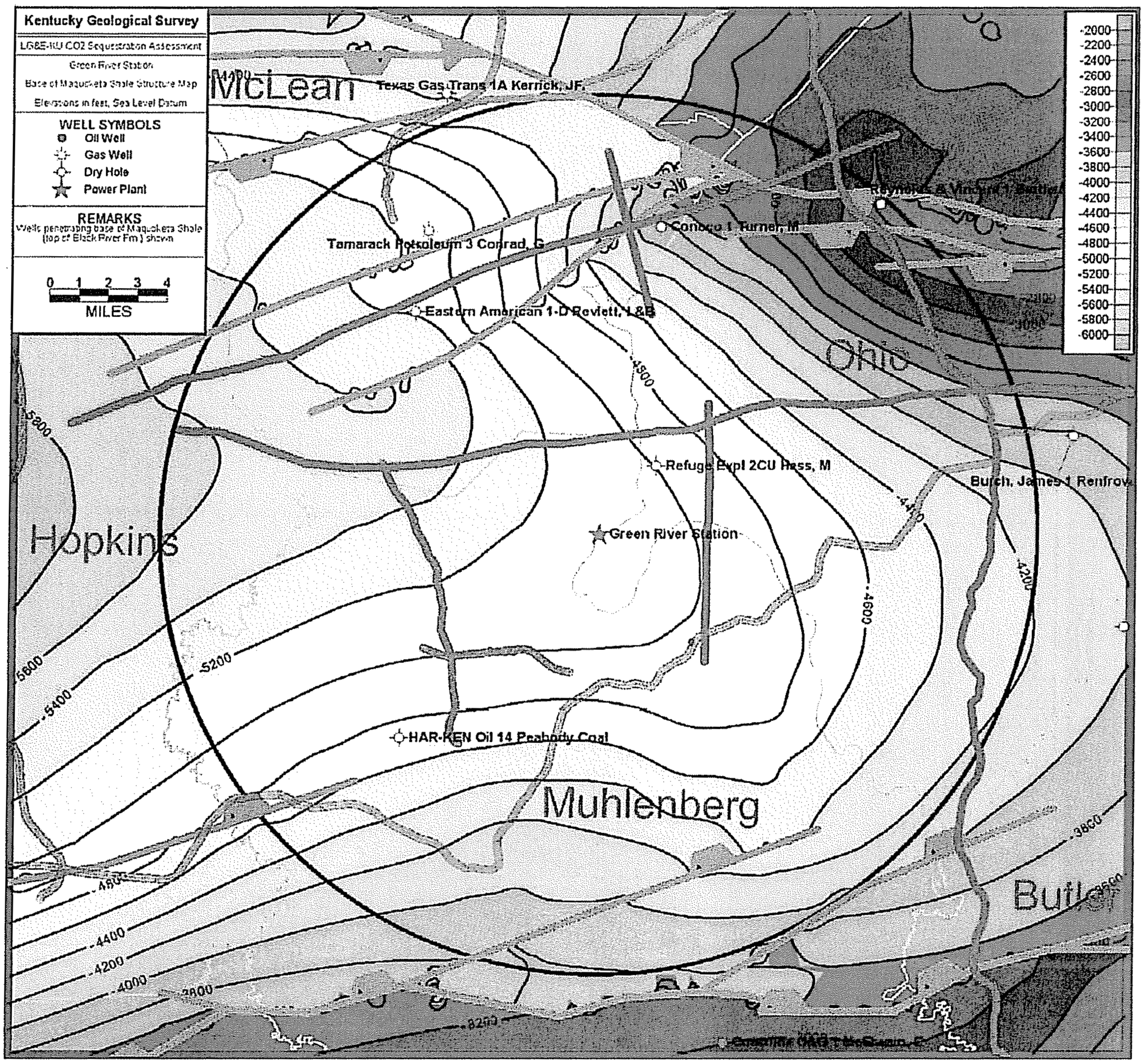


Figure 2-9 - Structure map of the top of the Middle Ordovician Black River Group (base of the Maquoketa Shale). Contour interval is 200 ft. Regional fault systems are indicated by dark grey lines, and seismic profile locations are marked in green.

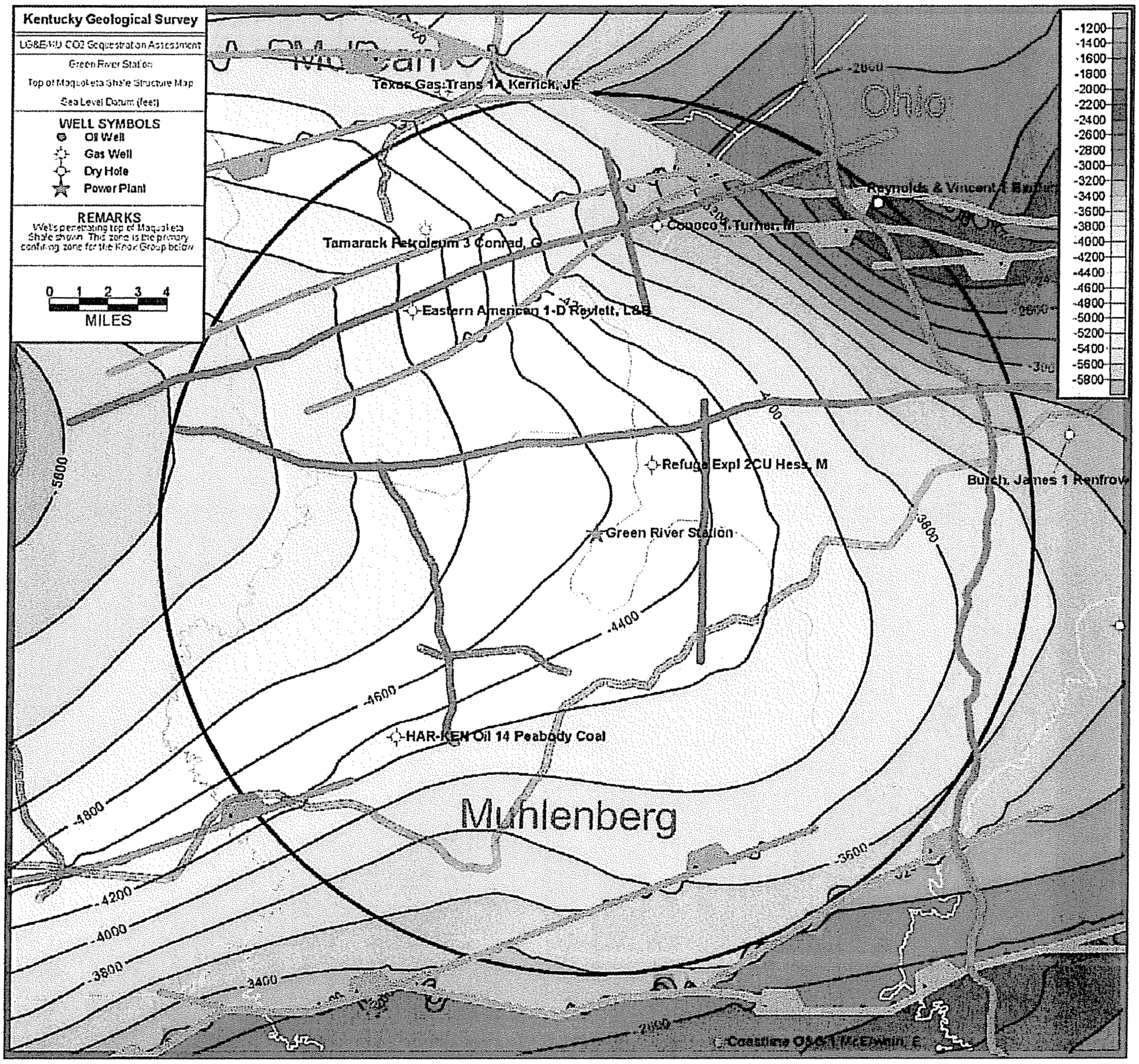


Figure 2-10 - Structure map of the top of the Upper Ordovician Maquoketa Shale (primary confining unit). Contour interval is 200 ft. Regional fault systems are indicated by dark grey lines, and seismic profile locations are marked in green.

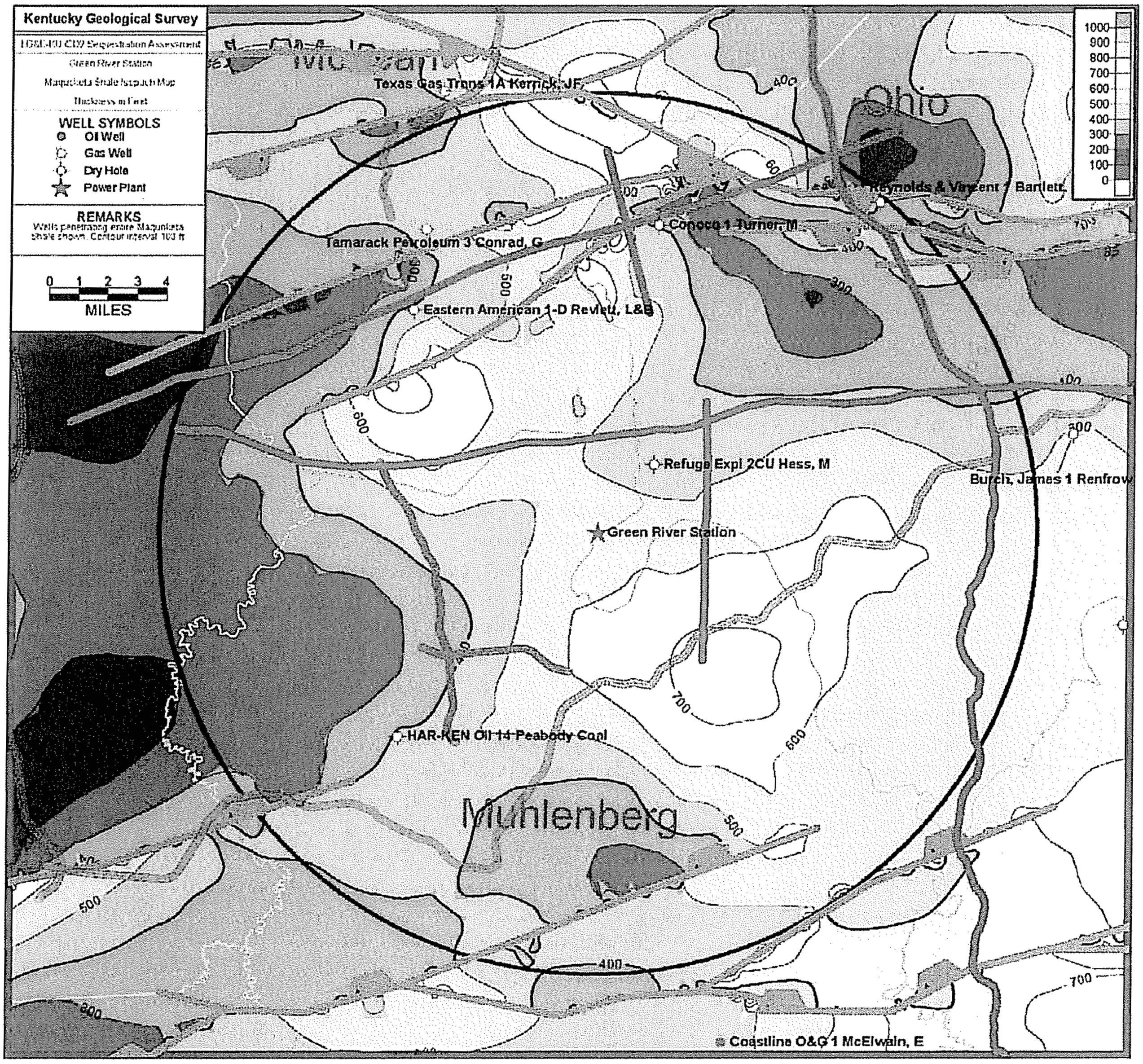


Figure 2-11 – Thickness map of the Maquoketa Shale (primary confining unit). Contour interval is 100 ft. Regional fault systems are indicated by dark grey lines, and seismic profile locations are marked in green.

Seismic Data Interpretation and Deep Faults

Six reflection seismic profiles on-file at KGS were used to interpret the stratigraphy and geologic structure surrounding the Green River Station. In addition, LGE-KU purchased segments of three different seismic lines within about 5 mi of the site, in order to help constrain the interpretation of reservoir integrity below the station: seismic lines CGG-101, CGG-202, and DIB-17 (Figure 2-1). With these supplementary data, a nearly complete circumference of seismic data surrounds the station. This raises the confidence level of the structure and stratigraphy interpretations below the Green River Station.

Numerous individual faults have been mapped at the surface within the 15 mi study radius around the Green River Station (Figure 2-1). At the depth of the primary confining unit (Maquoketa Shale), these faults are interpreted to coalesce into seven fault system segments, and are represented by bold dark grey lines on the map figures. These interpretations were made after an analysis of both well and seismic data (green lines in the previous maps) from the region. However, these fault systems are not evenly distributed, and exist primarily along the northern and southern edges of the study area. The nearest fault zone to the station is about 7 miles away to the northwest. Because of the structure at the top of the Knox Group, up-dip migration of buoyant CO_2 away from the station will tend move to the east-northeast, away from the closest faults that area to the northwest and southwest (Figure 2-5).

One major concern with the sequestration integrity of the Knox Group below the Green River Station was the possible subsurface extensions of the North and South Graham Faults in northwestern Muhlenberg County (Figure 2-12). These faults are exposed at the surface 7.9 miles southwest of the station (Figure 2-1). If these faults did extend beyond their surface exposures and along the same strike (compass direction), they would cross Green River valley within 1.5 miles of the station. The parts of seismic lines CGG-101 and CGG-202 that were purchased by LGE-KU were chosen specifically to address this concern. The north-south profile CGG-202 was acquired just east (< 0.5 mi) of these fault exposures (Figure 2-1). The near surface deformation from these faults is visible on the southern end of the line (Figure 2-13). No structural offset is visible at or below the secondary confining unit, but a linear, sub-vertical zone of reduced amplitudes below this deformed area implies the presence of extensive fracturing near or just beyond the tip of this fault (highlighted in purple in Figure 2-13). If this truly is a fault related deformation zone, it appears to end before crossing line CGG-101 (Figure 2-14), 3 mi to the northeast (Figure 2-12). East of the station, no faults or fracture deformation is visible along the 8.7 mi of line DIB-17 (Figure 2-15). From the data available to this study, it is interpreted that no faults breach the Knox Group or its primary or secondary confinement units within 5 mi of the Green River Station.

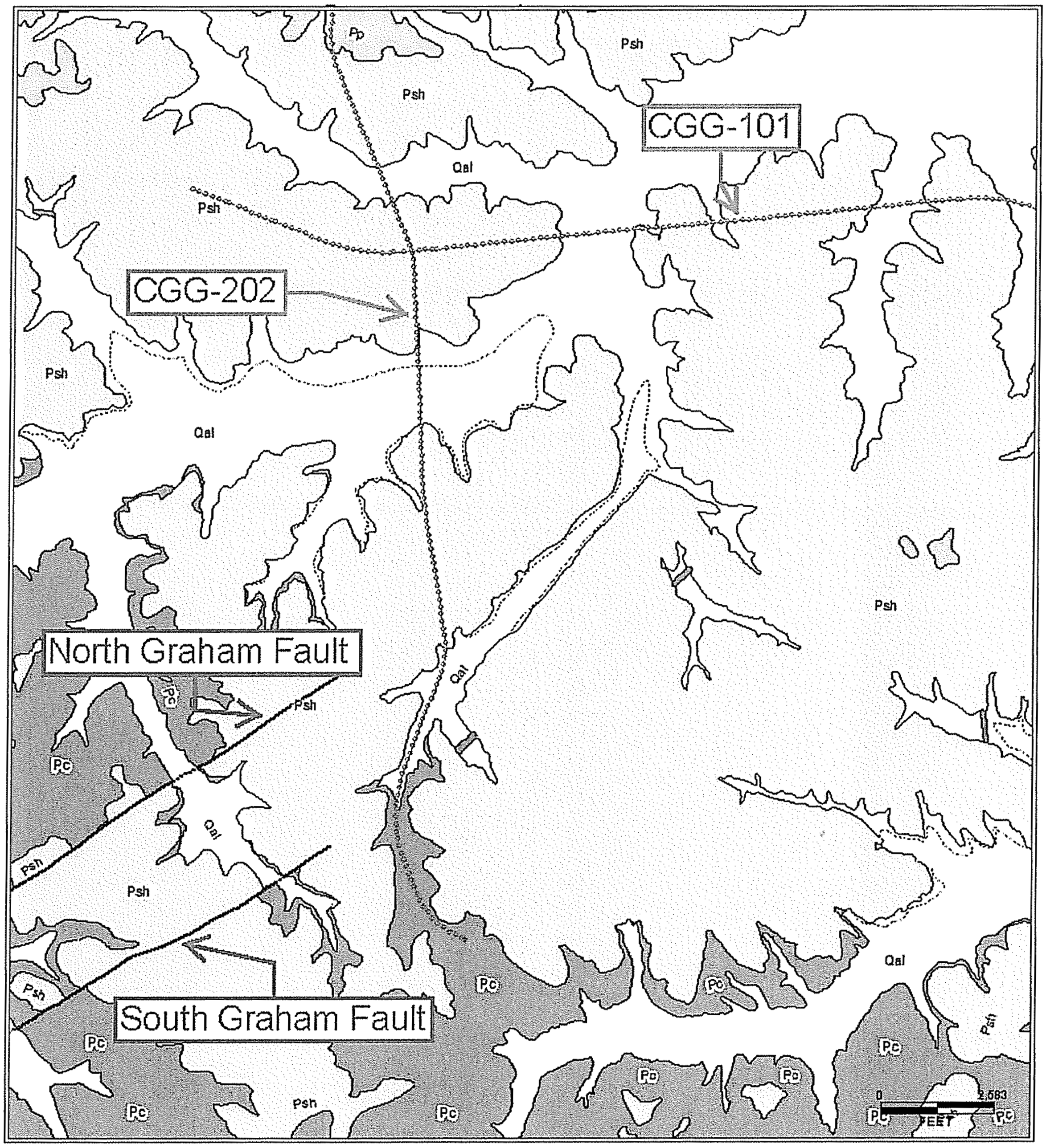


Figure 2-12 - Detailed view of the surface geology and seismic line locations (green dotted lines) near the northeastern ends of the North and South Graham Faults. Geology data from Kehn (1968).

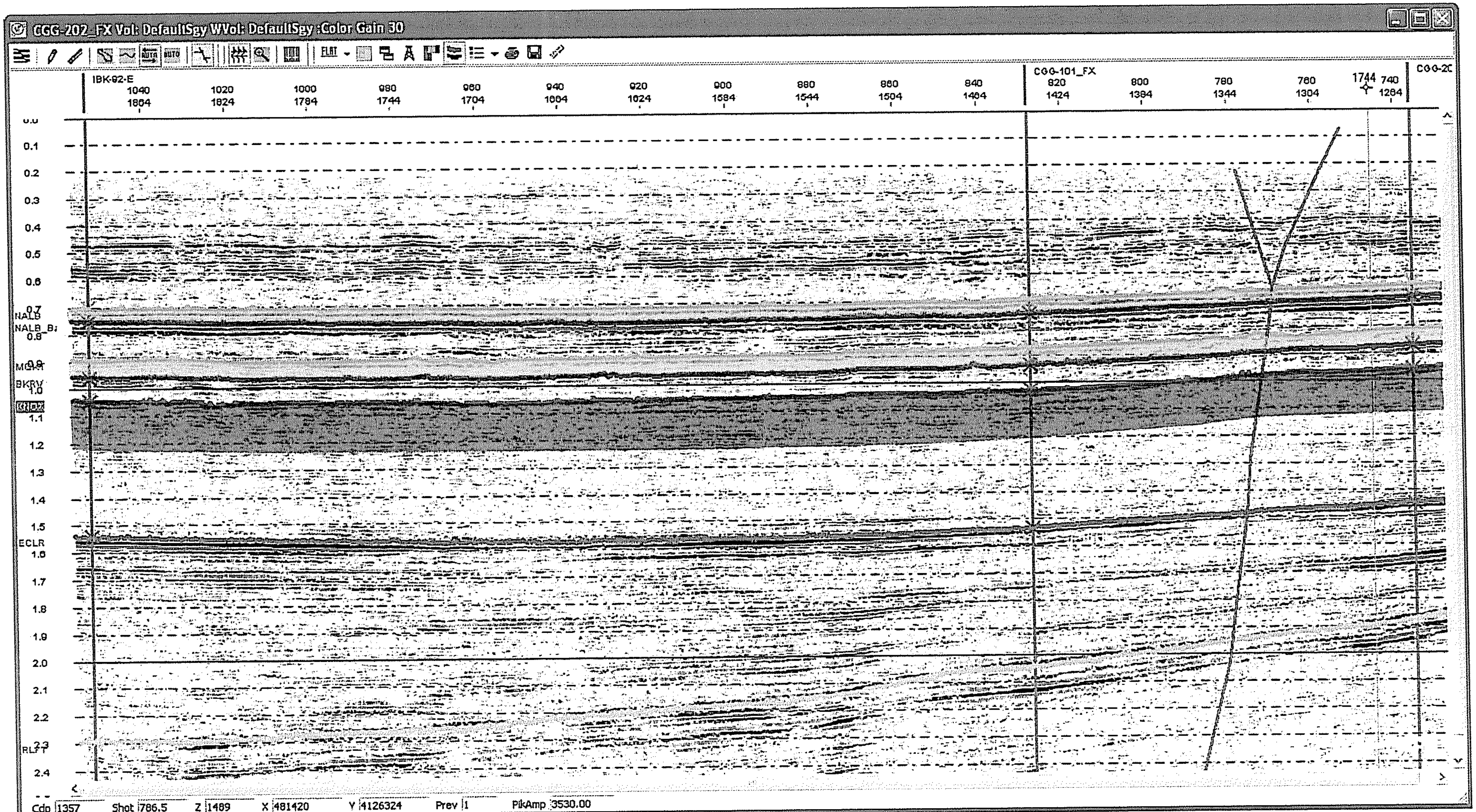


Figure 2-13 - Seismic profile CGG-202, Muhlenberg County, Ky. The deeper, primary confining unit (Maquoketa Shale) and shallower, secondary confining unit (New Albany Sh.) are highlighted in green. The estimated porous interval of the Knox Group is highlighted in purple. The Knox porosity zone is not resolvable on seismic data. The thin purple line on right is the interpreted deformation zone of the Graham Faults (Figure 2-12).

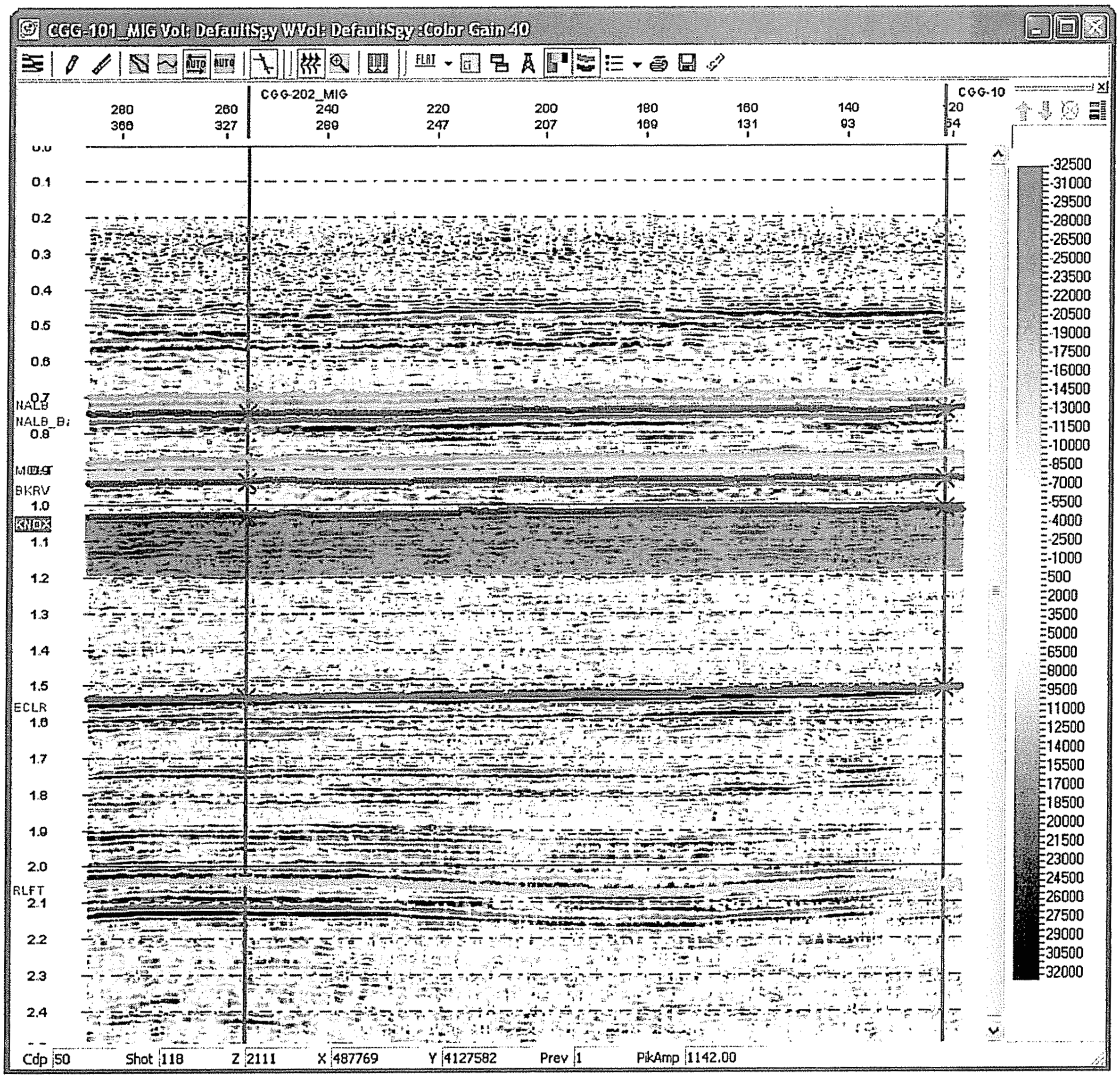


Figure 2-14 - East-West seismic profile CGG-101, central Muhlenberg County, Ky. The deeper, primary confining unit (Maquoketa Shale) and shallower, secondary confining unit (New Albany Sh.) are highlighted in green. The estimated porous interval of the Knox Group (although not resolvable on seismic data) is highlighted in purple. The base of the Knox Group (Eau Claire Fm.) is marked in dark green.

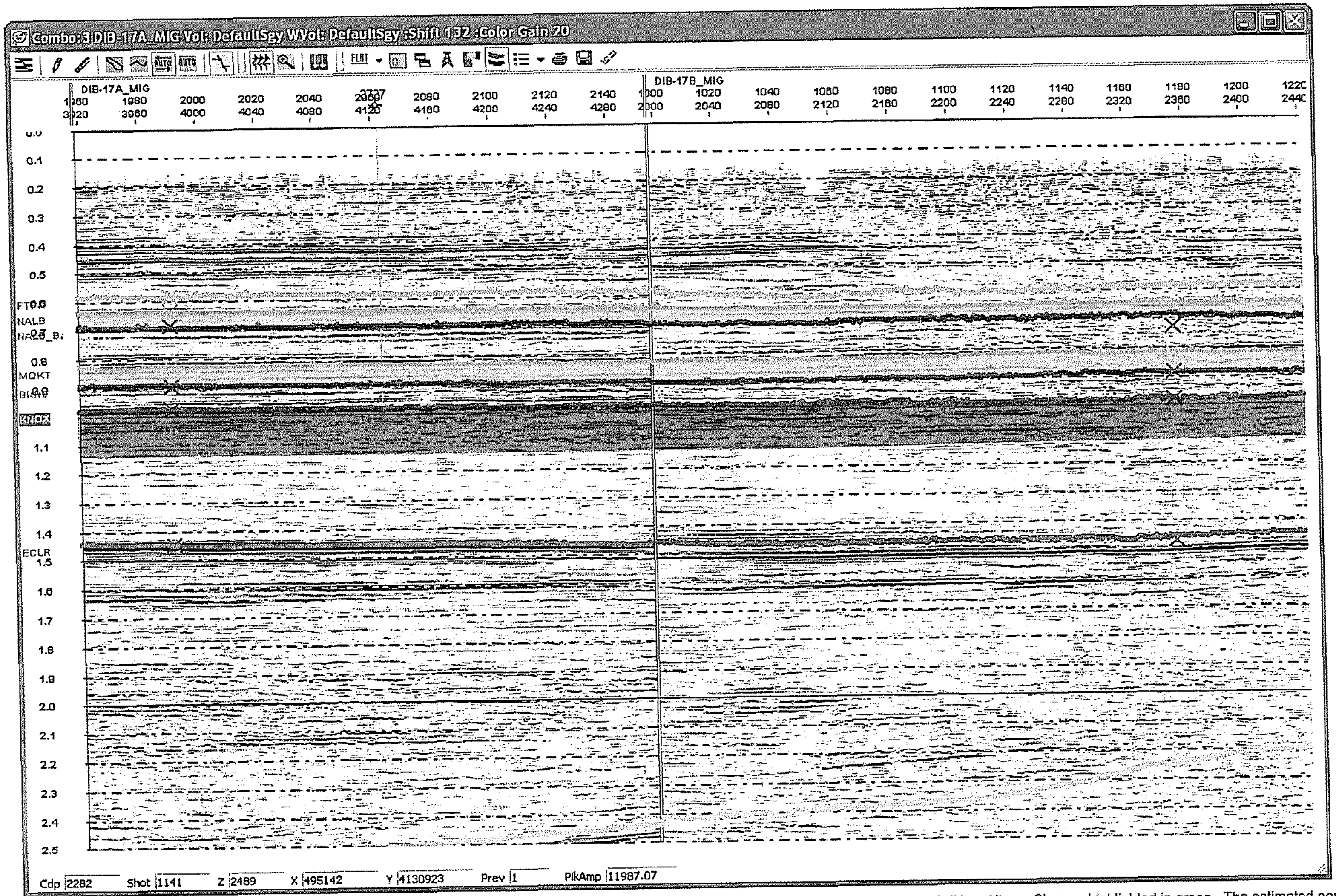


Figure 2-15 - Seismic profile DIB-17, Muhlenberg and Ohio Counties, Ky. The deeper, primary confining unit (Maquoketa Shale) and shallower, secondary confining unit (New Albany Sh.) are highlighted in green. The estimated porous interval of the Knox Group (although not resolvable on seismic data) is highlighted in purple. The base of the Knox Group (Eau Claire Fm.) is marked in dark green.

Reservoir Quality and Injection Zone Thickness

In order to calculate carbon storage capacity, the average porosity and thickness of the storage reservoir is required. Because there are currently no wells drilled to the base of the Knox Group on the Green River Station plant site, exact porosity data are not available. For this reason, estimates for porosity and net injection zone thickness were calculated from data from nearby wells. Data from the Kentucky Geological Survey #1 Marvin Blan CO_2 injection test well are especially helpful, since high-quality well logs and core data are available from this well.

Porosity and Permeability

The most direct and accurate method of determining porosity and permeability is through the analysis of rock samples. Because of the cost associated with drilling well cores, far fewer well samples vs. well logs of the Knox Group are available. Porosity (but not permeability) data is also derived from downhole well logs, especially the bulk density log. Logs provide a continuous dataset for the entire formation, but are not as accurate as core data. A total of 4 wells with density logs were used to estimate dolostone porosity at the plant site (Refuge Exploration #2CU Hess, Conoco #1 Turner, Texas Gas Transmission #1A Kerrick, and Kentucky Geological Survey #1 Marvin Blan).

Plotting porosity vs. permeability illustrates the positive correlation between the two. Because porosity can be measured with downhole logs and permeability cannot, this cutoff allows the thickness of rock with suitable porosity and permeability for injection to be summed from porosity log data alone. A empirical analysis of the relationship of porosity vs. permeability within the Knox Group was performed by Bowersox (2010), using 54 rock samples (from sidewall and whole cores) obtained from the Kentucky Geological Survey #1 Marvin Blan well in Hancock County, Kentucky. Although this well lies outside of the Rough Creek Graben and is 38 mi from the station, the lithology and depositional environment of the Knox Group does not vary significantly over this area. Therefore, we believe that those characteristics are applicable to the Knox Group below the Green River Station. Although there is some variability in the data, the best fit curve of the data can be described as:

$$k = 8.4 \times 10^{-4} e^{0.75\Phi}$$

Where,

k = permeability in millidarcys (md)

Φ = porosity in percent

Using this methodology, the average permeability in the Knox Group is calculated as 1.24 md at an average porosity of 9.7%. The "floor" of the injection zone within the Knox Group is calculated to have a permeability of 0.16 md at 7.0% porosity.

Porosity in the Knox Group decreases with increasing burial depth. This is primarily due to cementation and compaction, and is a result of increased temperature, pressure, and the amount of time the rocks have been buried. Cross-plots of porosity vs. depth establish a general correlation between porosity and depth within the Knox (approximately 1.8% loss of porosity per 1,000 ft of depth). This rate of porosity loss correlates well with regional Knox porosities calculated from available well log data. At depths below about 8,000 ft in the Knox, porosity values drop below 7% and therefore is unsuitable for CO_2 storage. For this reason, 8,000 ft is considered the "floor" of the potential sequestration zone within the Knox Group. It should be noted that these are based on average porosity values, and significant variability exist in the data.

Calculation of Net Porous Dolostone

Once a porosity cutoff was chosen, the amount of net porous dolostone, and average porosity of dolostones above the cutoff, was determined for each well in the study area from bulk density logs. Results of the net dolostone calculations are shown in Table 2-1. Average porosity calculated from bulk density logs and total porosity-feet (thickness of void space) were also calculated. Gross thickness is the thickness of the Knox Group above 8,000 ft depth. A net to gross ratio was calculated for each well to allow a similar thickness to be calculated at the Green River site using the total mapped thickness. The net to gross ratio ranges from 0. 35 in the Refuge Exploration #2CU Hess well, to 0.017 in both the Conoco #1 Turner and Texas Gas Transmission #1A Kerrick wells. Average log-derived porosity of the net dolostone interval ranges from 10.6% in the Refuge Exploration #2CU Hess to 8.4% in the Texas Gas Transmission #1A Kerrick well. The Kentucky Geological Survey #1 Marvin Blan well is outside of the Rough Creek Graben and the Knox is at a much shallower depth than it is below the Green River Station. This led to a much higher proportion of porous dolomite and dolomitic sandstone within the Knox Group in the #1 Blan well than would be expected at the study site. For this reason, the net/gross ratio from Kentucky Geological Survey #1 Marvin Blan well (0.307) was not used for the calculation of storage volumes at Green River Station.

Table 2-1 includes calculated data for the Green River site. The gross thickness was taken from the thickness map of the Knox Group above 8,000 ft depth (Figure 2-7). Then a net dolostone footage was calculated using the net-to-gross ratios determined from the 4 analog wells. This yields a net dolostone estimate for Green River Station of 149 ft.

Table 2-1 - Knox Group reservoir data.

Knox Group Well Log Data	Average Depth (below surface, ft)	Gross Thickness (ft)	Net Porous Dolostone >7% porosity (ft)	Net to Gross Ratio	Average Log Porosity of Net Porous Dolostone	Porosity-Feet
Refuge Expl. 2CU Hess	7054	1693	59	0.03	10.6%	15.0
Conoco 1 Turner	6368	2665	45	0.02	10.3%	29.5
KGS 1 Blan	5441	3318	1020	0.31	9.6%	97.7
TGT 1A Kerrick	6665	2068	36	0.02	8.4%	16.4
Calculated Data						
Green River Station	7211	1579	149	0.09	9.7%	14.5

CO_2 Capacity Calculations

Storage capacity is based on the porosity, thickness and area of the injection zone, and density of the injected CO_2. The density of CO_2 is a function of reservoir pressure and temperature. The Knox Group is deep enough for supercritical (dense) phase CO_2 injection (reservoir temperature and pressure greater than 1,072 psi and 88 °F) at the Green River Station. The CO_2 density calculations were made using the CO_2 properties calculator at the MIDCARB project web site: http://www.midcarb.org/calculators.shtml. The Midcontinent Interactive Digital Carbon Atlas and Relational dataBase (MIDCARB) was a research consortium composed of the State Geological Surveys of Illinois, Indiana, Kansas, Kentucky, and Ohio, funded by the US Department of Energy. Calculated CO_2 densities are shown in **Table 2-2**.

Table 2-2 - Density of CO_2 at reservoir conditions expected under the Green River Station.

CO_2 Density	Reservoir Pressure (psi)	Reservoir Temperature (°F)	CO_2 Density lbs/ft^3	CO_2 Density kg/m^3
Green River	3300	130	49.41	791.47

The following parameters are required to calculate CO_2 storage capacity:

Reservoir pressure: assumed hydrostatic conditions (with a salinity of 100,000 ppm), and calculated at 0.465 psi/ft for the reservoir depth

Temperature: assumed a continental thermal gradient of 1 °F/100 ft depth

Reservoir thickness: the net porous dolostone thickness as calculated above

Reservoir area: a standard area of 100 acres was used for these calculations

Reservoir porosity: the average porosity for the net reservoir footage

The equation for CO_2 storage capacity, modified from Medina et al. (2011) is:

$$SC = A_n * h_n * \Phi_n * \rho_{CO2} * \acute{\varepsilon} / 1000$$

Where SC is the storage capacity in metric tons, A_n is the area, h_n is the net reservoir thickness, Φ_n is the average porosity of the net reservoir, ρ_{CO2} is the density of CO_2 at the reservoir conditions, and $\acute{\varepsilon}$ is the storage efficiency factor (discussed below). The reservoir parameters used and CO_2 capacities calculated are shown in the **Table 2-3**.

Efficiency of CO_2 Storage

The storage capacity equation used above includes an efficiency factor which reduces the CO_2 storage capacity. This factor is applied because 100% of the available pore volume is never completely saturated with CO_2 due to fluid characteristics and geologic variability within the reservoir.

Litynski, et al. (2010) calculated efficiency factors for carbon storage in various reservoir types that account for factors which reduce the volume of CO_2 that can be stored. These factors include:

Geologic Factors

- Net to total area of a basin suitable for sequestration;
- Net to gross thickness of a reservoir that meets minimum porosity and permeability requirements; and
- Ratio of effective to total porosity (fraction of connected pores).

Displacement Factors

- Areal displacement efficiency- area around a well that can be contacted by CO_2;
- Vertical displacement efficiency- fraction of vertical thickness that will be contacted by CO_2;

- Gravity- fraction of reservoir not contacted by CO_2 due to buoyancy effects; and
- Displacement efficiency- portion of pore volume that can be filled by CO_2 due to irreducible water saturation.

Combining all of these factors in a Monte Carlo simulation results in a probable range of total efficiency factors of 0.64% to 5.5% (Litynski et al., 2010). For the purposed of this assessment, we assumed the geologic factors are equal to 1. In our 100-acre unit, the net to total area is the same, the net to gross thickness has already been calculated and used in the calculation, and for dolomite reservoirs (dolostones) we assumed that the porosity is well-connected with a ratio of effective (connected) porosity to total porosity equal to 1. Litynski et al. (2010) calculated efficiency factors for just the *displacement* factors separately, and for dolostone reservoirs they range from 16% to 26%, with a most likely efficiency factor of 21%. This means the most likely case is that 21% of the pore space can be filled with CO_2. The range of storage volumes using the probabilistic efficiency factors for Green River Station is shown in **Table 2-4**.

Table 2-3 - Reservoir parameters and calculated CO_2 storage capacities for a 100 acre area at theoretical limits (100%) and probable (21%) storage efficiencies. The 21% efficiency rate for porous dolostone reservoirs taken from US-DOE's 2010 Carbon Sequestration Atlas of the United States and Canada, by Litynski, et al. (2010).

Site	**Net Reservoir Thickness (ft)**	**Net Reservoir Thickness (m)**	**Avg. Porosity**	**CO_2 Density (kg/m^3)**	**CO_2 Capacity per 100 ac @ 100% Efficiency (metric tons)**	**Storage Efficiency Factor**	**CO_2 Capacity per 100 ac @ 21% Efficiency (metric tons)**
Green River	36	11.1	9.7%	791.47	345,515	0.21	**72,558**

Table 2-4 - Range of probabilistic storage volumes using U.S. DOE displacement efficiency factors for clastic reservoirs (Litynski et al., 2010).

Site	**Minimum Volume (metric tons/100 ac.) $\acute{\varepsilon}$ = 16%**	**Most Likely Volume (metric tons/100 ac.) $\acute{\varepsilon}$ = 21%**	**Maximum Volume (metric tons/100 ac.) $\acute{\varepsilon}$ = 26%**
Green River	55,282	**72,558**	89,834

Summary

The Green River Station has potential for geologic storage of CO_2 beneath the site property. The strata of the Knox Group are the only formations interpreted to have suitable porosity and permeability at the depths required for storage of supercritical CO_2. Excellent confinement for injected CO_2 is provided by the overlying 545 ft thick Maquoketa Shale.

Geologic data control for the Green River Station is moderate with only 4 wells drilled to the reservoir within a 15-mile radius, including only 1 (Conoco #1 Turner) that penetrated the entire section of Knox. The proximity of the Kentucky Geological Survey #1 Marvin Blan well to Green River Station lowers the risk of finding a suitable reservoir, and excellent core, log and engineering data are available from that research project. The three seismic lines purchased for this project surrounding the station were useful not only in subsurface mapping, but also with analyzing the extent and locations of fault systems within and above the target injection zone. Using these data, the authors interpret no faults below the confining units within a 5-mile radius of Green River Station. Interpretation of the Knox Group structure map (Figure 2-5) suggests that injected CO_2 would migrate slowly up dip (≈ 1°) to the east-northeast.

Reservoir quality is probably adequate for injection at the Green River Station. The additional cost (compared to the other LGE-KU stations in this project) of drilling a 7,000+ ft well to the Knox would be offset somewhat by the increased volume of CO_2 that can be stored at that greater depth and pressure.

The most likely storage volume of CO_2 that could be stored at the Green River Station site, using property owned by LG&E-KU is shown in (**Table 2-5**).

Table 2-5 - Total storage volume on-site assuming 100% use of LG&E-KU property

Site	CO_2 Storage Volume (metric tons per acre)	Total Site Size (acres)	Total Site Storage Volume (m. tons)
Green River	726	415.8	301,697

References Cited

Bowersox, J. R., 2010, *Geologic Evaluation of the Kentucky Geological Survey Marvin Blan #1 deep saline reservoir injection test well, Hancock County, Kentucky*: Kentucky Geological Survey.

Goudarzi, G. H., 1969, Geologic map of the Equality quadrangle, western Kentucky: U.S. Geological Survey, scale 1:24,000.

Hanson, D. E., and Smith, A. E., 1978, Geologic map of the Livermore quadrangle, western Kentucky: U.S. Geological Survey, scale 1:24,000.

Kehn, T. M., 1968, Geologic map of the Graham quadrangle, western Kentucky: U.S. Geological Survey, scale 1:24,000.

Litynski, J., Deel, D., Rodosta, T., Guthrie, G., Goodman, A., Hakala, A., Bromhal, G., and Frailey, S., 2010, Appendix B: Summary of the Methodology for Development of Geologic Storage Estimates for Carbon Dioxide, Carbon Sequestration Atlas of the United States and Canada, U.S. Department of Energy - National Energy Technology Laboratory, p. 162.

Medina, C. R., Rupp, J. A., and Barnes, D. A., 2011, Effects of reduction in porosity and permeability with depth on storage capacity and injectivity in deep saline aquifers: A case study from the Mount Simon Sandstone aquifer: *International Journal of Greenhouse Gas Control*, v. 5, p. 146-156.

Palmer, J. E., 1969, Geologic map of the Central City West quadrangle, Muhlenberg and Ohio Counties, Kentucky: U.S. Geological Survey, scale 1:24,000.

-, 1972, Geologic map of the Central City East quadrangle, Muhlenberg and Ohio Counties, Kentucky: U.S. Geological Survey, scale 1:24,000.

Chapter Three

Geologic CO_2 Sequestration Potential of the LG&E-KU E.W. Brown Station, Central Kentucky

Dave Harris and John Hickman
Kentucky Geological Survey

LG&E-KU CO_2 Sequestration Geologic Summary Sheet

Power Plant: E.W. BROWN **County:** MERCER **Geologic Basin:** Cincinnati Arch

Data Quality

Distance to nearest well control in reservoir:	6.8 miles
Wells to primary injection zone within 15 mile radius:	8
Distance to nearest core in injection zone:	10.8 miles
Distance to nearest good quality seismic control:	N/A (all poor quality)

Reservoirs

Primary injection zone:	Cambrian Rome Fm. and basal sandstone
Rock type:	sandstone (quartz arenite and arkose)
Drilling depth at plant site:	N/A (4,600 ft off-site)
Trapping mechanism:	closed fault trap
Max. reservoir pressure:	2,400 psi (hydrostatic)
Reservoir temperature:	110°F
Salinity of reservoir fluid:	200,000 ppm
Reservoir thickness (gross/net):	1,561/312 ft
Average porosity:	10%
Average permeability:	56md
Secondary injection zone:	None at this site

Confinement and Integrity

Primary confining zone:	Cambrian Conasauga Group
Rock type:	shale and limestone
Thickness of primary confining zone:	1000 ft
Height above primary injection zone:	0 (overlies injection zone)
Well penetrations of primary seal within 15 mile radius:	13
Secondary confining zone:	Ordovician Black River Ls (High Bridge)
Rock type:	Limestone
Thickness of secondary confining zone:	600 ft
Height above primary injection zone:	4,000 ft
Well penetrations of secondary seal within 15 mile radius:	

Number of faults cutting primary seal within 15 mile radius:	numerous
Distance to nearest mapped fault:	0.3 mi

Storage Capacity

Calculated CO_2 storage capacity, primary injection zone:
2,918,344 metric tons/100 acres (assuming 100% efficiency)
408,568 metric tons/100 acres (at 14% efficiency)

Introduction

An evaluation of geologic CO_2 sequestration potential was performed for an area surrounding the LG&E-KU E.W. Brown Station in Mercer County, Kentucky. A circular area with a 15-mile radius around the plant was defined as the primary focus of the evaluation, but data from beyond 15 miles was also used due to limited data within the primary area. The 15 mile radius circle around the E.W. Brown station is shown in Figure 3-1.

The following data were compiled for the evaluation:

1. 7.5 minute topographic and geologic quadrangle maps for the Wilmore and Little Hickman quads
2. Locations of all mineral and petroleum exploration wells and boreholes
3. Formation tops for geologic units from the top of the Ordovician to Precambrian
4. Available digital geophysical logs for Knox and deeper wells
5. Core analyses (porosity and permeability) for the Rome Formation in 1 well
6. Reflection seismic data available at KGS (4 lines)

Within the 15-mile radius around the E.W. Brown Station three wells have been drilled that penetrate the entire Paleozoic sequence, ending in Precambrian rocks. These wells provide the key geologic data used in this assessment. Two additional Precambrian wells are located just outside the 15-mile radius, and were also used in the evaluation. Numerous other shallower wells have been drilled in the area around the Brown station, and were used for mapping shallower formations.

Based on the evaluation of the Brown site that is discussed below, we do not feel that carbon sequestration is feasible directly below the power plant site. The geologic formations are either too shallow (Knox Supergroup), or not present (Mt. Simon Sandstone) at depths below 2,500 feet (the minimum depth required for supercritical phase CO_2 storage). There is potential for sequestration approximately 6 miles to the east of the site in a geologic feature known as the Rome Trough, a deeper, fault-bounded basin that contains thick sandstones at depths greater than 2,500 feet. The western end of the Rome Trough lies within the 15-mile radius around the E.W. Brown Station, and this evaluation proposes that this area be used for CO_2 storage. This would required a pipeline to transport CO_2 a minimum of 6 miles east of the Brown Station. This option would also involve obtaining access to surface property and subsurface pore space.

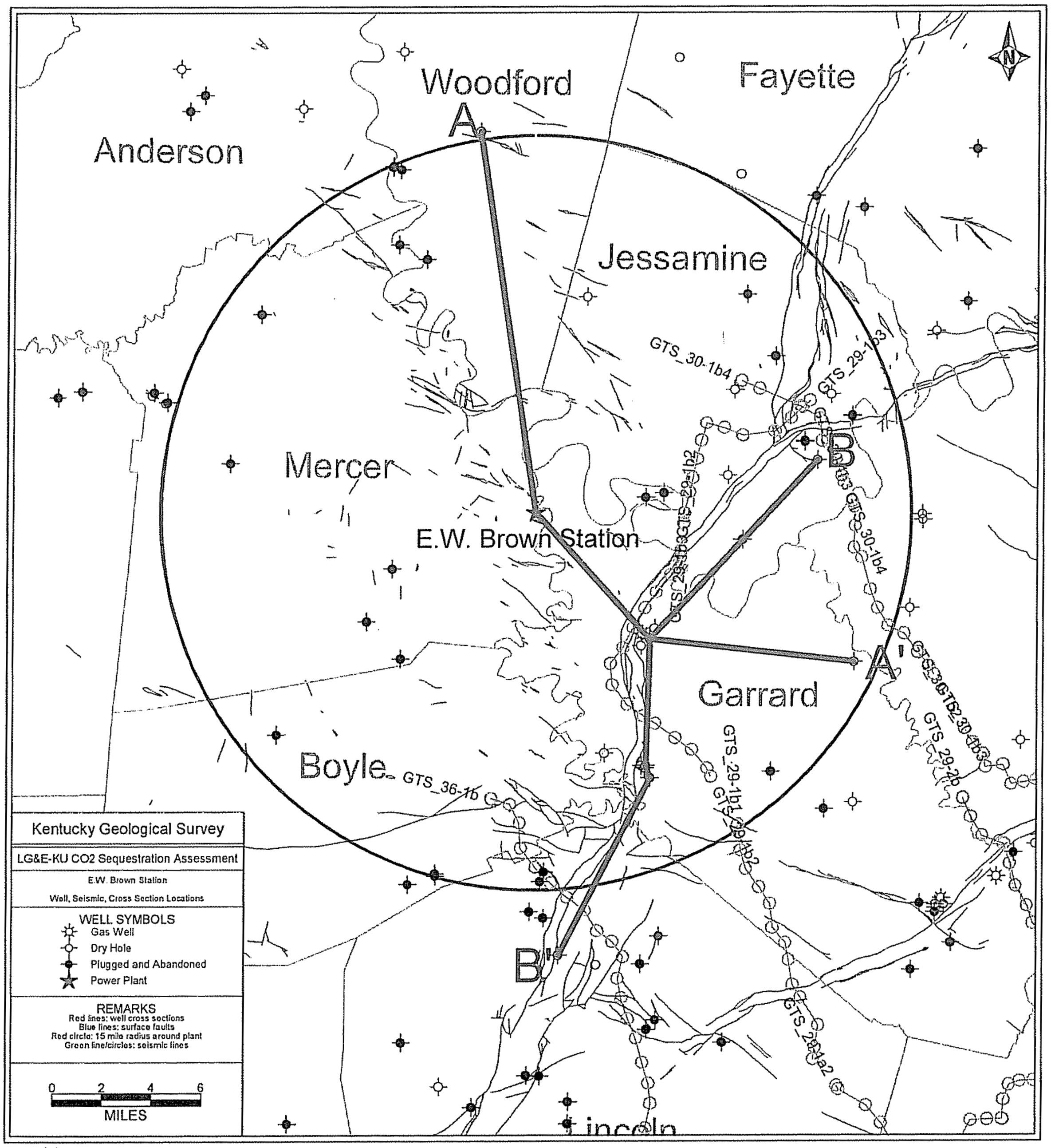


Figure 3-1. Index map showing location of E.W. Brown Station in central Kentucky. Red circle is the 15-mile radius the site. All known wells are shown. Blue lines are the location of mapped surface faults. The location of two geologic cross-sections are shown by the red lines, A-A', and B-B'. Reflection seismic lines are indicated by the lines with small circles (shot point locations).

Geologic Setting and Surface Geology

The E.W. Brown Station lies near the crest of the Cincinnati Arch, a broad anticline (arch) that separates the deeper sedimentary basins in western Kentucky (Illinois Basin) and eastern Kentucky (Appalachian Basin). The arch developed in Middle Ordovician time, and rock units deposited prior to this time have been tilted to the west toward the Illinois Basin. Rocks deposited from the Middle Ordovican and younger were influenced to some extent by the growing arch, but for the interval of interest in this study the arch had no effect on thickness or lithology. Geologic formations at the Brown site are shallower than in northern Kentucky at the Ghent and Trimble County Stations.

The Brown Station is located on the Wilmore 7.5 minute topographic quadrangle, and a geologic map for this quadrangle was published by Cressman and Hrabar (1970). This map indicates the plant is located on bedrock consisting of the Ordovician Lexington Limestone (Figure 3-2). This formation is primarily limestone, with interbedded shale. Since the plant site itself is not feasible for CO_2 sequestration, Figure 3-2 includes the area to the east (where sequestration is possible) which includes the Little Hickman quadrangle. A geologic map of this quadrangle was published by Wolcott (1969). A prominent feature on the Little Hickman quadrangle is the Kentucky River Fault Zone (Figure 3-2). This zone of faulting extends from surface to the Precambrian basement rocks. This fault forms the western boundary of the Rome Trough. At the basement level, there is over 2,700 feet of throw (offset) between the upthrown (west) and downthrown (east) sides of the fault. East of the fault zone, surface rocks are Ordovician-age, and consist of the Clays Ferry Formation, Garrard Siltstone, and the Calloway Creek Limestone. The Clays Ferry Fm. Is predominantly shale with minor limestone, while the Calloway Creek has mostly limestone with less abundant shale. In lower elevations on both sides of the fault zone, the deeper Tyrone Limestone of the High Bridge Group is exposed. This formation consists of thickly-bedded dense limestone.

Surface geology does not have a direct impact on carbon sequestration potential, since CO_2 injection will occur at much deeper depths. However, surface geology will impact the design and implementation of shallow groundwater monitoring wells that will be required by U.S. EPA for an underground injection (UIC) permit. The EPA UIC permit will likely require monitoring down to the base of the underground source of drinking water (USDW), which may require drilling into bedrock. However, the Upper and Middle Ordovician rocks at the surface east of the Kentucky River Fault Zone may not be suitable for groundwater monitoring due to low porosity and permeability. Wolcott (1969) reports the occurrence of springs along faults, fractures, and above a widespread bentonite (altered volcanic ash) bed in the Tyrone Limestone that forms an impermeable layer. The presence of this relatively shallow impermeable layer should be considered when planning a monitoring program, as it could prevent upward movement of CO_2 if leakage were to occur. Monitoring wells may need to be drilled deeper than this layer for effective monitoring.

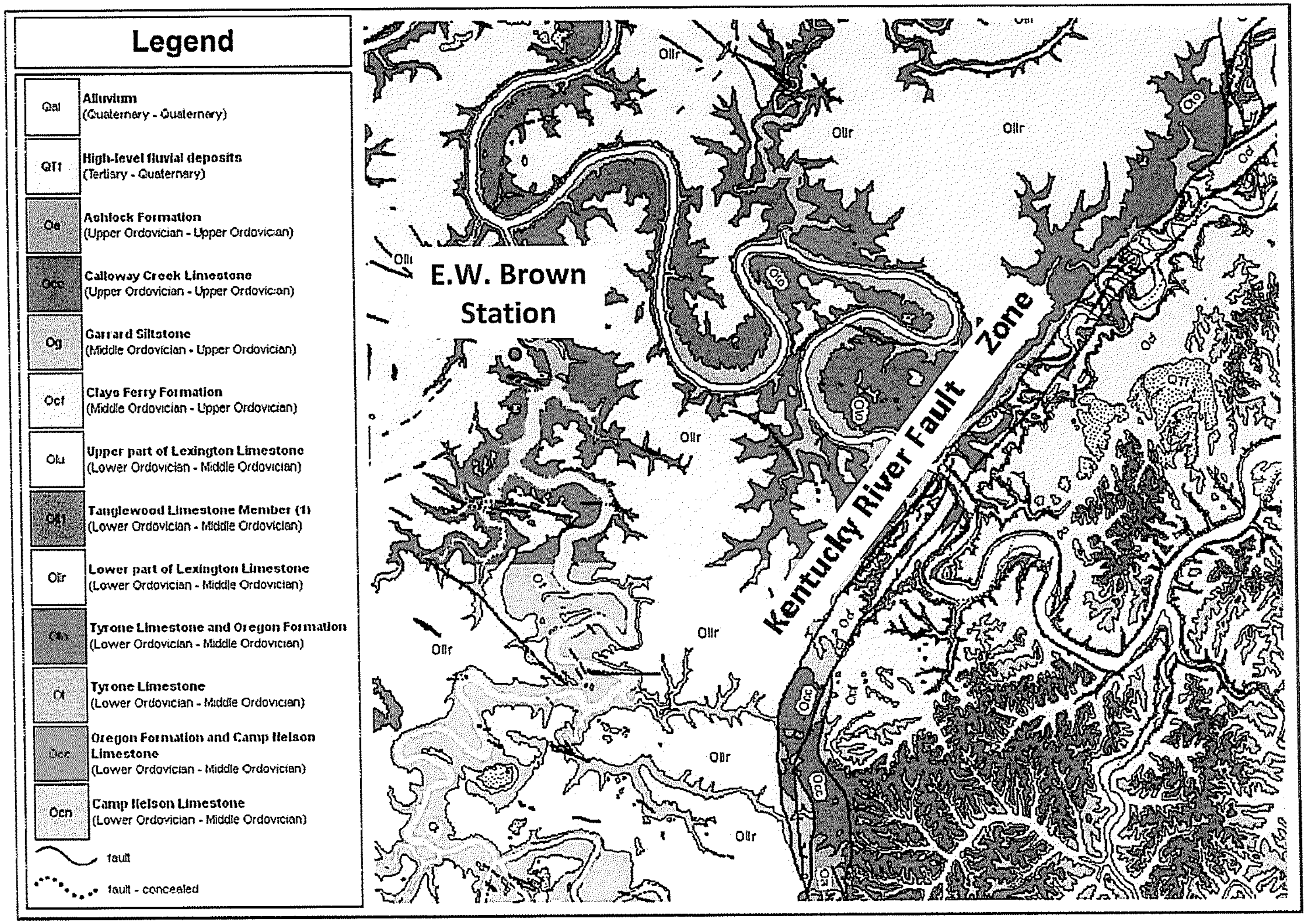


Figure 3-2. Geologic map of a portion of the Wilmore and Little Hickman 7.5 minute quadrangles (Cressman and Hrabar, 1970; Wolcott, 1969). The E.W. Brown Station is labeled. The geology changes abruptly along the Kentucky River Fault Zone, the prominent line of faults that run NE–SW across the map. This fault is downthrown to the east, and forms the western boundary of the Rome Trough, a deeper geologic basin where CO_2 from the Brown Station could be sequestered. The surface geology to the east of the fault zone consists of the Ordovician Clays Ferry Formation (Ocf), primarily shale, with minor interbedded limestones. The Kentucky River runs NW–SE across the map, with Quaternary alluvium (Qal) deposits along the valley bottom.

Stratigraphy and Structure

The subsurface geology of the area around the E.W. Brown varies dramatically on opposite sides of the Kentucky River Fault Zone. Discussion will focus on the east (downthrown) side of the fault, where sequestration is favored. We do not believe carbon sequestration is feasible west of the fault zone, such as at the Brown site, for two reasons. First, the Cambrian Mt. Simon Sandstone is not present in this area, as indicated by the Texaco #1 Sherrer well in Jessamine County (within the 15-mile radius). This well drilled through the Knox Supergroup and Eau Claire shale section, and then into Precambrian basalt and the Middle Run Formation. No Mt. Simon Sandstone was encountered. This well confirms evidence from seismic data that the Mt. Simon Sandstone was not deposited in central Kentucky. Other studies have used data from seismic lines outside the Mercer County area to map the extent of the Mt. Simon Sandstone across Kentucky. The broader regional data show the Mt. Simon is present in northern Kentucky, and pinches out toward the south, and is absent in central Kentucky (Figure 3-3, Greb and Drahovzal, 2011).

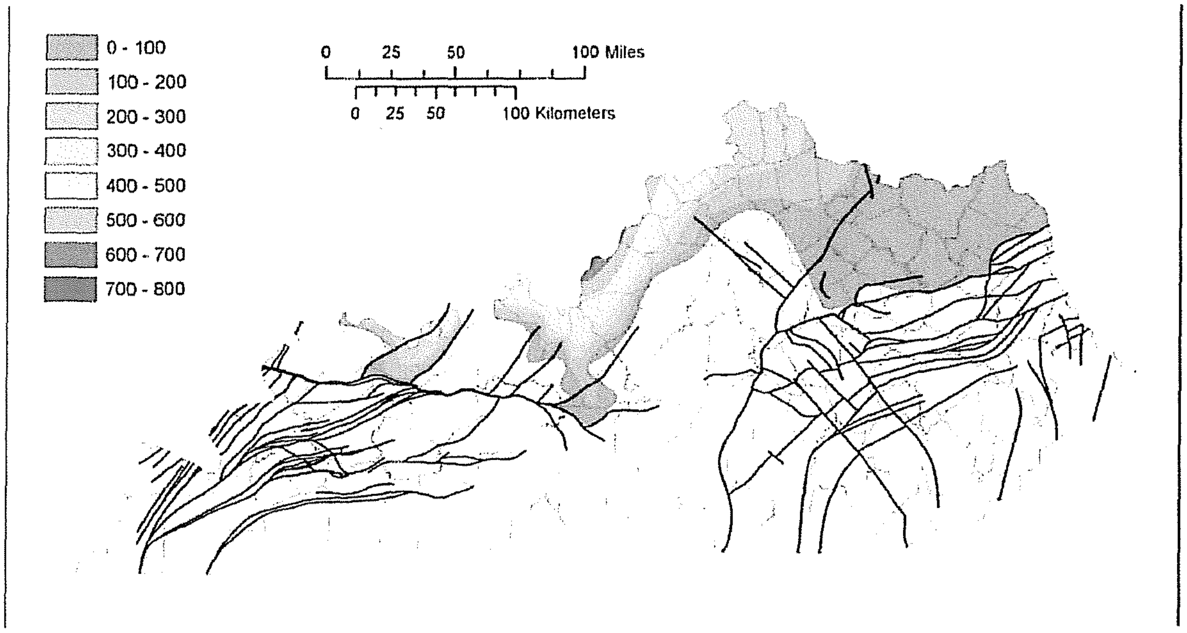


Figure 3-3. Regional thickness map of the Mt. Simon Sandstone in Kentucky. This map indicates the Mt. Simon is present in northern Kentucky (under the Ghent and Trimble County Stations), but is absent at the E.W. Brown Station in central Kentucky. Interpretation based on seismic and well data. Contours in feet. From Greb and Drahovzal, 2011.

Second, in addition to the absence of Mt. Simon Sandstone in Mercer County, dolomites in the Cambrian-Ordovician Knox Supergroup are thought to be unsuitable for sequestration. The basal part of the Knox at Brown is deep enough for sequestration, but the overlying seal is not. Geologic storage of carbon dioxide (CO_2) is limited to depths greater than 2,500 ft below the surface so that CO_2 exists in the supercritical, or dense phase. In the Mercer County area, this 2,500 ft depth occurs in the lower part of the Knox, (the Copper Ridge Dolomite). Despite the depth and possibility for good porosity, CO_2 storage in the Knox at the E.W. Brown site is not feasible because the shale and limestone seals overlying the Knox occur above 2,500 feet (the top of the Knox is interpreted to be at a depth of about 750 feet at Brown). With the top of the Knox and overlying seal so shallow, a concern is that if CO_2 were to migrate upward through the Knox interval (along fractures), it could rise well above 2,500-foot depth before being trapped by the overlying seals. Above 2,500 feet, the CO_2 phase would change from supercritical to gas, resulting in a large volume and pressure increase. If the permeability of the formation was not sufficient to dissipate this pressure pulse, it could be sufficient to fracture the rock, and breach the reservoir.

Other geologic formations below the 2,500 ft depth in the area west of the fault zone include the Upper/Middle Cambrian Eau Claire Formation, and Precambrian Middle Run Formation. These formations lack suitable porosity for storage of CO_2 and thus have no sequestration potential.

East of the Kentucky River Fault Zone (KRFZ), the deep geology is very different. Movement on this fault in Early to Middle Cambrian time created a deeper basin to the east (the Rome Trough) which was filled with a thick package of sandstone and shale that does not extend outside of the basin (Rome Formation). These sandstones have good porosity and are at depths of 4,500 to 5,500 feet. Although in the same stratigraphic position as the Mt. Simon Sandstone in other parts of Kentucky, the Rome Formation is older and not laterally connected to the Mt. Simon sandstones. Figure 3-4 is a type geophysical log for the western end of the Rome Trough, showing the stratigraphic units in this area. Above the Rome Formation is the Conasauga Group, roughly equivalent to the Eau Claire Formation to the west of the fault. The Conasauga contains mostly shale with minor limestone, and forms a seal above the Rome. These units are discussed in more detail below.

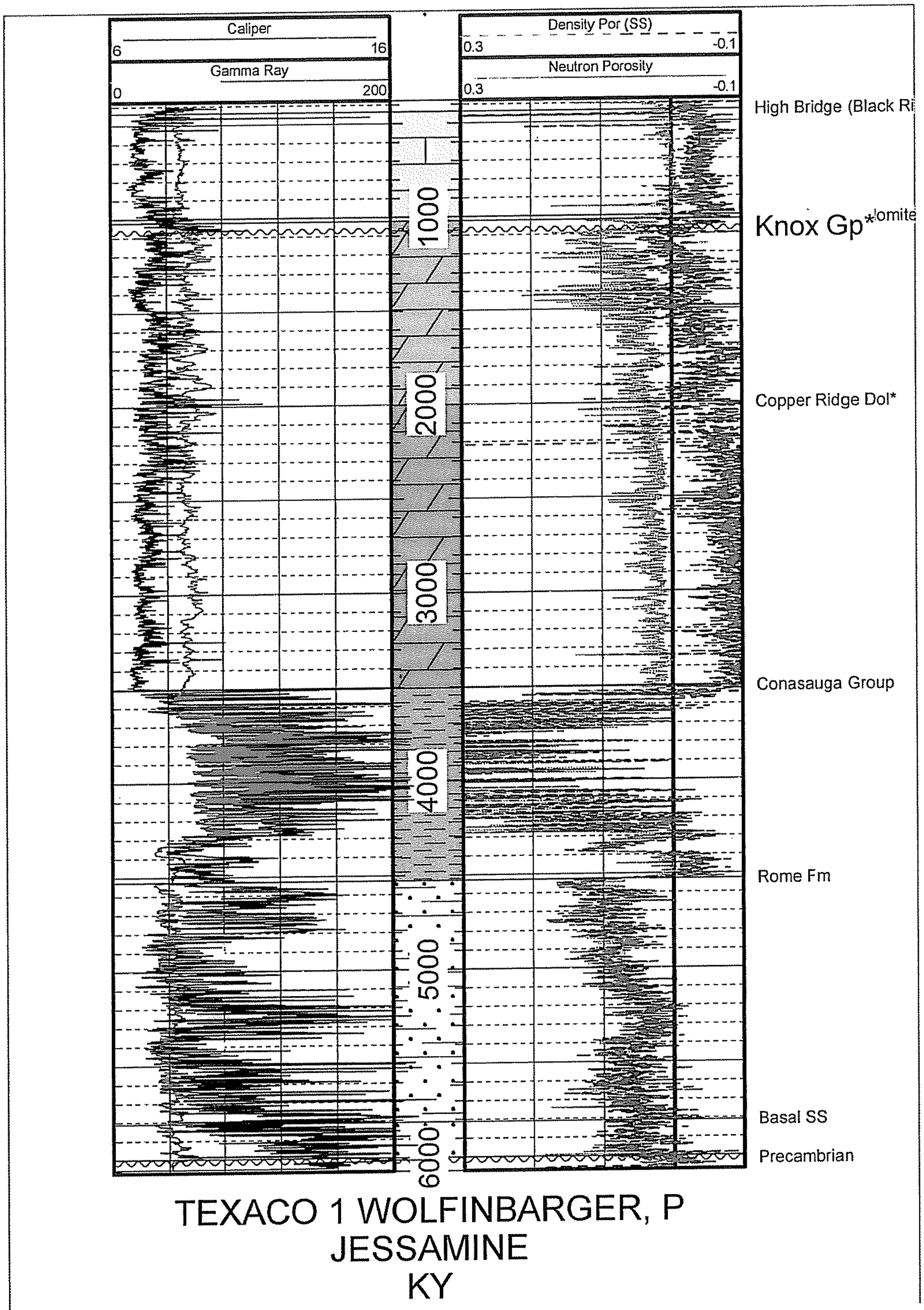


Figure 3-4. Geophysical log for the Texaco #1 Wolfinbarger well drilled in Jessamine County, Ky. Stratigraphic units are labeled. This well is located to the east of the Kentucky River Fault Zone, in the Rome Trough. The potential CO_2 injection zone is in the Cambrian Rome Formation and "basal sandstone". The density porosity log is shaded blue in the Rome and "basal sandstone" interval where porosity is greater than 7%. The gamma ray log on the left is shaded yellow where less than 80 API units (clean sandstone). Red line in the left track is the caliper log (hole size), which is erratic in the Conasauga zone due to washout of shale.

Precambrian Rocks

The Precambrian basement rocks in the study area are different on opposite sides of the KRFZ. On the west, outside of the Rome Trough, Precambrian rocks include basalt (a volcanic rock) and red sandstones assigned to the Middle Run Formation. Both basalt and Middle Run sandstones were drilled in the Texaco #1 Sherrer well in Jessamine County, 8 miles from the E.W. Brown site. In this well 600 feet of basalt overlies 2,000 feet of Middle Run sandstones. The Middle Run consists of fine-grained red lithic sandstones and minor siltstone and shale. It was deposited in non-marine fluvial environments in a fault-bounded rift basin (Drahovzal and others, 1992). The sandstone is well-cemented and lacks porosity and permeability in this area. It has no potential for carbon sequestration in the study area.

East of the KRFZ, in the Rome Trough, Precambrian basement rocks consist of metamorphic rocks of the Grenville Province. Grenville rocks were encountered in three wells in the Jessamine–Garrard–Madison County area. These metamorphic rocks have no porosity and no potential for carbon sequestration.

A structure map on the top of Precambrian rocks is shown in Figure 3-5. This map is based on the few wells that penetrate the Precambrian surface in the area and the older seismic reflection data indicated. As such, it should be considered a general representation of the structure of the area. This map indicates that the depth to basement is about 3,788 ft (-2,875 below sea level) at the E.W. Brown Station. To the east, and across the KRFZ, Precambrian rocks are much deeper due to displacement on the fault. Basement rocks range from about -4,600 ft to about -6,000 ft below sea level. This extra space was filled with the Rome Formation and Conasauga Group rocks. The Precambrian surface in the trough deepens to the east, and is shallowest against the fault. This forms a closed structure or trap against the fault that is present at shallower levels also.

Cambrian Mt. Simon Sandstone

As discussed, the Mt. Simon Sandstone, the proposed injection zone at Trimble County and Ghent Stations, is absent in the area around the E.W. Brown Station. The main injection zone in the area around Brown is the Rome Formation, confined to the east side of the KRFZ.

Cambrian Basal Sandstone and Rome Formation

In areas to the east of the KRFZ, a graben or deeper depositional basin was developed due to movement on the fault. Sediment deposition was limited to this deeper area, named the Rome Trough, with limited deposition outside the trough. Initial depositon in the trough was a sandstone informally referred to as the "basal sandstone". This sandstone is overlain by the thicker Rome Formation. These two formations differ somewhat in lithology, but for the purposes of this study the two units are combined. Both contain porous sandstones that could store CO_2. The "basal sandstone" directly overlies Precambrian metamorphic rocks, and is 200-300 ft. thick in the study area. It contains variable amounts of feldspar grains which can cause a high gamma ray response, similar to shale. No core or core data is available from the basal sandstone zone in the study area.

Above the basal sandstone is the Rome Formation, a complex interval of sandstone, shale and thin limestones. Many of the sandstones in the Rome are porous in the study area, and form the

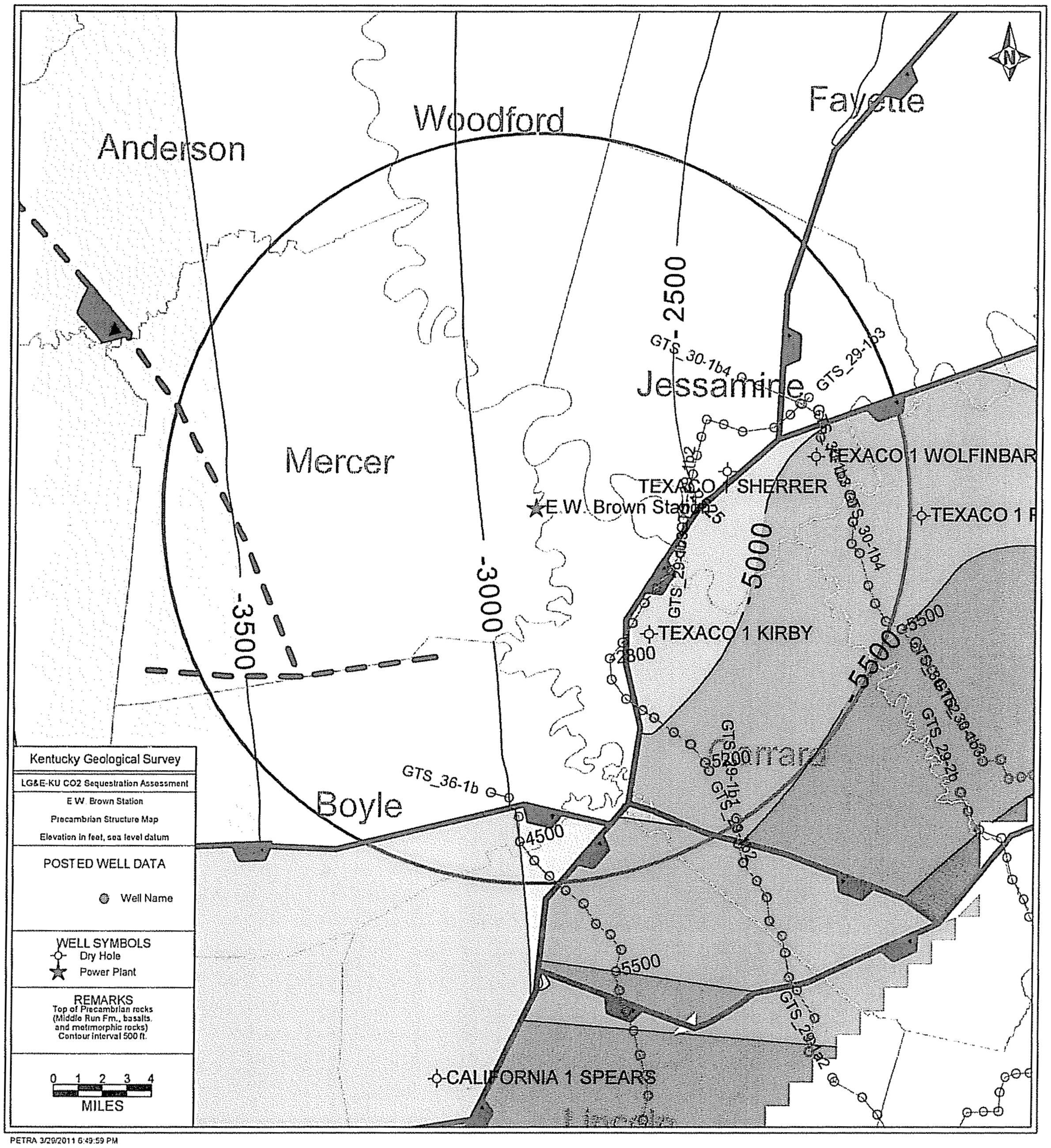


Figure 3-5. Structure map on top of Precambrian basement surface. Solid blue lines are simplified traces of mapped basement faults, and dashed blue lines are faults inferred from shallow geology, but offset is uncertain. Precambrian rocks are much shallower on the west (upthrown) side of the Kentucky River Fault. The Precambrian surface is much deeper to the east, in the Rome Trough.

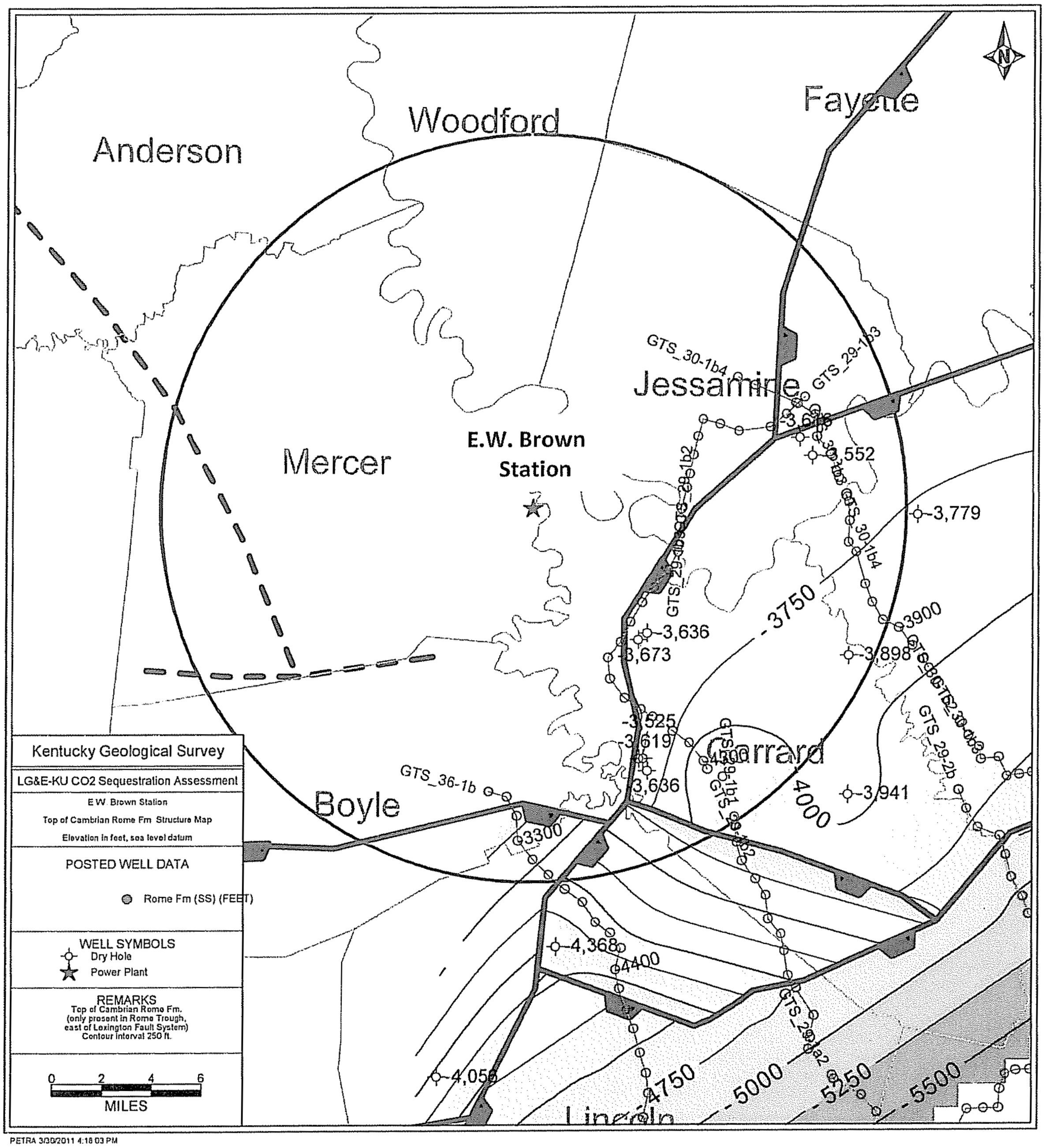


Figure 3-6. Structure map on top of Cambrian Rome Formation. Contour interval is 250 ft. These rocks deepen to the southeast, away from the KRFZ. The structure indicates that injected CO_2 would migrate toward the KRFZ, and likely be trapped by the fault.

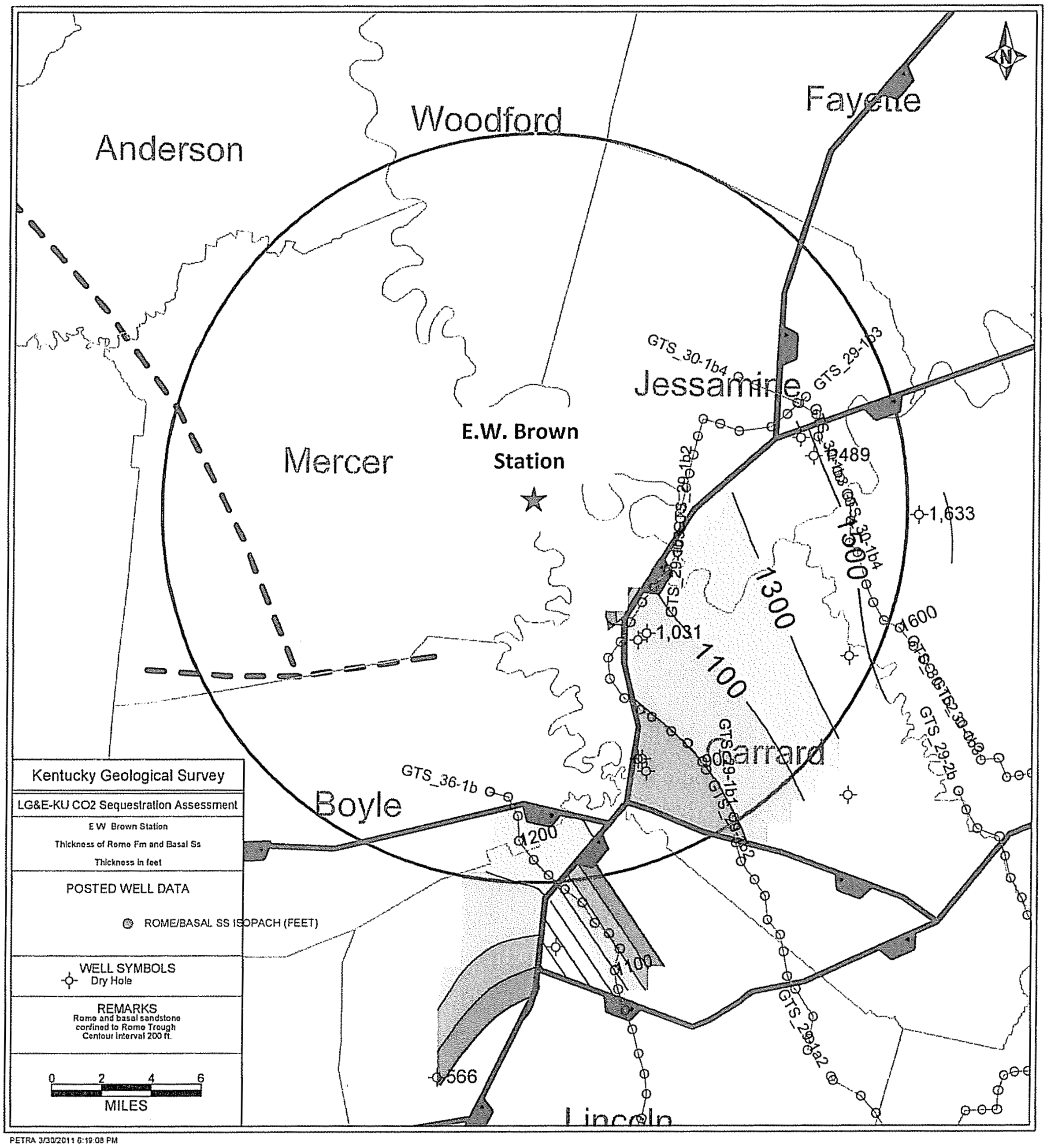


Figure. 3-7. Isopach (thickness) map of the Cambrian basal sandstone and Rome Formation. The Rome/basal sandstone interval thins to the south, but this map is based on limited data (4 wells and poor seismic), so should be considered very general. The formations extend further than the color-shaded areas show because the map is limited to data in the Brown Station area. Contour interval is 200 ft.

proposed primary injection zone for CO_2. The Rome is commonly thinly-bedded, with numerous shale interbeds as indicated on the gamma ray log (Figure 3-4). Porous sandstones occur as multiple stacked beds, separated by shale, rather than a thick uniform reservoir.

A structural contour map on the top of the Rome Formation is included as Figure 3-6. Like the Precambrian map, this map shows the formation deepens away from the KRFZ to the east. With the sandstones dipping away from the fault, a potential trapping mechanism is present, where buoyant fluids like CO_2 would migrate up toward the fault, and be trapped there. Near the fault, where sequestration would likely occur, the top of the Rome is at -3,600 to -3,700 feet below sea level (4,600 to 4,700 below the surface).

The isopach map (Figure 3-7) shows thinning of the combined basal sand/Rome interval toward the southwest. The gross thickness ranges from about 1,500 ft to 1,000 feet away from the fault. The thickness of sandstone in this interval will be significantly less due to abundant interbedded shale. This map is based on limited data because so few wells have penetrated the entire sequence.

Cambrian Conasauga Group and Eau Claire Formation

The Cambrian Conasauga Group directly overlies the Rome Formation in the Rome Trough, and is partly equivalent to the Eau Claire Formation outside of the trough. The Conasauga is predominantly composed of green and gray marine shale, with some interbedded limestones. The Conasauga Group consists of several formations defined by their lithology. In this area, three of these formations are present, two are limestone-dominated, and one is a thick shale. This shale (the Nolichucky Shale), and the limestones form the primary confining zone above the Rome Formation. Figure 3-4 shows the thickness of the Conasauga interval. The erratic log response in the Conasauga, (particularly on the red caliper curve) is due to enlarged borehole conditions due to sloughing of the shale during drilling.

Figure 3-8 is a structure map on the top of the Conasauga and the equivalent Eau Claire Formation west of the KRFZ. In the Rome Trough it shows a general deepening to the south and east. It is important to note the Conasauga is below the 2,500 ft. depth required to store supercritical phase CO_2. This ensures CO_2 will remain in the dense phase at the level of the primary seal. Figure 3-9 is an isopach (thickness) map of the Conasauga for only the Rome Trough area east of the KRFZ. The Conasauga ranges from 800 to over 1,100 ft. thick indicating there is a large amount of impermeable rocks immediately above the Rome/basal sandstone injection zone.

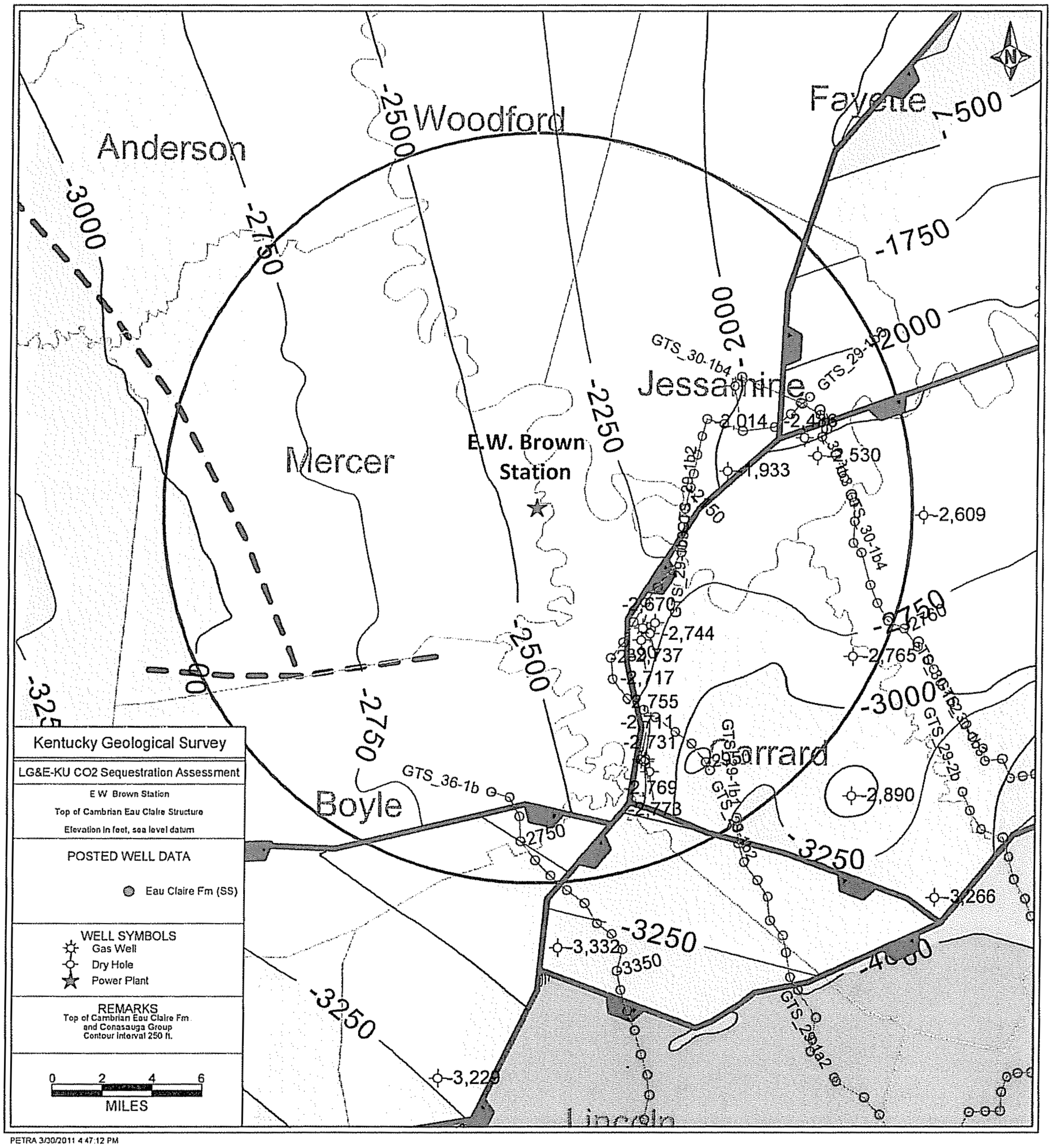


Figure 3-8. Structure map on top of the Cambrian Conasauga Group and equivalent Eau Claire Formation. Contour interval is 250 ft. The map indicates that this confining interval is deeper than 2,500 ft below the surface throughout most of the area (depth required to store supercritical phase CO_2)

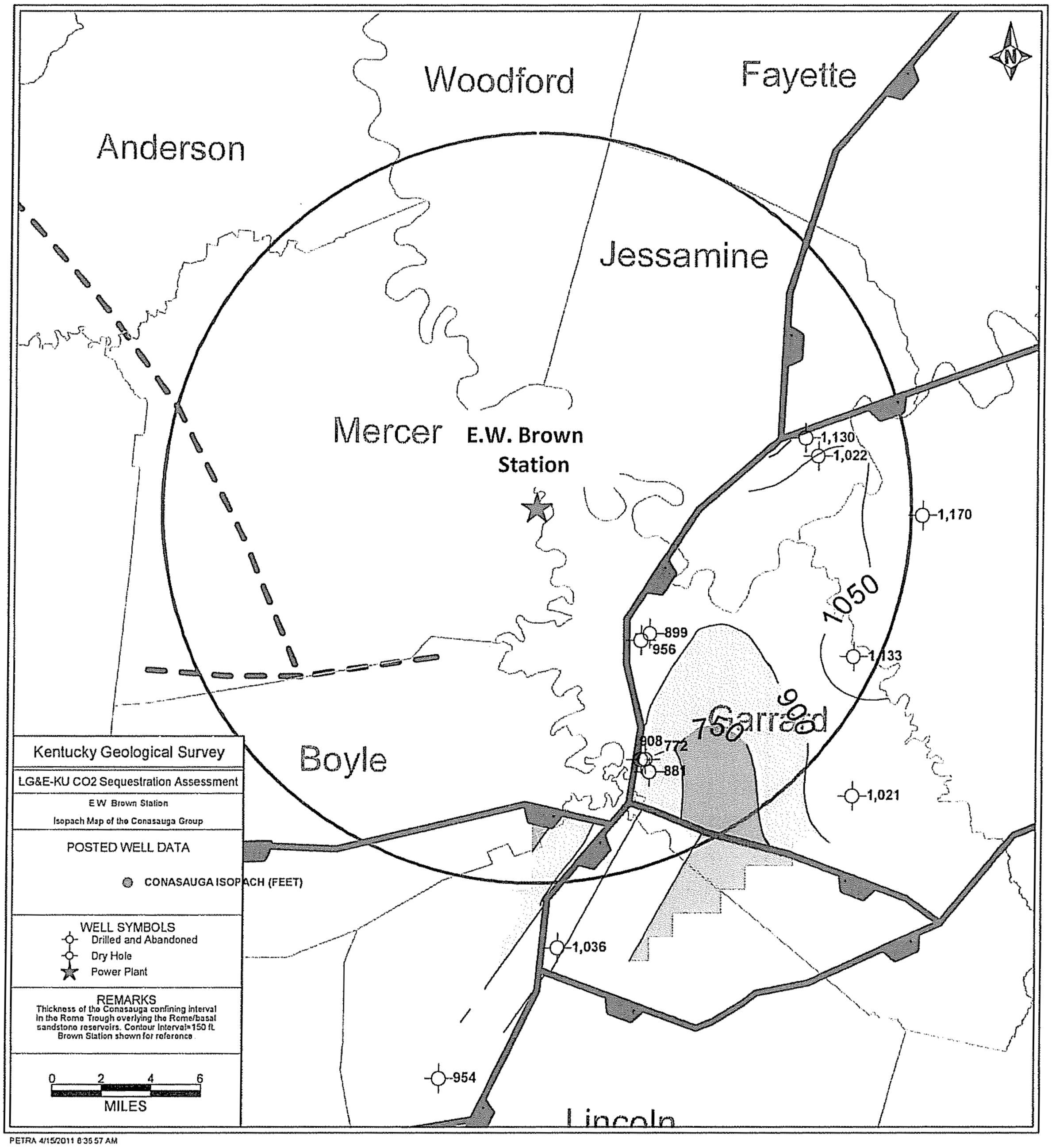


Figure 3-9. Isopach (thickness) map of the Conasauga Group in the Rome Trough portion of the study area. Equivalent Eau Claire Formation to the west is not included. Shale and limestones in this interval range from about 800 to over 1,100 ft thick, providing a seal for CO_2 injected into the Mt. Simon Sandstone below.

Cambrian-Ordovician Knox Supergroup

The Knox Supergroup is divided into an upper dolomite unit, the Beekmantown Dolomite, and the lower Copper Ridge Dolomite, separated by sandstone or sandy dolomite unit (Rose Run Sandstone) that is poorly developed in this area. The Knox is 2,200 to 3,000 ft thick in the study area. As discussed previously, the Knox is too shallow at the E.W. Brown site for CO_2 sequestration. Much of the Knox lies above the 2,500 ft depth limit for CO_2 to be in a supercritical phase. The lower part of the Knox (below 2,500 ft depth) is also not a potential injection target, since the primary seal above the Knox is above the phase change boundary for CO_2. Movement of CO_2 upward within the Knox would result in a rapid phase change to gas, increasing pressure significantly. This pressure pulse could fracture the seal above the Knox, allowing CO_2 to leak upward.

The Knox is the shallowest interval mapped in this evaluation. Figure 3-10 is a structure map of the top of the Knox. Because of its shallow depth more wells have been drilled to the top of the Knox than the deeper formations, and thus more data is available for the Knox structure map. The Knox deepens to the west and to the east, with the shallowest area at the crest of the Cincinnati Arch (center of the map, near the E.W. Brown Station).

The Knox contains scattered porous and permeable intervals separated by impermeable intervals. It has injection potential in deeper parts of Kentucky (such as the KGS #1 Blan research well in Hancock County), and was used as a hazardous waste injection zone at the DuPont chemical plant in Louisville. The top of the Knox is a regional erosional unconformity that formed when the Knox was uplifted above sea level during the early Ordovician. In this area impermeable intervals in the Knox would provide an additional confining zone for CO_2 injected in deeper reservoirs like the Rome sandstones.

Wells Creek Dolomite, Black River Group and Trenton Limestone

Overlying the Knox in this area are limestones and dolomites in the Wells Creek Dolomite, Trenton Limestone, and High Bridge (Black River) Group which together form a shallow secondary confining seal for CO_2 injected into the deeper Rome and basal sandstone zones. These rocks are composed of limestone, minor dolomite, and interbedded shale. The interval typically has very low porosity and permeability unless fractured. In the Rome Trough area, these formations have a combined thickness of 700-850 ft.

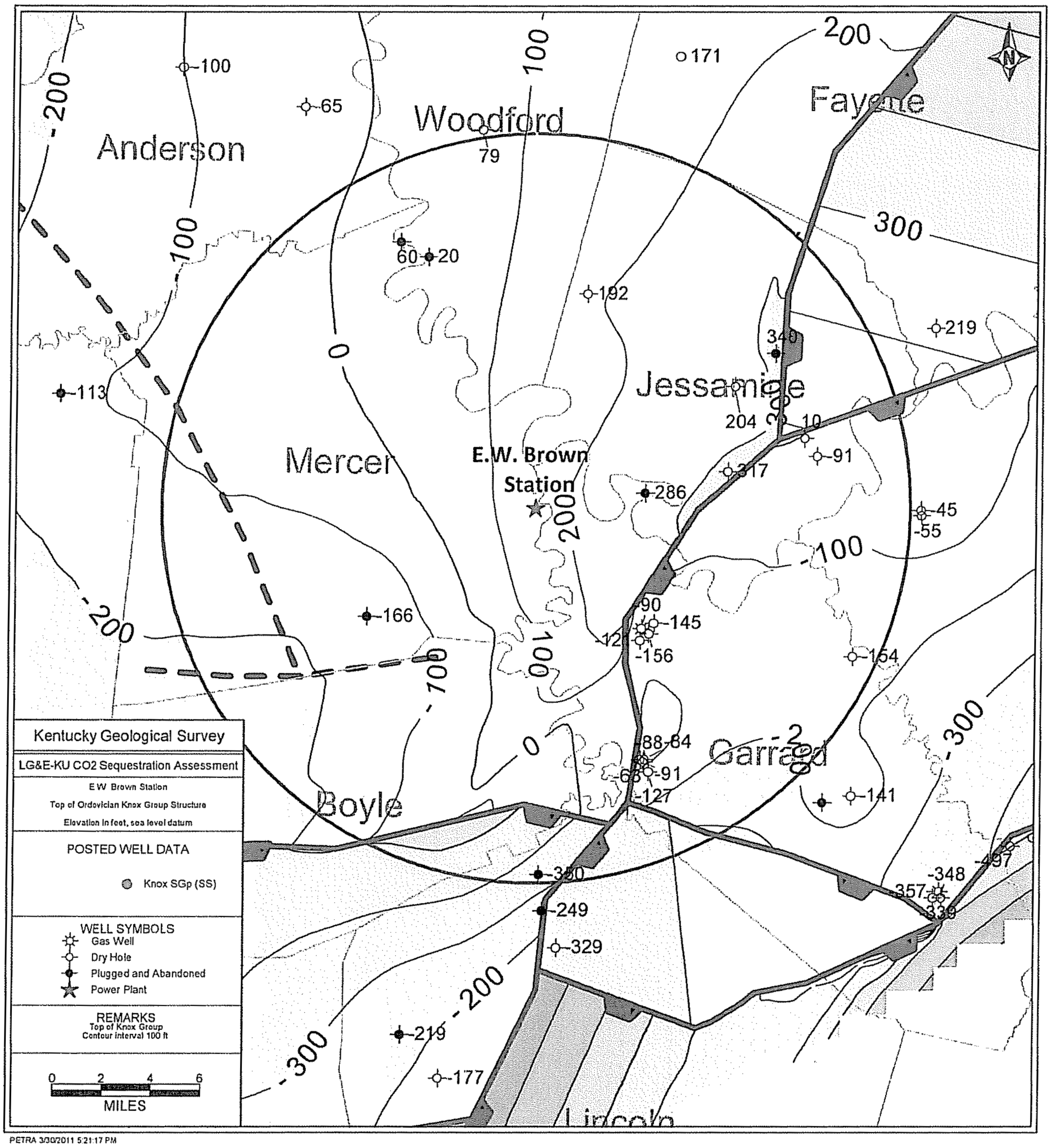


Figure 3-10. Structure map on the top of the Knox Supergroup. The top of the Knox is shallowest near the E.W. Brown Station (more than 300 ft above sea level), and deepens to the west away from the Cincinnati Arch and to the east across the KRFZ. The Knox is too shallow for CO_2 storage in this area. Contour interval is 100 ft.

Deep Faults and Available Seismic Data

Older 1970's-vintage seismic data is available for the eastern part of the study area, east of the KRFZ. Locations of these lines are shown on the various maps where the data was used. Selected depth and thickness estimates from these lines were incorporated into structure and isopach maps.

The E.W. Brown area has numerous faults mapped at the surface. These are shown in blue on Figure 3-1. The complex surface faults were simplified for use in making the structure maps. West of the KRFZ numerous short en-echelon faults trend SE to NW through the E.W. Brown site. These faults likely extend to basement, but do not impact potential sequestration since this area is too shallow for CO_2 injection. The main fault of interest is the KRFZ, which runs east of the E.W. Brown site, and forms the western boundary of the Rome Trough. Structure maps indicate reservoir strata dip away from this fault, and it will form a lateral seal for CO_2 injected into the Rome sandstones. Fortunately there is good evidence that this fault is sealed, and will not transmit CO_2. Several wells drilled adjacent to the KRFZ found natural gas in the Rome sandstone reservoirs. This gas was of low-quality (not commercial) but has unusually high levels of helium. This gas appears to be trapped by the KRFZ, indicating the fault has good sealing capability. Thus the KRFZ is interpreted to have a low risk of leakage of injected CO_2, and provides a structural trap to contain CO_2 in the area east of the fault. The helium found in these reservoirs is a potential economic resource, and its future development could create legal problems for CO_2 sequestration in the area. Any sequestration project would need to be designed to protect existing gas resources from contamination.

Structural Cross Sections

Two subsurface correlation cross sections were constructed from well logs to illustrate the geology and structure around the E.W. Brown Station. Locations of these sections are shown on Figure 3-1. Section A-A' (Figure 3-11) is oriented northwest to southeast, and crosses the KRFZ. It includes the location of the Brown Station for reference. This section shows the basal sandstone and Rome Formation confined to the east side of the KRFZ, on the downthrown side. This section also shows the absence of deep sandstones west of the fault, and how near Precambrian basement is to the 2,500 ft. supercritical CO_2 storage boundary.

Section B-B' (Figure 3-12) is oriented northeast to southwest, parallel to the KRFZ, but on the downthrown side. It includes two wells that were drilled to Precambrian basement, and two wells that only penetrated the upper part of the Rome Formation. This section illustrates the depth, continuity, and porosity of the reservoir sandstones, and the thickness of the overlying Conasauga, Knox, and High Bridge Group/Lexington Limestone confining zones.

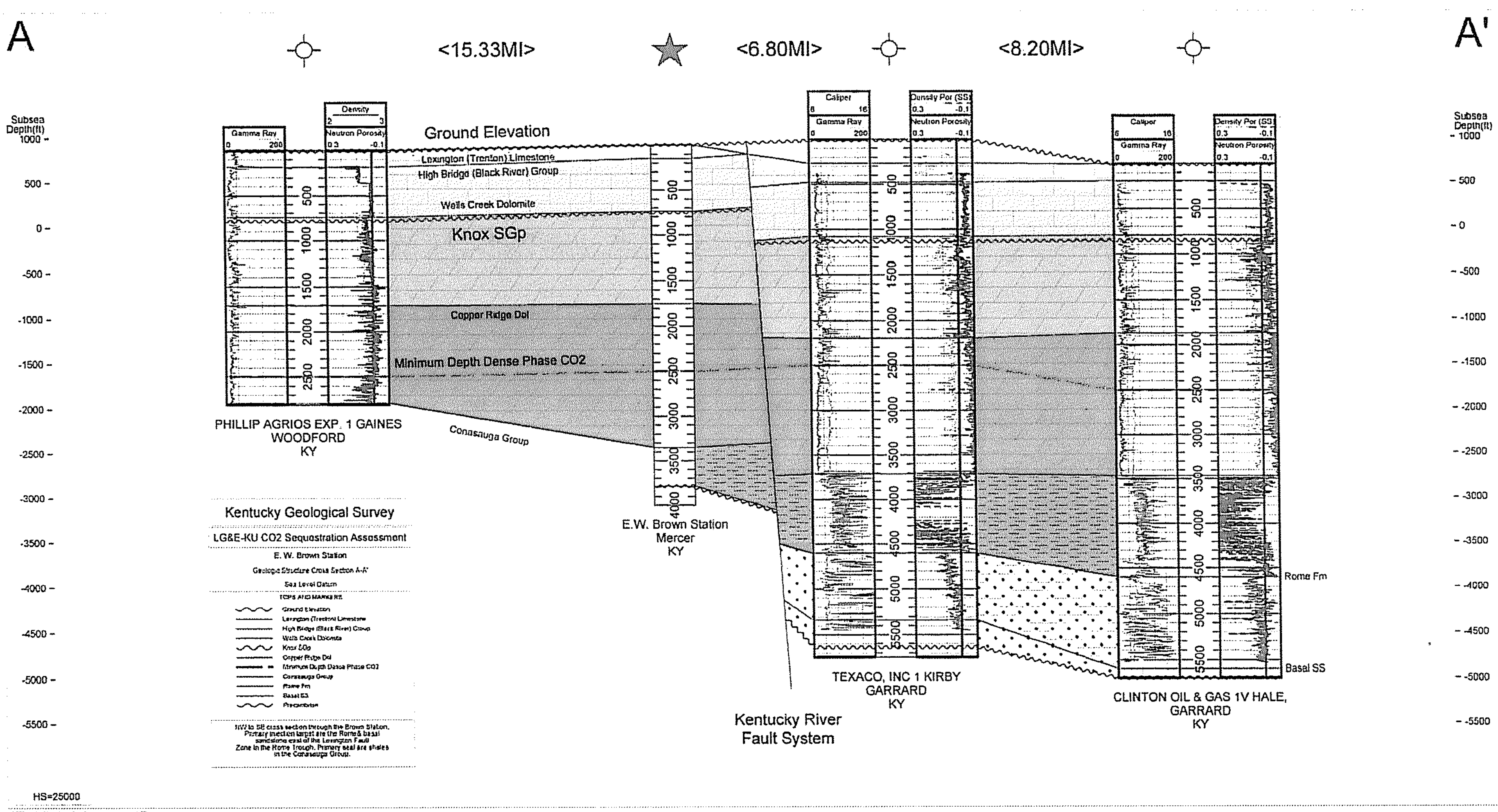


Figure 3-11. Northwest to southeast regional structure cross section showing well logs for deep wells and the location of the E.W. Brown Station for reference. The proposed injection zone in the Rome Fm. and basal sandstone is restricted to areas east of the Ky. River Fault Zone. Well logs include the gamma ray and caliper in the left track, and density and neutron porosity logs in the right track. The density porosity log is shaded blue where porosity is greater than 7% in the Rome Fm. and basal sandstone. The Conasauga Group (and equivalent Eau Claire Fm.) is the primary seal for the underlying Rome and basal sandstones.

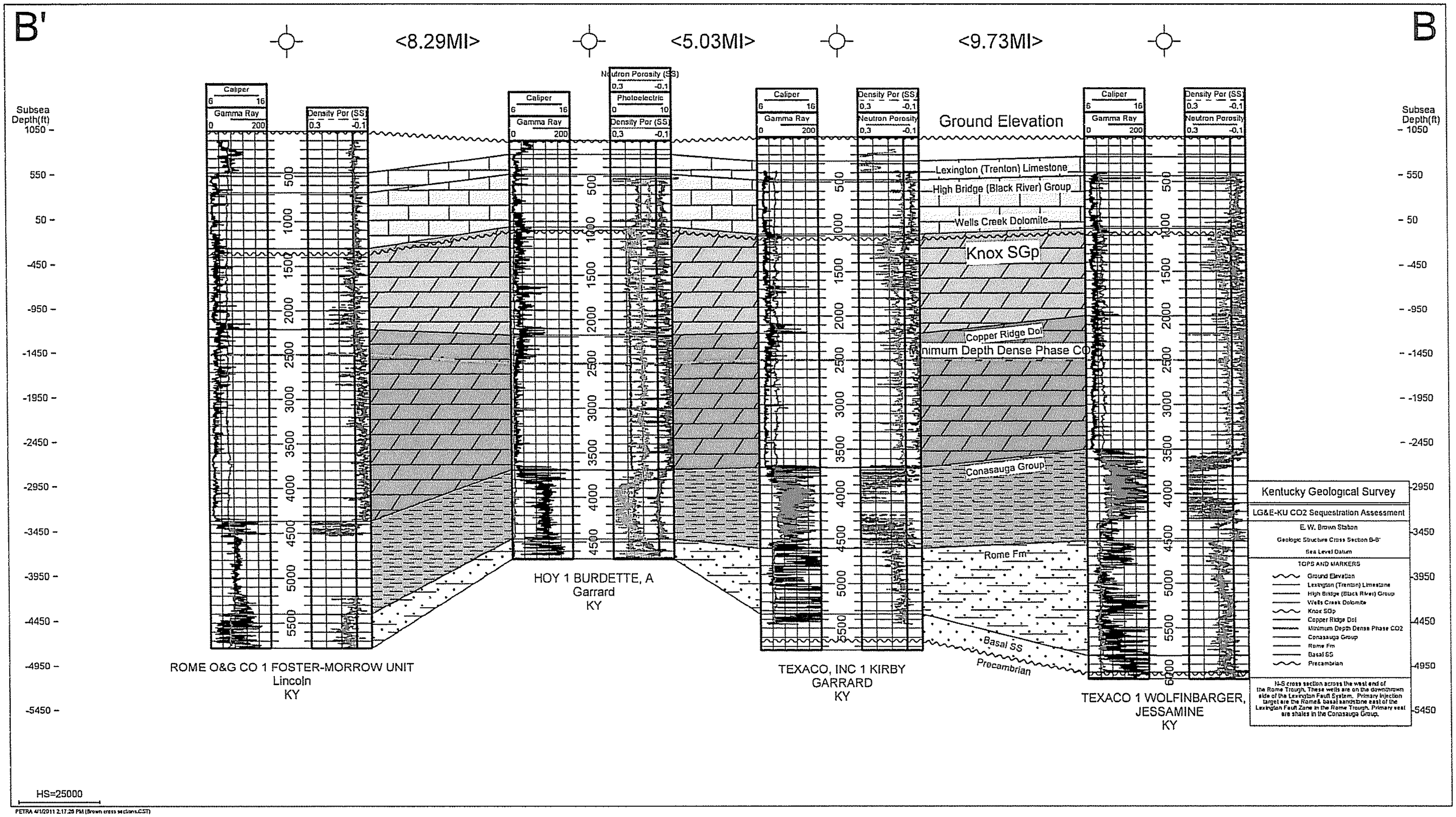


Figure 3-12. Northeast to southwest regional structure cross section showing well logs for deep wells drilled in the Rome Trough east of the Ky. River Fault Zone. The proposed injection zone is the Rome Fm. and basal sandstone shaded yellow. Note the 2 wells on the left only penetrated the top of the Rome Formation. Well logs include the gamma ray and caliper in the left track, and density and neutron porosity logs in the right track. The density porosity log is shaded blue where porosity is greater than 7% in the Rome Fm. and basal sandstone. The Conasauga Group (and equivalent Eau Claire Fm.) is the primary seal for the underlying Rome and basal sandstones.

Reservoir Quality and Injection Zone Thickness

In order to calculate carbon sequestration capacity, the average porosity and thickness of the storage zone is required. Since the geology is not suitable for sequestration at the E.W. Brown Station, we are proposing using sandstones in the Rome Formation and basal sandstone east of the KRFZ, approximately 7-10 miles from the E.W. Brown Station. Figure 3-13 shows the area that was evaluated.

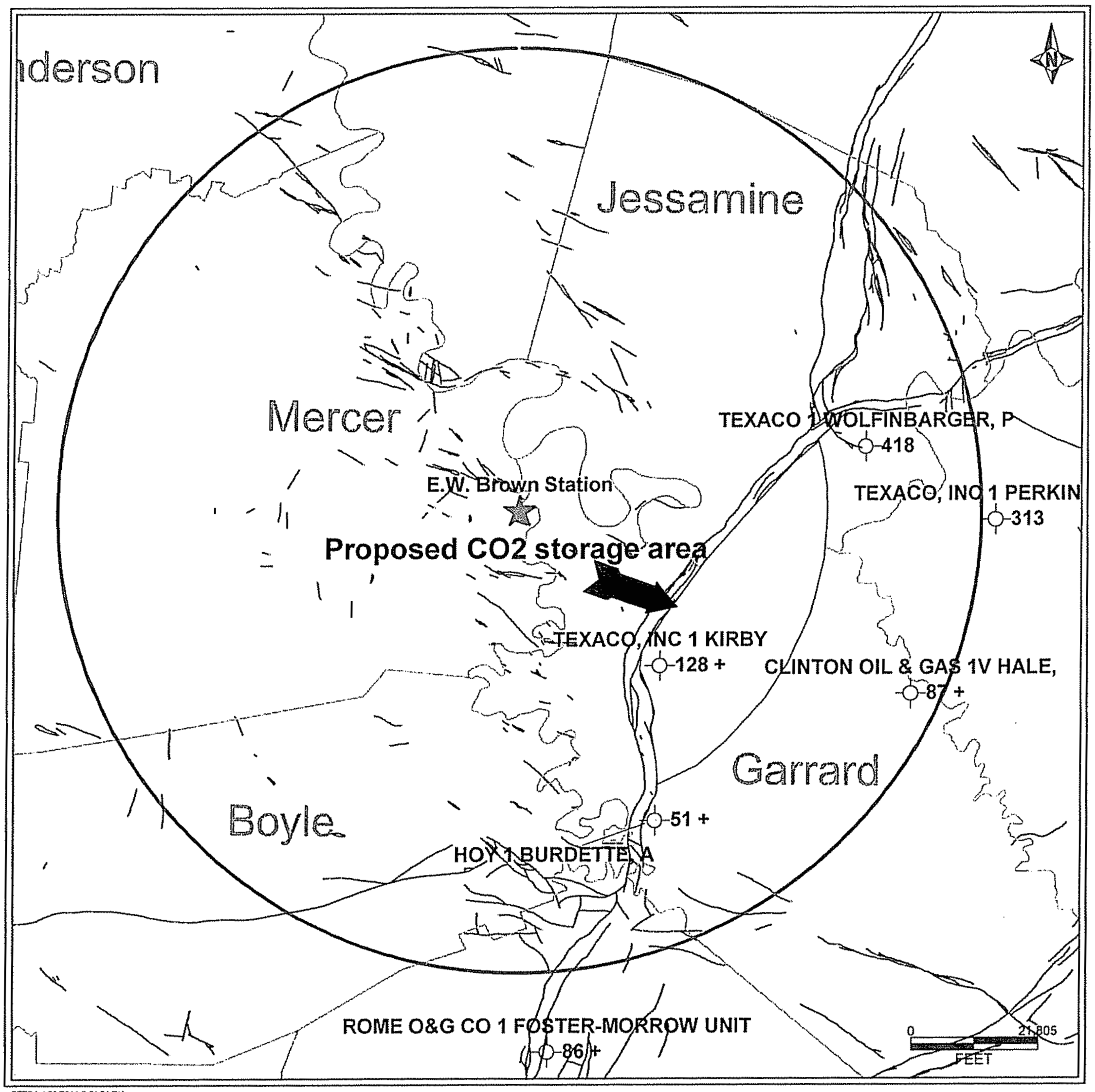


Figure 3-13. Map of proposed sequestration target area within 10 miles of E.W. Brown Station. Yellow area has suitable reservoir and seals less than 10 miles from Brown. The locations and thickness of net porous sandstone (ft) are shown for the six wells used in the reservoir calculations. A plus symbol (+) indicates the well only partly penetrated the reservoir interval.

A limit of 10 miles from E.W. Brown was used to define the potential sequestration area which is highlighted in yellow on the map. Reasonable estimates for porosity and net injection zone thickness were calculated from six wells and locations are shown on Figure 3-13. Only one of these wells lies within 10 miles of E.W. Brown, but four are located within 15 miles.

Reservoir Porosity Estimates

Both geophysical well logs and porosity measured from core samples were used to estimate porosity. Cores provide the most accurate porosity and permeability data because they are analyzed directly in a laboratory. Porosity from well logs is an indirect measurement, based on the density or other rock properties measured with radioactive devices. Core-measured porosity and permeability data for the Rome Formation is available from a single well (the Texas West Bay #1 Burdette in Garrard County). Core data from this well is presented in Figures 3-14 and 3-15. The porosity and permeability vs. depth plots (Figures 3-14a and 3-14b) also include data from the Mt. Simon Sandstone for comparison (the reservoir at the Trimble County, Ghent and Mill Creek Stations). The Rome sandstone porosity and permeability data indicate good reservoir quality exists. Average porosity is higher (13.1%) than for the Mt. Simon reservoir (Figure 3-14a), whereas permeabilities are similar (Figure 3-14b and 3-15).

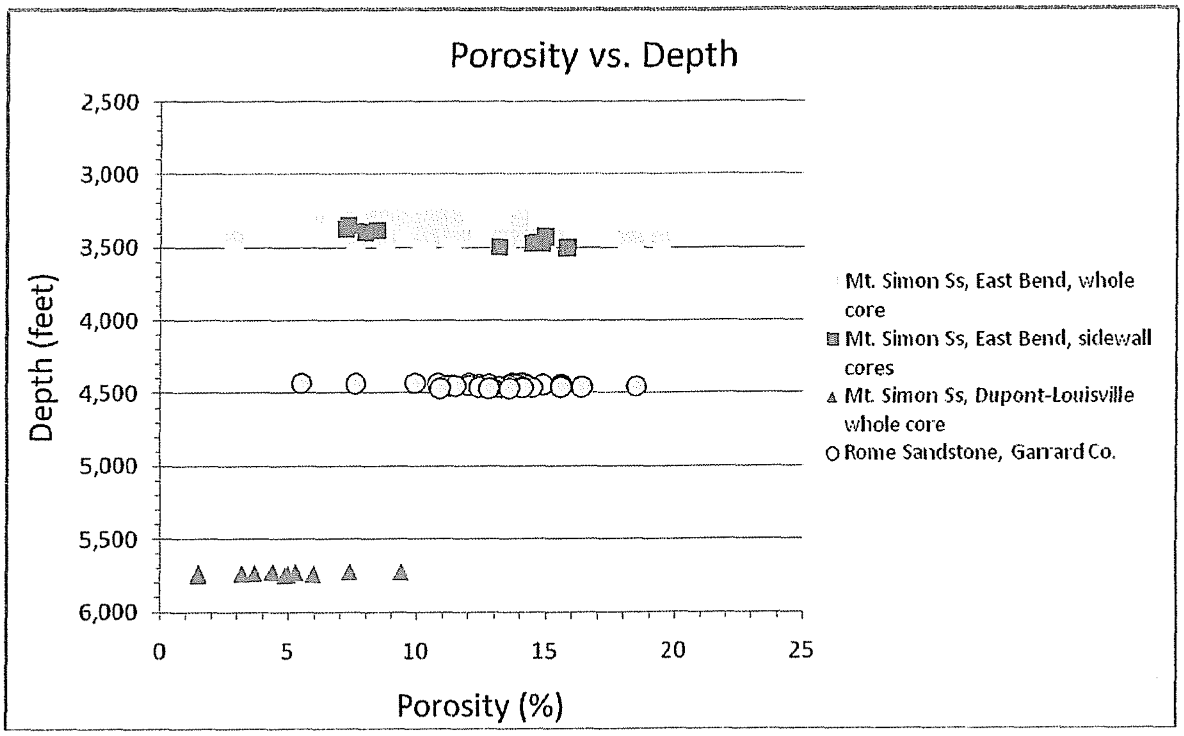


Figure 3-14a. Plot of core porosity vs. depth below surface for Rome sandstones (circles). Data from the Mt. Simon Sandstone in northern Kentucky and Louisville is included for comparison. Average core porosity for the Rome sandstones is 13.1%, and is higher than the Mt. Simon Sandstone cores.

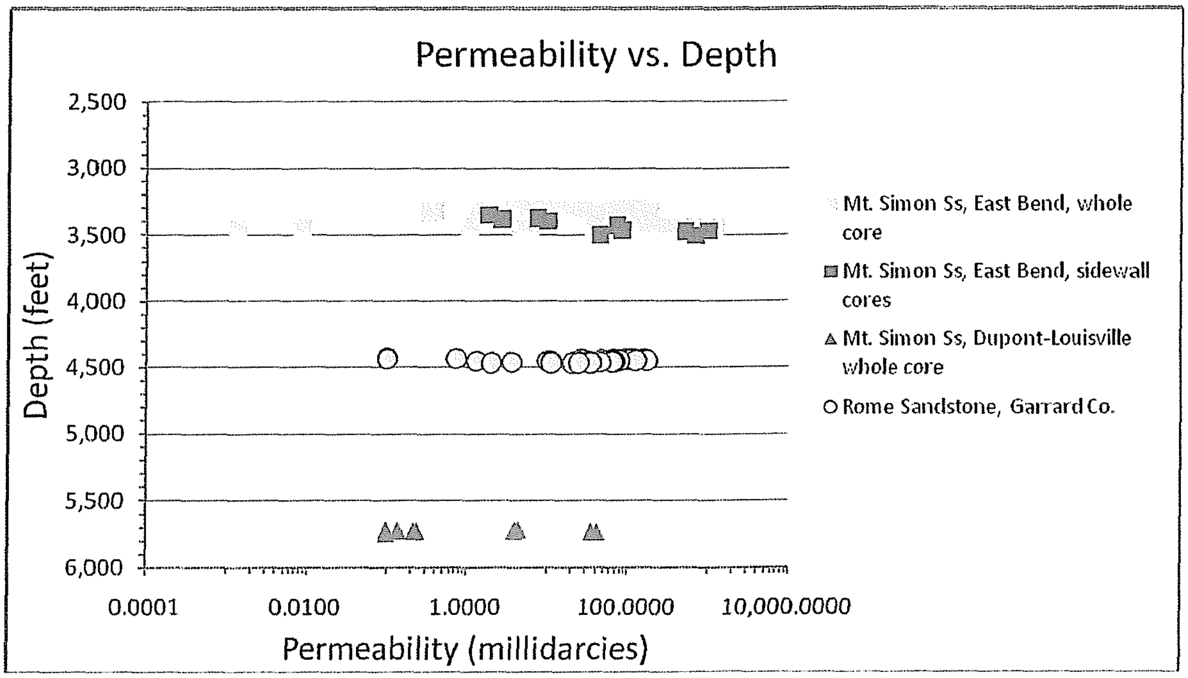


Figure 3-14b. Plot of core permeability vs. depth below surface for Rome Formation sandstones (circles). Data from the Mt. Simon Sandstone in northern Kentucky and Louisville is included for comparison. Permeability in the Rome is variable, but is comparable with the Mt. Simon in northern Kentucky. Average permeability for the Rome sandstone core is 56 millidarcies.

Plotting porosity vs. permeability illustrates the apparent positive correlation between the two measurements (Figure 3-15). This plot allows a minimum porosity to be interpreted for sandstone with acceptable permeability for injection. Because porosity can be measured with downhole logs and permeability cannot, a porosity cutoff allows the net thickness of rock with suitable porosity and permeability for injection to be summed from porosity geophysical log data alone.

A minimum porosity of 7% was chosen as the porosity cutoff for the Rome interval in this area. This was done for consistency with published Mt. Simon reservoir calculations (Medina and others, 2011), and because the core porosities are higher than the log derived porosities (discussed below). The reason for this difference is not clear, and will require additional study.

Core data was available for a 38 ft. interval in one well, Porosity (but not permeability) data is also derived from geophysical well logs, especially the bulk density log. Logs provide a continuous dataset for the entire formation, but are not as accurate as core data. A total of 6 wells with formation bulk density geophysical logs were used to estimate sandstone porosity.

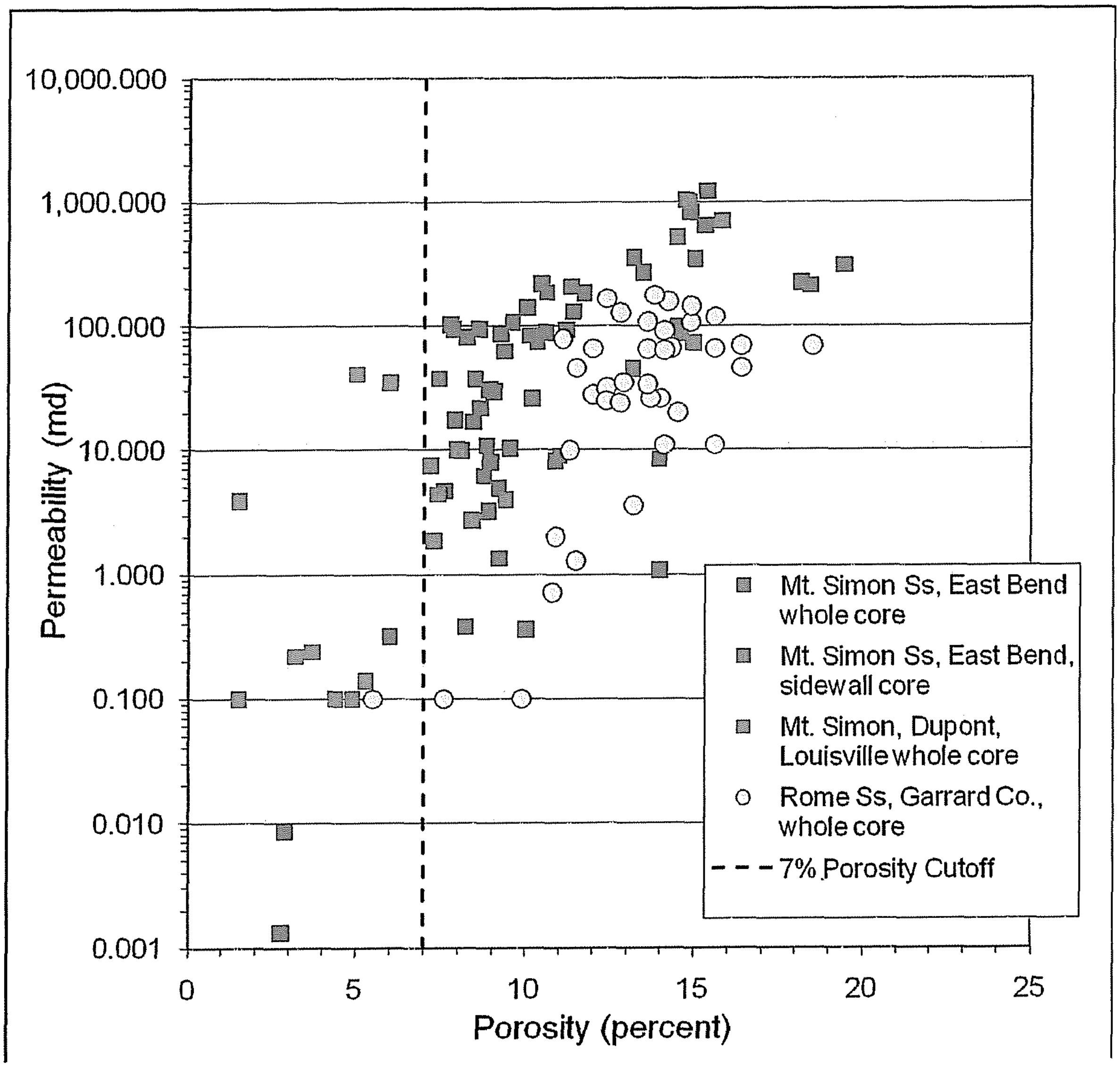


Figure 3-15. Plot of porosity vs. permeability for the Rome sandstone core in Garrard County (circles). Data from the Mt. Simon Sandstone in northern Kentucky and Louisville is included for comparison. Porosity in the Rome is higher than the Mt. Simon in northern Kentucky, while permeability is similar.

Calculation of Net Porous Sandstone

Once a porosity cutoff was chosen, the net thickness of porous sandstone, and average porosity of sandstones above the cutoff were determined for use in CO_2 capacity calculations. Because the Rome and basal sandstones contain abundant thin shales and some clay-rich sandstones with poor reservoir quality, only clean, shale-free sandstone was included in the net sandstone calculation. The natural gamma ray geophysical log is the best discriminator of clay and shale, and a cutoff of 80 API gamma ray units was used to identify clean sandstone. Intervals with 80 or less API units were classified as sandstone.

A log analysis program (Petra) was used to calculate the net feet of sandstone in each well with a gamma ray reading of less than 80 API units, and sandstone density porosity greater than or equal to 7%. The results of the net sandstone calculation are shown in Table 3-1. Average log porosity and total porosity feet (thickness of void space) were also calculated. Gross thickness is the total thickness of the Rome and basal sandstone, or the feet penetrated in the well if a partial penetration. Only two wells penetrated the entire Rome/basal sandstone interval in the area. A net to gross sandstone ratio was also calculated for each well to . The net to gross sandstone ratio ranges from 0.09 to 0.28. Average log-derived porosity of the net sandstone interval ranges from 8.6% to 11.5%.

Table 3-1. Rome and basal sandstone reservoir data.

Well Data	Average Depth (ft)	Gross Thickness (ft)	Full or Partial Interval	Net Porous Sandstone (ft)	Net to Gross Ratio	Average Porosity	Porosity Feet
Texaco Perkins	5,500	1,633	Full	312.5	0.19	9.40%	29.3
Texaco Wolfinbarger	5,100	1,489	Full	418	0.28	9.50%	39.5
Clinton Oil Hale	5,100	937	partial	87	0.09	9.20%	7.9
Texaco Kirby	5,000	842	partial	128	0.15	8.60%	11.0
Hoy Burdette	4,800	184	partial	50.5	0.27	11.50%	5.8
Rome Oil Foster-Morrow	5,600	380	partial	85.5	0.23	9.40%	8.0
Average	5,183	–	–	--	0.20	9.60%	–
Calculated Data							
Estimate for Capacity Calculation	**5,200**	**1,561**		**312**	**0.20**	**10%**	**31.2**

Table 3-1 also includes estimated data based on averages of the six wells for use in the capacity calculation. The gross thickness is the average of the two wells that fully penetrated the interval. The net to gross sandstone ratio is the average of the six wells. This ratio (0.2) gives an estimated net porous sandstone thickness of 312 feet. The average porosity of 9.6% was rounded to 10% for the capacity calculation.

CO_2 Capacity Calculations

Using the compiled and calculated data, CO_2 storage volume calculations were made. CO_2 storage capacity is based on the porosity, thickness and area of the injection zone, and density of the injected CO_2. CO_2 density is a function of reservoir pressure and temperature. The Rome interval is deep enough for supercritical (dense) phase CO_2 injection in the area east of the E.W. Brown Station. CO_2 density calculations were made using the CO_2 properties calculator at the MidCarb project web site: http://www.midcarb.org/calculators.shtml. The Midcontinent Interactive Digital Carbon Atlas and Relational dataBase (MIDCARB) was a research consortium composed of the state geological surveys of Illinois, Indiana, Kansas, Kentucky, and Ohio, funded by the US Department of Energy.

Calculated CO_2 density is shown in Table 3-2.

Table 3-2. Calculated CO_2 density at reservoir conditions.

CO_2 Density	Reservoir Pressure (psi)	Reservoir Temperature (F)	CO_2 Density lbs/ft^3	CO_2 Density kg/m^3
E.W. Brown	2200	110	47.3	758.3

These parameters are required to calculate CO_2 storage capacity:

Reservoir pressure: assumed hydrostatic, and calculated at 0.433psi/ft for the reservoir depth
Temperature: taken from well log data in Garrard and Jessamine Counties
Reservoir thickness: the net porous sandstone thickness as calculated above
Reservoir area: a standard area of 100 acres was used for these calculations
Reservoir porosity: the average porosity for the net reservoir footage

The equation for CO_2 storage capacity is modified from Medina and others (2011):

$$SC = A_n * h_n * \Phi_n * \rho_{CO2} * \acute{\varepsilon} / 1000$$

Where SC is the storage capacity in metric tons, A_n is the area in square meters, h_n is the net reservoir thickness, Φ_n is the average porosity of the net reservoir, ρ_{CO2} is the density of CO_2 at the reservoir conditions, and $\acute{\varepsilon}$ is the storage efficiency factor (discussed below).

The reservoir parameters used and CO_2 capacities calculated are shown in the Table 3-3.

Table 3-3. Reservoir parameters and calculated CO_2 storage capacity for a 100 acre area at 100% and 14% storage efficiency.

Site	100 Acre Area (m^2)	Net Reservoir Thickness (ft)	Net Reservoir Thickness (m)	Porosity	CO_2 Density (kg/m3)	CO_2 Capacity @ 100% Efficiency (metric tons)	Storage Efficiency Factor	CO_2 Capacity @ 14% Efficiency (metric tons)
Brown	404,686	312	95.1	10%	758.31	2,918,344	0.14	**408,568**

Efficiency of CO_2 Storage

The storage capacity equation used above includes an efficiency factor which reduces the CO_2 storage capacity. This factor is applied because 100% of the available pore volume is never completely saturated with CO_2 due to fluid characteristics and geologic variability within the reservoir.

Litynski and others (2010) calculated efficiency factors for carbon storage in various reservoir types that account for factors which reduce the volume of CO_2 that can be stored. These factors include:

Geologic Factors

- Net to total area of a basin suitable for sequestration
- Net to gross thickness of a reservoir that meets minimum porosity and permeability requirements
- Ratio of effective to total porosity (fraction of connected pores)

Displacement Factors

- Areal displacement efficiency- area around a well that can be contacted by CO_2
- Vertical displacement efficiency- fraction of vertical thickness that will be contacted by CO_2
- Gravity- fraction of reservoir not contacted by CO_2 due to buoyancy effects
- Displacement efficiency- portion of pore volume that can be filled by CO_2 due to irreducible water saturation

Combining all of these factors using a Monte Carlo simulation results in a probability range of total efficiency factors of 0.51% to 5.4% (P_{10} to P_{90} range) (Litynski and others, 2010). For the purposed of this assessment, the *geologic* factors are known and thus equal to one. In our 100-acre evaluation unit, the net to total area is the same, the net to gross thickness has already been calculated, and for clastic reservoirs (sandstones) we can assume that the porosity is well-connected with a ratio of effective (connected) porosity to total porosity equal to one. Litynski and others (2010) calculated efficiency factors for just the *displacement* factors separately, and for sandstone reservoirs they range from 7.4% to 24%, with a P_{50} (most likely) efficiency factor of 14%. This means the most likely case is that 14% of the pore space can be filled with CO_2. The range of storage volumes using the probabilistic efficiency factors for the E.W. Brown site is shown in Table 3-4.

Table 3-4. Range of probabilistic storage volumes using U.S. DOE displacement efficiency factors for clastic reservoirs (Litynski and others, 2010).

Site	Minimum Volume (metric tons/100 ac.) E=7.4% (P10)	Most Likely Volume (metric tons/100 ac.) E=14% (P50)	Maximum Volume (metric tons/100 ac.) E=24% (P90)
E.W. Brown Station	215,957	**408,568**	700,403

The application of an efficiency factor significantly reduces the storage capacities but is necessary to estimate storage volume.

Summary

The E.W. Brown Station is located in an area where geologic sequestration is not feasible directly below the plant site due to the absence of porous reservoirs at depths necessary for supercritical (dense) phase CO_2 storage. However an area 7 to 10 miles east of the Brown Station is suitable for geologic sequestration in deep sandstones of the Rome Formation. Use of this area would require transporting compressed CO_2 from the Brown Station by pipeline. This area, east of a major fault zone, has excellent confinement for injected CO_2 provided by the 1,000 ft. thick Conasauga Group. In addition, this area provides a structural trap for injected CO_2 against the KRFZ. Injected CO_2 would migrate a short distance to the west toward the fault, which forms a lateral barrier to further migration. The fault has a low risk of leakage because oil and gas exploration wells have encountered natural gas trapped in the same sandstones against the fault.

Geologic data for this area is good, with numerous wells in the reservoir, and one core of the reservoir rock. Additional seismic data will be necessary to better define the specific area chosen for a demonstration project. Existing seismic data is of poor quality, and limited in extent.

One problem with using this area for sequestration is a potential conflict with oil and gas mineral owners. Natural gas has been found in wells in the area, but is high in nitrogen and has too little methane for commercial production. However, several wells contain gas with anomalously high levels of helium (up to 2%). This potential helium resource has been known since the 1970's, but has not been commercially developed. Rising prices for helium may generate interest in this area to develop the helium resource. Obviously injection of CO_2 into a reservoir with potentially economic resources would contaminate this resource. These potential issues will have to be resolved before sequestration begins. It may be possible to identify deeper reservoirs for CO_2 sequestration that do not affect potential gas resources.

Because the sequestration target for the E.W. Brown Station if off-site, total site capacity will depend on the size of the property leased for the storage project. For comparison with the other larger sites (Ghent and Trimble County), we have assumed an area of 2,000 acres will be used (Table 3-5). A site of this size near the E.W. Brown Station would allow 8.2 million tons of CO_2 to be stored.

Table 3-5. Total site storage capacity at E.W. Brown assuming a 2,000 acre area.

Site	CO2 Storage Volume (metric tons per acre)	Total Site Size (acres)	Total Site Storage Volume (metric tons)
E.W. Brown	4,086	2,000	8,171,363

References Cited

Cressman, E.R., and Hrabar, S.V., 1970, Geologic map of the Wilmore quadrangle, central Kentucky: U.S. Geological Survey Geologic Quadrangle Map GQ-847, scale 1:24,000.

Drahovzal, J.A., Harris, D.C., Wickstrom, L.H., Walker, D., Baranoski, M.T., Keith, B.D., and Furer, L.C., 1992, The East Continent Rift Basin: a new discovery: Spec. Pub. 18, Ser. XI, Kentucky Geological Survey, 25 p

Greb, S. and Drahovzal, J.A., 2011, unpublished report for Midwest Regional Carbon Sequestration Partnership (MRCSP).

Litynski, J., Deel, D., Rodosta, T., Guthrie, G., Goodman, A, Hakala, A., Bromhal, G., and Frailey, S., 2010, Appendix B, Summary of the Methodology for Development of Geologic Storage Estimates for Carbon Dioxide, 2010 Carbon Sequestration Atlas of the United States and Canada, U.S. Department of Energy, National Energy Technology Laboratory, http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlasIII/.

Medina, C. R., Rupp, J. A., Barnes, D. A. 2011, Effects of reduction in porosity and permeability with depth on storage capacity and injectivity in deep saline aquifers: A case study from the Mount Simon Sandstone aquifer. International Journal of Greenhouse Gas Control 5: 146-156.

Wolcott, D.E., 1969, Geologic map of the Little Hickman quadrangle, central Kentucky: U.S. Geological Survey Geologic Quadrangle Map GQ-792, scale 1:24,000.

Chapter Four

Geologic CO_2 Sequestration Potential of the LG&E-KU Mill Creek Station, West-Central Kentucky

John Hickman and Dave Harris
Kentucky Geological Survey

LG&E-KU CO_2 Sequestration Geologic Summary Sheet

Power Plant: MILL CREEK **County:** JEFFERSON **Geologic Basin:** Cincinnati Arch

Data Quality

Distance to nearest well control in reservoir:	12 miles
Wells to primary injection zone within 15 mile radius:	1
Distance to nearest core in injection zone:	12 miles
Distance to nearest good quality seismic control:	11 miles

Reservoirs

Primary injection zone:	Cambrian Mt. Simon Sandstone
Rock type:	sandstone (quartz arenite)
Drilling depth at plant site:	5,600 ft
Trapping mechanism:	regional dip (capillary and solution trapping)
Max. reservoir pressure:	2,800 psi (hydrostatic)
Reservoir temperature:	116°F
Salinity of reservoir fluid:	200,000 ppm (est.)
Reservoir thickness (gross/net):	470/70 ft
Average porosity:	8%
Average permeability:	8md
Secondary injection zone:	None at this site

Confinement and Integrity

Primary confining zone:	Cambrian Eau Claire Shale
Rock type:	shale and dolomite
Thickness of primary confining zone:	900 ft
Height above primary injection zone:	0 (overlies injection zone)
Well penetrations of primary seal within 15 mile radius: 2	
Secondary confining zone:	Ordovician Black River/Trenton Ls
Rock type:	Limestone

Thickness of secondary confining zone:	575 ft
Height above primary injection zone:	4,500 ft
Well penetrations of secondary seal within 15 mile radius:	12

Number of faults cutting primary seal within 15 mile radius:	2
Distance to nearest mapped fault:	5 mi

Storage Capacity

Calculated CO_2 storage capacity, primary injection zone:

563,583 metric tons/100 acres (assuming 100% efficiency)

78,902 metric tons/100 acres (at 14% efficiency)

Introduction

An evaluation of geologic CO_2 sequestration potential was performed for an area surrounding the LG&E-KU Mill Creek power generation station in Jefferson County, Kentucky. A circular area with a 15-mile radius around the plant was defined as the primary focus of the evaluation, but data from beyond 15 miles was also used because of limited data within the primary area. The 15-mile buffer includes parts of Harrison and Floyd Counties, Indiana, as well as Jefferson, Meade, and Bullitt Counties in Kentucky. An index map is included as in Figure 4-1, which shows the locations of well data, faulting, and geologic cross sections.

The following data were compiled for the evaluation:

1. 7.5 minute topographic and geologic quadrangle maps for the Valley Station/Kosmosdale quads
2. Locations of all petroleum exploration and waste disposal wells penetrating the Cambro-Ordovician Knox Group or deeper (Kentucky and Indiana Geological Surveys)
3. Formation tops for geologic units from the top of the Ordovician to Precambrian (Kentucky, and Indiana Geological Surveys)
4. Available digital geophysical logs for Knox and deeper wells (Kentucky and Indiana Geological Surveys)
5. Core analyses (porosity and permeability) for Mt. Simon Sandstone, Knox, and Eau Claire Fm.
6. Reflection seismic data

Within the 15-mile radius around the Mill Creek Station one well has been drilled that penetrates the entire Paleozoic sequence, bottoming in Precambrian rocks. This well was drilled as a Class 1 hazardous waste disposal well at the E.I. DuPont plant in Louisville, 12 miles northeast of Mill Creek. This well tested the injectivity of the Cambrian Mt. Simon Sandstone, but due to low permeability, waste disposal injection was confined to the Knox dolomite interval. Two other wells were drilled on the DuPont property, both only went to the Knox– one of these was an injection well, the other an observation well. These wells provide key geologic data used in this assessment. A total of 13 wells have been drilled to 2,500 ft. or deeper within the 15-mile area. Most are saltwater disposal wells associated with the Laconia gas field (New Albany Shale reservoir) in Indiana.

There are numerous abandoned shallow wells near the Mill Creek site associated with the Meadow gas field (SW Jefferson County and adjacent Bullitt County, Figure 4-1). This field produced gas for domestic use from the New Albany Shale around 250 feet deep, and was drilled in the early 1900's. There is no current production from this field, and records are scarce (Kepferle, 1972).

In Meade County to the west, two shallow gas fields, Doe Run and Muldraugh, have been converted to gas storage fields. The these fields produced from several shallow reservoirs, including the Devonian New Albany Shale, Devonian Jeffersonville Limestone, and Silurian Laurel Dolomite. Both of these fields lie within a 15-mile radius of the Mill Creek Station, but are shallow enough that they will have no impact on deeper CO_2 storage operations. In addition, they both occur downdip from Mill Creek, opposite the direction of likely CO_2 migration.

More recently In Meade County, in the southwest part of the study area, numerous wells have been drilled to the Devonian New Albany Shale and underlying carbonates for natural gas. These wells are typically less than 1,000 ft deep, and are shown as the large gas field in southern Meade County on Figure 4-1. This gas production is too shallow affect deeper injection of CO_2 at Mill Creek.

Other deep wells are located to the northeast and southwest, but lie outside the 15-mile radius. Wells to the northeast were used in the Trimble County and Ghent Stations evaluations (see Chapter 1). These include two wells drilled in Switzerland County, Indiana by Ashland Oil. In 2009, a CO_2 injection test well was drilled by Battelle Memorial Institute at the Duke Energy East Bend Station in Boone County, Kentucky as part of the U.S. DOE-funded Midwest Regional Carbon Sequestration Partnership (MRCSP, www.mrcsp.org). This well, 82 miles from Mill Creek, was drilled to test the Cambrian Mt. Simon Sandstone, the same potential reservoir zone that underlies Mill Creek. Data from this well was available for this evaluation, but the distance from Mill Creek and difference in depth limit its applicability in this evaluation.

Figure 4-1. Index map showing location of Mill Creek Station in Jefferson County, Kentucky. Heavy gray line is the Ohio River, separating Indiana from Kentucky. Red circle is the 15-mile radius around the station, defining the primary area of study. Wells deeper than 2,500 ft are shown. The location of one seismic line (E-W line of circles in Harrison Co., Indiana) is shown. Mapped surface faults are indicated by solid blue lines. Gas (orange) and oil (light green) fields are also shown.

To the southwest, two Precambrian wells are located 42 to 46 miles from Mill Creek, in Breckenridge and Hancock Counties. In both of these wells the Cambrian Mt. Simon Sandstone is absent, and thus they provide no data for that formation at Mill Creek. The deep well in Hancock County was drilled by the Kentucky Consortium for Carbon Storage (Kentucky Geological Survey and partners). This well was a CO_2 sequestration test of the Knox Group, and numerous cores, seismic data, and logs are available. The Precambrian well in Breckenridge County was an unsuccessful oil and gas exploration well, with only logs available (no core).

Geologic Setting and Surface Geology

Jefferson County lies on the west flank of the Cincinnati Arch, a broad anticline (arch) that separates the deeper sedimentary basins in western Kentucky (Illinois Basin) and eastern Kentucky (Appalachian Basin). The arch developed in Middle Ordovician time, and rock units deposited prior to this time have been tilted to the west toward the Illinois Basin. Rocks deposited from the Middle Ordovican and younger were influenced to some extent by the growing arch, but for the interval of interest in this study the arch had no effect on thickness or lithology.

The Mill Creek Station is located on the Kosmosdale 7.5 minute topographic quadrangle, and a geologic map for this quadrangle was published by Kepferle (1972). The Mill Creek power plant is located on unconsolidated sediments in broad alluvial valley along the Ohio River (Figure 4-2). Sediments underlying the river valley are Quaternary-age (Holocene) alluvium, and Pleistocene glacial outwash deposits. Bedrock is exposed in the hills and bluffs to the east. Bedrock consists of Mississippian siltstones and shales of the Borden Group, with hills capped by the Mississippian Harrodsburg and Salem Limestones.

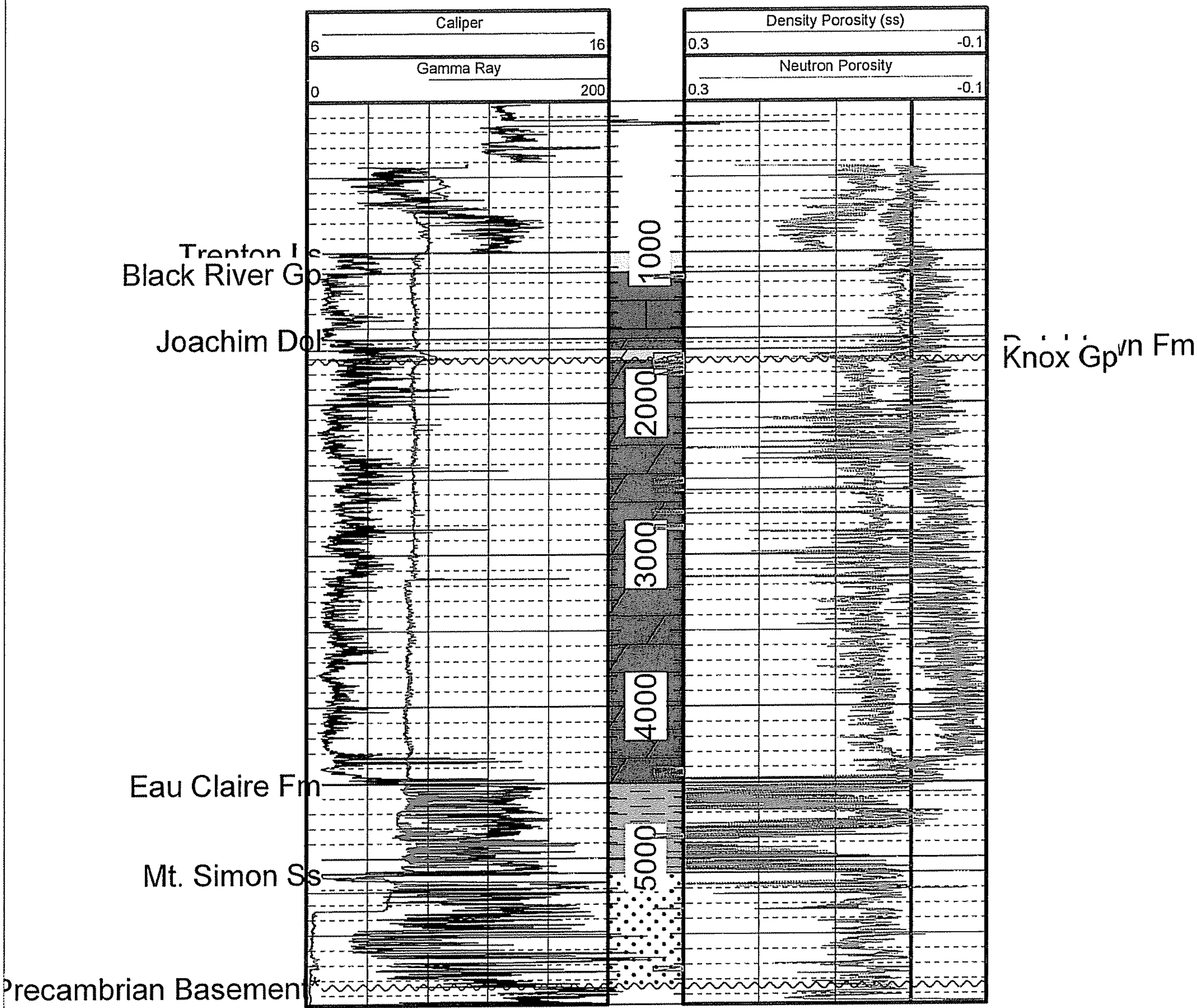
Surface geology does not have a direct impact on carbon sequestration potential, since CO_2 injection will occur at much deeper depths. The New Albany Shale and New Providence Shale are too shallow to form effective seals, and outcrop about 10 miles to the east of Mill Creek. Deeper Upper Ordovician shales (500-1,000 ft deep) would serve as potential secondary confining layers in the unlikely event CO_2 were to migrate through the deeper primary seals.

The surface geology will impact the design and implementation of shallow groundwater monitoring wells that will be required by U.S. EPA for an underground injection (UIC) permit. The presence of unconsolidated alluvial sediments and glacial outwash along the Ohio River at the Mill Creek site allows relatively inexpensive construction of monitoring wells that will yield good water flows. The EPA UIC permit will likely require monitoring down to the base of the underground source of drinking water (USDW), which may require drilling into Mississippian bedrock.

Stratigraphy and Structure

Geologic storage of carbon dioxide (CO_2) is confined to depths greater than 2,500 ft below the surface so that CO_2 exists in the supercritical, or dense phase. Supercritical CO_2 has properties of both a liquid and gas, but much higher density. In the Jefferson County area, this 2,500 ft depth falls within the Cambrian-Ordovician Knox Group. Geologic formations below the 2,500 ft depth in this area include basal part of the Knox, the Upper/Middle Cambrian Eau Claire Formation and Middle Cambrian Mt. Simon Sandstone, and Precambrian igneous rocks (see Figure 4-3). These formations are briefly described below, from oldest to youngest.

Mill Creek Station



E.I. DuPont 1WAD DuPont de Nemours
Jefferson
KY

Figure 4-3. Geophysical log for the E.I. DuPont #1WAD well in Jefferson County, Ky. Stratigraphic units are labeled. Cored intervals are marked on the right edge of the depth column. The potential CO_2 injection zone is the Mt. Simon Sandstone (yellow). The density porosity log is shaded blue in the Mt. Simon interval where porosity is greater than 7%, and the gamma ray log is shaded yellow in the Mt. Simon where less than 80 units (clean sandstone). Porosity in the Mt. Simon is not well developed in this well.

Precambrian Rocks

The Precambrian basement in the study area consists of igneous rocks. A core of gabbro was recovered from the DuPont #1WAD well in Jefferson County, 12 miles NE of Mill Creek. Maps by the Cincinnati Arch Consortium shows these igneous rocks continue to the SW below Mill Creek (Drahovzal and others, 1992). The Louisville area is situated on an uplifted block of igneous rocks, unlike the sedimentary Middle Run Formation found at Trimble County and Ghent Stations. Precambrian rocks dip to the southwest in the study area, consistent with the trend of the Cincinnati Arch (Figure 4-4). This structure map is based on the few wells that penetrate the Precambrian surface in the area, and one seismic line. As such, it should be considered a general representation of the structure of the area. This map indicates that the depth to basement is 6,255 ft (-5,800 below sea level) at the Mill Creek Station. This would be the maximum depth required for an injection well in the overlying Mt. Simon Sandstone.

Mill Creek
Station

Figure 4-4. Structure map on the top of Precambrian basement. The Precambrian surface deepens to the southwest, and is estimated to be at -5,800 feet below sea level at Mill Creek. Inferred deep faults trend NE-SW to the northeast and southwest of Mill Creek.

Cambrian Mt. Simon Sandstone

The Cambrian Mt. Simon Sandstone unconformably overlies Precambrian igneous rocks in most of the study area. The Mt. Simon Sandstone is predominantly quartz-rich, and because of its depth will be the primary CO_2 injection zone in the Mill Creek area. The Mt. Simon has been penetrated in one well in the study area. Cores from the Mt. Simon Sandstone are available from this well (the DuPont waste injection well in Louisville). Porosity and permeability data derived from these cores is described further in the reservoir quality section.

Figure 4-5. Regional thickness map of the Mt. Simon Sandstone in Kentucky. The formation is present along the Ohio River Valley in northern Kentucky, and thins to the south. It is absent in much of western and southern Kentucky. Interpretation based on seismic and well data. Contours in feet. From Greb and Drahovzal, 2011.

The Mt. Simon Sandstone is 748 ft thick in the DuPont well in Louisville, and the formation top is at 5,098 below surface (-4,633 below sea level) feet. Using available well data and reflection seismic lines in the area, structure and thickness maps for the Mt. Simon were constructed. Figure 4-6 is a structure contour map on the top of the Mt. Simon Sandstone. It shows depth increasing to the south and southwest. The top of the Mt. Simon is estimated to be 5,785 ft (-5,330 below sea level) at Mill Creek.

The isopach (thickness) map (Figure 4-7) shows thinning of the Mt. Simon Sandstone toward the south. Its thickness is estimated to be 470 ft at Mill Creek. The isopach map was interpreted from nearby well data, and using the zero thickness line on the regional map.

Mill Creek
Station

Figure 4-6. Structure contour map on top of Cambrian Mt. Simon Sandstone around the Mill Creek Station. This unit deepens to the southwest. Contour interval is 100 ft. The dashed line in the southwest corner of the map is the inferred pinchout of the Mt. Simon from the regional thickness map (Figure 4-5).

Mill Creek
Station

Figure 4-7. Isopach (thickness) map of the Cambrian Mt. Simon Sandstone, near Mill Creek Station. Contour interval is 50 ft. The Mt. Simon thins to the south. The Mt. Simon is interpreted to pinch out at the zero contour line (SW corner). This interpretation is based on data from several older seismic lines, and should be regarded as approximate.

Cambrian Eau Claire Formation

The Eau Claire Formation directly overlies the Mt. Simon Sandstone and is predominantly composed of green and gray marine shale, with some interbedded dolomite. The Eau Claire Formation was cored in the DuPont #1WAD waste disposal well in Louisville, from 4,409 to 4,459 and 4,842 to 4,871 ft. The Eau Claire has very low porosity and permeability and is the primary confining layer (seal) for CO_2 injected into the Mt. Simon below.

Figure 4-8 is a structure contour map on the top of the Eau Claire Formation. The Eau Claire deepens to the southwest into the deeper parts of the Illinois Basin. The top is projected to be at 4,880 ft (- 4,425 ft subsea) at the Mill Creek site. The top of this confining layer is well below the minimum depth for supercritical CO_2.

Figure 4-9 is an isopach (thickness) map of the Eau Claire. The Eau Claire Formation thickens to the south, and is projected to be 905 ft. thick at Mill Creek. This is about 300 ft thicker than at the DuPont #1WAD well. As the Mt. Simon Sandstone thins to the south, the Eau Claire thickens- the combined interval is relatively consistent. This map indicates there is an adequate thickness of impermeable rocks immediately above the Mt. Simon injection zone.

Cambrian-Ordovician Knox Group

The Knox Group is divided into an upper dolomite unit, the Beekmantown Dolomite, and the lower Copper Ridge Dolomite, separated by sandstone or sandy dolomite unit (Rose Run Sandstone) that is poorly developed in this area. The Knox is approximately 2,800 ft thick in the study area. The Knox contains scattered porous and permeable intervals separated by impermeable dolomite. It has injection potential in deeper parts of Kentucky (such as the KGS #1 Blan research well in Hancock County), and was used as a hazardous waste injection zone at the DuPont chemical plant in Louisville. Porous zones in the Knox have also been used for natural gas storage by LG&E northeast of the study area, in Grant and Oldham Counties (Ballardsville and Eagle Creek storage fields). The top of the Knox is a regional erosional unconformity that formed when the Knox was uplifted above sea level during the early Ordovician.

In the study area, the upper third of the Knox lies above the 2,500 ft depth limit for CO_2 to exist in the supercritical phase. The lower part of the Knox (below 2,500 ft depth) is not a potential injection target, since the primary seal (containment zone) above the top of the Knox is well above 2,500 ft. depth required to keep CO_2 in a supercritical phase.

The Knox is the shallowest interval mapped in this evaluation. Figure 4-10 is a structure map on the top of the Knox. Many more wells have been drilled to the top of the Knox than the deeper formations, and thus more well data is available for the Knox structure map. The Knox deepens to the west, with the projected top of the Knox at about 1,915 ft below surface (-1,460 ft subsea) at Mill Creek.

Mill Creek
Station

Figure 4-8. Structure contour map on top of the Cambrian Eau Claire Formation. Contour interval is 100 ft. The structure deepens to the southwest, and the top of the Eau Claire is 4,880 below surface (-4,425 below sea level) at Mill Creek.

Mill Creek
Station

Figure 4-9. Isopach (thickness) map of the Eau Claire Formation. Contour interval is 50 ft. Shale and minor dolomite in this formation are over 900 ft thick at Mill Creek, providing a good seal for CO_2 injected into the Mt. Simon Sandstone below.

Mill Creek
Station

Figure 4-10. Structure contour map on the top of the Knox Group. Contour interval is 100 ft. The top of the Knox is a regional erosional surface, and the structure deepens to the west toward the Illinois Basin. The upper part of the Knox is too shallow for carbon storage in this area.

Ordovician Dutchtown Formation and Joachim Dolomite

The Dutchtown Formation and Joachim Dolomite are dolomite intervals that contain variable amounts of shale, and overlie the Knox unconformity. They are equivalent to the Wells Creek Dolomite in Ohio, and are partly gradational with the St. Peter Sandstone. They generally have low porosity and permeability. They would provide additional confinement for CO_2 injected in deeper zones. The formations were not mapped in detail.

Ordovician Black River Group and Trenton Limestone

The Trenton Limestone and Black River Group together form a shallow secondary confining zone (seal) for CO_2 injected into the deeper Mt. Simon Sandstone. These rocks are composed of limestone, minor dolomite, and interbedded shale. The interval typically has very low porosity and permeability unless fractured. In the DuPont #1WAD well these formations have a combined thickness of 572 ft. At Mill Creek the top of the Trenton Limestone is at 1,200 ft below surface (-745 subsea).

Ordovician Maquoketa Shale

The shallowest interval mapped in the Mill Creek area is the Upper Ordovician Maquoketa Shale. This interval was not mapped in the Trimble County and Ghent area (Chapter 1) because it was very close to the surface. In the Mill Creek area it is deeper, and could serve as another confining interval. It overlies the Trenton Limestone. In the DuPont #1 WAD well, the top of the Maquoketa is 437 ft. below surface (28 ft. above sea level), and is 565 ft. thick. The Maquoketa thickens to the south, and is interpreted to be 625 ft. thick at the Mill Creek site. Figure 4-11 is a thickness map of the Maquoketa shale interval.

Mill Creek
Station

Figure 4-11. Isopach (thickness) map of the Maquoketa Shale. Contour interval is 50 ft.

Cross Sections

Two regional cross section were constructed using geophysical well logs. Interpreted interval tops at the Mill Creek and Trimble County Stations were included on the sections for reference (Figure 4-12). Section A-A' (Figure 4-13) is a north-south line from southern Indiana through the DuPont well and Mill Creek location. Section B-B' (Figure 4-14) is a southwest to northeast section. These sections illustrate the structure and stratigraphic variations across the study area, including the thinning of the Mt. Simon Sandstone from north to south.

Figure 4-12. Index map showing locations of two structural cross sections, A-A' (Figure 4-13), and B-B' (Figure 4-14). Both sections include the DuPont waste disposal well in Louisville, and the interpreted geology at the Mill Creek Station site. Seismic lines used in the evaluation are shown by the lines of overlapping colored circles (shotpoint locations). Deep faults are shown by the solid dark gray lines.

Figure 4-13. Cross-section A-A' runs N-S through the Mill Creek property. Note the thinning of the Mt. Simon Sandstone to the south (right).

Figure 4-14. Cross-section B-B′ runs from the KGS #1 Blan well on the SW (left) to the Trimble County Station on the NE (right).

Deep Faults and Available Seismic Data

Seismic data available in the study area is primarily outside the 15-mile radius around Mill Creek. Figure 4-12 shows the location of seismic lines used in the study– only one line is located within the 15-mile radius. These lines were used as control data for the structure and thickness maps discussed previously. Seismic data quality varies significantly, from very new, high quality data around the KGS Blan well, to older data in southern Indiana and central Kentucky. The closest seismic line to Mill Creek is an east-west line that extends to the west from near the DuPont well in Louisville, across Floyd, Harrison, and Crawford Counties, Indiana. This line shows some deep faulting in the Precambrian section, but none that penetrate the younger Paleozoic rocks where sequestration would occur.

There is some faulting present in the Mill Creek area. Figure 4-12 shows several deep fault trends that extend to basement level. The dashed faults on this map are inferred; data suggests there may be a fault present, but they have not been imaged on seismic or mapped at the surface. To the southwest of Mill Creek, a northeast trending fault extends part way into the 15-mile area. This fault could extend closer to the Mill Creek property, but there is no seismic data available to determine this.

Reservoir Quality and Injection Zone Thickness

In order to calculate carbon sequestration capacity, the average porosity and thickness of the storage zone is required. Since there are no wells drilled to the Mt. Simon Sandstone at the Mill Creek site, we must calculate reasonable estimates for porosity and net injection zone thickness from nearby well control. Data from the DuPont #1WAD well is helpful, since good well logs and some core data are available from this well.

Regional Porosity Trends

Like many sandstones, porosity in the Mt. Simon Sandstone decreases with increasing burial depth. This is primarily due to cementation and compaction, and is a result of increased temperature, pressure, and the amount of time the rocks have been buried. A substantial set of Mt. Simon porosity and permeability data from across the midwest has been published by Medina and others (2011). Cross-plots of porosity vs. depth in this paper establish a general correlation between porosity and depth. The authors found a dramatic decrease in porosity at depths below 7,000 feet. This depth generally corresponds to a porosity value of 7%, although significant variability exist in the data.

In the Trimble County and Ghent assessments (Chapter 1) significant variations in porosity are observed in the Mt. Simon, and were correlated with burial depth (Figure 4-15). The DuPont #1WAD well in Louisville was drilled to over 6,000 ft to test the Mt. Simon for hazardous waste injection. Initial injection tests in the Mt. Simon determined it lacked sufficient porosity and permeability for commercial waste disposal. An alternate zone in the shallower Knox dolomite was eventually used as the injection zone. The average depth of the Mt. Simon in the DuPont well is 5,600 ft, and the average log-derived sandstone porosity is 6.5%. The regional depth/porosity correlation proposed by Medina and others (2011) suggests the Mt. Simon should have about 8.4% porosity at 5,600 ft. This means that the DuPont well has *lower* porosity than predicted for its depth. The reason for this is not known, but the DuPont well provides a key control point that must be considered as we evaluate Mill Creek.

Figure 4-15a. Plot of core porosity vs. depth below surface for Mt. Simon Sandstone (reservoir) and Eau Claire Formation (seal) core from the Duke East Bend and DuPont #1WAD wells. Note significantly lower Mt. Simon porosity in the DuPont cores due to deeper burial depth. Average porosity for the DuPont core plugs, 4.3%.

Figure 4-15b. Plot of core permeability vs. depth below surface for Mt. Simon Sandstone and Eau Claire Formation. Permeability is quite variable, but is lower in the DuPont cores and in the Eau Claire shales. Average permeability for the DuPont core plugs is 6.1 millidarcies.

Plotting porosity vs. permeability illustrates the apparent positive correlation between the two measurements (Figure 4-16). This plot allows a minimum porosity to be interpreted for sandstone with acceptable permeability for injection. Because porosity can be measured with downhole logs and permeability cannot, a porosity cutoff allows the net thickness of rock with suitable porosity and permeability for injection to be summed from porosity geophysical log data alone.

Based on the core data in Figure 4-16, a minimum porosity of 7% was chosen as the porosity cutoff for the Mt. Simon. The 7% line separates the majority of the East Bend data (acceptable porosity and permeability) from the DuPont core data, where fluid injection was not successful. Medina and others (2011) also used a 7% porosity cutoff for the Mt. Simon across the Midwest in their calculation of CO_2 sequestration capacities. Their cutoff, based on a much larger dataset is supported by the core data used in this study. Figure 4-16 shows that most of the core analyses from the DuPont well fall below the 7% cutoff. This suggests the core interval is not a good injection zone, but as the following discussion indicates, there are some intervals with porosity above the cutoff.

Figure 4-16. Mt. Simon Sandstone core porosity vs. permeability plot for the Duke East Bend and DuPont #1WAD wells. Many of the DuPont analyses fall below the 7% cutoff, indicating limited injectivity for this interval. In general, permeability decreases rapidly below 7% porosity, and this trend was the basis for the 7% porosity cutoff used to calculate net reservoir thickness.

Calculation of Net Porous Sandstone

Once a porosity cutoff was chosen, the thickness of net porous sandstone, and average porosity of sandstones above the cutoff, were determined for use in CO_2 capacity calculations. The DuPont well is the only well near Mill Creek that has data available for the Mt. Simon. The reservoir calculations for Mill Creek are based on this single well.

The Mt. Simon Sandstone contains thin shales and some shaly sandstones with poor reservoir quality. Since only clean, non-shaly sandstone should be included in the net sandstone calculation a gamma ray cutoff was used. The natural gamma ray log is the best discriminator of clay and shale, and a cutoff of 80 API units was used to identify clean sandstone. Intervals with 80 or less API gamma ray were classified as sandstone. This 80 API unit cutoff is very close to the 75 API cutoff used by Media and others (2011) in their Mt. Simon study.

A log analysis program (Petra) was used to calculate the net feet of Mt. Simon with a gamma ray reading of less than 80 API units, and density porosity (calculated using a sandstone matrix) greater than or equal to 7%. The results of the net sandstone calculation are shown in Table 4-1. Average log porosity and total porosity feet (thickness of void space) were also calculated. Gross thickness is the total Mt. Simon thickness. A net to gross sandstone ratio was calculated to allow a similar thickness to be calculated at the Mill Creek site using the mapped thickness. The net to gross ratio is 0.15 in the Louisville DuPont well. Average log-derived porosity of the net sandstone interval is 8.7% in the DuPont well.

Table 4-1. Mt. Simon reservoir data for the DuPont #1WAD well, and calculated for the Mill Creek site.

Mt. Simon Sandstone Well Log Data	Average Depth (below surface, ft)	Gross Thickness (ft)	Net Porous Sandstone <80 GR and >7% porosity (ft)	Net to Gross Ratio	Average Log Porosity of Net Porous Sandstone	Porosity Feet
DuPont #1WAD	5600	748	111.5	0.15	8.7%	9.6
Calculated Data						
Mill Creek Station	6020	470	70	0.15	8.2%	5.7

Table 4-1 also includes calculated data for the Mill Creek site. The gross thickness was taken from the thickness map of the Mt. Simon. (Figure 4-7). Then a net sandstone footage was calculated using the net-to-gross ratios determined from the DuPont well. This yields a net sandstone estimate of 70 ft for Mill Creek. This site is about 400 ft. deeper than the DuPont well so a slightly lower average porosity of 8.2% was used.

Comparison with regional data suggests the DuPont well has lower porosity than it should for its depth (Medina and others, 2011). If this is a local anomaly, Mill Creek may have better porosity than the conservative number used here.

CO_2 Capacity Calculations

Using the compiled and calculated data, CO_2 storage volume calculations were made. CO_2 storage capacity is based on the porosity, thickness and area of the injection zone, and density of the injected CO_2. CO_2 density is a function of reservoir pressure and temperature. The Mt. Simon interval is deep enough for supercritical (dense) phase CO_2 injection at the Mill Creek Station. CO_2 density calculations were made using the CO_2 properties calculator at the MidCarb project web site: http://www.midcarb.org/calculators.shtml. The Midcontinent Interactive Digital Carbon Atlas and Relational dataBase (MIDCARB) was a research consortium composed of the state geological surveys of Illinois, Indiana, Kansas, Kentucky, and Ohio, funded by the US Department of Energy. Calculated CO_2 density is shown in Table 4-2.

Table 2. Calculated CO_2 density at reservoir conditions.

CO_2 Density	Reservoir Pressure (psi)	Reservoir Temperature (F)	CO_2 Density lbs/ft^3	CO_2 Density kg/m^3
Mill Creek Station	2800	116	49.65	795.32

These parameters are required to calculate CO_2 storage capacity:

Reservoir pressure: assumed hydrostatic, and calculated at 0.433psi/ft for the reservoir depth
Temperature: taken from well log data in Boone and Jefferson Counties.
Reservoir thickness: the net porous sandstone thickness as calculated above.
Reservoir area: a standard area of 100 acres was used for these calculations.
Reservoir porosity: the average porosity for the net reservoir footage.

The equation for CO_2 storage capacity is modified from Medina and others (2011):

$$SC = A_n * h_n * \Phi_n * \rho_{CO2} * \acute{\varepsilon} / 1000$$

Where SC is the storage capacity in metric tons, A_n is the area in square meters, h_n is the net reservoir thickness, Φ_n is the average porosity of the net reservoir, ρ_{CO2} is the density of CO_2 at the reservoir conditions, and $\acute{\varepsilon}$ is the storage efficiency factor (discussed below).

The reservoir parameters used and CO_2 capacities calculated are shown in the table below:

Table 4-3. Reservoir parameters and calculated CO_2 storage capacity for a 100 acre area at 100% and 14% storage efficiency.

Site	100 Acre Area (m^2)	Net Reservoir Thickness (ft)	Net Reservoir Thickness (m)	Porosity	CO_2 Density (kg/m^3)	CO_2 Capacity @ 100% Efficiency (metric tons)	Storage Efficiency Factor	CO_2 Capacity @ 14% Efficiency (metric tons)
Mill Creek	404,686	70	21.4	8.2%	795.32	563,583	0.14	**78,902**

The efficiency factor applied is discussed in more detail below.

Efficiency of CO_2 Storage

The storage capacity equation used above includes an efficiency factor which reduces the CO_2 storage capacity. This factor is applied because 100% of the available pore volume is never completely saturated with CO_2 due to fluid characteristics and geologic variability within the reservoir.

Litynski and others (2010) calculated efficiency factors for carbon storage in various reservoir types that account for factors which reduce the volume of CO_2 that can be stored. These factors include:

Geologic Factors

- Net to total area of a basin suitable for sequestration
- Net to gross thickness of a reservoir that meets minimum porosity and permeability requirements
- Ratio of effective to total porosity (fraction of connected pores)

Displacement Factors

- Areal displacement efficiency- area around a well that can be contacted by CO_2
- Vertical displacement efficiency- fraction of vertical thickness that will be contacted by CO_2
- Gravity- fraction of reservoir not contacted by CO_2 due to buoyancy effects
- Displacement efficiency- portion of pore volume that can be filled by CO_2 due to irreducible water saturation

Combining all of these factors using a Monte Carlo simulation results in a probability range of total efficiency factors of 0.51% to 5.4% (P_{10} to P_{90} range) (Litynski and others, 2010). For the purposed of this assessment, the *geologic* factors are known and thus are equal to one. In our 100-acre evaluation unit the net to total area is the same, the net to gross thickness has already been calculated, and for clastic reservoirs (sandstones) we will assume that the porosity is well-connected with a ratio of effective (connected) porosity to total porosity equal to one. Litynski and others (2010) calculated efficiency factors for just the *displacement* factors separately, and for sandstone reservoirs they range from 7.4% to 24%, with a P_{50} (most likely) efficiency factor of 14%. This means the most likely case is that 14% of the pore space can be filled with CO_2. The range of storage volumes using the probabilistic efficiency factors for the Mill Creek site is shown in Table 4-4.

Table 4-4. Range of probabilistic storage volumes using U.S. DOE displacement efficiency factors for clastic reservoirs (Litynski and others, 2010).

Site	Minimum Volume (metric tons/100 ac.) $\acute{\varepsilon} = 7.4\%$ (P_{10})	Most Likely Volume (metric tons/100 ac.) $\acute{\varepsilon} = 14\%$ (P_{50})	Maximum Volume (metric tons/100 ac.) $\acute{\varepsilon} = 24\%$ (P_{90})
Mill Creek Station	41,705	**78,902**	135,260

The application of an efficiency factor significantly reduces the storage capacities but is necessary to estimate storage volumes.

Summary

The Mill Creek Station has limited potential for geologic storage of CO_2 beneath the site property. The Mt. Simon Sandstone is the only formation with suitable porosity, permeability, and seal at depths required to store dense phase sequestration. Excellent confinement for injected CO_2 is provided by the 500+ ft thick Eau Claire Formation.

Geologic data control for Mill Creek is fair with one well to the reservoir within a 15-mile radius. This well, a hazardous waste disposal well, was unable to establish fluid injection in the Mt. Simon 12 miles from Mill Creek. Mapping indicates the reservoir at Mill Creek is thinner and deeper than at DuPont. This suggests the reservoir properties will be worse than at DuPont. The proximity of the DuPont well to Mill Creek creates a risk of finding a suitable reservoir. The nearest seismic data are 11 miles from Mill Creek, and are not close enough to characterize the Mill Creek site. There is one surface fault mapped within a 15-mile radius. The Mt. Simon structure map (Figure 4-6) indicates that injected CO_2 would migrate slowly to the north, parallel to the Ohio River. Migration of some CO_2 under the river into Indiana is possible, but this would depend on the volume of CO_2 injected and the length of time. If this is a concern, an injection simulation could be run to predict the CO_2 plume size and direction over time. KGS does not currently have this modeling capability, but it may be available in the near future.

It may be possible to use the Knox Group as a sequestration reservoir at Mill Creek. The Knox was used at the DuPont site for injection of hazardous waste. This project actually resulted in the formation and trapping of supercritical CO_2 in the Knox, as the acidic waste dissolved the dolomite reservoir forming a cavern. This limited amount of CO_2 was trapped in the injection zone, but larger volumes may not behave the same way. Our concern at Mill Creek is the top of the Knox and the overlying seal are shallower than 2.500 ft. If CO_2 migrates upward within the Knox, it could reach depths where the supercritical phase is no longer stable, and a phase change to gaseous CO_2 occurs. This would result in a large volume increase, possibly fracturing the rock.

Using the most likely storage volumes at each site, the following volume of CO_2 could be stored on at each site, using property owned by LG&E-KU (Table 4-5).

Table 4-5. Total storage volume on-site at Mill Creek assuming 100% use of LG&E-KU property

Site	CO_2 Storage Volume (metric tons per acre)	Total Site Size (acres)	Total Site Storage Volume (metric tons)
Mill Creek Station	789	548.8	432,988

References Cited

Drahovzal, J.A., Harris, D.C., Wickstrom, L.H., Walker, D., Baranoski, M.T., Keith, B.D., and Furer, L.C., 1992, The East Continent Rift Basin: a new discovery: Spec. Pub. 18, Ser. XI, Kentucky Geological Survey, 25 p

Greb, S. and Drahovzal, J.A., 2011, unpublished report for Midwest Regional Carbon Sequestration Partnership (MRCSP).

Kepferle, R.C., 1972, Geologic map of the Valley Station quadrangle and part of the Kosmosdale quadrangle, north-central Kentucky: U.S. Geological Survey Geologic Quadrangle Map GQ-962, scale 1:24,000.

Litynski, J., Deel, D., Rodosta, T., Guthrie, G., Goodman, A, Hakala, A., Bromhal, G., and Frailey, S., 2010, Appendix B, Summary of the Methodology for Development of Geologic Storage Estimates for Carbon Dioxide, 2010 Carbon Sequestration Atlas of the United States and Canada, U.S. Department of Energy, National Energy Technology Laboratory, http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlasIII/.

Medina, C. R., Rupp, J. A., Barnes, D. A. 2011, Effects of reduction in porosity and permeability with depth on storage capacity and injectivity in deep saline aquifers: A case study from the Mount Simon Sandstone aquifer. International Journal of Greenhouse Gas Control 5: 146-156.

LG&E/KU Carbon Storage Evaluation Ranking Criteria				Power Generating Station				
	Description	Criteria and Rationale	Criteria Scoring	Ghent	Trimble Co.	Green River	E.W. Brown	Mill Creek
1.0 Physical Characteristics								
1.1	**Size**	The area and linear dimensions of the plant site must accommodate additional carbon capture facilities and underground storage. This criterion addresses the availability of additional acreage at the plant site to support future expandability of the facility and for CO2 storage onsite. Larger sites are preferred.	Site size: 15 - ≥1000+ acres 10 - 500-1000 acres 5 - >5 to 500 acres	15	15	5	15	15
1.2	**Topography**	This criterion address how much relative groundwork will be required at the site before it is suitably graded for facility construction. Flat sites requiring little or no grading are preferred. Contoured sites with appropriate available bench width are considered flat although staging facility process equipment in non-contiguous locations may increase capital costs.	5 - Minimal to no groundwork required 3 - Some groundwork required 1 - Significant amount of groundwork required	5	5	5	3	5
1.3	**Floodplain**	The plant must have low potential for flood damage and plant shutdown. The site of the capture facility must be above the 100-year floodplain. Floodplain restrictions are not as important for land used for storage wells.	25 - Carbon capture facility site above 100-year floodplain 15 - Majority of the site is above 100-year floodplain; small impact on critical building area 0 - Critical project elements within 100-year floodplain	25	25	15	25	25
1.4	**Wetlands**	It is preferable to avoid impacts to wetlands to the extent possible, for both the capture facility and the injection wells.	25 - No wetlands affected 20 - Less than 1 acre of wetlands affected 15 - >1 to 5 acres of wetlands affected 10 - >5 to 10 acres of wetlands affected 5 - More than 10 acres of wetlands affected	25	25	25	25	25
			Subtotal	70	70	50	68	70
2.0 Geologic Factors								
2.1	**Seismic Stability**	Assuming DOE will use similar criteria as for FutureGen, the plant should have low risk from significant seismic events. Proven by supporting geological data and calculations demonstrating peak ground acceleration less than 20 percent g, with a 10 percent chance of exceedance in 50 years. Peak ground acceleration is the most appropriate seismic hazard criterion because of pipeline infrastructure, and other shallow subsurface facilities.	10 - 0.05g MCE 8 - 0.10g MCE 6 - 0.20g MCE 4 - 0.30g MCE 2 - 0.50g MCE 0 - >0.50g MCE	10	10	8	10	10
2.2	**Faults**	Presence of mapped fault(s) within 15 miles of plant site or proposed injection area if off-site. Faults can be transmissive (leakage pathway) or sealing (forming a trap). Absence of faults is preferred.	5 - No faults w/in 15 miles 0 - Fault(s) within 15 miles of the site	5	0	0	0	0
2.3	**Oil fields (immiscible EOR potential)**	1 or more oil fields **within 15 miles** and **less than 2,500 feet depth.** CO2 injection is a demonstrated technology for enhanced oil recovery (EOR). Sequestration of CO2 when combined with recovery of additional resources is mutually beneficial.	5 - One or more oil fields within 15 miles & < 2,500' deep 0 - No oil fields within 15 miles & < 2,500' deep	0	0	5	0	0
			Subtotal	15	10	13	10	10
3.0 Other Site Characteristics								
3.1	**Existing Land Use Around Plant Site**	Current use on the plant site and surrounding existing land use must be consistent with the construction and operation of the carbon capture and storage facility. Construction and operation of the storage facility at the plant would be incompatible with non-industrial uses such as residential areas.	25 - Compatible: Brownfield, heavy industry, or mineral extraction 15 - Somewhat compatible: Agriculture or forestry 0 - Incompatible: Recreational, institutional, or residential area within a one mile radius of the site property	0	0	15	0	0
3.2	**Public Acceptance**	Public perception and acceptance of carbon storage projects is a critical factor for success. This criteria is an attempt to evaluate local support or opposition for a carbon storage project.	25 - Local familiarity with mining and oil & gas drilling operations, local support with no known opposition 15 - No local mineral extraction industry, but support from local community, and no known environmental opposition 0 - Visible or known organized opposition to coal-fired generation or carbon storage projects; little local support	15	15	25	15	15
			Subtotal	15	15	40	15	15
4.0 Regulatory and Permitting								
4.1	**National Environmental Policy Act (NEPA)**	DOE funding will require compliance with NEPA. The imposition of any requirements of NEPA (where applicable) on the construction and operation of the carbon capture & storage facility can impact project and/or schedule.	25 - No NEPA requirements or the ability to adopt the Federal NEPA document as adequate without delays 15 - NEPA requirements, but directed to be done concurrently with the other state requirements 5 - NEPA requirements to be done independently or after any state requirements.	25	25	25	25	25
			Subtotal	25	25	25	25	25

LG&E/KU Carbon Storage Evaluation Ranking Criteria				Power Generating Station				
	Description	Criteria and Rationale	Criteria Scoring	Ghent	Trimble Co.	Green River	E.W. Brown	Mill Creek
5.0 Sequestration Potential								
5.1	**Presence of deep saline reservoir**	Current best practice indicates that deep saline formations are likely to have the largest capacity for long-term storage of CO2 as a supercritical fluid. This criteria evaluates distance to wells demonstrating suitable thickness, porosity, and permeability, that is 2,500-10,000 ft in depth, and has at least one demonstrated overlying seal at least 20 feet thick. This criteria is intended to demonstrate the presence and utility of such a zone in the immediate vicinity of the plant site.	25 - Well/core indicating reservoir and seal within 1 mile of site (proven) 15 - Well indicating reservoir and seal between 1 and 15 miles from site (probable) 5 - Well indicating reservoir and seal within 15 to 25 miles of plant site (possible) 0 - No well/core indicating reservoir and seal within 25 miles	15	0	15	15	15
5.2	**Multiple deep saline reservoirs**	Two or more **proven** or **probable** saline reservoirs as defined above. Multiple stacked intervals increases the likelihood of sufficient capacity for sequestration.	10 - Two or more saline reservoirs 0 - Less than 2 saline reservoirs	0	0	0	0	0
5.3	**Estimated CO2 Storage Capacity**	Storage capacity estimated for 100 acre area of the primary storage reservoir	25 - More than 200,000 metric tons/100 acres 15 - 100,000 to 200,000 metric tons/100 acres 5 - Less than 100,000 metric tons/100 acres	25	15	5	25	5
5.4	**Demonstrated closed trap for CO2**	Sufficient data to show structural closure (trap) on 1 or more of the available reservoirs for sequestration **within 15 miles.** Structural closure will limit migration of injected CO2. Additional analysis is required to determine the volume of the closure to its spill point. A closed trap is desirable, but not required.	25 - Structural closure on 1 or more available reservoirs 0 - No structural closure on available reservoirs	0	0	0	25	0
5.5	**Subsurface activity/access**	The presence of oil and gas fields, underground coal mines, or limestone/aggregate quarries or mines within **15 miles.** Need to assess potential issues with respect to mining health and safety, ownership and leases of the mineral estate, and potential subsurface access conflicts.	5 - No sites within 15 miles 0 - Sites within 15 miles	0	0	0	0	0
5.6	**Well penetrations into primary seal**	How many penetrations are there through the primary seal of the main target formation within a **15 mile area of review.** Well bores represent potential migration pathways for CO2 leakage into underground sources of drinking water (USDW) or to the surface. Need to assess integrity of the seal with respect to the density (number) of well bores, their depths, and the possibility of unlocated holes to ensure CO2 does not leak.	15 - Less than 4 well penetrations w/in 15 miles 9 - 4 to 6 well penetrations w/in 15 miles 0 - More than 6 well penetrations w/in 15 miles	9	15	9	0	15
5.7	**Availability of seismic reflection data**	Proximity of seismic reflection data to the plant site. Seismic reflection data is essential for use in assessing the nature and potential integrity of a unit for sequestration and modeling the geometry of the area of pore space to be contacted by CO2.	15 - seismic lines available on-site or within 1 mile radius 12 - Seismic lines available within 1-5 mile radius 9 - Seismic data available within 5-10 miles 6 - Seismic data available within 10-15 miles 3 - No seismic data available within 15 miles of plant	6	3	12	9	6
			Subtotal	55	33	41	74	41
			TOTAL SCORE	180	153	169	192	161