

# **OPTIMIZING TECHNOLOGY TO REDUCE MERCURY AND ACID GAS EMISSIONS FROM ELECTRIC POWER PLANTS**

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## ABSTRACT

Maps showing potential mercury, sulfur, chlorine, and moisture emissions for U.S. coal by county of origin were made from publicly available data (plates 1, 2, 3, and 4). Published equations that predict mercury capture by emission control technologies used at U.S. coal-fired utilities were applied to average coal quality values for 169 U.S. counties. The results were used to create five maps that show the influence of coal origin on mercury emissions from utility units with: (1) hot-side electrostatic precipitator (hESP), (2) cold-side electrostatic precipitator (cESP), (3) hot-side electrostatic precipitator with wet flue gas desulphurization (hESP/FGD), (4) cold-side electrostatic precipitator with wet flue gas desulphurization (cESP/FGD), and (5) spray-dry adsorption with fabric filter (SDA/FF) emission controls (plates 5, 6, 7, 8, and 9). Net (lower) coal heating values were calculated from measured coal Btu values, and estimated coal moisture and hydrogen values; the net heating values were used to derive mercury emission rates on an electric output basis (plate 10).

Results indicate that selection of low-mercury coal is a good mercury control option for plants having hESP, cESP, or hESP/FGD emission controls. Chlorine content is more important for plants having cESP/FGD or SDA/FF controls; optimum mercury capture is indicated where chlorine is between 500 and 1000 ppm. Selection of low-sulfur coal should improve mercury capture where carbon in fly ash is used to reduce mercury emissions. Comparison of in-ground coal quality with the quality of commercially mined coal indicates that existing coal mining and coal washing practice results in a 25% reduction of mercury in U.S. coal before it is delivered to the power plant. Further pre-combustion mercury reductions may be possible, especially for coal from Texas, Ohio, parts of Pennsylvania and much of the western U.S.

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## INTRODUCTION

Switching to low-mercury-emission coal may be an effective strategy to comply with the new Clean Air Mercury Rule (CAMR; USEPA, 2005), which is intended to reduce U.S. mercury emissions from electric utilities. For example, despite proven emission control technology, burning low-sulfur coal is the most popular method to reduce sulfur emissions. Because technology to reduce mercury emissions is less certain, burning low-mercury coal is a likely method to reduce mercury emissions. Like sulfur, the amount of mercury in U.S. coal shows substantial geographic variation. However, unlike sulfur, mercury emissions also vary with the abundance of other elements in the coal, such as chlorine and sulfur, which influence mercury capture by emission control technologies. Moreover, empirical equations indicate that the ability of these elements to promote or inhibit mercury capture categorically varies among existing emission control technologies (Chu and others, 2000).

This project uses Geographic Information System technology (ArcView GIS) to create maps that show where U.S. coal with low-mercury and acid-gas emissions might be found. The map series shows geographic variation of mercury, chlorine, and sulfur in coal, as well as the mercury emission penalty, calculated for data aggregated by U.S. county-of-origin using equations specific to power plants classified by boiler type and flue gas emission controls. Removing mercury from flue gas is a technically complex task – different technologies will be required for different coals. Maps showing the geographic variation of mercury and acid-gas emission factors for U.S. coal will help locate the best coal for each technology and identify the best technology for each coal.



## EXECUTIVE SUMMARY

Coal quality data used in this study were selected from public data sets and include: 19,493 FERC 423 data records (USEIA, 2003a), 27,006 ICR data records (USEPA, 2003), 5823 CTRDB data records (USEIA, 2003b), 5059 COALQUAL data records (Bragg and others, 1997), and 73 PSU-DOE data records (Anonymous, 1990; Davis and Glick, 1993; Scaroni and others, 1999). Additional data considered in this report are from CEA (2004) and USMSHA (2004).

Native mercury capture by existing emission control technologies can be evaluated using the ICR part 3 data set (USEPA, 2003), which includes measurements of mercury in boiler flue gas as well as mercury stack emissions from about 80 U.S coal-fired boilers. We examined a variety of published equations derived from the ICR 3 data that predict mercury capture from fuel mercury, chlorine, sulfur and heating values. Ultimately, equations from SAIC (2003), Roberson (2002), or ENSR (2003) were chosen to predict mercury capture by five common emission control technologies. Using county-specific coal quality data and technology-specific mercury emission factors obtained from these equations, we made maps showing the expected mercury emissions by coal origin for pulverized-coal-fired electric generating units with (1) hot-side electrostatic precipitator [hESP], (2) cold-side electrostatic precipitator [cESP], (3) hot-side electrostatic precipitator / wet flue-gas desulfurization [hESP/FGD], (4) cold-side electrostatic precipitator / wet flue-gas desulfurization [cESP/FGD], and (5) spray-dry adsorption / fabric filter [SDA/FF] emission controls. The map series shows mercury emission on both a fuel-input basis (lbs Hg/10<sup>12</sup> Btu) and an electric-output basis (lbs x 10<sup>-6</sup> Hg/ MWh), as well as geographic variation of coal sulfur, chlorine, and moisture content.

A tonnage-weighted comparison of in-ground coal mercury concentrations with coal mercury concentrations in commercially produced coal showed that U.S. coal shipped to utilities during 1999 contained 8.3 lbs Hg/10<sup>12</sup> Btu whereas the actively-mined, in-ground coal contained about 11 lbs Hg/10<sup>12</sup> Btu. The 25% reduction of mercury in commercially mined coal is attributed to selective mining of low mercury coal and mercury reductions due to coal washing. However, this difference is not geographically uniform. Finally, empirical data from the Canadian Electricity Association (CEA, 2004) were used to evaluate the negative correlation between coal sulfur content and mercury capture.

Significant findings include:

- Selection of low-mercury coal is a reasonable way to reduce mercury emissions from units equipped with hESP, cESP, or hESP/FGD controls, whereas selection of coal with high-chlorine content is a better option for units with cESP/FGD, or SDA/FF controls.
- Coal selection or blending to an optimum level between 500 and 1000 ppm chlorine could reduce mercury emissions for units with cESP/FGD, or SDA/FF controls.
- Although coal shipped to utilities contains about 25% less mercury than the in-ground resource, this difference is not geographically uniform. With the notable exception of Powder River Basin (PRB) coal from Wyoming, the mercury content of commercial coal from the western U.S., Ohio, northern Pennsylvania, and the Gulf Coast, is similar to or greater than that in the in-ground coal resource. Coal washing or selective mining might be an effective mercury mitigation strategy in these areas.
- Selection of low-sulfur coal may improve mercury capture where carbon in fly ash is used to reduce mercury emissions.

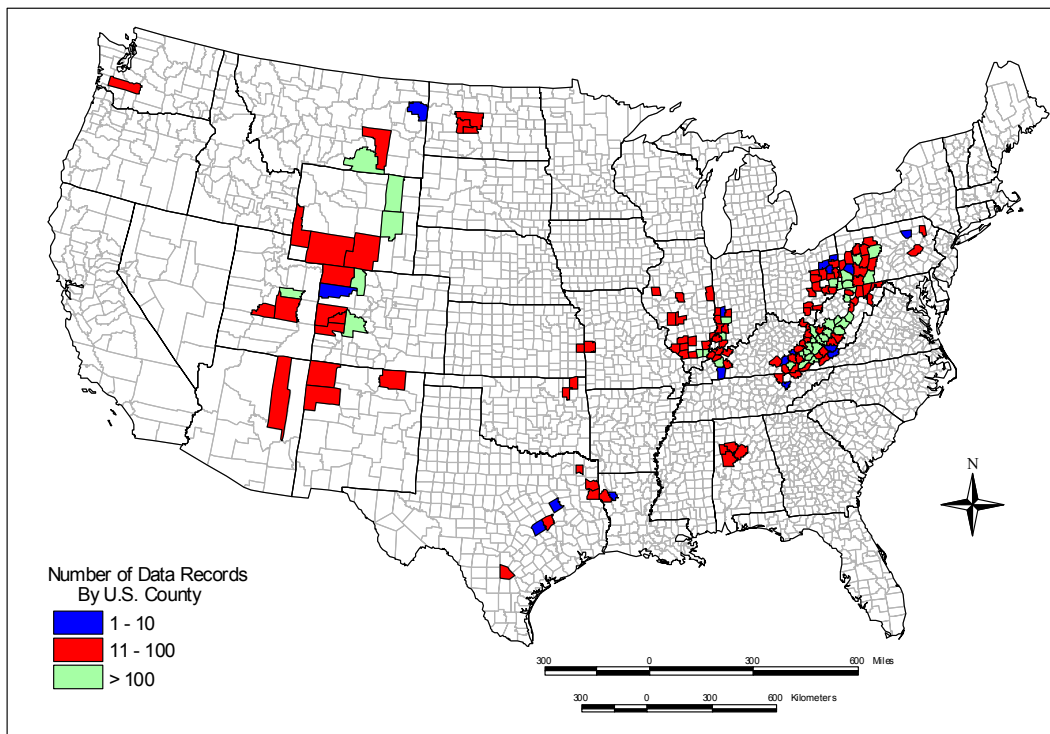
# EXPERIMENTAL

## Data Selection

Coal quality data were selected from five public data sets, which are identified in this report as the FERC 423, ICR, CTRDB, COALQUAL, PSU-DOE, and CEA data sets. Notably, most of these data are available online.

### FERC 423 Data

Figure 1 shows the geographic distribution of the 19,493 records selected from the 35,887 records listed in the 1999, FERC 423 data set (USEIA, 2003a). The FERC 423 data are from the Form 423 monthly survey of fossil-fueled electric utilities collected by the Federal Energy Regulatory Commission (FERC). Among other things, the records list the cost, quality, and origin of fuel shipments delivered to electric utility power plants with steam generator capacities of at least 50 MW. Data fields listed in the FERC 423 are described in table 1.



**Figure 1.** Geographic distribution of selected FERC 423 data by U.S. county-of-origin.

**Table 1.** List of data fields in the 1999, FERC 423 Data.

Company	Code for the name of utility parent company.
Plant	Code for the name of the utility power plant.
Year	Reporting year.
Month	Reporting month.
BOM District	U.S. Bureau of Mines coal producing district, country-of-origin (coal only).
State-of-origin	U.S. state-of-origin (coal).
Mine Type	Surface or underground coal mine.
Region (plant)	Regional location of the electric utility.
State (plant)	State location of the electric utility.
Generic Fuel	Type of fuel (solid, liquid, gaseous).
Specific Fuel	Bituminous, subbituminous, lignite, fuel oil, natural gas, etc.
Contract Type	Simple contract, contract with escalator, new, firm (gas), interruptible gas, spot and off peak gas, spot coal, or spot oil.
Contract Expire	Indicates if the contact expires within 24 months.
Quantity	Tons in coal shipment (short tons).
Btu	Heating value (gross Btu/lb, as-shipped).
Sulfur	Sulfur content (weight%, as-shipped).
Ash	Ash value (weight%, as-shipped).
Cost	Cents per million Btu (total cost, including transportation and taxes).
County	U.S. county-of-origin (mostly for coal shipments).

Table 2 shows that about half of the FERC 423 data records are selected for this project. Records for liquid, gaseous, and other non-coal fuels are ignored, as are records for imported coal and domestic coal of uncertain state or county origin.

**Table 2.** Tabulation of selected and ignored 1999, FERC 423 data records.

35,886	ORIGINAL RECORDS
15,790	Liquid or gas <sup>1</sup>
20,096	Solid fuel
20,096	SOLID FUEL RECORDS
116	Imported coal <sup>1</sup>
146	Uncertain location <sup>1</sup>
231	Petroleum coke <sup>1</sup>
68	Refuse <sup>1</sup>
42	Wood <sup>1</sup>
19,493	Coal
19,493	SELECTED RECORDS
20	Anthracite
15,948	Bituminous
235	Lignite
3,290	Subbituminous

<sup>1</sup> ignored.

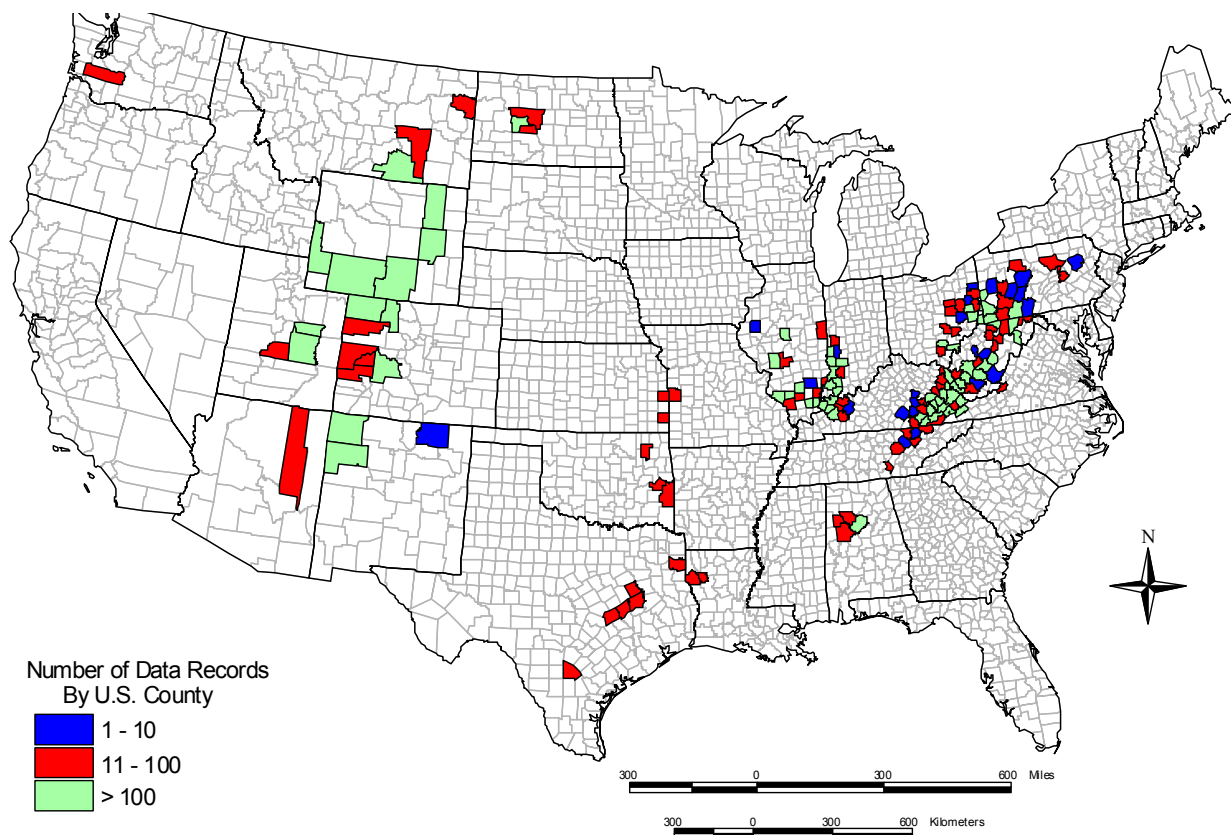
Although fuel receipts reported on the FERC Form 423 include over 99% of coal delivered to electric utility power plants, non-utility power plants (independent power producers and combined heat and power plants) do not report on FERC Form 423. These non-utility power plants consumed 56 million tons of coal during 1999, which is about five percent of the total 950 million tons burned at power plants (USEIA 2003c). Consequently, the FERC 423 data are missing about five percent of the coal tonnage shipped to electric power plants during 1999.

### **ICR Data**

The ICR coal quality data set includes 152,476 records, which are available in four quarterly data files on a U.S. Environmental Protection Agency website (USEPA, 2003). Figure 2 shows the geographic distribution of the 27,006 records selected from this data set. The ICR data originate from the Information Collection Request (part 2) issued by the EPA. The EPA required electric utility steam generating units of 25 MW or more to report coal origin, tonnage, and assay values for every solid fuel shipment received during 1999, and to periodically measure and report the mercury and chlorine values for these shipments. The U.S. Geological Survey (USGS) added some data fields in June 2002 to indicate (where possible) consistent names for the coal bed, mine, field, and other attributes. Data fields listed in the ICR data are summarized in table 3. Notably, the ICR assay values are reported on a dry basis, and include mercury and chlorine values.

Of the 152,476 ICR data records, only 26,007 (17%) are used in this project (table 4). Most of the ignored records lack mercury assay values. Records corresponding to coal waste products, coal blends, or non-coal fuels are also ignored. Of the remaining records for single coals that include mercury values, over five thousand are not used because they lack location origins. In some instances, it was possible to infer location origins. For example, 85 ICR data

records originating from the Martin Lake power station (but lacking county-of-origin information) were assigned to Panola and Rusk Counties, Texas. Likewise, 87 records from the Monticello station were assigned to Titus County, Texas. Notably, the Monticello records may include coal originating from nearby Hopkins County, Texas. Similarly, examination of coal supplier names identified nine records for coal from Washington County, Illinois, and seven records from Schuylkill County, Pennsylvania. With the exception of samples from mine-mouth power plants, records listed as grab samples or as-fired samples are also ignored; these sample collection methods tend to result in biased or non-representative assay specimens. Finally, several hundred records for samples from outside the study area are also ignored.



**Figure 2.** Geographic distribution of selected ICR data records, by U.S. county-of-origin.

**Table 3.** *Summary of data fields in the 1999, ICR data.*

---

Plant Name	The name of the power plant.
Shipment date	The date of the coal shipment.
Received	The amount of the shipment in dry tons.
State	The shipment State-of-origin.
County	The shipment county-of-origin.
Seam	The coal bed name reported by the power plant.
Method	The shipment transportation mode.
Fuel Type	The kind of fuel.
Supplier	The supplier name, location, and address.
Amount	The amount of the shipment that the assay represents in dry tons.
Sulfur	Sulfur content (weight%, dry basis).
Btu	Heating value (gross Btu/lb, dry basis).
Ash	Ash value (weight%, dry basis).
Mercury	Mercury content (ppm, dry basis) where results below the detection limit are flagged.
Chlorine	Chlorine content (ppm, dry basis) where results below the detection limit are flagged.
Assay Methods	Including reference to standard or in-house methods used to collect, prepare, and measure mercury in assay specimens, with an indication of assay accuracy and precision.
Laboratory	The name, location and address of the laboratory.
Coal Bed	USGS <sup>1</sup> Coal Bed.
Coal Group	USGS <sup>1</sup> Coal Group.
Coal Zone	USGS <sup>1</sup> National Coal Resource Investigations and Assessments coal bed zone.
Coal Basin	USGS <sup>1</sup> Coal basin or field.
Coalfield	USGS <sup>1</sup> Local coalfield name.
Coal Mine	USGS <sup>1</sup> Coal mine name.

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<sup>1</sup> United States Geological Survey, added June 2002.

Quick and others (2003) used a graph of ash verses the heating value (Btu) for coal from Campbell County, Wyoming to identify erroneous ICR assay data. This graphic method, when applied to each of the 169 U.S. counties represented in the ICR, shows 2852 erroneous data records (table 4). Most (73%) of the erroneous records are attributed to incorrect reporting bases where assay results are data reported on a moist basis, or on a dry ash-free basis, rather than the dry basis specified by the ICR. In a few instances it was possible to identify mistaken location origins. No cause is known for the remaining erroneous records. Possible causes include data

entry errors, mistaken location origins, unrecognized coal blends, and analytical error; these data were ignored.

**Table 4.** *Tabulation of selected and ignored data records for the 1999, ICR data.*

152,476	ORIGINAL RECORDS	
	103,403	Coal without Hg or Cl values <sup>1</sup>
	4,361	Coal waste <sup>1</sup>
	3,283	Coal blends <sup>1</sup>
	3,256	Petroleum coke <sup>1</sup>
	1,045	Tire derived fuel <sup>1</sup>
37,128	RECORDS FOR COAL WITH MERCURY VALUES	
	5,351	Coal without state or county locations <sup>1</sup>
	1,005	As-fired samples <sup>1</sup>
	763	Apparent duplicate records <sup>1</sup>
	697	Apparent nominal data <sup>1</sup>
	348	Foreign coal <sup>1</sup>
	70	Grab samples <sup>1</sup>
	35	Alaskan coal <sup>1</sup>
28,859	INITIAL RECORDS	
	2,852	Data outliers <sup>1</sup> , including:
		1,363 on a dry, ash-free basis <sup>1</sup>
		713 on a moist basis <sup>1</sup>
		90 with bad location origins <sup>1</sup> , and
		686 of undetermined cause <sup>1</sup>
26,007	SELECTED RECORDS	

<sup>1</sup> ignored.

Comments to the USEPA related to the proposed mercury reduction rule (McCall, 2004; Eutizi, 2005; Glacken, 2005) suggest that the mercury values reported in the ICR data for most Gulf Coast coal are erroneously low. Accordingly, average mercury values, from ICR part 3 testing<sup>1</sup> or newly reported values (McCall, 2004; Eutizi, 2005), were used to estimate county-average mercury values for coal from Panola, Titus, Atascosa, Freestone, Milam, and Robertson Counties, Texas. Mercury values for Leon County, Texas, as well as Red River and De Soto Parishes, Louisiana, have not been revised and may be too low.

<sup>1</sup> The ICR part 3 data originate from measurements of atmospheric mercury emissions from about 80 selected U.S. power plants (USEPA, 2003). The data show measured mercury emissions and mercury capture observed during three, multiple hour intervals for each plant, and are complementary to the more comprehensive ICR coal assay data.



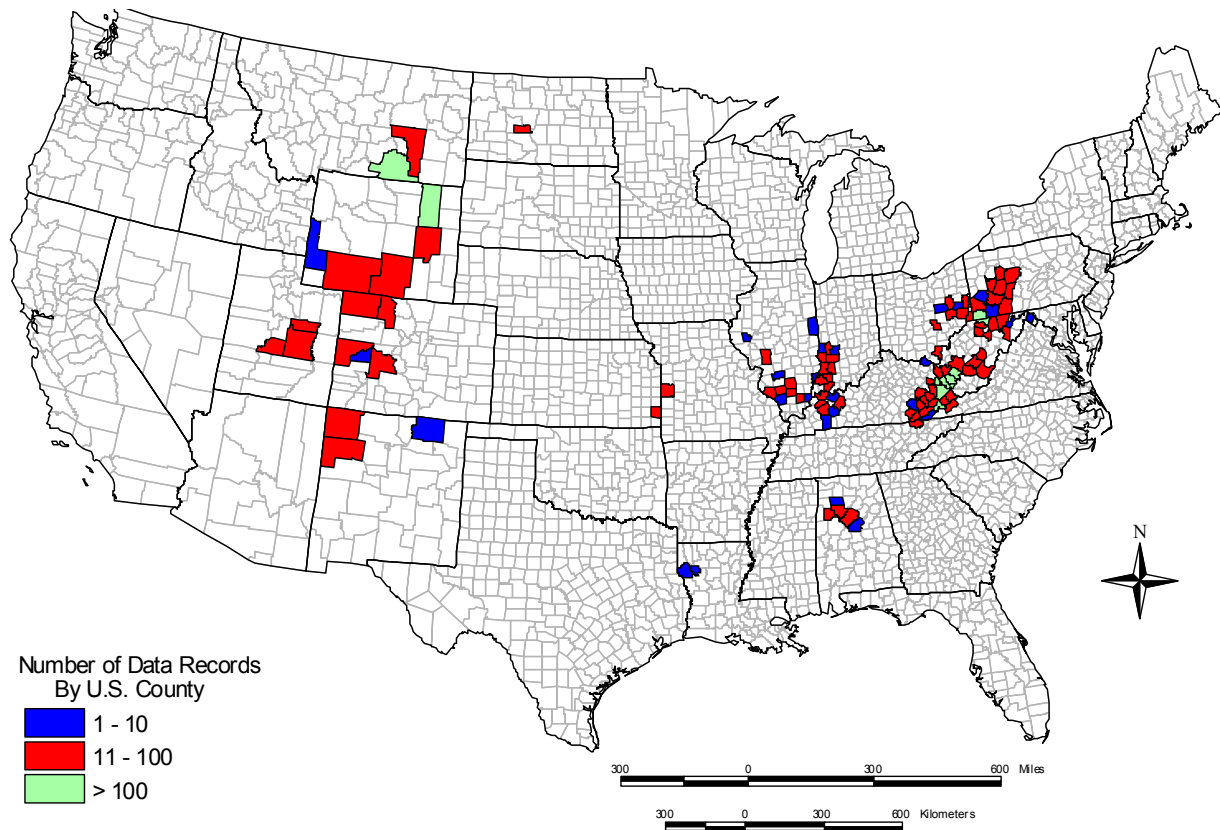
Comparison of ICR county origins, with 1999 county coal production (USEIA 2000; USMSHA, 2004) showed that not all coal-producing counties are represented in the ICR data. Table 5 lists the counties missing from the selected ICR data, together with their 1999 coal production. The missing counties represent 15.7 million tons, which is less than 2% of 1999 U.S. coal production.

*Table 5. Coal production from counties not represented in the ICR data selected for this study.*

<b>State</b>	<b>County</b>	<b>1999 production (tons)</b>
Alabama	Bibb	44,500
Alabama	Cullman	35,700
Alabama	Marion	35,700
Alabama	Winston	338,500
Arkansas	Johnson	14,600
Colorado	Fremont	242,200
Colorado	La Plata	245,700
Illinois	Christian	72,200
Indiana	Dubois	72,800
Indiana	Spencer	204,400
Kentucky	Knox	506,100
Mississippi	Choctaw	18,400
Missouri	Barton	73,000
Ohio	Gallia	220,600
Ohio	Monroe	489,600
Ohio	Muskingum	663,100
Ohio	Noble	689,800
Ohio	Stark	316,400
Oklahoma	Craig	194,100
Pennsylvania	Carbon	39,300
Pennsylvania	Clarion	418,100
Pennsylvania	Jefferson	1,119,100
Pennsylvania	Lawrence	84,800
Pennsylvania	Sullivan	47,100
Pennsylvania	Venango	91,600
Texas	Hopkins	2,126,100
Texas	Webb	235,000
Virginia	Tazewell	2,062,700
West Virginia	McDowell	4,698,900
West Virginia	Mineral	48,500
West Virginia	Tucker	172,423
Wyoming	Sheridan	76,400

## CTRDB Data

The CTRDB data set is from the U.S. Energy Information Administration (USEIA, 2003b). It contains 7905 records for certain commercial coal shipments delivered to power plants between 1992 and 1999. Figure 3 shows the geographic distribution of the 5823 selected CTRDB data records. The CTRDB acronym is an abbreviation for the *Coal Transportation Rate Data Base*. The data largely originate from the FERC Form 580, biannual survey of investor-owned, interstate electric power plants. Among other things, the records list the quality and origin of contract fuels delivered to steam-electric power plants of 50 MW or more. Data fields listed in the CTRDB data set are summarized in table 6. Note that the CTRDB data fields include coal moisture values; these moisture values are used to verify moisture values estimated for ICR coal (discussed below).



**Figure 3.** Geographic distribution of selected CTRDB data by U.S. county-of-origin.

**Table 6.** Summary of data fields in the 1992–1999, CTRDB data.

---

Utility Name	Name of the utility parent company.
Year	The year the data represent.
Contract Specifications	Including: contracted dates, tonnage, and coal quality specifications.
Contractor Name	Name of the coal supplier.
Mine Name	Name of the coal mine.
Origin State	State of the coal origin.
Origin County	County of the coal origin.
BOM District	Bureau of Mines coal-producing district of the coal origin.
Destination Plant	Power plant name.
Destination State	Location state of the power plant.
Destination County	Location county of the power plant.
Tons Shipped	Tons of coal shipped.
Mine Price	Price of the coal at the coal mine.
Delivered Price	Price of the coal at the power plant.
Btu	Coal heating value (gross Btu/lb, as-shipped).
Sulfur	Coal sulfur content (weight%, as-shipped).
Ash	Coal ash value (weight%, as-shipped).
Moisture	Coal moisture content (weight%, as-shipped).
Transportation Information	Type of transportation (train, truck, barge, etc); the number of transport modes, carriers, and transfers; transport distance.
Carrier Information	Name(s) of transport carriers, transfer locations etc.
Transport Costs	Mode rates, transfer fees, and so forth.

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About three-fourths of the records included in the CTRDB are selected for use in this project (table 7). Records corresponding to duplicate assays are most frequently ignored; this is done to preclude weighting effects in subsequent analyses. Records that lack coal quality values or location origins, as well those for coke or imported coal, are also ignored. Finally, a few records with anomalous coal quality values (outliers on Btu vs. moisture plots) are also ignored.

**Table 7.** Tabulation of selected and ignored data records for the 1992–1999, CTRDB data.

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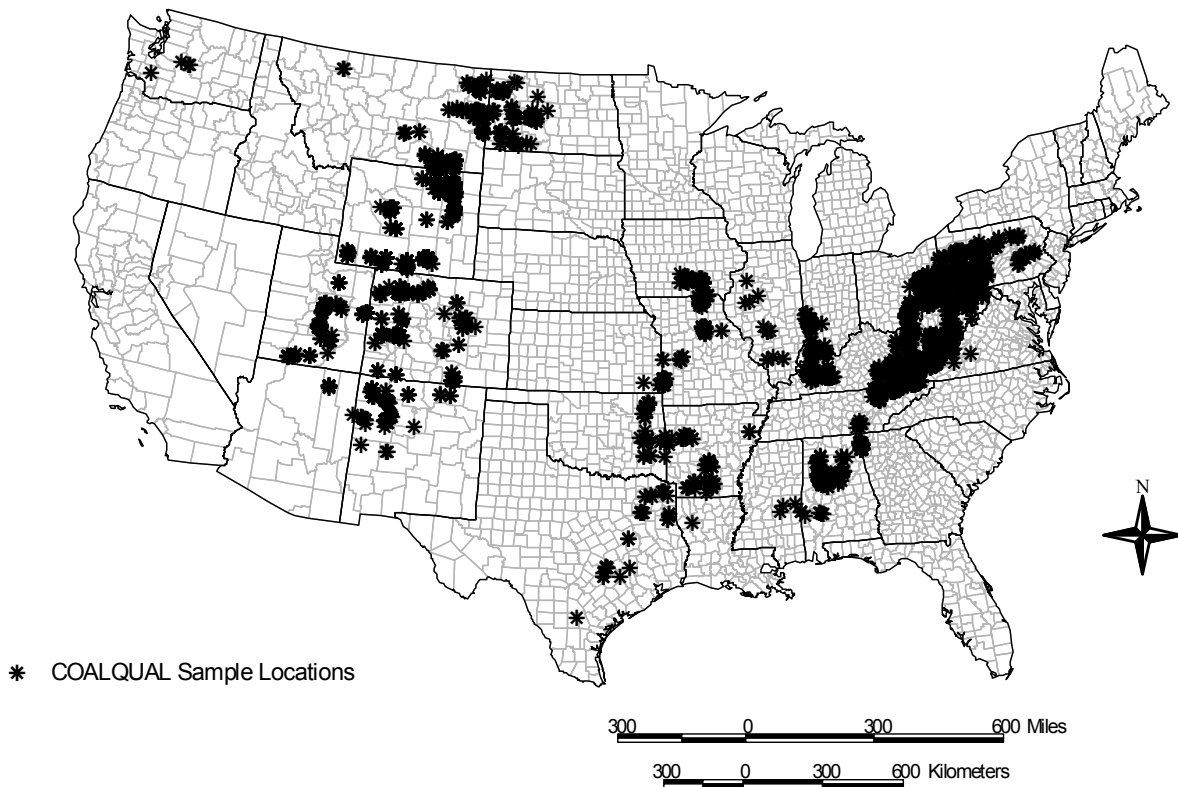
7,905	ORIGINAL RECORDS
1,041	Duplicate assay values <sup>1</sup>
868	No coal quality data <sup>1</sup>
113	Foreign coals <sup>1</sup>
26	No origin location <sup>1</sup>
25	Coal quality outliers <sup>1</sup>
9	Petroleum coke <sup>1</sup>
5,823	SELECTED RECORDS

---

<sup>1</sup> ignored.

## COALQUAL Data

The COALQUAL data set (Bragg and others, 1997) contain 7432 records for coal samples collected from U.S. drill holes, mines, and outcrops. Figure 4 shows the geographic distribution of the 5059 selected COALQUAL data records. Up to 136 data fields listing the sample type, location, and assay results are included for each record. Nearly all records have complete proximate and ultimate assays as well as major, minor, and trace element values. Data fields listed in the COALQUAL data are summarized in table 8.



**Figure 4.** Geographic distribution of selected COALQUAL data records.

**Table 8.** *Summary of COALQUAL data fields.*

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Location Information	Including: state, county, latitude, longitude, province, region, field, district, quadrangle.
Geologic Information	Including: formation, group, bed, member, zone, depth, bed thickness, system, and geologic age.
Collection Information	Collector name, drillhole/mine name, estimated rank, and laboratory submission date.
Laboratory	Assay laboratory: U.S. Bureau of Mines, Geochemical Testing Co., State agencies, USGS, Dickinson Laboratories Inc.
Sample Type	Channel, drillcore, weathered channel, or outcrop.
Data Type	Single sample assay, physical composite assay, calculated composite assay, partial composite assay, partial bed split.
ASTM <sup>1</sup> Assays	(Moist, whole-coal basis) including: moisture, Btu, ash, volatile matter, CHNOS, <sup>2</sup> ash fusion temperatures, free swelling index, sulfur forms, air-dry-loss, equilibrium moisture, and Hardgrove grindability.
USGS Assays	(Residual moisture basis) including: USGS ash value, 11 major and minor ash oxides, and up to 62 trace elements.

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<sup>1</sup> American Society for Testing and Materials

<sup>2</sup> Carbon, Hydrogen, Nitrogen, Oxygen, and Sulfur

Details of the sampling and assay methods used for the COALQUAL data set are fully described in text accompanying the data on the CD-ROM format; several of these details are worth noting:

- The ASTM assays are reported on a whole-coal (moist) basis and the USGS assays are reported on a residual moisture basis where the residual moisture content of the analysis specimen was not measured. Quick and others (2003) showed a method to estimate residual moisture.
- Hydrogen values include the hydrogen in moisture. This convention has significance for the calculation of flue gas volumes, the calculation of heating values from elemental composition, and the calculation of the lower (net) heating value.
- Qualitative values (typically where an assay result was below the detection limit) are listed in the data set as the detection limit value multiplied by 0.7. Although the

percentage of qualified values for each data field is reported, the status of individual records is not.

- Some data records are calculated, whole-bed composites where results from component partial-bed samples are mathematically combined by weighting component assays by volume (thickness) rather than mass; we ignored these records. Table 9 shows the tabulation of selected and ignored COALQUAL data records.

**Table 9.** *Tabulation of selected and ignored COALQUAL data records*

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7,432 ORIGINAL RECORDS
948 Calculated composites <sup>1</sup>
568 No Btu, ash, or sulfur values <sup>1</sup>
551 Weathered coal <sup>1</sup>
150 Outcrop samples <sup>1</sup>
105 Anomalous moisture values <sup>1</sup>
51 Geographically isolated, or Alaskan coal <sup>1</sup>
5,059 SELECTED RECORDS

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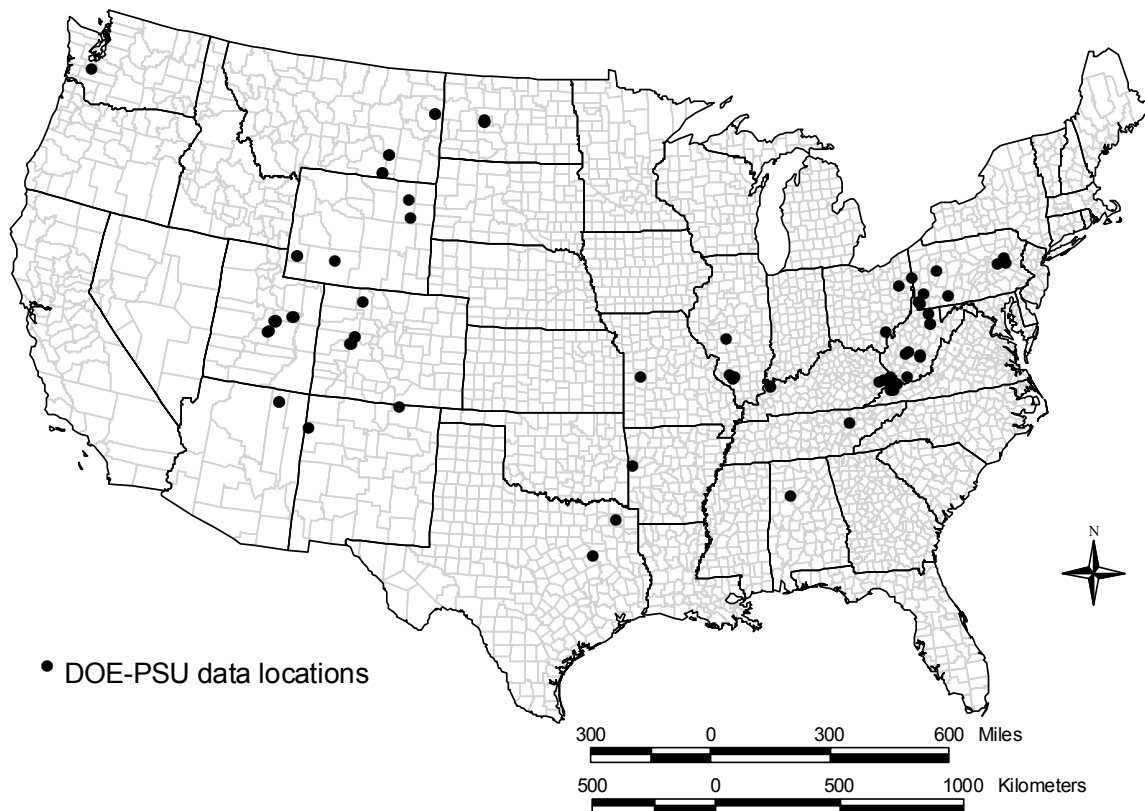
<sup>1</sup> ignored.

The 5059 selected COALQUAL data records (table 9) include samples collected from 340 U.S. counties. Comparison with coal production records (USEIA 2000; USMSHA, 2004) indicates that 3671 of the COALQUAL records originate from 146 of the approximately 170 counties that reported coal production during 1999.

### **DOE-PSU Data**

Figure 5 shows the geographic distribution of the 73 selected DOE-PSU data records. The data are for coal samples collected between 1983 and 1995 from active mines in 48 U.S. counties and 18 U.S. states; they include 67 full-bed or working-section channel samples, 5 run-of-mine samples, and 1 drill-hole core. Thirty-three (DOE) records are from Davis and Glick (1993) and Scaroni and others (1999). The remaining 40 (PSU) records are from Quick and Glick (2000) with additional information from the Pennsylvania State University Coal Data Base

(anonymous, 1990). Petrographic assays, Gieseler fluidity, as well as major, minor, and trace element assays are from the Pennsylvania State University; the other assays are from a commercial laboratory. Data fields included in the DOE-PSU data are summarized in table 10.



**Figure 5.** Geographic distribution of selected DOE-PSU data records.

**Table 10.** Summary of DOE-PSU data fields.

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Location Information	Including: state, county, coal province, region, field, quadrangle, latitude, and longitude.
Geologic Information	Including: formation, group, bed, bed thickness, lithologic description, system, and geologic age.
Collection Information	Collection date, laboratory submission date, and assay dates.
Sample Type	Channel, working section, run-of-mine, drillcore.
Assays	As received and equilibrium moisture, Btu, ash, volatile matter, CHNOS, free swelling index, sulfur forms, chlorine, carbonate CO <sub>2</sub> , maceral components, vitrinite reflectance, Hardgrove grindability, Gieseler fluidity, ash fusion temperatures, major, minor, and trace elements.

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## **CEA Data**

The Canadian Electricity Association (CEA) made coal, fly ash, and bottom ash composition data publicly available on its website (CEA, 2004). The data were collected to create an inventory of mercury emissions where emissions equal the difference between mercury in the fuel and mercury in the combustion ash. These preliminary data are weekly assays of composite samples for boiler fuel and by-product ash. The data include values for Btu, ash, sulfur, mercury, and chlorine in coal, as well as sulfur, moisture, mercury and carbon (LOI) in fly ash and bottom ash. The weekly unit data are posted on the CEA website as a series of quarterly reports in portable document format, for the nearly two-year testing program.

### **Calculation Net Heating Values**

The CAMR includes output-based emission limits (pounds Hg  $\times 10^{-6}$  per megawatt-hour electricity manufactured) for power plants built after January 30, 2004 (table 11). The output-based limits presumably assume 35 percent efficiency (9,833 gross Btu/kilowatt-hour) for new power plants (Cole, 2003). Although the USEPA used the gross heating value of coal to calculate the output-based emission, figure 6 shows that output-based emissions are better calculated from fuel emission factors expressed on a net energy basis.

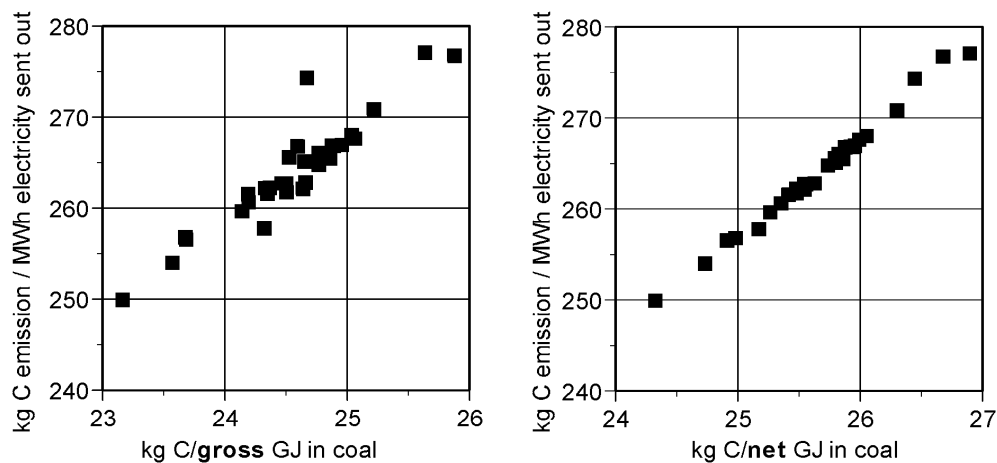
The gross coal heating value, (also called the higher heating value) is the familiar Btu/lb (or MJ/kg) value reported from the laboratory. The gross heating value is measured by using a high-pressure, constant-volume combustion bomb. Because water vapor from combustion condenses inside the combustion bomb the gross heating value includes the latent heat of water vapor. Unlike the laboratory combustion bomb, combustion in a coal-fired boiler occurs at constant pressure and moisture from combustion exits the boiler with the flue gas.



Consequently, the net heating value (also called the lower heating value) does not include the latent heat of water vapor and is a better measure of the energy available to the boiler than the gross heating value. Accordingly, we use emission factors expressed on a net energy basis to calculate output-based emissions. This required that we calculate county-average, ICR net heating values.

**Table 11.** CAMR standards of performance for new coal-fired power plants (gross electric output basis)

<u>Fuel/Technology Class</u>	<u>SI units</u>	<u>U.S. customary units</u>
Bituminous-fired Units:	2.6 pg Hg/J	21 x 10 <sup>-6</sup> lbs Hg/MWh
Subbituminous-fired Units		
wet FGD:	5.3 pg Hg/J	42 x 10 <sup>-6</sup> lbs Hg/MWh
dry FGD:	9.8 pg Hg/J	78 x 10 <sup>-6</sup> lbs Hg/MWh
Lignite-fired Units:	18.3 pg Hg/J	145 x 10 <sup>-6</sup> lbs Hg/MWh
Coal Refuse-fired Units:	0.18 pg Hg/J	1.4 x 10 <sup>-6</sup> lbs Hg/MWh
Integrated Gasification Combined Cycle Units:	2.5 pg Hg/J	20 x 10 <sup>-6</sup> lbs Hg/MWh



**Figure 6.** Emissions expressed on an output basis (vertical axes) are better estimated if the fuel emission factor is expressed on a net energy basis (right plot) rather than on a gross energy basis (left plot). Data show output-based carbon emissions calculated by Juniper (1998) for commercial coals in a model 500 MW plant equipped with ESP and FGD emissions controls.

The net heating value is calculated as:

$$Btu_{net} = Btu_{gross} - 92.7(0.1119M + H) \quad (1)$$

where:  $Btu_{gross}$  is the familiar Btu per pound value reported from the laboratory and expressed on a moist, whole-coal basis,

$M$  is the weight percent moisture content of the coal,

$H$  is the weight percent hydrogen of the coal (not including hydrogen in coal moisture) expressed on a moist, whole-coal basis,

0.1119 is the gravimetric factor applied to the moisture value ( $M$ ) to obtain the weight percent hydrogen in coal moisture and,

92.7 is the Btu penalty, which is largely due to the latent heat of water vapor (Bowling, 1996), which is lost from the boiler with the combustion flue gas.

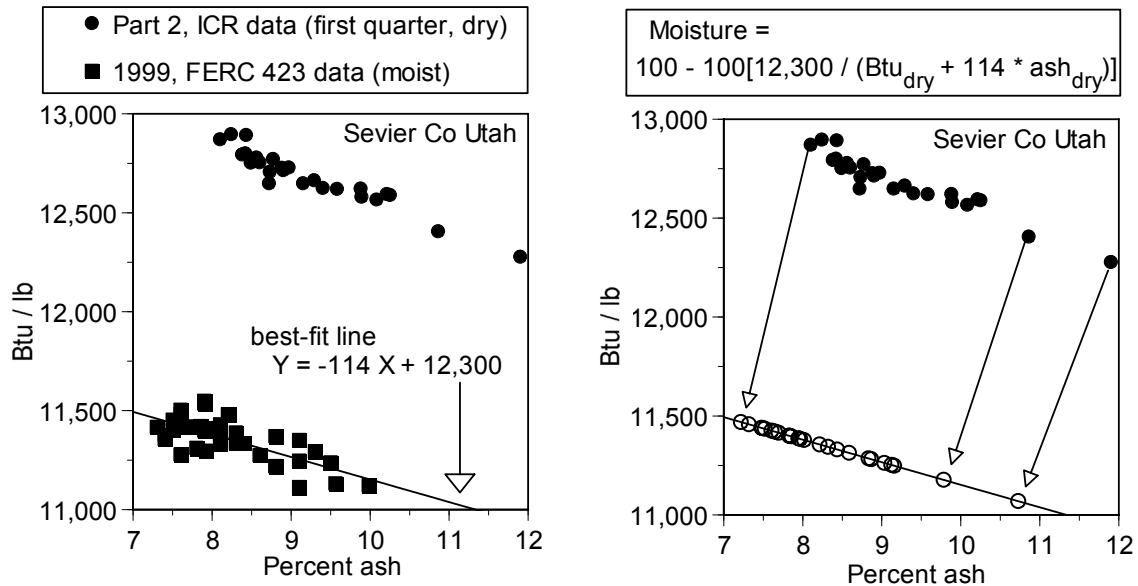
Note that the ICR data do not include moisture or hydrogen values, which are required for equation 1. Methods used to estimate and verify county-average ICR moisture and hydrogen values are described below.

### **Estimating Moisture**

As noted above, the ICR data are reported on a dry basis, whereas the FERC 423 data are reported on a moist basis. Where data records are aggregated by county-of-origin, comparison of the two data sets allows moisture to be estimated (figure 7). Note that this approach is not accurate for individual coals but, as will be shown, does provide a reasonable average moisture value for the 169 U.S. counties in the ICR data.

1. Calculate best-fit line for the FERC 423 data for a selected county-of-origin.

2. Algebraically estimate moisture values so ICR data move to the FERC 423 line.



**Figure 7.** Illustration of the method used to estimate ICR moisture values. Note that the method is not valid for individual coals, but is useful to calculate an average moisture value for coals grouped by U.S. county-of-origin. Since the FERC 423 data are commonly too few or too homogeneous to calculate a best-fit line, a method is presented in the text to calculate an intercept value (12,300 above) to use in the regression analysis.

As illustrated in figure 7, the first step to estimate ICR moisture is to find the best-fit regression line for moist-basis FERC 423 data from a single U.S. county. The slope and intercept of this line are then used to calculate moisture values for the dry basis ICR data from the same county, and the average ICR moisture value is calculated.

The method works reasonably well for U.S. counties with abundant data. However, a significant best-fit regression line is not possible where the FERC 423 data are too few in number, or are too homogeneous. To solve this problem, the intercept value determined fixed according to regionally established relationships between the American Society for Testing and Materials (ASTM, 1990) rank parameter ( $Btu/lb_{m,mmf}$ ); the intercept value can then be used with the otherwise limited FERC 423 data to obtain a best-fit line. These regional relationships used

to determine the intercept are made using plots of ash versus Btu/lb values for regional subsets of the FERC 423 data that are grouped according to 250 Btu/lb<sub>m,mmf</sub> intervals. A regression intercept value is established for each group, and a second linear regression analysis between the group average Btu/lb<sub>m,mmf</sub> values and their corresponding intercepts provides a unique solution for each region. The regional solutions are listed in table 12.

**Table 12.** Equations used to estimate regional ash versus Btu intercept values for FERC 423 data.

BOM district	Descriptive Geographic Extent	Equation
13	Eastern Province, southern Appalachian region: Alabama and southern Tennessee.	Intercept = 1.315 Btu/lb <sub>m,mmf</sub> – 4,541
7, 8	Eastern Province, central Appalachian region: northern Tennessee, eastern Kentucky, Virginia, and southern West Virginia.	Intercept = 1.034 Btu/lb <sub>m,mmf</sub> – 519
1, 2, 3, 4, 6	Eastern Province, northern Appalachian region: Ohio, northern West Virginia, and Pennsylvania.	Intercept = 0.9811 Btu/lb <sub>m,mmf</sub> + 225
9, 10, 11	Eastern Interior Province (Illinois Basin): western Kentucky, Indiana, and Illinois.	Intercept = 0.9699 Btu/lb <sub>m,mmf</sub> + 361
15	Western Interior Province: Kansas, Missouri, and Oklahoma.	Intercept = 1.127 Btu/lb <sub>m,mmf</sub> – 1,859
15	Gulf Province: Texas and Louisiana.	Intercept = 0.7883 Btu/lb <sub>m,mmf</sub> + 1,652
17	Rocky Mountain Province: Colorado.	Intercept = 1.002 Btu/lb <sub>m,mmf</sub> + 111
18,19, 20	Rocky Mountain Province: southern Wyoming, Utah, New Mexico, and Arizona.	Intercept = 0.9936 Btu/lb <sub>m,mmf</sub> + 73
19, 21, 22	Northern Great Plains Province: northeastern Wyoming, Montana, and North Dakota.	Intercept = 1.088 Btu/lb <sub>m,mmf</sub> – 804
1, 7, 8, 24	Eastern Province counties with medium volatile bituminous and higher rank coal: Allegany and Garrett Counties Maryland; Bedford, Cambria, Clearfield, Lackawanna, Lycoming, Schuylkill, Somerset, and Sullivan Counties Pennsylvania; Tazewell Co Virginia; Grant, Greenbrier, McDowell, Mercer, Raleigh, and Wyoming Counties West Virginia.	Intercept = 0.9827 Btu/lb <sub>m,mmf</sub> + 217

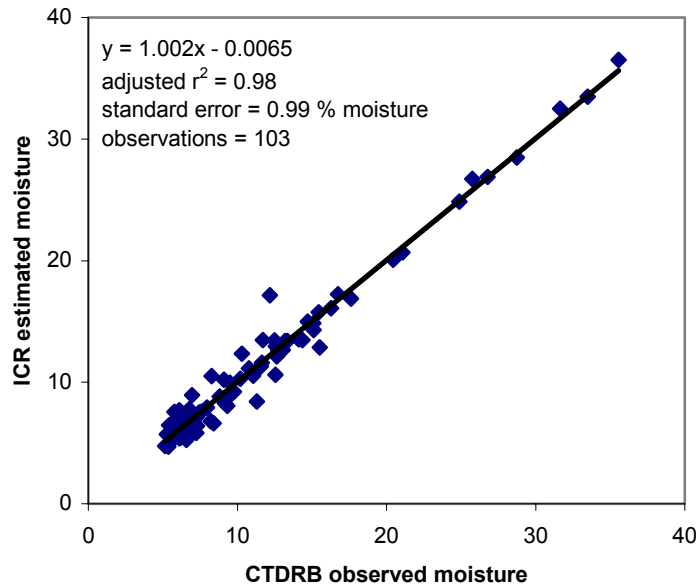
Note that the Btu/lb<sub>m,mmf</sub> value used in the listed equation is calculated from the county-average, FERC 423 data using the equation:  $Btu / lb_{m,mmf} = \frac{100 (Btu_{FERC423} - 50 Sulfur_{FERC423})}{[100 - (1.08 Ash_{FERC223} + 0.55 Sulfur_{FERC423})]}$ .

The average Btu/lb<sub>m,mmf</sub> value calculated using FERC 423 data from a single U.S. county is used with the appropriate equation listed in table 12 to obtain the intercept value. This

intercept value is then fixed during the ash versus Btu/lb regression analysis (figure 7, part 1) to obtain the best-fit line. The line slope and intercept are then used to estimate the ICR coal moisture values (figure 7, part 2), and the average moisture content is calculated for the U.S. county.

### Verification of Estimated Moisture Values

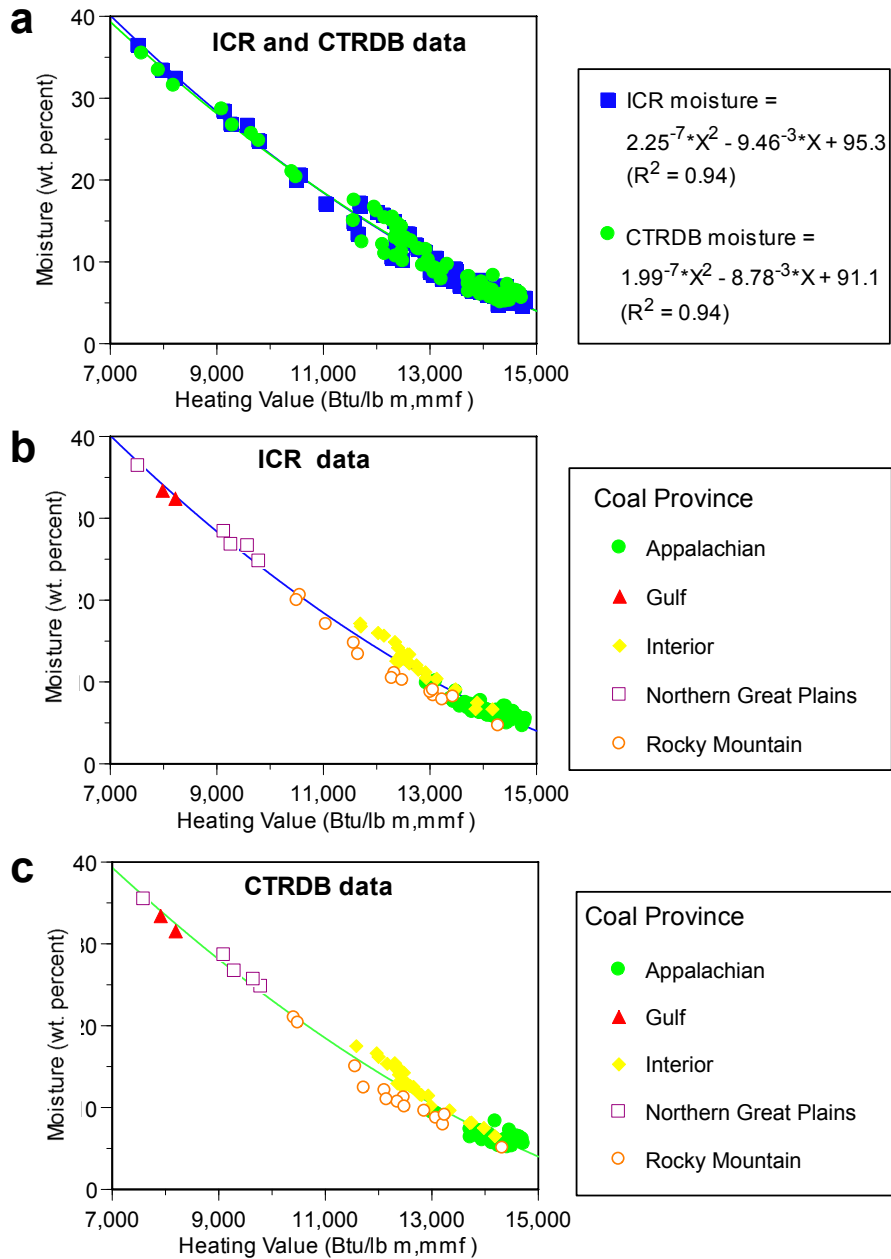
Figure 8 shows a cross plot of coal moisture values observed in the CTRDB data with the corresponding coal moisture values calculated for the ICR data; each data point represents a county average. The figure shows a nearly 1:1 relationship, and a standard error of about one percent moisture. The most notable outlier is for Moffat County, Colorado where the CTRDB includes a lower moisture population not observed in the ICR, or FERC 423 data. The CTRDB data records for the low moisture population list Eagle/Fiodel as the mine name. Since the Fiodel mine is located in Routt, rather than Moffat, County unrecognized location errors are likely responsible for this and perhaps other deviations in figure 8.



**Figure 8.** The estimated ICR moisture values are nearly the same as the observed CTRDB moisture values; each data point is a U.S. county average.

Further verification of the estimated ICR moisture values is illustrated in figure 9. Figure 9a shows that the relationship between the Btu/lb<sub>m,mmf</sub> rank parameter (ASTM, 1990) and coal moisture is essentially identical for both the ICR and CTRDB data. Perhaps more significant is the similar provincial variation of coal moisture values for these two data sets shown in figures 9b and 9c. For example, both the ICR and CTRDB data show that U.S. Interior province coal has more moisture than Rocky Mountain province coal of the same rank (Btu/lb<sub>m,mmf</sub>). Calculations (not shown) show that this provincial variation of moisture content is not caused by differences in mineral content.

A significant geographic component of coal moisture content may also be present within provincial groups of coal. McCutcheon and Barton (1999) showed that the mineral components of coal contain less moisture than the organic components. Accordingly, we used multivariate regression analysis, where the Btu/lb<sub>m,mmf</sub> and the Parr mineral matter values are used together to predict moisture. Although mineral matter does show the expected negative correlation with moisture for Gulf and Eastern province coals, it is not a significant factor to explain moisture variation for Interior, Rocky Mountain, or Northern Great Plains province coal. Given the importance of coal moisture for calculation of coal rank (ASTM, 1990), taxes and fees (Neavel, 1990; Luppens and Hoeft, 1991), and boiler efficiency (Sarunac and others, 2005) the impact of mineral content on coal moisture deserves further study.



**Figure 9.** The essentially identical relationships between the coal heating value and coal moisture content for the ICR and CTRDB data (a) verify the estimated moisture values for the ICR data. The similar provincial distribution of moisture values around each line (b, c) is likewise significant. Each data point is a U.S. county population average. The standard error for both lines is 1.2% moisture.

## Estimating Hydrogen

A multivariate regression method was applied to selected COALQUAL data (Mott-Spooner [1940] values within  $\pm 250$  Btu, appendix A) to develop a set of geographically specific equations to predict coal hydrogen from dry-basis Btu/lb, ash, and sulfur values. The equations were validated using the PSU-DOE data, and used to estimate ICR coal hydrogen values.

The dependent COALQUAL variable was dry-basis hydrogen. Note that moist-basis hydrogen values, which include hydrogen in coal moisture, are listed in the COALQUAL data set. Consequently, the COALQUAL hydrogen values were adjusted to a dry basis by subtracting the stoichiometric contribution of hydrogen to water ( $0.1119 \times \text{moisture}$ ), and multiplying the result by  $\frac{100}{100 - \text{moisture}}$  (ASTM, 2000a).

The four independent variables used in the regression analysis ( $Btu_{dmmf}$ ,  $Btu_{dmmf}^2$ ,  $MM_{Parr, dry}$ , and lbs S/million Btu) were calculated for the selected COALQUAL data records using the equations:

$$Btu_{dmmf} = \frac{100 \times (Btu_{dry} - 50S_{dry})}{100 - (1.08Ash_{dry} + 0.55S_{dry})} \quad (2)$$

$$Btu_{dmmf}^2 = Btu_{dmmf} \times Btu_{dmmf} \quad (3)$$

$$MM_{Parr, dry} = 1.08Ash_{dry} + 0.55S_{dry} \quad (4)$$

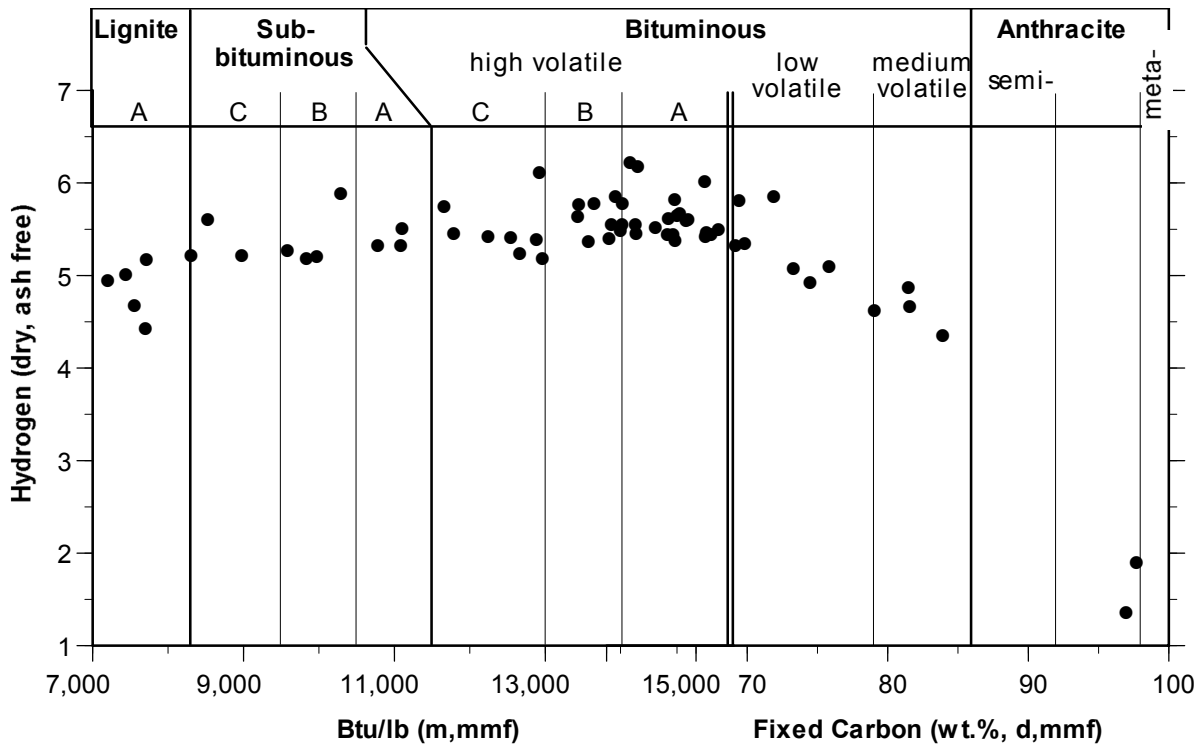
$$\text{lbs S/million Btu} = \frac{10^6}{Btu_{dry}} \times \frac{S_{dry}}{100} \quad (5)$$

where,  $Btu_{dry}$  is the dry-basis Btu per pound value,  
 $S_{dry}$  is the dry-basis weight percent sulfur, and  
 $Ash_{dry}$  is the dry-basis weight percent ash.

Although the regression equations were obtained using relationships observed in the COALQUAL data, they were used to predict ICR coal hydrogen values. Consequently, the



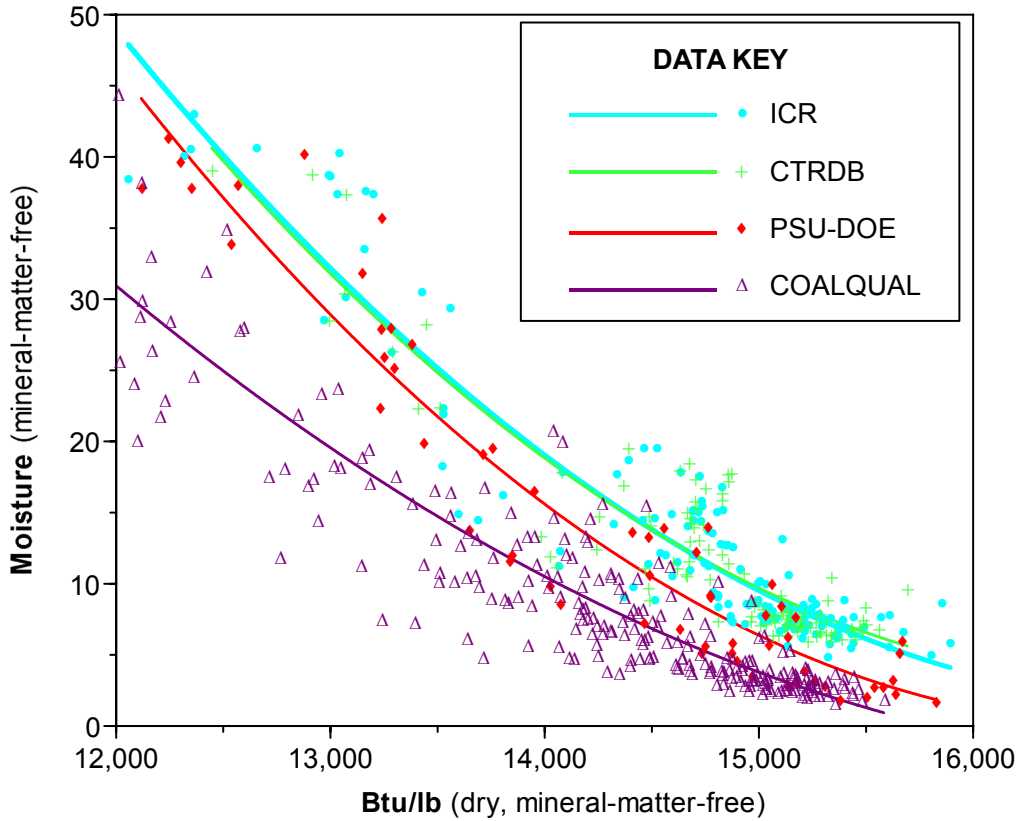
selection of the independent variables was necessarily constrained by the available ICR assay data (Btu/lb, ash, S, Cl, Hg, and estimated moisture). Considering this constraint, the independent variables were selected to indicate coal rank, ( $Btu_{dmmf}$  and  $Btu_{dmmf}^2$ ), coal grade ( $MM_{Parr,dry}$ ), and coal type (lbs S/million Btu), all of which may influence the hydrogen content of coal. For example, the influence of coal rank is illustrated in figure 10, which shows that coal hydrogen increases slightly through the coalification series to a maximum in the high volatile A bituminous stage, and then decreases as rank advances to the anthracite stage.



**Figure 10.** Variation of coal hydrogen with ASTM (1990) coal rank (PSU-DOE data).

Note that the ASTM rank classification (figure 10) requires two parameters: (1) the Btu value on a moist, mineral-matter-free basis [ $Btu/lb (m,mmf)$ ] and (2) the fixed carbon value on a dry, mineral-matter-free basis [ $Fixed Carbon (d,mmf)$ ]. Regrettably, neither parameter could be used as an independent variable in the regression analysis to predict coal hydrogen. We used the Btu/lb value on a dry, mineral-matter-free basis (instead of the moist, mineral-matter-free basis

used in the ASTM rank classification) because the COALQUAL moisture values are systematically lower than those observed in other data sets (figure 11). The fixed carbon parameter could not be used because fixed carbon values are not included in the ICR data.



**Figure 11.** COALQUAL moisture values are lower than moisture values for other data sets. Notes: The ICR moisture values are estimated, county-average, as-shipped values. The CTRDB, and COALQUAL data points show measured, county-average moisture values (as-received basis). The PSU-DOE data points show equilibrium moisture values for single coal assays. Data from U.S. counties with medium volatile bituminous or higher rank coal are not shown. Also not shown are data for 46 counties included in the COALQUAL data where the average dry, mineral-matter-free Btu value is less than 12,000 (the ICR, CTRDB, and PSU-DOE data do not include data records where the dry, mineral-matter-free Btu/lb value is less than 12,000). The Btu/lb (dry, mineral-matter-free) values were calculated using equation 2 (see text). Moisture (mineral-matter-free) ( $M_{mmf}$ ) was calculated as:  $M_{mmf} = \text{Moisture} [100 / (1.08 \text{ Ash}_{\text{moist}} + 0.55 \text{ Sulfur}_{\text{moist}})]$ . The best-fit lines correspond to: ICR  $M_{mmf} = 1.82E^{-6} (\text{Btu}/\text{lb}_{d,mmf})^2 - 6.22E^{-2} \text{Btu}/\text{lb}_{d,mmf} + 533$ , ( $R^2 = 0.88$ ); CTRDB  $M_{mmf} = 1.92E^{-6} (\text{Btu}/\text{lb}_{d,mmf})^2 - 6.47E^{-2} \text{Btu}/\text{lb}_{d,mmf} + 549$ , ( $R^2 = 0.83$ ); PSU-DOE  $M_{mmf} = 2.05E^{-6} (\text{Btu}/\text{lb}_{d,mmf})^2 - 6.88E^{-2} \text{Btu}/\text{lb}_{d,mmf} + 576$ , ( $R^2 = 0.92$ ); and COALQUAL  $M_{mmf} = 1.17E^{-6} (\text{Btu}/\text{lb}_{d,mmf})^2 - 4.05E^{-2} \text{Btu}/\text{lb}_{d,mmf} + 349$ , ( $R^2 = 0.94$ ).

The relationship between coal rank and coal hydrogen (figure 10) also shows that hydrogen declines at higher ranks with increasing fixed carbon. This indicates that different equations are required for high and low-rank coals. Accordingly, fixed carbon values listed in the COALQUAL data were used to identify U.S. counties with high-rank coal. COALQUAL data values ( $Btu_{dmmf}$ ,  $Btu_{dmmf}^2$ ,  $MM_{Parr,dry}$ , and lbs S/million Btu values) from these counties were used to establish equations to predict the hydrogen content of high-rank coal, and the equations were applied to the ICR data originating from the same counties.

Attempts to develop a single equation to predict hydrogen for high volatile A bituminous (hvAb) and lower rank coals gave unsatisfactory results. The results overestimated coal hydrogen in some geographic regions and underestimated coal hydrogen in others. For example, a multiple regression equation based on all the COALQUAL data for hvAb and lower rank coal (not shown), gave average residuals of -0.15% hydrogen for Western Interior coal and +0.23% hydrogen for Gulf Coast coal. To avoid these systematic errors, equations to predict coal hydrogen were determined for coal from each of the geographic regions shown in figure 12.

The regression equations used to predict coal hydrogen in this report are described in table 13. Several results are noteworthy. Excluding high-rank coal, relatively large t-statistic values, and consistently negative coefficients for the coal grade parameter ( $MM_{Parr,dry}$ ) show the strong influence of mineral matter content on coal hydrogen; coal hydrogen declines with increasing mineral content. The general lack of significance (t-statistic < 2) for the rank parameter ( $Btu_{dmmf}$ ) for coal from the Western Interior and Northern Great Plains groups may be due to small range of variation of the Btu variable in coal from these areas. Although the type parameter (lbs S/million Btu) is typically the least significant of the independent variables, its

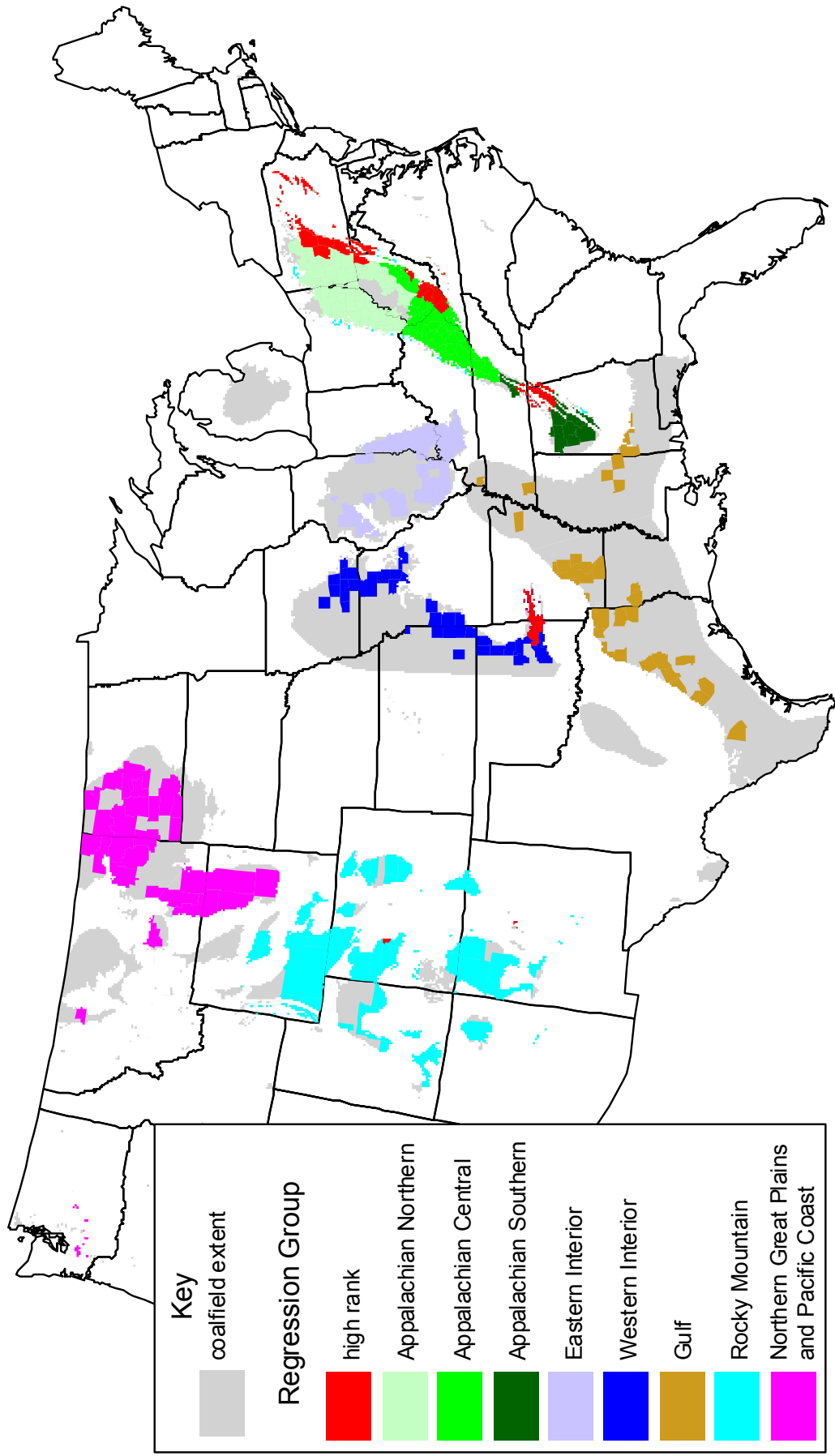


Figure 12. Regression equations to predict coal hydrogen content were developed for nine, coal-producing regional groups (modified from Trumbell, 1960).

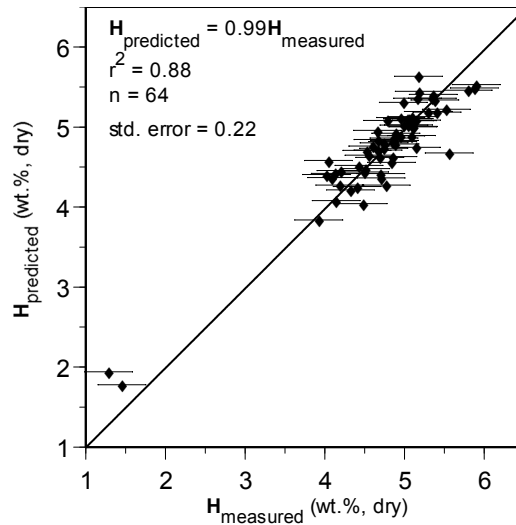
generally positive coefficient is consistent with the geologic enrichment of coal hydrogen due to the preservation of otherwise labile hydrogen-rich compounds by an early diagenetic natural vulcanization process where aliphatic compounds are cross-linked by hydrogen sulfide from sulfate-reducing bacteria (Sinninghe Damste and others, 1989). The inability of the sulfur variable to predict coal hydrogen for coal from five of the nine groups ( $t$ -statistic  $< 2$ ) is also noteworthy and may have varied origins; possibilities include (1) a late-stage abiogenic sulfide contribution to Western Interior coal (after diagenetic loss of labile hydrogen), (2) greater initial hydrogen of geologically younger (western U.S.) peat-forming biomass (more H-rich cellulose; Robinson, 1990) with early bacterial stripping of hydrogen by methanogenic bacteria, which thrive in the absence of dissolved sulfate (Belyaev and others, 1980), and (3) catagenetic loss of hydrogen associated with sulfur in aliphatic structures, as aliphatic sulfur is lost or transformed into aromatic sulfur at higher ranks (Maes and others, 1997; Gorbaty and Kelemen, 2001).

### **Verification of Estimated Hydrogen Values**

The geographically specific equations used to predict coal hydrogen are described in table 13. These equations were applied to the PSU-DOE data to verify their accuracy. Figure 13 shows the near 1:1 correspondence between the measured PSU-DOE hydrogen values and the predicted PSU-DOE hydrogen values. Error bars on the figure correspond to an assay reproducibility of 0.3% hydrogen (ASTM, 2000b) and show that most of the scatter can be attributed to the limited precision of the hydrogen assay. The departure of two, low-hydrogen coals (anthracite rank) from the forced regression line suggests that the regression model is not well suited to predict the hydrogen content of anthracite.

*Table 13. List of variables, coefficients, and statistics for geographically specific regression equations used to predict the hydrogen content of coal (see text for variable descriptions).*

Data Group	variable name	coefficient	t-statistic	equation statistics
<b>Northern Appalachian</b>	Intercept	-56.22	14.9	adjusted R <sup>2</sup> = 0.75
	Btu <sub>dmmf</sub> <sup>2</sup>	-2.82	E-07	
	Btu <sub>dmmf</sub>	8.35	E-03	
	MM <sub>Parr,dry</sub>	-5.34	E-02	observations = 1028
lbs S/million Btu	5.97	E-02		
<b>Central Appalachian</b>	Intercept	-55.81	18.1	adjusted R <sup>2</sup> = 0.74
	Btu <sub>dmmf</sub> <sup>2</sup>	-2.76	E-07	std. error = 0.19
	Btu <sub>dmmf</sub>	8.22	E-03	
	MM <sub>Parr,dry</sub>	-5.10	E-02	
lbs S/million Btu	1.06	E-01		
<b>Southern Appalachian</b>	Intercept	-65.88	13.3	adjusted R <sup>2</sup> = 0.71
	Btu <sub>dmmf</sub> <sup>2</sup>	-3.19	E-07	std. error = 0.21
	Btu <sub>dmmf</sub>	9.55	E-03	
	MM <sub>Parr,dry</sub>	-5.145	E-02	
lbs S/million Btu	7.323	E-02		
<b>Eastern Interior</b>	Intercept	-41.39	2.8	adjusted R <sup>2</sup> = 0.73
	Btu <sub>dmmf</sub> <sup>2</sup>	-2.11	E-07	std. error = 0.15
	Btu <sub>dmmf</sub>	6.30	E-03	
	MM <sub>Parr,dry</sub>	-5.33	E-02	
lbs S/million Btu	2.55	E-02		
<b>Western Interior</b>	Intercept	-4.54	-0.6	adjusted R <sup>2</sup> = 0.82
	Btu <sub>dmmf</sub> <sup>2</sup>	-3.54	E-08	std. error = 0.19
	Btu <sub>dmmf</sub>	1.21	E-03	
	MM <sub>Parr,dry</sub>	-5.00	E-02	
lbs S/million Btu	2.94	E-03		
<b>Gulf Coast</b>	Intercept	20.97	2.5	adjusted R <sup>2</sup> = 0.73
	Btu <sub>dmmf</sub> <sup>2</sup>	1.35	E-07	std. error = 0.23
	Btu <sub>dmmf</sub>	-2.95	E-03	
	MM <sub>Parr,dry</sub>	-3.95	E-02	
lbs S/million Btu	-5.27	E-02		
<b>Rocky Mountain</b>	Intercept	-5.87	5.4	adjusted R <sup>2</sup> = 0.83
	Btu <sub>dmmf</sub> <sup>2</sup>	-3.39	E-08	std. error = 0.20
	Btu <sub>dmmf</sub>	1.29	E-03	
	MM <sub>Parr,dry</sub>	-4.31	E-02	
lbs S/million Btu	2.41	E-02		
<b>Northern Great Plains, Pacific Coast</b>	Intercept	1.88	0.5	adjusted R <sup>2</sup> = 0.72
	Btu <sub>dmmf</sub> <sup>2</sup>	5.98	E-09	std. error = 0.19
	Btu <sub>dmmf</sub>	1.64	E-04	
	MM <sub>Parr,dry</sub>	-3.88	E-02	
lbs S/million Btu	3.80	E-03		
<b>High Rank</b> (mva to lva)	Intercept	-35.66	5.9	adjusted R <sup>2</sup> = 0.52
	Btu <sub>dmmf</sub> <sup>2</sup>	-1.66	E-07	std. error = 0.28
	Btu <sub>dmmf</sub>	5.20	E-03	
	MM <sub>Parr,dry</sub>	-4.19	E-02	
lbs S/million Btu	3.91	E-02		
<b>(anthracite)</b>	Intercept	209.20	5.9	adjusted R <sup>2</sup> = 0.67
	Btu <sub>dmmf</sub> <sup>2</sup>	1.02	E-06	std. error = 0.38
	Btu <sub>dmmf</sub>	-2.92	E-02	
	MM <sub>Parr,dry</sub>	1.74	E-02	
lbs S/million Btu	-4.78	E-01		

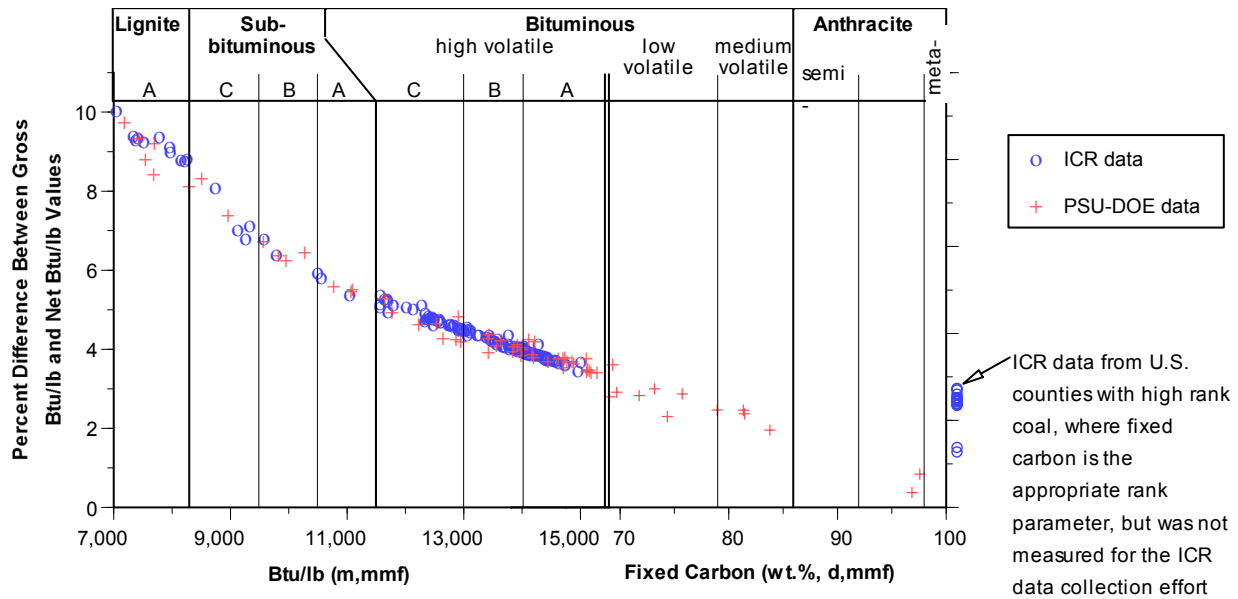


**Figure 13.** A near 1:1 relationship is observed between the measured PSU-DOE hydrogen values ( $H_{\text{measured}}$ ) and predicted PSU-DOE hydrogen values ( $H_{\text{predicted}}$ ). The predicted hydrogen values were calculated using equations described in table 13 (in text). The points represent individual PSU-DOE data records selected to have Mott-Spooner difference values within  $\pm 250$  Btu. Error bars illustrate an assay reproducibility of  $\pm 0.3\%$  hydrogen (ASTM, 2000b) and show that most of the scatter is explained by the precision of the hydrogen assay.

### Verification of ICR Net Heating Values

The predicted hydrogen, estimated moisture, and measured Btu/lb values were used with equation 1 to calculate the average net heating value for 169 counties represented in the ICR data set. The county-average results show that the net heating value is about 4.5% less than the gross heating value. This is similar to the 5% difference assumed by the reference method to verify greenhouse gas emissions for the Kyoto Protocol (Houghton and others, 1997). However, as shown in figure 14, the difference between the net and gross heating value varies with coal rank. The net heating value of lignite is about 10 percent less than its gross heating value; the difference smoothly declines through the coalification series to reach a minimum (1 to 2% difference) at the anthracite stage. Figure 14 also shows that the net heating values predicted for

the county-average ICR data mimic those calculated using the (measured) PSU-DOE moisture and hydrogen values.



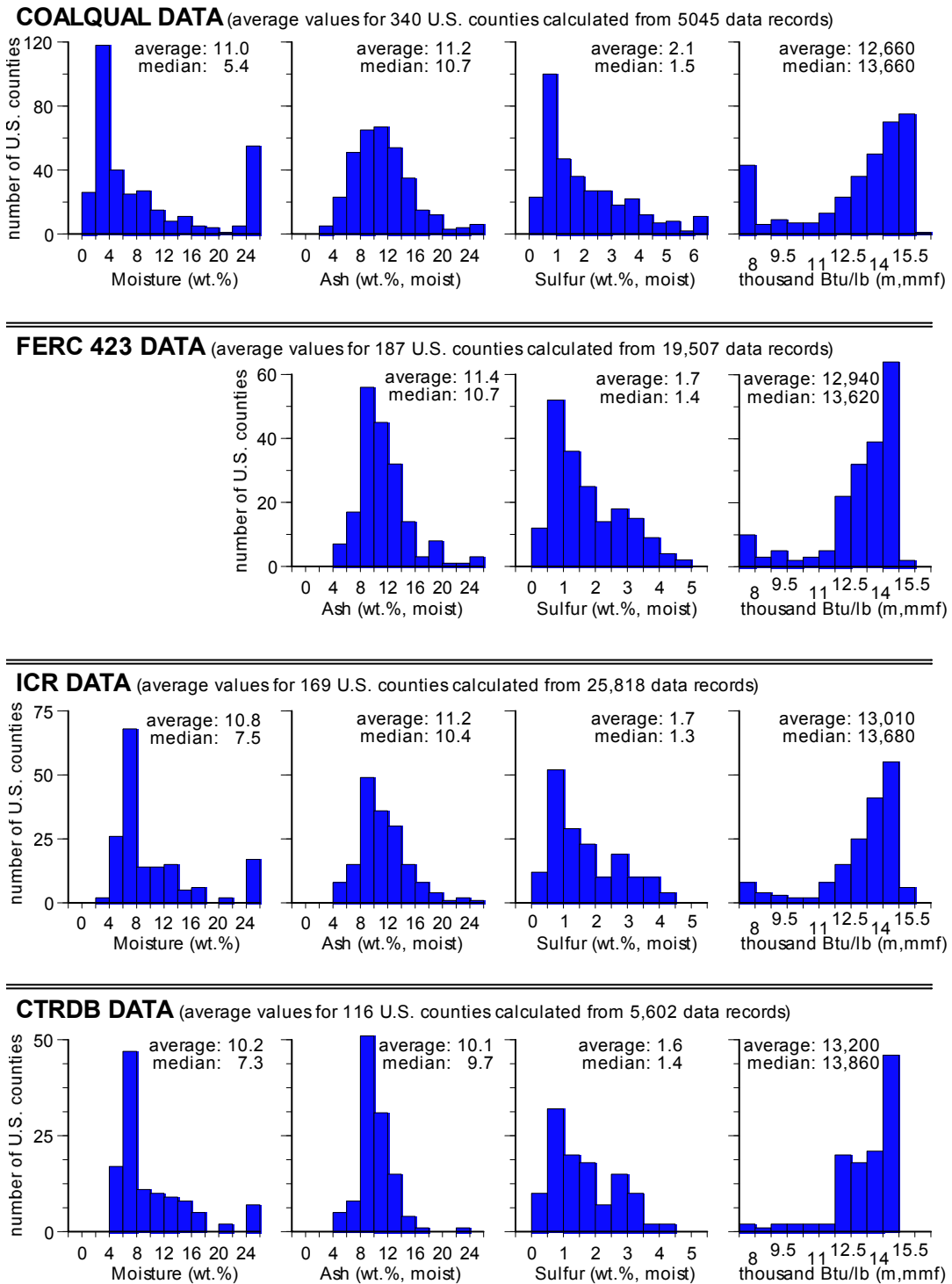
**Figure 14.** The difference between the net and gross heating value of U.S. coal from two data sets systematically varies with ASTM (1990) coal rank. The percent difference between the gross heating value of coal ( $Btu_{gross}$ ), and the calculated net heating value ( $Btu_{net}$ ) corresponds to:  $Percent\ Difference = \frac{100 (Btu_{gross} - Btu_{net})}{Btu_{gross}}$ . The PSU-DOE data points represent single coal assays on an equilibrium moisture basis. The ICR data points represent county-average values on an estimated, as-shipped moisture basis.

## RESULTS AND DISCUSSION

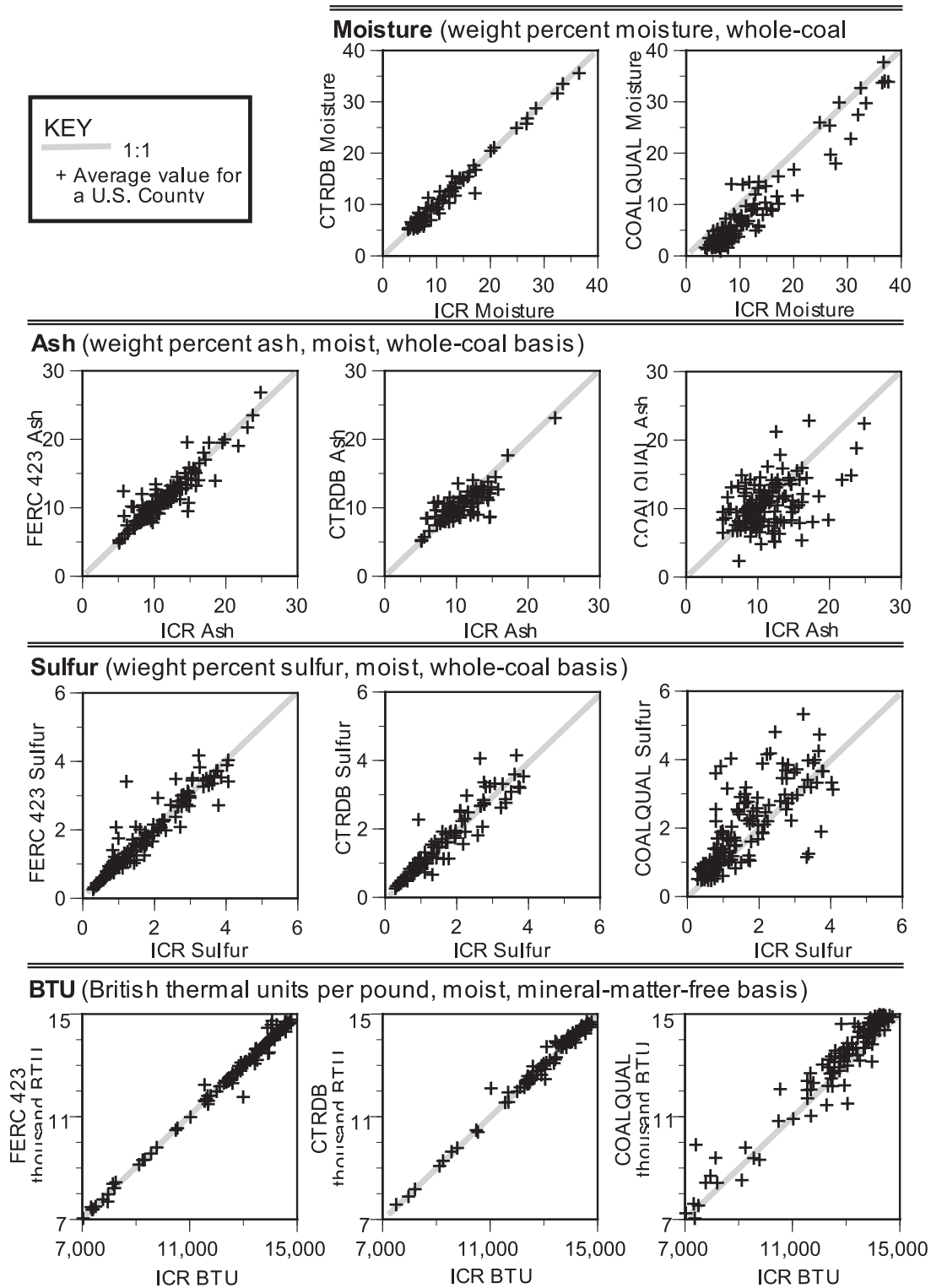
### Data Evaluation

County-average, moisture, ash, sulfur, and Btu/lb values for four data sets are compared in figures 15 and 16. Note that the data sets compared in figure 15 are populated by different numbers of counties, whereas the comparisons shown in figure 16 only include counties that are common to the ICR, and the FERC 423, CTRDB, or COALQUAL data sets.





**Figure 15.** Histograms showing the distribution of county-average coal quality values for the COALQUAL, FERC 423, ICR, and CTRDB data sets. Moisture, ash, and sulfur values are expressed on a moist, whole-coal basis, whereas the Btu/lb values are expressed on a moist, mineral-matter-free basis, calculated after ASTM (1990).



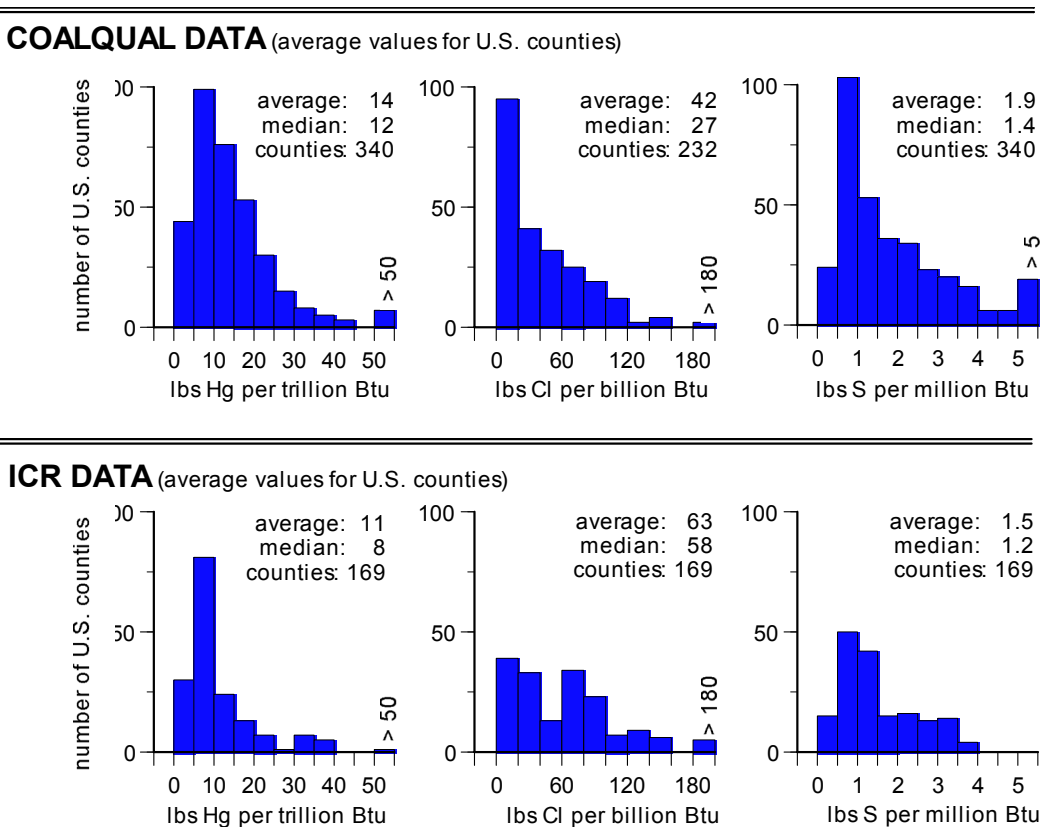
**Figure 16.** Cross-plots comparing the county-average moisture, ash, sulfur, and Btu/lb values from the ICR data set with those from the CTRDB, COALQUAL, and FERC 423 data sets; the Btu/lb values were calculated after ASTM (1990).

Figures 15 and 16 show reasonably good agreement between the data sets, especially for data corresponding to commercial coal shipments (FERC 423, CTRDB, and ICR). The correlation between the ICR and FERC 423 sulfur values shown in figure 16 deserves comment. Despite the good correlation, a few counties deviate from the 1:1 line. Many of these deviations can be attributed to instances where the county-average values are calculated from one or two data records. However a few instances may indicate potential bias in ICR data. Given that the ICR data relied on periodic assays, and include a disproportionate number of records for small (< 50 MW) utilities, it is likely that the FERC 423 data better represent the quality of commercial U.S. coal than the ICR data. Moreover, sulfur exhibits a positive correlation with mercury for aggregated data (Quick and others, 2003). Consequently, instances where ICR sulfur is higher than FERC 423 sulfur may indicate erroneously high county-average ICR mercury values. Conversely, instances where the ICR sulfur is lower than the FERC 423 sulfur may indicate erroneously low county-average ICR mercury values.

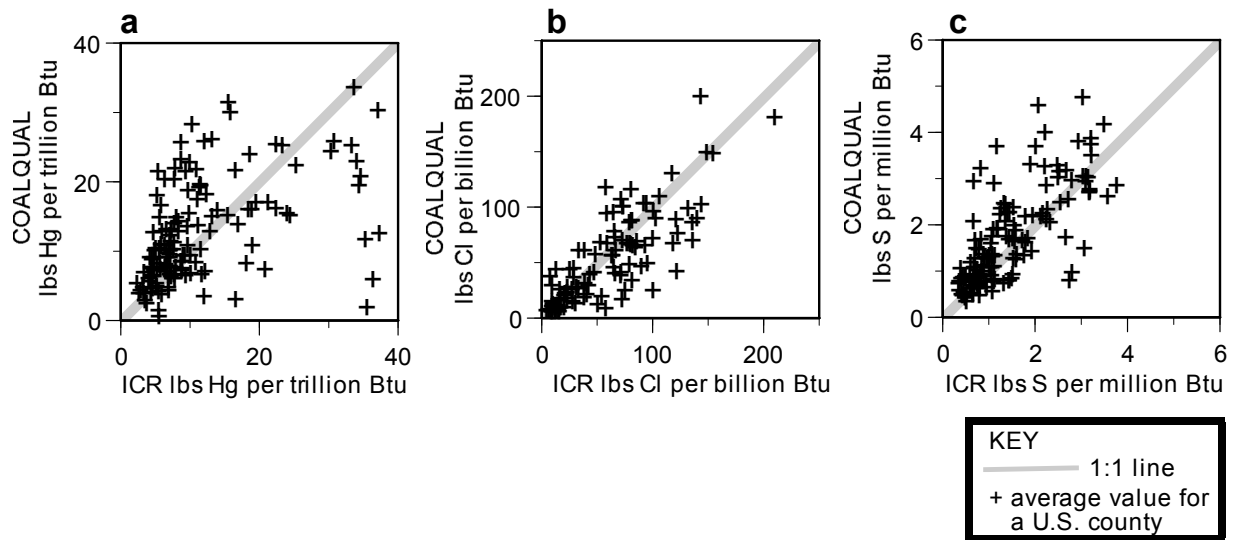
The larger number of counties included in the COALQUAL data set should be considered when evaluating the data distributions shown in figure 15. For example, the relatively high, average moisture value for the 340 counties listed in the COALQUAL data set (figure 15) is a result of the comparatively large number of counties in the COALQUAL data set with high-moisture (low-rank) coal. Thus, the relatively high average COALQUAL moisture value shown in figure 15 is due to a geographic, rather than analytical, bias. Restricting the comparison of moisture values to common counties (figure 16) shows that the COALQUAL assay moisture values are actually relatively low. Although the relatively low COALQUAL moisture values may relate to added moisture from washing of commercial coal (ICR and CTRDB data), moisture loss prior to analysis of the COALQUAL coal samples is probably more

significant. Indeed, Bragg and others (1997) noted that the calculated ASTM rank for some COALQUAL data records might be anomalously high due to air-drying of the samples before analysis. The low COALQUAL moisture values due to assay bias are also consistent with the relatively high, moist-basis COALQUAL Btu/lb values (figure 16).

As noted earlier in this report, systematically low COALQUAL moisture values complicate the evaluation of rank and the calculation of net heating values. Fortunately, the low moisture values have little effect on COALQUAL emission factors expressed on an energy basis. For example, the calculation of pounds sulfur per million Btu gives the same result regardless of whether moist-basis sulfur and Btu/lb values, or dry-basis sulfur and Btu/lb values, are used for the calculation. Figures 17 and 18 compare ICR sulfur, mercury, and chlorine values expressed on an energy-basis to equivalent COALQUAL values.



**Figure 17.** Distribution of county-average, mercury, chlorine and sulfur values for in-ground coal (COALQUAL DATA) and commercial coal (ICR DATA).



**Figure 18.** Comparison of mercury, chlorine, and sulfur values in the ICR and COALQUAL data sets. Data points show average values for U.S. counties common to both data sets.

When examining figures 17 and 18 it is useful to recognize that the COALQUAL data indicate the quality of the in-ground coal resource, whereas the ICR data indicate the quality of commercial coal produced during 1999. Differences between the COALQUAL and ICR data are inevitable because the COALQUAL data include additional records for coal beds that are not mined. Nonetheless, comparison of these data is instructive. Figure 17 shows higher sulfur and mercury values for the COALQUAL data than the ICR data. Quick and others (2003) also observed higher COALQUAL sulfur and mercury values, which they attributed to selective mining of low-sulfur and low-mercury coal, as well as reduction of sulfur and mercury due to washing of mined coal. However, figure 18a shows that the mercury content of in-ground coal (COALQUAL data) is not always higher than the mercury content of commercially shipped coal (ICR data) when the comparison is restricted to coal from common counties-of-origin. Counties where the mined coal contains more mercury than indicated by the COALQUAL data are colored red in figure 19. The reason for the higher mercury content of coal mined in these areas

may be the combined result of limited washing, and contamination of mined coal by high-mercury partings, roof rock, or floor rock; these contaminants are generally not included in COALQUAL assay specimens because USGS sample collections guidelines (Swanson and Huffman, 1976) require partings more than 5 mm thick to be excluded from the analysis sample. Increased coal washing may be an effective Hg reduction strategy in instances where the ICR mercury values are greater than the COALQUAL mercury values. Blue areas on figure 19 show where mined coal contains substantially less Hg than the in-ground resource. Selective mining and/or extensive coal washing probably explain these occurrences. For a few counties, these differences may simply indicate bias in the ICR data (suggested by the different FERC 423 and ICR sulfur values, discussed above) or instances where the county average values are based on only a few data records.

The different chlorine distributions for the COALQUAL and ICR data shown in figure 17 suggest preferential mining of counties with high-chlorine coal. However, such inferences are uncertain given the limitations of the chlorine assays. For example, nearly 30% of the COALQUAL chlorine values are reportedly below the assay detection limit (Bragg and others, 1997). Although only 14% of the selected ICR records are reportedly below the detection limit, this is probably a minimum value. Nyberg (2003) noted that methods used to determine chlorine concentrations in the ICR data collection effort were unreliable below 200 parts-per-million (ppm or  $\mu\text{g/g}$ ). Thirty percent of the selected ICR data records show dry chlorine at or below 200 ppm. Moreover, figure 20 shows that western U.S. counties are responsible for a disproportionate share of the low-chlorine ICR data records.

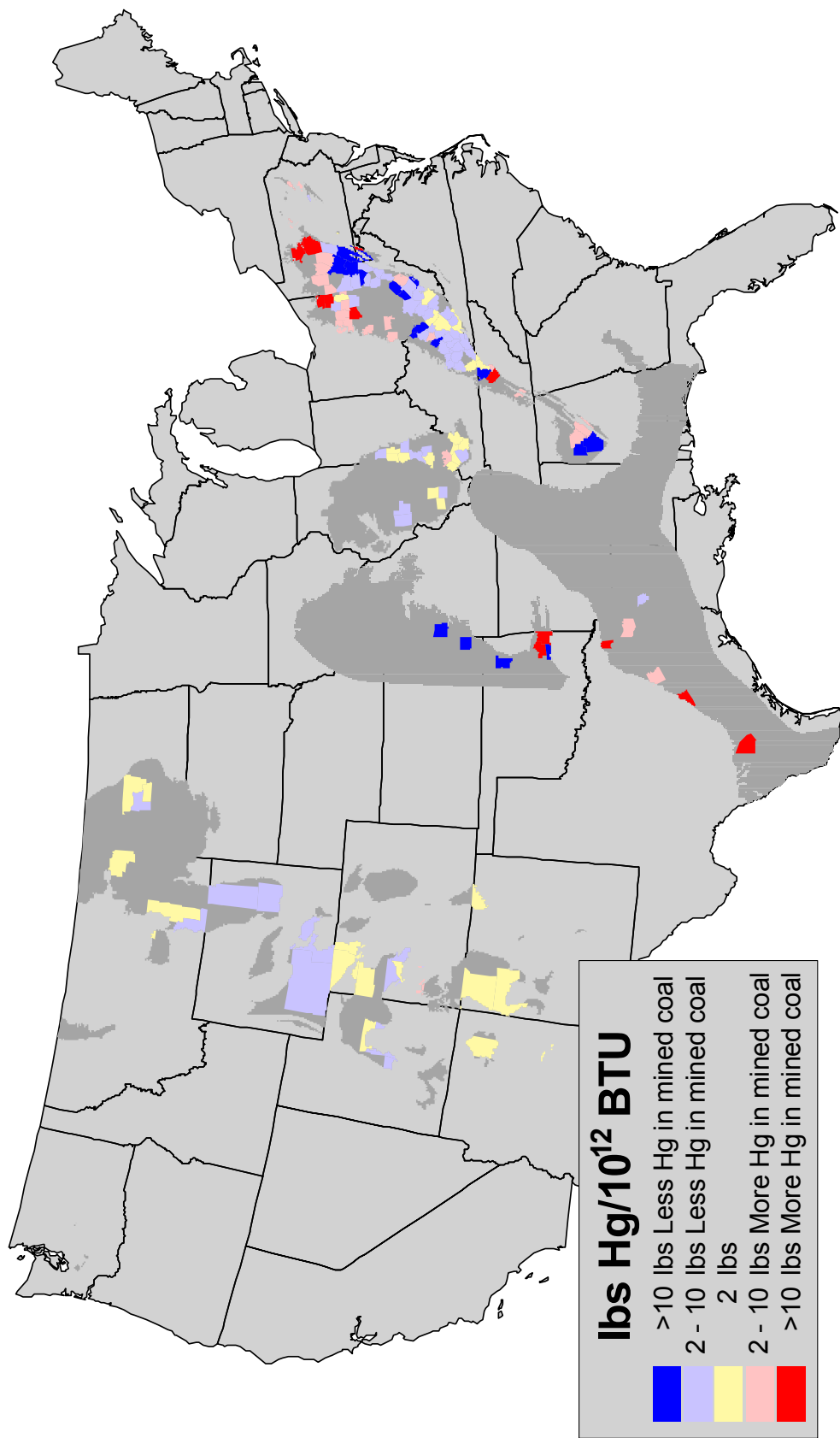


Figure 19. The difference between the mercury content of in-ground coal (COALQUAL data) and the mercury content of mined coal (ICR data) varies geographically (county-average COALQUAL Hg minus county-average ICR Hg, expressed as lbs Hg/10<sup>12</sup> Btu).

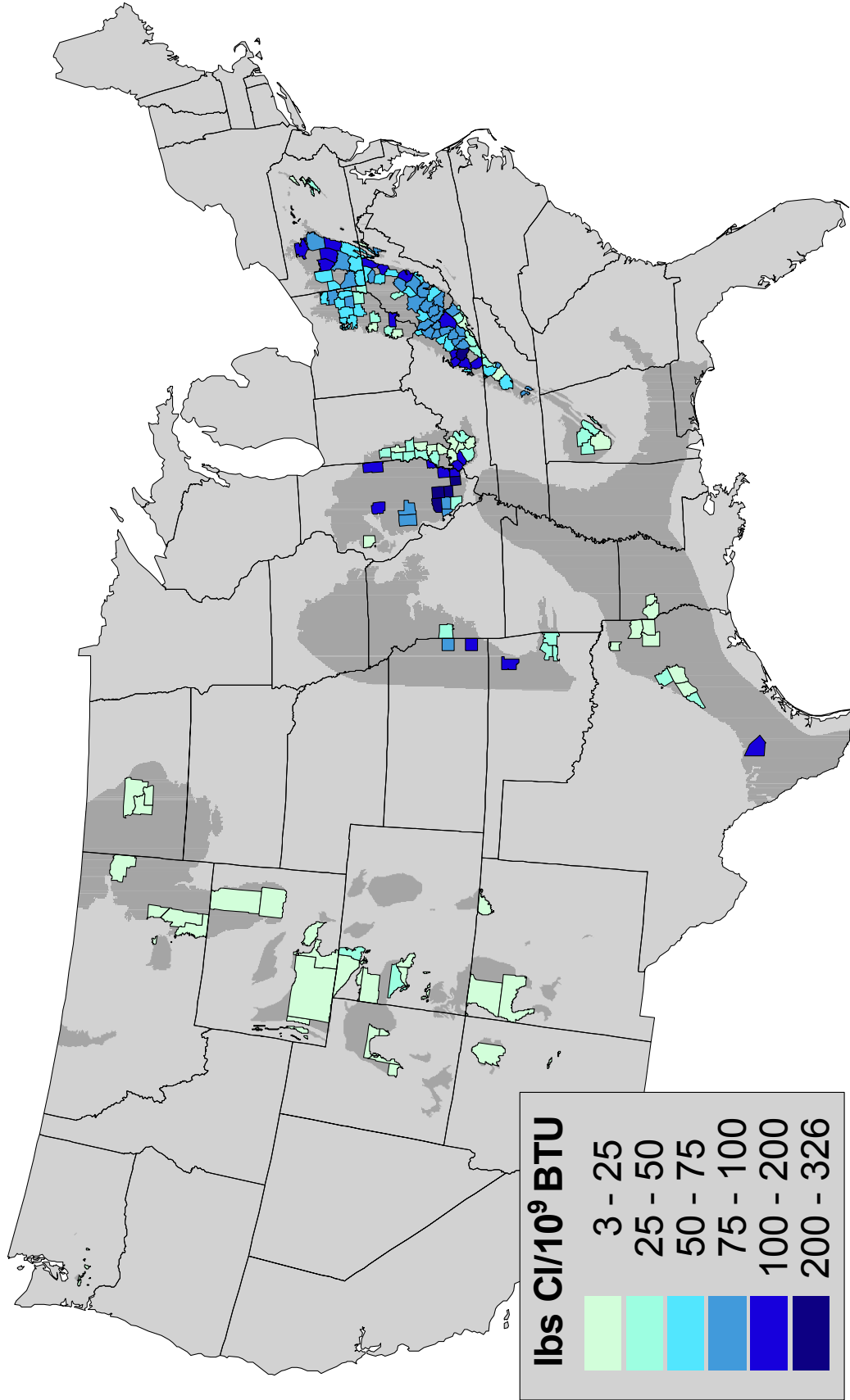


Figure 20. Average chlorine content of coal delivered to U.S. power plants during 1999, by county-of-origin (calculated using selected ICR data).



## Mercury Capture by Existing Emission Controls

The ICR part 3 data set (USEPA, 2003) includes mercury stack gas measurements from about 80 selected U.S. power plants that were collected for part 3 of the 1999 information collection request. The data show measured mercury emissions and allow calculation of boiler heat inputs from flue gas volume using the F-factor (Stultz and Kitto, 1992). Various groups have used the ICR 3 utility emission data to derive equations that predict mercury capture for existing emission control technologies (Chu and others, 2000; Laumb and others, 2000; Roberson, 2002; ENSR, 2003; SAIC, 2003; AEMS, 2004). The equations use coal chlorine, ash, Btu, or sulfur values as independent variables to predict mercury capture by different emission control technologies.

Table 14 lists three different equations for each of the (five) emission control technologies examined in this study. Figures 21, 22, 23, 24, and 25 compare the mercury capture predicted by these equations for each control technology. Note the similar  $r^2$  values, similar trends, but different results, for all five of the control technologies examined in this study (cESP, hESP, hESP/FGD, cESP/FGD, and SDA/FF controls).

**Table 14.** Technology-specific equations that predict mercury capture.

TECHNOLOGY Reference	Equation to Predict Mercury Capture (100% capture = 1)	r <sup>2</sup>	n
<b>cESP</b>			
Roberson (2002) <sup>1</sup>	$0.1233 \text{Ln} \left( \frac{Cl_{ppm,dry}}{1.998 S_{lbs/10^6 Btu}} \right) - 0.3885$	0.53	28
model 2, SAIC (2003)	$1 - \text{Exp} \left( -7.33E^{-2} - 3.309 \left( lbs \text{ Cl per } 10^{12} \text{ Btu} \right) \right)$	0.47	12
model 1, SAIC (2003)	$1 - \text{Exp} \left( 1.6374 - 0.18693 \text{Ln} \left( lbs \text{ Cl per } 10^{12} \text{ Btu} \right) \right)$	0.38	12
<b>cESP/FGD</b>			
Roberson (2002)	$0.1157 \text{Ln} \left( Cl_{ppm,dry} \right) - 0.1438$	0.70	11
model 1, SAIC (2003)	$1 - \text{Exp} \left( 1.8529 - 0.27149 \text{Ln} \left( lbs \text{ Cl per } 10^{12} \text{ Btu} \right) \right)$	0.74	8
model 3, SAIC (2003)	$1 - \text{Exp} \left( -0.2559 - 2.3343E^{-5} \left( \frac{100 Cl_{ppm,dry}}{S_{wt.%,dry}} \right) \right)$	0.73	8
<b>hESP</b>			
model 1, SAIC (2003)	$1 - \text{Exp} \left( 0.9451 - 9.995E^{-2} \text{Ln} \left( lbs \text{ Cl per } 10^{12} \text{ Btu} \right) \right)$	0.42	7
model 3, SAIC (2003)	$1 - \text{Exp} \left( 0.0611 - 2.169E^{-6} \left( \frac{100 Cl_{ppm,dry}}{S_{wt.%,dry}} \right) \right)$	0.54	7
ENSR (2003)	$1 - \text{Exp} \left( 0.12124 - 1.021E^{-4} \left( Cl_{ppm,dry} \right) \right)$	0.39	9
<b>hESP/FGD</b>			
model 1, SAIC (2003)	$1 - \text{Exp} \left( 2.7019 - 0.29952 \text{Ln} \left( lbs \text{ Cl per } 10^{12} \text{ Btu} \right) \right)$	0.75	6
model 2, SAIC (2003)	$1 - \text{Exp} \left( -3.59E^{-2} - 9.358E^{-6} \left( lbs \text{ Cl per } 10^{12} \text{ Btu} \right) \right)$	0.67	6
model 4, SAIC (2003)	$1 - \text{Exp} \left( 2.5618 - 0.268 \text{Ln} \left( \frac{100 Cl_{ppm,dry}}{S_{wt.%,dry}} \right) \right)$	0.42	6
<b>SDA/FF</b>			
Roberson (2002)	$0.2854 \text{Ln} \left( Cl_{ppm,dry} \right) - 1.1302$	0.91	10
model 1, SAIC (2003)	$1 - \text{Exp} \left( 10.7111 - 1.22628 \text{Ln} \left( lbs \text{ Cl per } 10^{12} \text{ Btu} \right) \right)$	0.89	10
ENSR (2003)	$1 - \text{Exp} \left( -0.19992 - 2.164E^{-3} \left( Cl_{ppm,dry} \right) \right)$	0.94	10

Notes, <sup>1</sup> corrected after EPRI (2000)

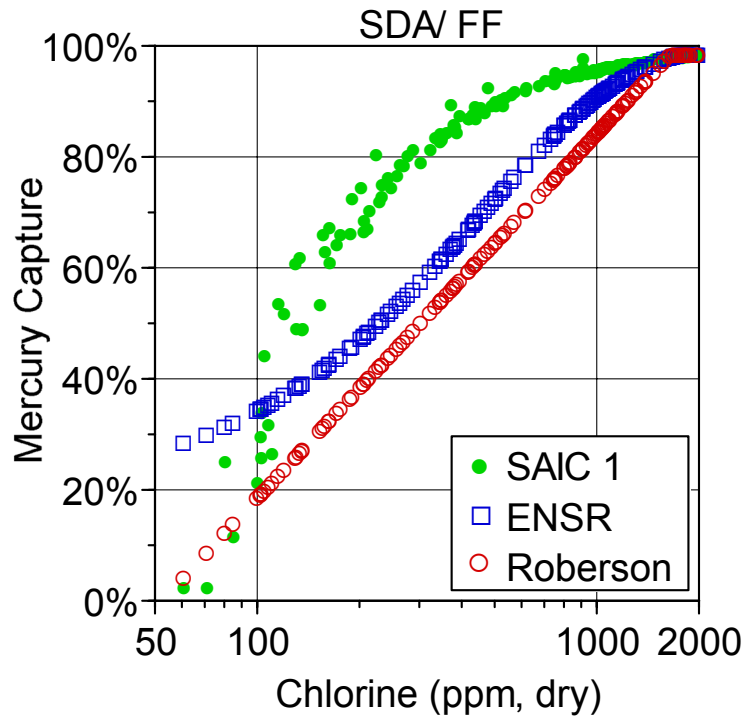
**cESP:** cold-side Electrostatic Precipitator;

**cESP/FGD:** cold-side Electrostatic Precipitator with wet Flue Gas Desulphurization;

**hESP:** hot-side Electrostatic Precipitator;

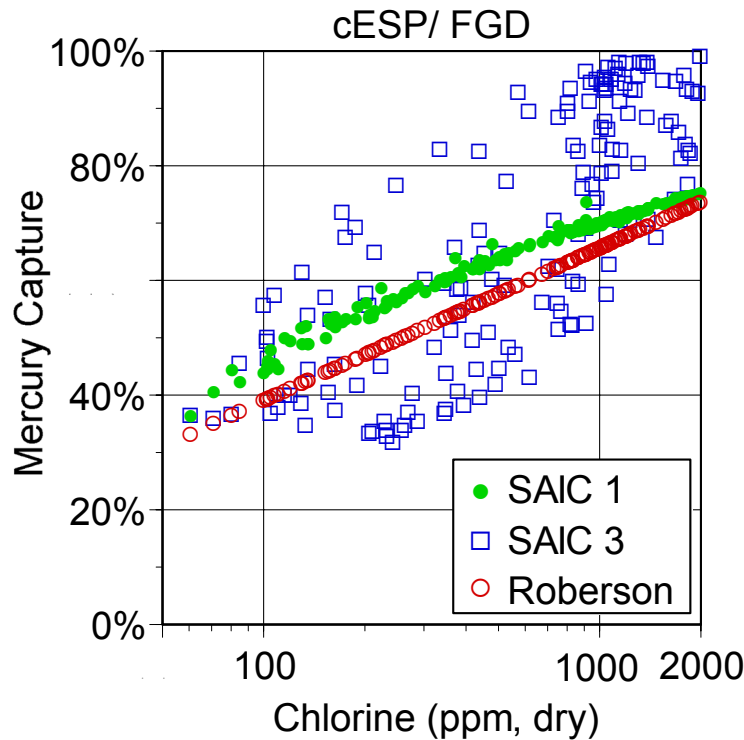
**hESP/FGD:** hot-side Electrostatic Precipitator with wet Flue Gas Desulphurization;

**SDA/FF:** Spray Dry Adsorption with Fabric Filter.



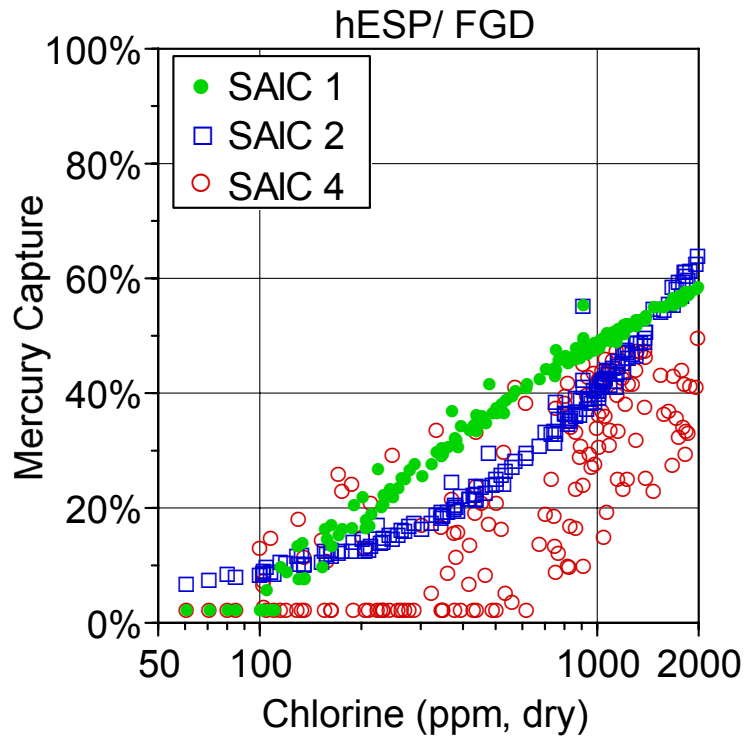
**Figure 21.** Three equations predict different amounts of mercury capture for SDA/FF technology when applied to data for 162 U.S. counties.

Notes, SDA/FF: Spray Dry Adsorption, Fabric Filter; SAIC (2003), ENSR (2003), and Roberson (2002) equations listed on table 14 (this report); ICR county-average coal assay data (appendix); results for six counties with > 2000 ppm chlorine and one county with < 50 ppm chlorine are not shown; results limited to 2% minimum capture and 98% maximum capture.



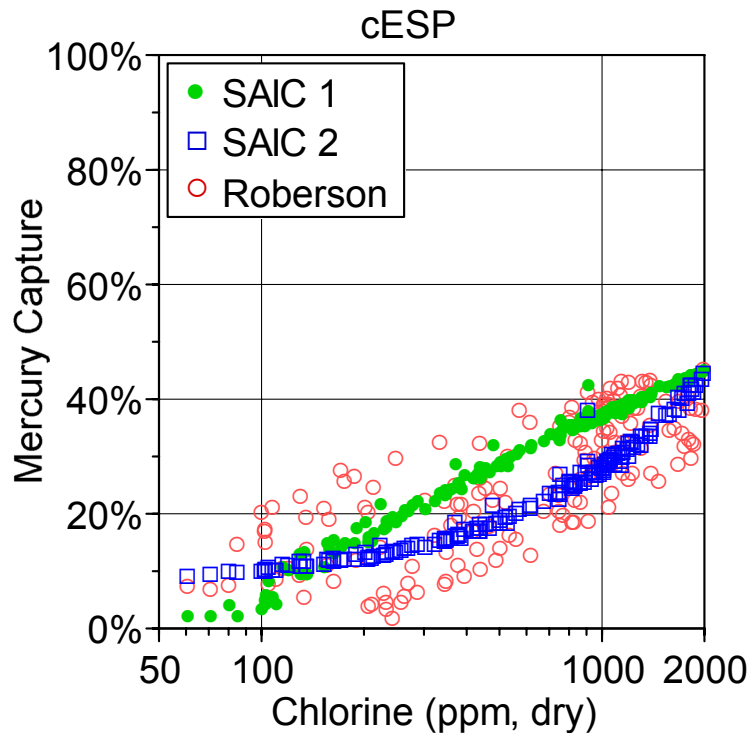
**Figure 22.** Three equations predict different amounts of mercury capture for cESP/FGD technology when applied to data for 162 U.S. counties.

Notes, cESP/FGD: cold-side Electrostatic Precipitator, wet Flue Gas Desulphurization; SAIC (2003), and Roberson (2002) equations listed on table 14 (this report); ICR county-average coal assay data (appendix); results for six counties with > 2000 ppm chlorine and one county with < 50 ppm chlorine are not shown; results limited to 2% minimum capture and 98% maximum capture.



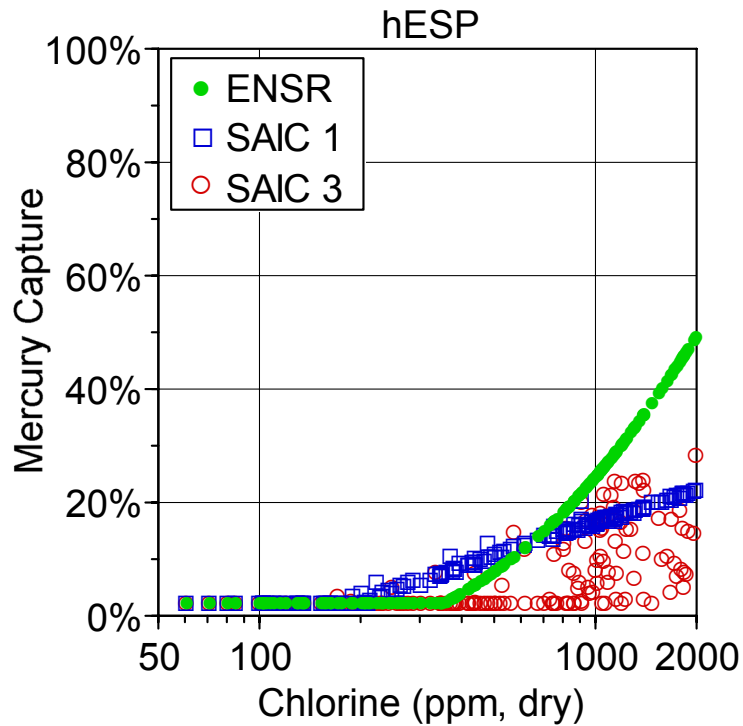
**Figure 23.** Three equations predict different amounts of mercury capture for hESP/FGD technology when applied to data for 162 U.S. counties.

Notes, hESP/FGD: hot-side Electrostatic Precipitator, wet Flue Gas Desulphurization; SAIC (2003) equations listed on table 14 (this report); ICR county-average coal assay data (appendix); results for six counties with > 2000 ppm chlorine and one county with < 50 ppm chlorine are not shown; results limited to 2% minimum capture and 98% maximum capture.



**Figure 24.** Three equations predict different amounts of mercury capture for cESP technology when applied to data for 162 U.S. counties.

Notes, cESP: cold-side Electrostatic Precipitator; SAIC (2003), and Roberson (2002) equations listed on table 14 (this report); ICR county-average coal assay data (appendix); results for six counties with > 2000 ppm chlorine and one county with < 50 ppm chlorine are not shown; results limited to 2% minimum capture and 98% maximum capture.

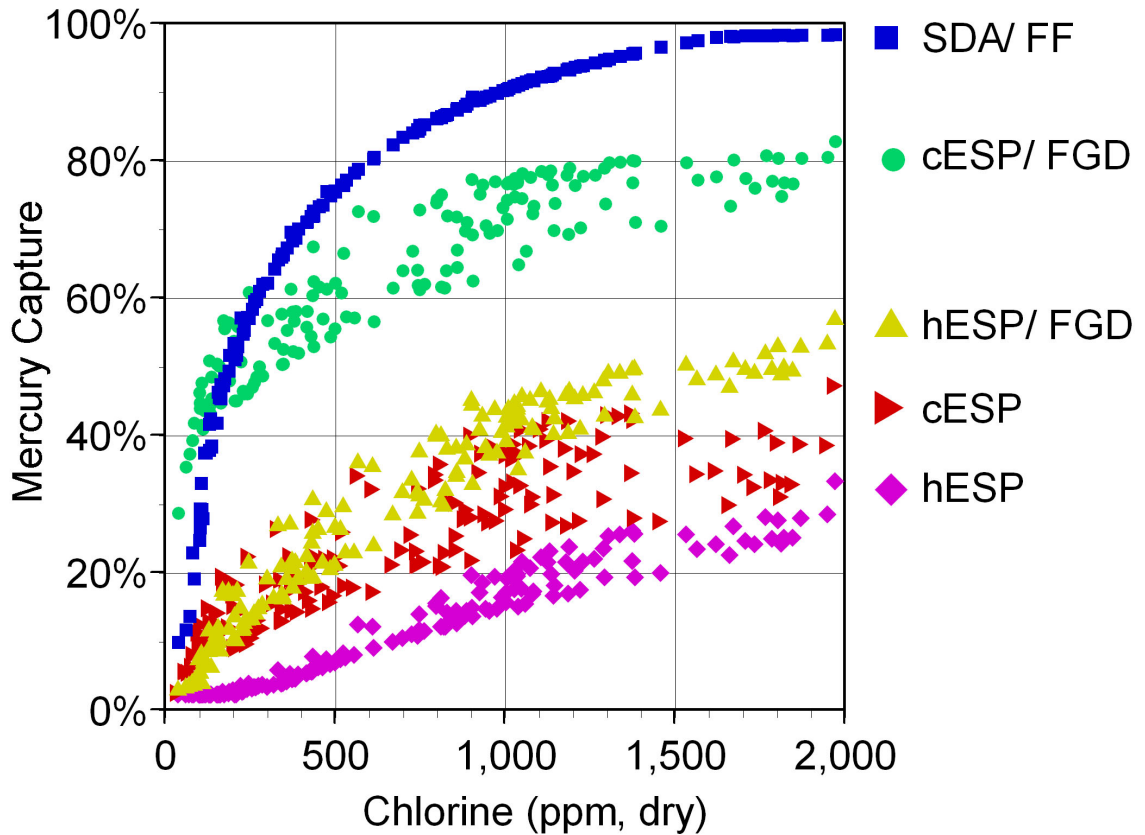


**Figure 25.** Three equations predict different amounts of mercury capture for hESP technology when applied to data for 162 U.S. counties.

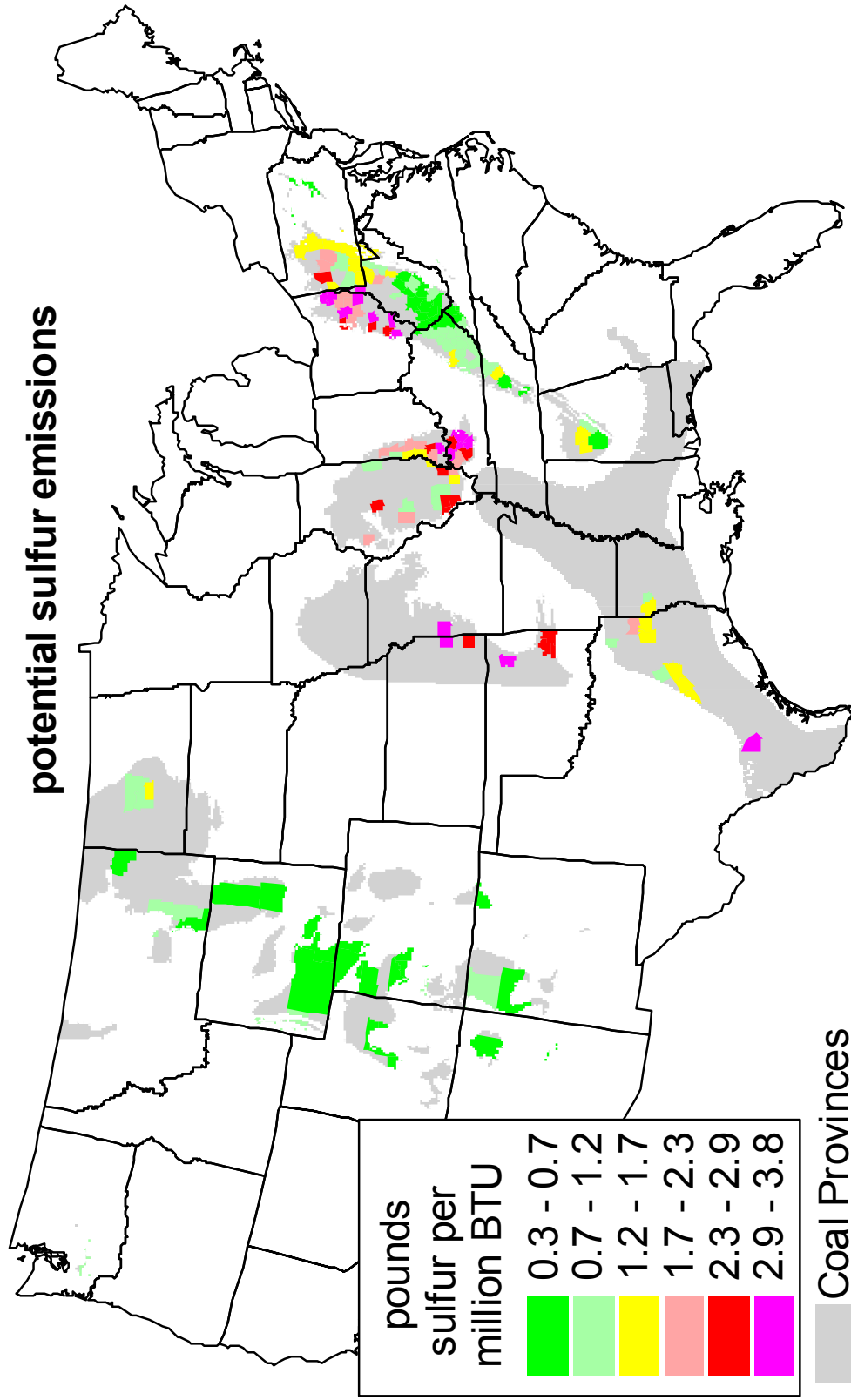
Notes, hESP: hot-side Electrostatic Precipitator; ENSR (2003) and SAIC (2003) equations listed on table 14 (this report); ICR county-average coal assay data (appendix); results for six counties with > 2000 ppm chlorine and one county with < 50 ppm chlorine are not shown; results limited to 2% minimum capture and 98% maximum capture.

The similar statistical significance but different county-specific results for the equations listed in table 14, coupled with the lack of a verification data set, makes selection of the best equation for each technology group largely arbitrary. Lacking objective criteria to select a single best equation, we chose to use the average result obtained from all three equations.

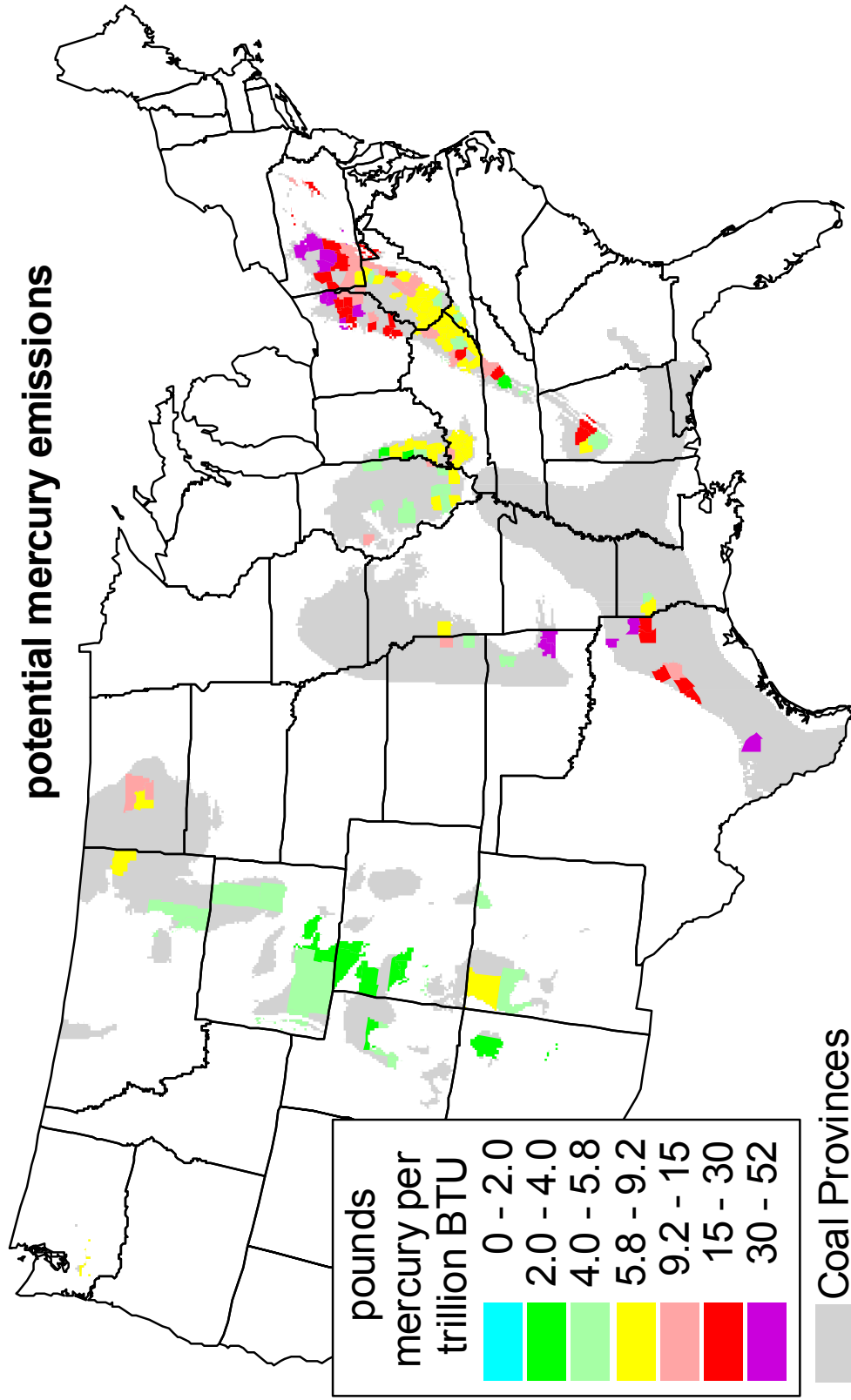
We applied all of the equations listed in table 14 to the county-average coal quality values from the ICR data set and averaged the result for each of the five technologies groups. The results are graphically compared in figure 26, and illustrated in figures 27 through 36.



**Figure 26.** Mercury capture predicted for 162 U.S. counties increases with increasing coal chlorine for five existing control technologies. Mercury capture is the average result of three equations for each control technology applied to county-average, ICR coal assay values. The equations are listed in table 14 (this report); county-average ICR assay values are listed the appendix.

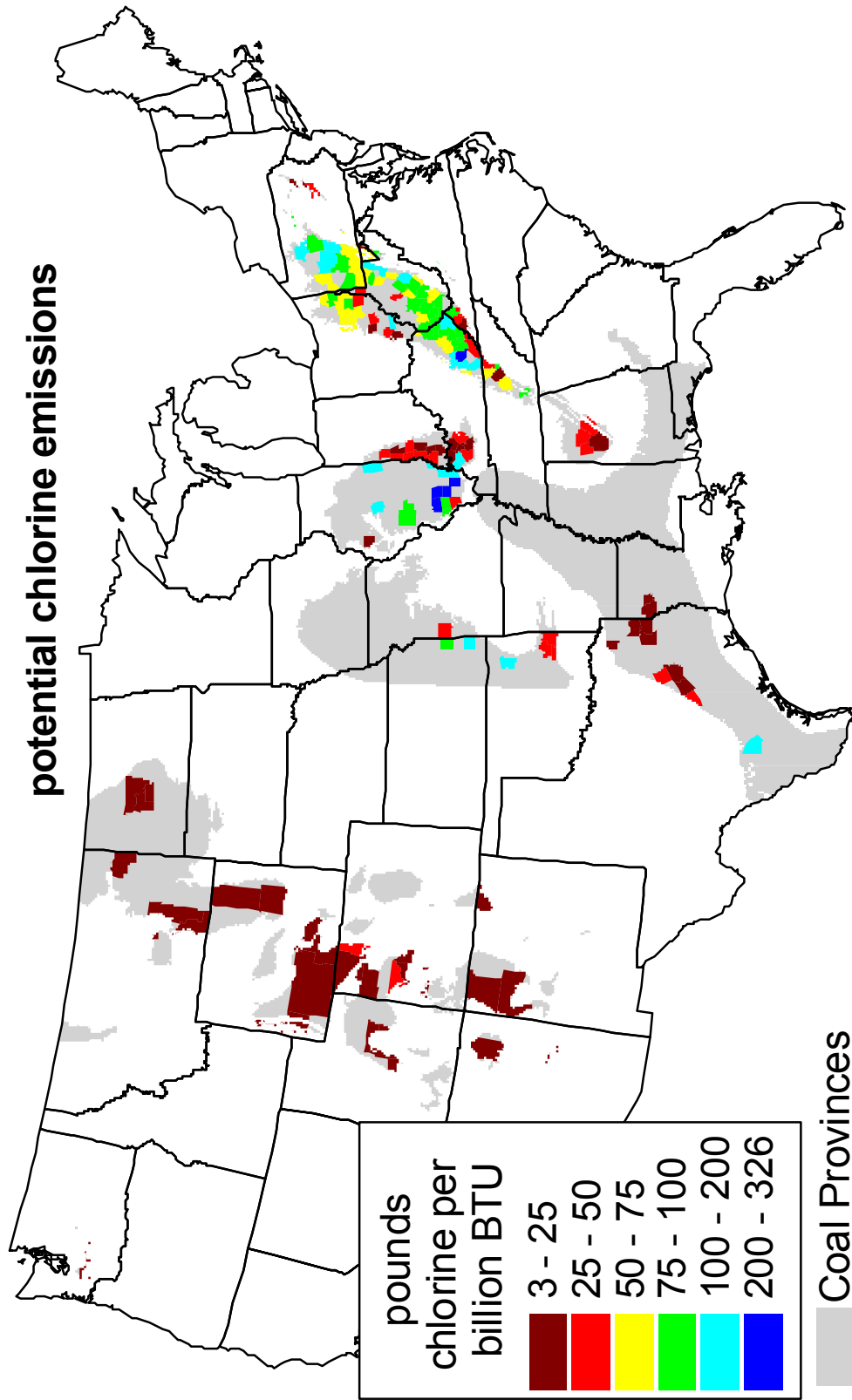


**Figure 27.** Potential uncontrolled sulfur emissions from coal (lbs S/10<sup>6</sup> Btu) by U.S. county-of-origin (county-average values calculated using selected ICR data).

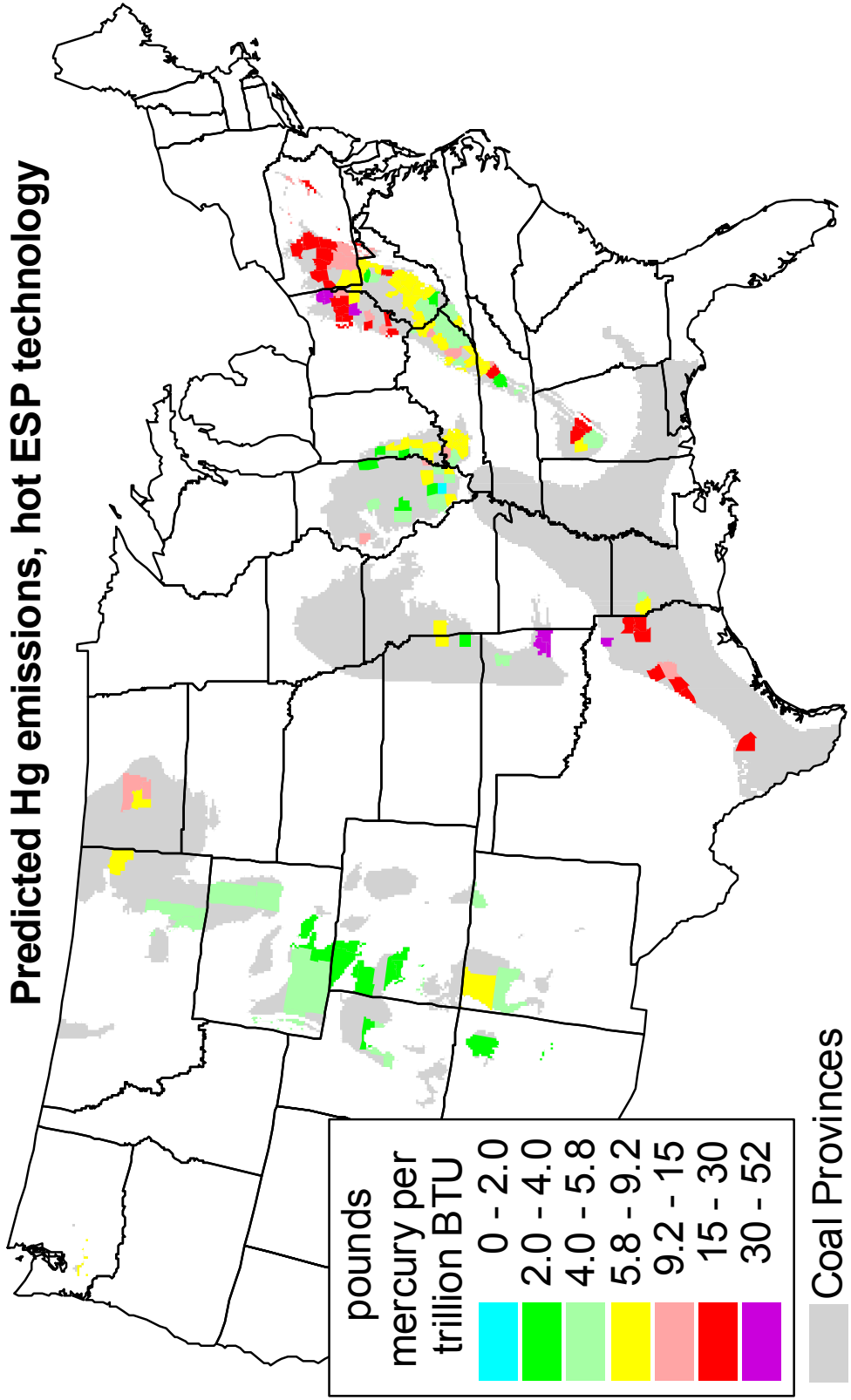


**Figure 28.** Potential uncontrolled mercury emissions from coal (lbs Hg/10<sup>12</sup> Btu) by U.S. county-of-origin (county-average values calculated using selected ICR data).



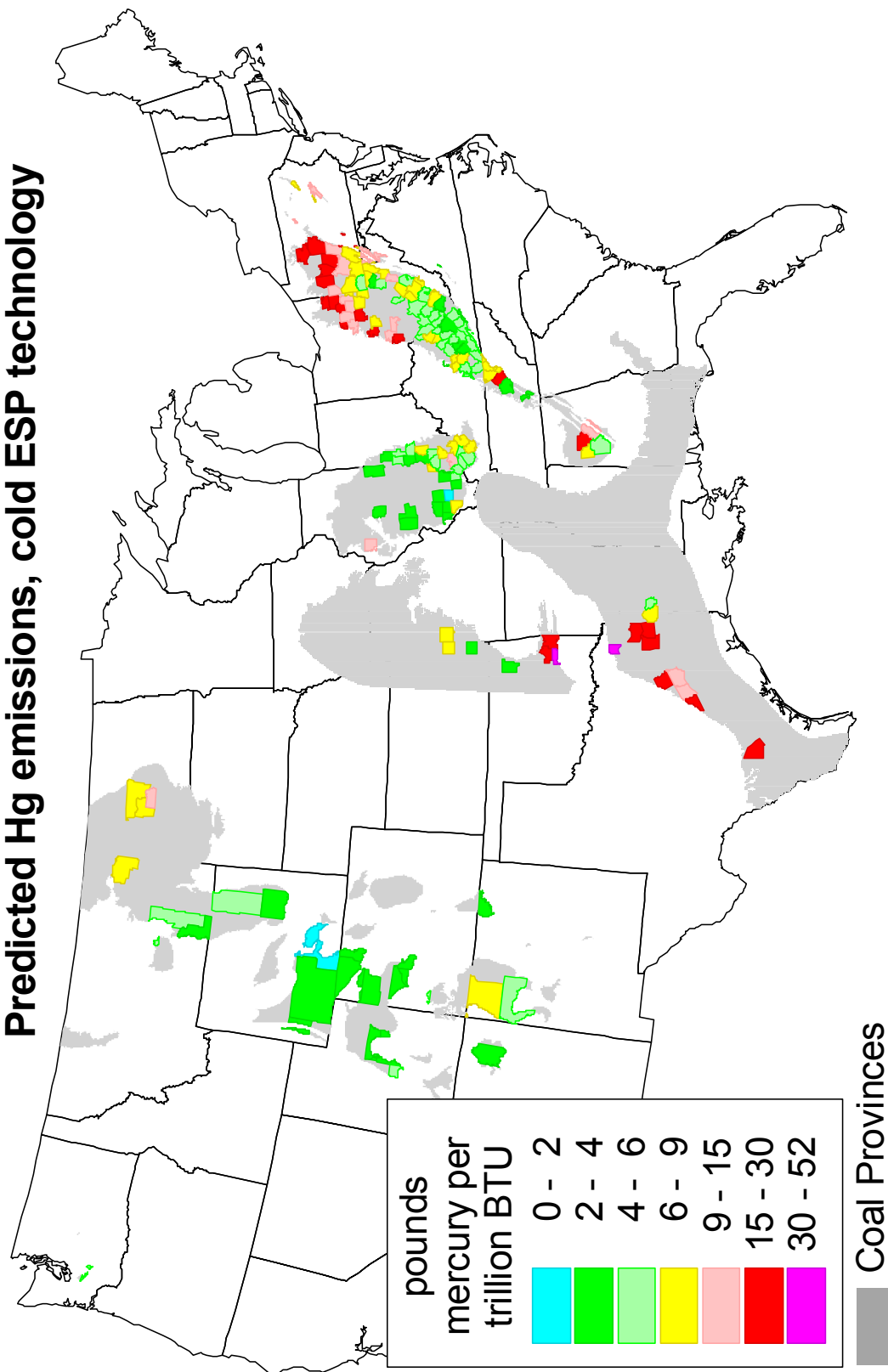


**Figure 29.** Potential uncontrolled chlorine emissions from coal (lbs Cl/10<sup>9</sup> Btu) by U.S. county-of-origin (county-average values calculated using selected ICR data).

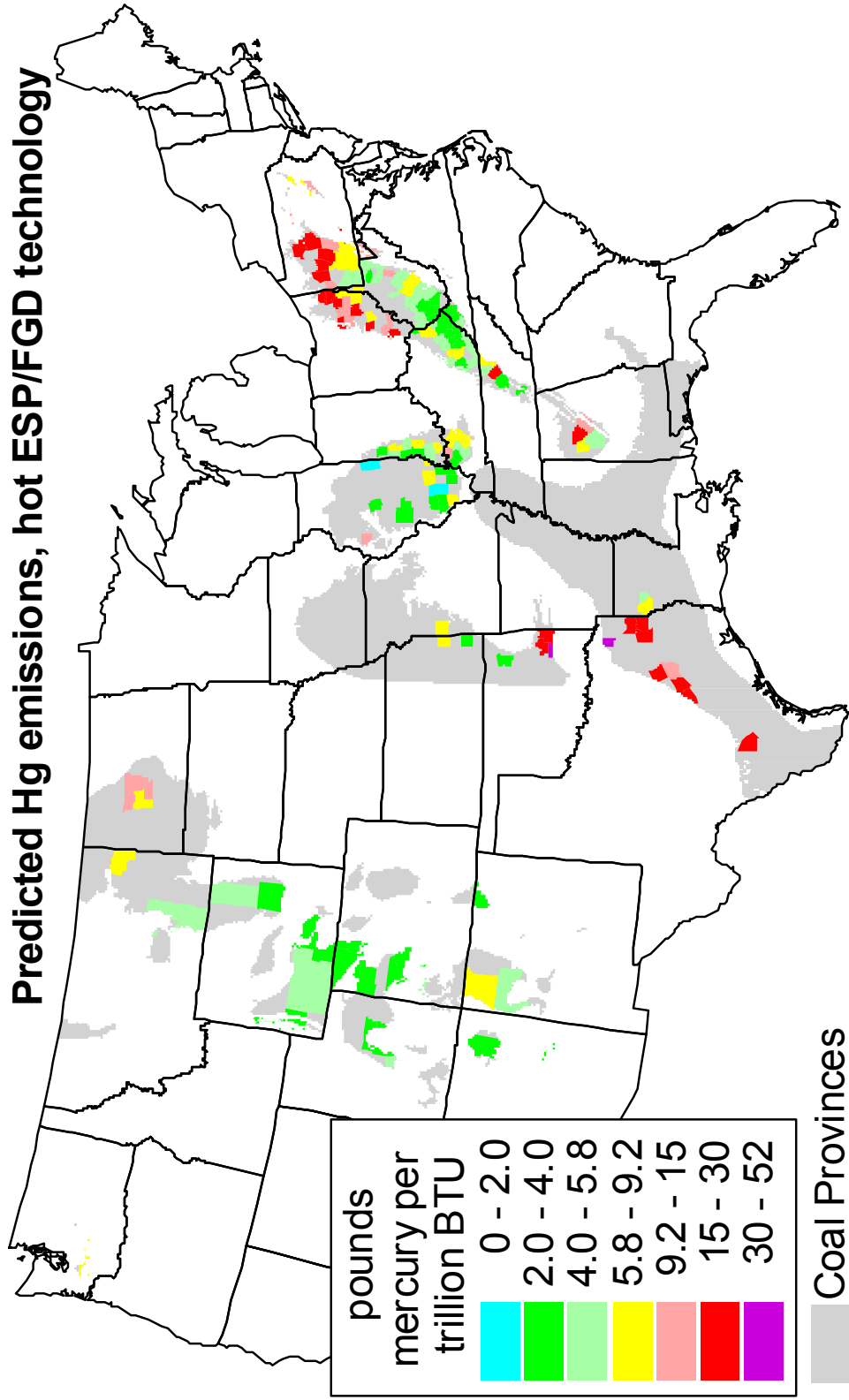


**Figure 30.** Predicted mercury emissions (lbs Hg/10<sup>12</sup> Btu) for coal burned in electric utilities with Hot-Side, Electrostatic Precipitators (hot ESP technology). Shown are county-average values calculated using selected ICR data and equations listed in table 14, this report.

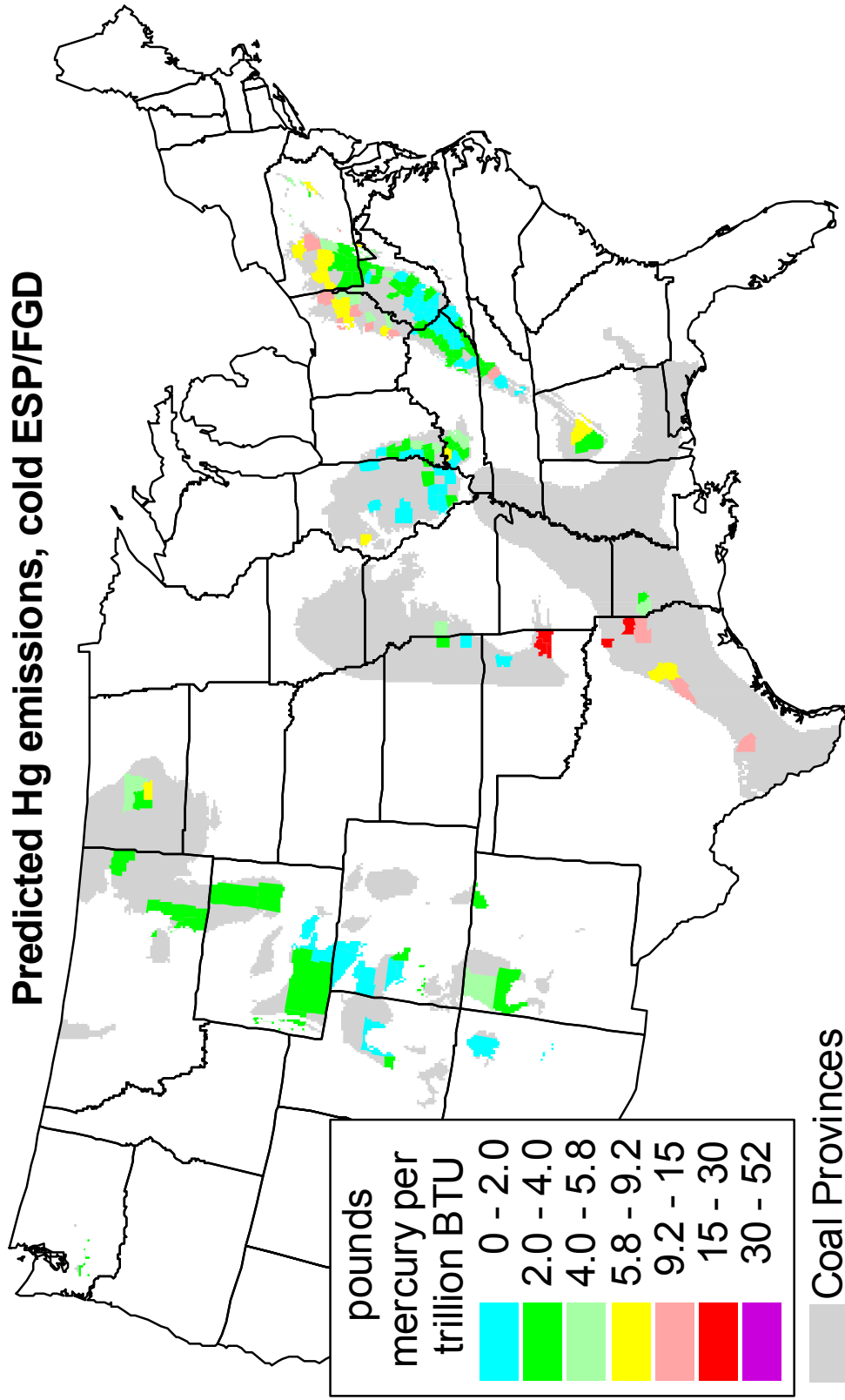
# Predicted Hg emissions, cold ESP technology



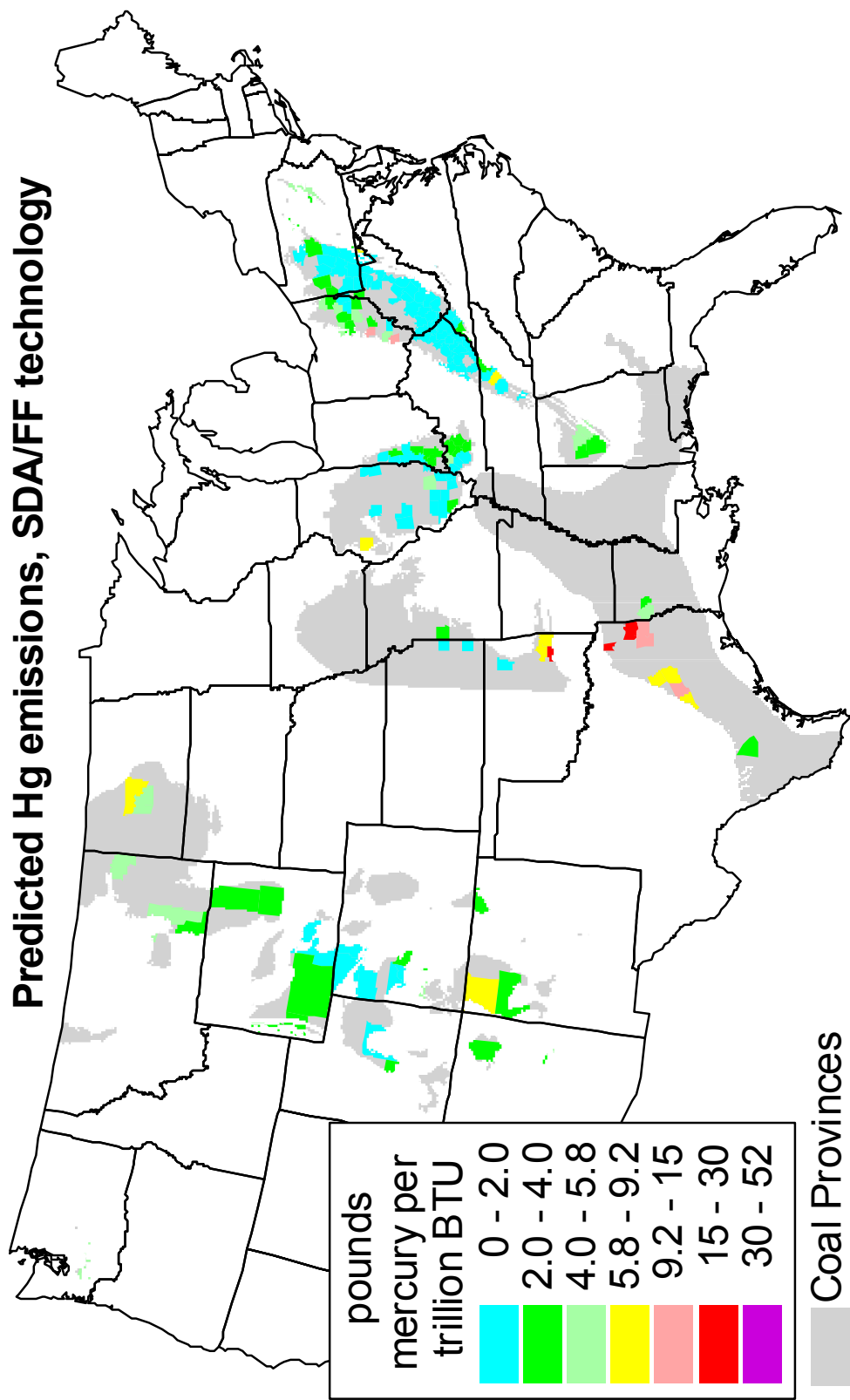
**Figure 31.** Predicted mercury emissions (lbs Hg/10<sup>12</sup> Btu) for coal burned in electric utilities with Cold-Side, Electrostatic Precipitators (cold ESP technology). Shown are county-average values calculated using selected ICR data and equations listed in table 14, this report.



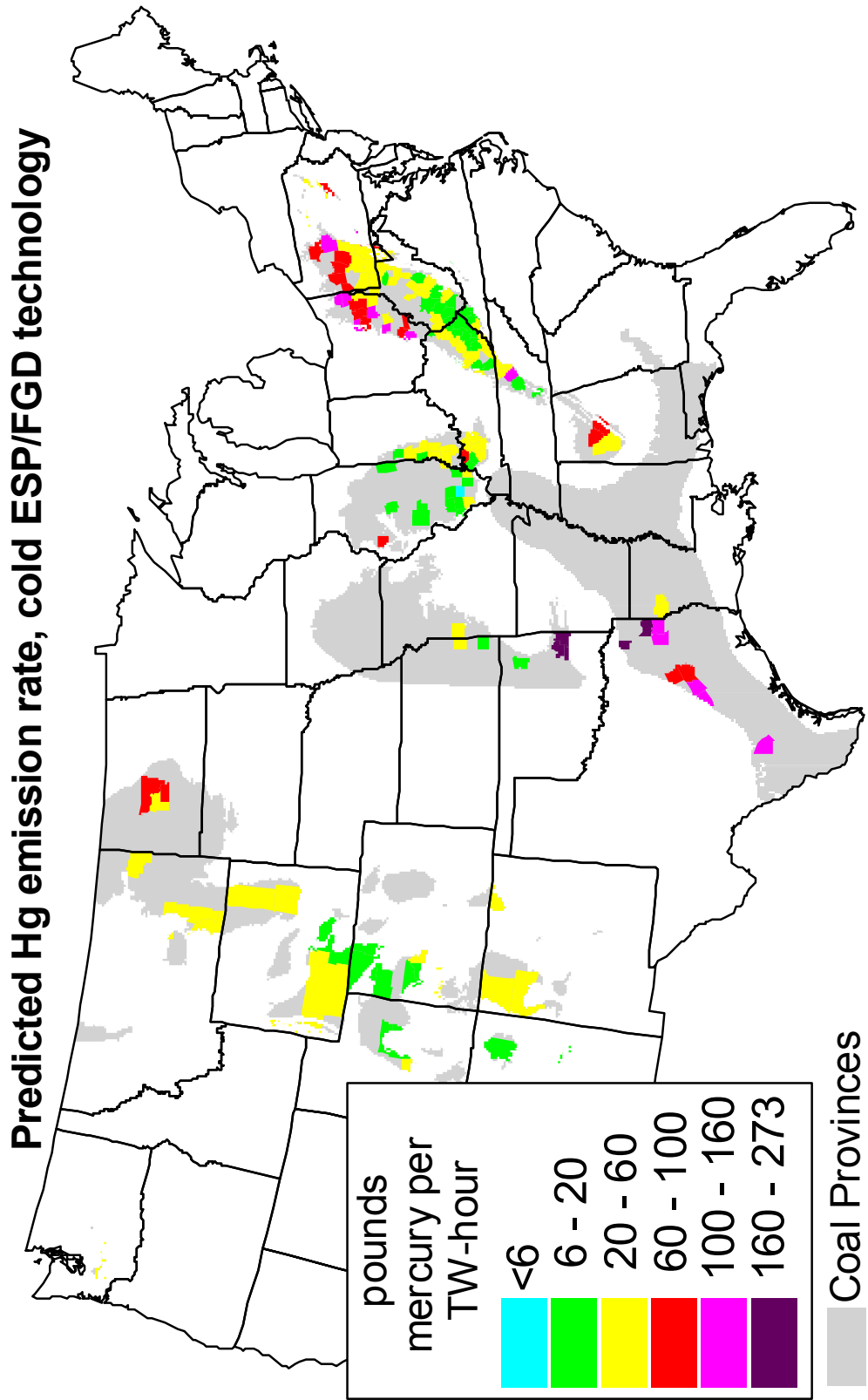
**Figure 32.** Predicted mercury emissions (lbs Hg/10<sup>12</sup> Btu) for coal burned in electric utilities with Hot-Side, Electrostatic Precipitators and wet Flue Gas Desulfurization controls (hot ESP/FGD technology). Shown are county-average values calculated using selected ICR data and equations listed in table 14, this report.



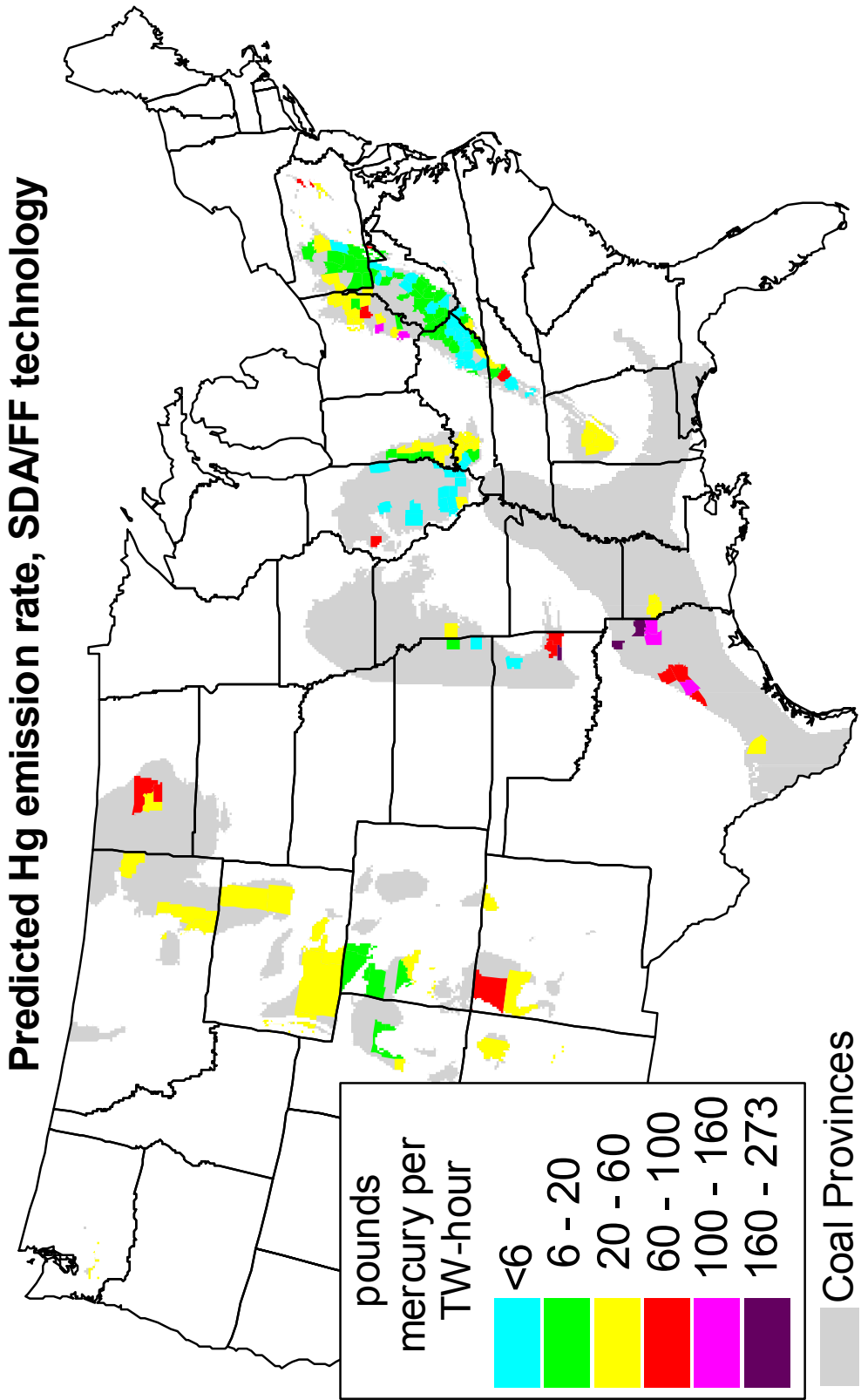
**Figure 33.** Predicted mercury emissions (lbs Hg/10<sup>12</sup> Btu) by U.S. county-of-origin for coal burned in electric utilities with Cold-Side, Electrostatic Precipitators and wet Flue Gas Desulfurization controls (cold ESP/FGD technology). Shown are county-average values calculated using selected ICR data and equations listed in table 14, this report.



**Figure 34.** Predicted mercury emissions (lbs Hg/10<sup>12</sup> Btu) by U.S. county-of-origin for coal burned in electric utilities with Spray-Dry Adsorption and Fabric Filter controls (SDA/FF technology). Shown are county-average values calculated using selected ICR data and equations listed in table 2, this report.



**Figure 35.** Predicted mercury emission rate (lbs Hg/terawatt-hour, which is the same as lbs Hg x 10<sup>-6</sup>/megawatt-hour) for coal burned in electric utilities with Cold-Side, Electrostatic Precipitators and wet Flue Gas Desulfurization controls (cold ESP/FGD technology). Shown are county-average values calculated using selected ICR data expressed on a net energy basis, a nominal heat rate of 35%, and equations listed in table 14, this report.



**Figure 36.** Predicted mercury emission rate (lbs Hg/terawatt-hour, which is the same as lbs Hg x 10<sup>-6</sup>/megawatt-hour) for coal burned in electric utilities with Spray-Dry Adsorption and Fabric Filter controls (SDA/FF technology). Shown are county-average values calculated using selected ICR data expressed on a net energy basis, a nominal heat rate of 35%, and equations listed in table 14, this report.



## Selecting the Best Equation to Predict Mercury Capture

Table 14 lists three equations that predict mercury capture for each of five different existing control technologies. As previously discussed, the equations were all derived by regression analysis on the ICR 3 stack emission data (USEPA, 2003), and use various measures of coal quality (chlorine, Btu/lb, and sulfur values) as independent variables. Although the technology-specific equations show similar correlations and trends (figures 21, 22, 23, 24, and 25), results sometimes differ when they are applied to the same county-average coal quality values. Lacking objective criteria to select a single best equation from those listed in table 14, we used the average result obtained from all three equations.

Clearly, our decision to use all three equations, rather than just one, could be considered arbitrary. However, using three equations should reduce extrapolation error when an equation is applied to assay values that are outside the range of ICR part 3 values that these regression equations were made from. For example, figure 25 shows that the different equations predict substantially different results for high-chlorine coal burned in units with hESP technology. With one exception (Cliffside unit 1), relatively low-chlorine coal was burned in ICR part 3 units equipped with this technology. Consequently, the validity of the hESP-specific equations is uncertain for high-chlorine coal. Nonetheless, given the divergent results for high-chlorine coal shown in figure 25, using the average result from all three equations clearly avoids large errors necessarily associated with at least one of the equations.

Admittedly, there are other useful and significant equations that are not included in table 14 (Chu and others, 2000; Laumb and others, 2000; AEMS, 2004). However, the selection of equations for table 14 was not wholly arbitrary. The selection was instead a compromise that required similar technology classes, and favored high  $r^2$  values, diverse authorship, and different

independent variables. Selecting three (rather than two, four, or more) equations for each technology group was likewise a compromise. This convention simplified spreadsheet calculations and allowed for the inclusion of convex, concave, and linear equation forms.

### **Comparison of Existing Technologies: Implications for Mercury Control**

Figure 26 compares the average technology-specific mercury capture calculated for 162 U.S. counties using the average result from the three equations listed in table 14 for each technology control class. Note that mercury capture increases as coal chlorine increases for each control technology. This trend is particularly noteworthy for SDA/FF and cESP/FGD technologies, where capture rapidly increases up to about 500 ppm chlorine, but only modestly increases above 1000 ppm chlorine. Thus, blending a low-chlorine coal with a high-chlorine coal to an optimum level between 500 and 1000 ppm chlorine, should result mercury capture for coal burned in units equipped with SDA/FF or cESP/FGD emission controls. Of course, mercury emissions will also depend on the total mercury content of the blended coal feedstock.

Units equipped with hESP/FGD, cESP, or hESP emission controls show relatively poor mercury capture. Absent effective mercury-specific controls, selection of lower mercury coal would be a good mercury reduction strategy for these units.

Weighting the county-specific results shown in figure 26 by county production tonnage allows calculation of the average mercury emissions, together with the average percent reduction, for each post-combustion technology. Likewise, the effectiveness of pre-combustion technology can be calculated by comparing in-ground coal mercury with commercially shipped coal mercury and weighting the results by county production. Table 15 shows the results of these calculations.

**Table 15. Comparison of mercury control technologies.**

	<u>Technology</u>	<u>Trillion Btu</u> <sup>1</sup>	<u>lbs Hg/10<sup>12</sup> Btu</u>	<u>% Mercury Reduction</u>
Pre-Combustion	None (In-ground coal, COALQUAL data) <sup>2</sup>	—	~ 11.0	—
	Counties with no mercury reduction (ICR data)	5,931	11.2	—
	Washing/Mining Practice (ICR data) <sup>3</sup>	11,335	6.3	~ 57%
	No data (counties without COALQUAL or ICR data)	1,809	?	?
Post-Combustion	None (delivered coal)	19,047	8.3	—
	hESP	1,769	7.5	9%
	cESP	10,260	6.4	23%
	hESP/FGD	565	6.2	25%
	cESP/FGD	3,579	3.4	59%
	SDA/FF	511	3.1	63%

<sup>1</sup> Amount of coal, expressed as coal Btu content; post-combustion values from Chu and others (2000).

<sup>2</sup> The 11 lb Hg/10<sup>12</sup> Btu value for the total U.S. in-ground coal resource was calculated using state-average COALQUAL Hg values, and weighting by estimated coal resource (tonnage) values from the USEIA (2005) 1997 vintage, demonstrated reserve base. This value (and the derived 57% mercury reduction due to washing and mining practice) will likely change when the demonstrated reserve base estimate is updated.

<sup>3</sup> Counties where the mercury content of the in-ground coal is more than 2 lbs Hg/10<sup>12</sup> Btu greater than the mercury content of commercial coal shipped from that county.

Several caveats apply to table 15. First, mercury reductions listed for cESP/FGD and SDA/FF technologies are likely minimum values because they indicate the fractional emissions expected if all U.S. coal were burned in these technology classes, rather than the coals that are currently burned. Many of these units burn coal blends originating from several counties. As noted above, the optimal mercury capture for these technologies occurs where the coal contains between 500 and 1000 ppm chlorine. Given that the tonnage-weighted average chlorine content of U.S. coal is ~530 ppm, coal blends are more likely to approach this optimal value than single-sourced coal.

Table 15 shows that in-ground U.S. coal contains about 11 lbs Hg/10<sup>12</sup> Btu. This value is less certain than the mercury content of coal delivered to power plants during 1999 included in the ICR data set. For example, weighting COALQUAL mercury values aggregated by U.S. state (excluding Alaska), by the USEIA (2005) Demonstrated Reserve Base tonnage estimates for these states shows an average 10.8 lbs Hg/10<sup>12</sup> Btu. However, where average COALQUAL mercury values for counties listed in the ICR data set are weighted by coal production tonnage, the result is 11 lbs Hg/10<sup>12</sup> Btu.

Another limitation of values listed in table 15 relates to the likely co-reduction of coal sulfur due to coal mining and coal washing practice. As noted below, coal sulfur decreases post-combustion mercury capture. Consequently, the technology-specific, post-combustion mercury reductions listed in table 15 may increase if the sulfur content of commercial U.S. coal continues to decline (Quick and others, 2003).

### **The Relationship Between Coal Sulfur and Mercury Capture**

Figure 26 shows that mercury emissions from SDA/FF controls are exclusively correlated with chlorine whereas mercury emissions predicted for the other technologies are more variable. The scatter shown in figure 26 for cESP/FGD, hESP/FGD, cESP, and hESP technologies is attributed to coal sulfur, which is a factor in one or more of the respective equations for these technologies (table 14), but not used in the SDA/FF equations. Notably, in every equation where sulfur is an independent variable (table 14), mercury capture is predicted to decline with increasing coal sulfur.

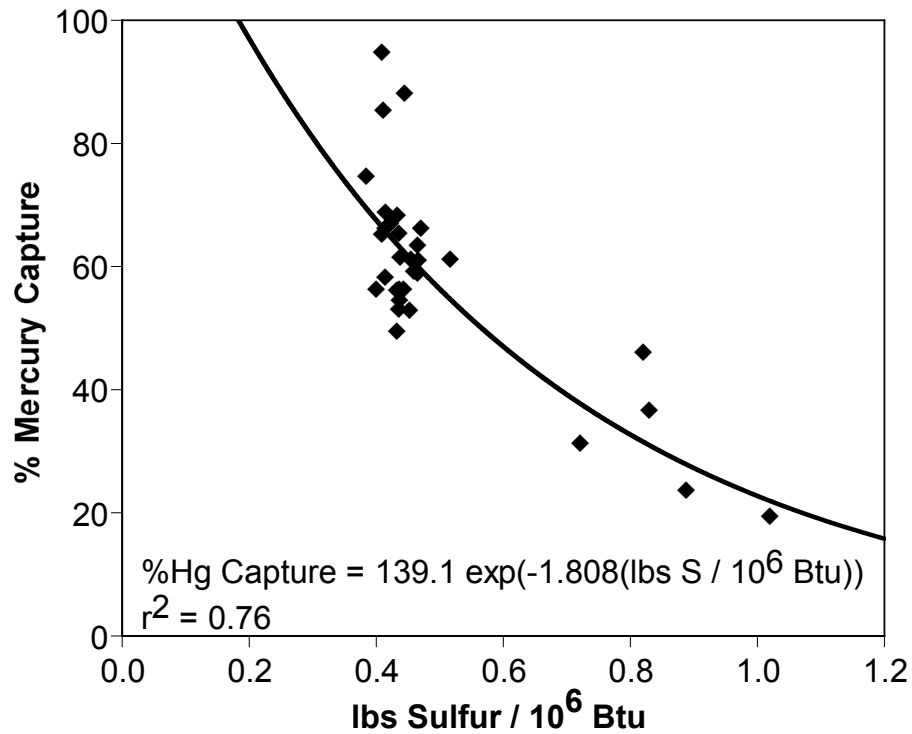
The equations listed in table 14 clearly show the consistently negative effect of coal sulfur on mercury capture. The explanation for this effect is less obvious. Hocquel and others (2001) offered two explanations for the negative effect of sulfur on mercury capture; both reduce

the amount of  $\text{Cl}_2$  available for mercury oxidation. The first inhibits the heterogeneous conversion of  $\text{HCl}$  to reactive  $\text{Cl}_2$  by sulfation of metal oxides that would otherwise catalyze this conversion. The second indicates that gaseous  $\text{SO}_2$  in the presence of water vapor can homogeneously reduce  $\text{Cl}_2$  to less-reactive  $\text{HCl}$  and by-product  $\text{SO}_3$ . A mechanistic model for mercury capture by fly-ash carbon (Olson and others 2003) suggests that sulfuric acid (from oxidation of flue-gas  $\text{SO}_2$ ) limits mercury capture by filling Hg binding/reaction sites on the carbon surface.

Alternately, the negative effect of coal sulfur on mercury capture may simply relate to higher flue-gas temperatures required to avoid corrosion of the ductwork from  $\text{H}_2\text{SO}_4$  when burning high-sulfur coal. Meij and others (2002) attributed the greater mercury capture by ESP controls on power plants in the Netherlands, compared to those in Germany and the U.S., to lower flue-gas ESP temperatures in the Netherlands power plants ( $\sim 120^\circ\text{C}$ ), which burn comparatively low-sulfur coal. The median temperature for cold-side ESP units included in the ICR part 3 data set of U.S. power plants is about  $160^\circ\text{C}$ , whereas Meij and others (2002) suggested that oxidized mercury, present as  $\text{HgCl}_2$ , does not condense on fly ash above about  $140^\circ\text{C}$ .

Empirical data from Canadian Electricity Association members (CEA, 2004) also show a negative correlation between coal sulfur on mercury capture. The relationship (figure 37) is strongest where fly-ash carbon exceeds five percent (and chlorine is coincidentally high). This relationship is consistent with the mechanistic model suggested by Olson and others (2003) where sulfur fills reactive sites on fly-ash carbon. Their explanation may also explain why sulfur is not a significant predictor of mercury capture for units equipped with SDA/FF technology; in this instance, gaseous flue-gas sulfur is converted to a non-reactive solid (sulfate) before it

arrives at the particulate filter, where effective mercury capture by fly-ash carbon presumably occurs.



**Figure 37.** Decreasing mercury capture with increasing coal sulfur. Data points show weekly averages (CEA, 2004) observed for two units equipped with cESP emission controls where fly-ash carbon exceeds 5% (average 11%). Mercury capture was estimated after Meij and others (2002) using coal and fly-ash mercury values, and assuming an 80:20, fly ash:bottom ash fractionation. Two data points greater than 100% capture are not shown.

In this section we have suggested that mercury capture by carbon in fly ash may be improved by reducing the amount of sulfur in the feed coal. This effect complements the likely reduction of mercury in the coal when the sulfur content of coal is reduced (Quick and others, 2003). Thus, selection of low-sulfur coal has two likely effects: (1) reducing the amount of mercury in the feed coal, and (2) improving post-combustion mercury capture.

## **In-Ground Coal Mercury Compared to Commercial Coal Mercury**

Direct comparison of COALQUAL data records (in-ground coal) with ICR data records (commercial coal) showed that coal delivered to utilities during 1999 has about half as much mercury as the in-ground coal resource (Quick and others, 2003). This difference was attributed to preferential mining of relatively low-mercury coal, and coal washing. Toole-O'Neil and others (1999) noted that washing reduces coal mercury levels by about 35%. Restricting the comparison to counties where both COALQUAL and ICR data are available, and weighting the county-average mercury values by coal production tonnage, shows that the in-ground coal resource averages about 11 lbs Hg/10<sup>12</sup> Btu, whereas commercial coal deliveries during 1999 averaged about 8.3 lbs Hg/10<sup>12</sup> Btu. Perhaps more significantly, this difference is not geographically uniform. For example, figure 19 shows that coal produced from the northern Appalachians and Gulf Coast regions typically has more mercury than expected from the mercury content of the in-ground coal. The reason for these increased mercury levels is uncertain. Possibly, the increased mercury levels result from dilution of mined coal with either surrounding, high-mercury country rock or included, high-mercury rock partings. If so, coal washing or selective mining might be effective mercury reduction strategies in these areas.

Areas where mined coal contains more mercury than the in-ground coal may be good places to consider pre-combustion mercury reduction strategies. Comparing the mercury content of mined coal with the mercury content of in-ground coal has more immediate significance because it shows the significance of pre-combustion mercury reduction strategies (selective mining and coal washing). Indeed, the mercury content of U.S. coal delivered to the power plant during 1999 contained, on average, 2.8 lbs Hg/10<sup>12</sup> Btu less mercury than the in-ground coal resource. This 25% mercury reduction is significant.

## CONCLUSIONS

- Selection of coal with low mercury content may be an effective control strategy for units equipped with hESP/FGD, cESP, or hESP controls, whereas selection of high-chlorine coal is indicated for units with cESP/FGD or SDA/FF controls.
- Blending to an optimum level between 500 and 1000 ppm chlorine may be an effective mercury control strategy for units equipped with SDA/FF or cESP/FGD controls.
- Flue-gas sulfur may reduce mercury capture by carbon in fly ash.
- Coal washing or selective mining might be an effective mercury reduction strategy, especially for coals from the northern Appalachians or Gulf Coast.



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## Appendix A

### Calculation and significance of the Mott-Spooner value

The Mott-Spooner value is the heating value (Btu/lb) calculated from the elemental composition of the coal. The difference between the calculated and the measured Btu/lb value ( $\text{Btu/lb}_{\text{measured}} - \text{Btu/lb}_{\text{calculated}}$ ) is called the Mott-Spooner difference, and is useful to identify erroneous data (sources of error include data entry mistakes, assay errors, or inconsistent reporting bases). We calculated Mott-Spooner difference values to evaluate the suitability of the COALQUAL data for estimation of coal hydrogen values. Coal hydrogen values are required to calculate net specific energy values.

Although numerous equations can be used to calculate the heating value from elemental composition (Neavel and others, 1986) we use equations listed by Mott and Spooner (1940). For higher rank coals with less than 15% oxygen, the coal heating value is calculated as:

$$\text{Btu} / \text{lb}_{\text{daf}} = 144.5 H_{\text{daf}} + 40.5 S_{\text{daf}} - 62.5 O_{\text{daf}} .$$

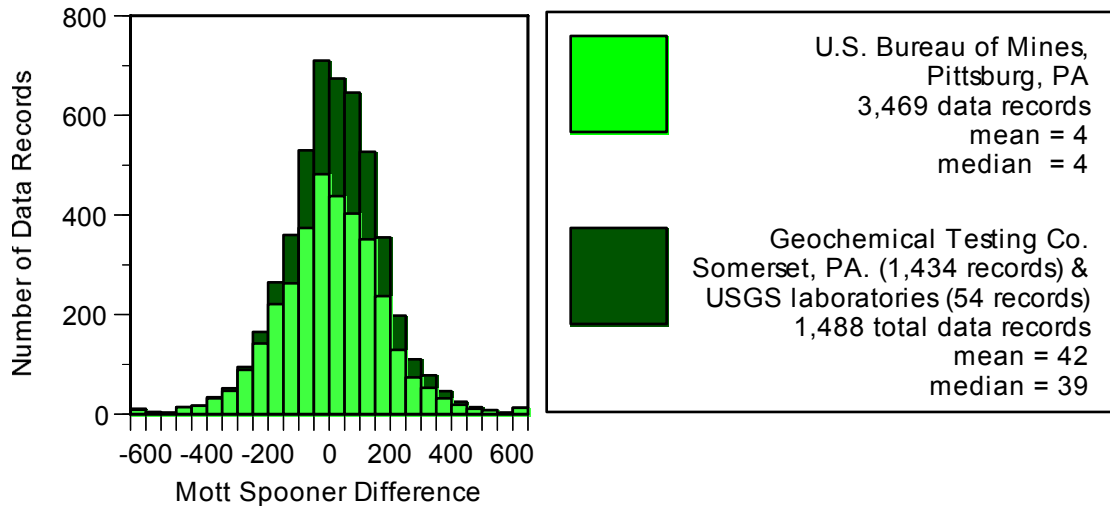
For lower rank coals with more than 15% oxygen, the equation is:

$$\text{Btu} / \text{lb}_{\text{daf}} = 144.5 C_{\text{daf}} + 610.2 H_{\text{daf}} + 40.5 S_{\text{daf}} - 65.9 O_{\text{daf}} + 0.310 (O_{\text{daf}})^2 .$$

The variables in these equations are expressed on a dry, ash-free (daf) basis, where C is weight percent carbon, H is weight percent hydrogen, S is weight percent total sulfur, and O is weight percent oxygen calculated as:  $O_{\text{daf}} = 100 - C_{\text{daf}} - H_{\text{daf}} - S_{\text{daf}}$ . Because hydrogen in the COALQUAL data includes the hydrogen in moisture, the contribution of moisture to the hydrogen value is stoichiometrically calculated ( $\text{moisture} \times 0.1119$ ) and subtracted from the reported hydrogen value, before calculation to a dry, ash-free basis.



Mott Spooner values are calculated for 98% of the 5059 selected COALQUAL data records; values cannot be calculated for 2% of the records because they lack elemental data. Mott-Spooner values for fifteen data records exceed  $\pm 1000$  Btu/lb and are ignored, as are four records with relatively high (positive) Mott-Spooner values reported by a single laboratory. The distribution of Mott-Spooner values for the remaining 4961 data records is shown in figure A1.



**Figure A1.** The distribution of Mott-Spooner difference values for 4957 selected COALQUAL data records is negligibly skewed about a mean near zero. A slight difference is observed between analytical laboratories.

The data in figure A1 are normally distributed about a median value of +15 Btu/lb. This trivial, positive value appears to be partly due to a difference between analytical laboratories illustrated in the figure. However, provincial variation of Mott-Spooner difference values shown in table A1 may also contribute to the slightly positive value. More remarkable, is that the mean Mott-Spooner difference for data from the U.S. Bureau of Mines laboratory is only +4 Btu/lb, which is essentially zero.

**Table A1.** Provincial variation of Mott-Spooner difference values in the COALQUAL data.

Province	Eastern	Interior	Gulf	Rocky Mountain	Northern Great Plains <sup>1</sup>
Number of Records	3071	471	91	755	573
Average Mott-Spooner Difference	3	22	1	40	49
Median Mott-Spooner Difference	1	26	-9	54	64

<sup>1</sup> includes four records from the Pacific province.

Mott and Spooner (1940) stated that the difference between the calculated and the measured heating value should be within  $\pm 100$  Btu/lb; if not, they suggested that the results of the elemental analysis should be suspected and repeated. Given and others (1986) argued that no precise limits of acceptability can be stated, but that the data are probably wrong if the difference exceeds  $\pm 250$  Btu/lb. About 11% of the records shown in figure A1 exceed this threshold; 230 records have Mott-Spooner values  $< 250$  Btu/lb, and 296 records have Mott-Spooner values  $> 250$  Btu/lb.

## Appendix B

### Summary of ICR data

<u>Coal Origin, Assay Frequency, and Production</u>				<u>Average Assay Values</u>							<u>Mercury Capture (100% capture = 1)</u>			
State	County	Count	Tons	Btu (moist)	%Ash (moist)	%Sulfur (moist)	%Moisture	Cl ppm (dry)	Hg ppm (dry)	hESP	cESP	hESP /FGD	cESP /FGD	SDA /FF
Alabama	Fayette	25	1,603,575	12,028	12.5	1.7	7.1	358	0.099	0.04	0.20	0.19	0.55	0.67
Alabama	Jefferson	113	6,872,058	12,257	12.7	1.3	6.6	374	0.217	0.04	0.22	0.22	0.58	0.68
Alabama	Tuscaloosa	64	3,630,889	12,558	12.1	0.8	7.5	204	0.068	0.02	0.17	0.14	0.52	0.51
Alabama	Walker	46	1,077,252	11,904	13.7	1.8	6.2	517	0.267	0.07	0.24	0.27	0.60	0.76
Arizona	Navajo	98	12,621,600	10,495	8.4	0.5	14.7	101	0.038	0.02	0.11	0.06	0.44	0.27
Colorado	Delta	34	1,152,040	12,052	7.0	0.4	8.4	99	0.035	0.02	0.12	0.08	0.46	0.24
Colorado	Gunnison	194	5,637,241	11,736	8.9	0.5	8.8	102	0.049	0.02	0.11	0.06	0.44	0.26
Colorado	Mesa	39	625,837	11,238	12.8	0.5	9.1	567	0.039	0.12	0.31	0.36	0.72	0.78
Colorado	Moffat	173	6,606,747	10,326	5.9	0.4	17.1	186	0.031	0.02	0.19	0.17	0.56	0.49
Colorado	Montrose	46	359,400	10,783	19.9	0.8	5.8	70	0.061	0.02	0.07	0.04	0.37	0.13
Colorado	Rio Blanco	53	1,221,660	10,152	11.2	0.4	13.1	174	0.038	0.02	0.18	0.17	0.55	0.48
Colorado	Routt	238	8,506,600	11,101	9.1	0.5	11.1	331	0.038	0.06	0.25	0.27	0.65	0.65
Illinois	Franklin	44	133,576	11,790	5.8	0.9	13.5	4,446	0.060	0.55	0.60	0.71	0.87	0.98
Illinois	Gallatin	220	3,542,050	12,663	9.3	2.8	6.8	1,847	0.109	0.25	0.40	0.50	0.76	0.98
Illinois	Jackson	47	426,412	11,165	10.1	2.7	12.4	427	0.105	0.05	0.20	0.19	0.54	0.72
Illinois	Jefferson	139	3,353,496	12,008	6.2	1.2	11.3	3,960	0.071	0.49	0.57	0.69	0.87	0.98
Illinois	Logan	130	1,720,958	10,451	9.0	3.0	17.3	1,662	0.074	0.22	0.38	0.47	0.73	0.98
Illinois	Macoupin	192	3,562,497	10,629	8.1	2.3	16.9	1,143	0.064	0.16	0.33	0.40	0.69	0.92
Illinois	McDonough	3	67,383	12,128	5.7	2.8	11.7	209	0.193	0.02	0.12	0.10	0.45	0.51
Illinois	Montgomery	54	421,800	10,674	8.6	1.2	16.0	1,205	0.058	0.20	0.37	0.46	0.76	0.93
Illinois	Perry	187	4,261,814	11,031	9.7	2.7	12.9	1,186	0.062	0.17	0.33	0.40	0.69	0.93
Illinois	Randolph	295	139,091	10,908	10.4	3.0	12.7	1,060	0.063	0.15	0.32	0.38	0.67	0.91
Illinois	Saline	331	8,994,720	12,175	8.5	1.8	9.2	3,088	0.101	0.39	0.51	0.63	0.85	0.98

Illinois	Vermillion	74	581,427	10,849	8.8	1.3	16.1	2,561	0.054	0.36	0.49	0.61	0.84	0.98
Illinois	Wabash	54	1,274,002	11,006	10.5	1.5	13.4	1,804	0.164	0.27	0.42	0.53	0.80	0.98
Illinois	Washington	9	3,151,783	11,375	5.4	1.2	17.0	4091	0.112	0.50	0.57	0.69	0.86	0.98
Illinois	White	56	2,525,550	11,807	7.5	3.0	10.9	1,383	0.076	0.19	0.35	0.43	0.71	0.95
Indiana	Clay	4	90,700	10,429	14.7	2.2	12.9	275	0.082	0.03	0.16	0.15	0.50	0.61
Indiana	Daviess	46	3,102,043	11,318	8.8	2.6	13.5	227	0.111	0.02	0.13	0.12	0.46	0.54
Indiana	Gibson	113	7,783,831	11,210	9.0	2.2	13.5	346	0.082	0.04	0.18	0.17	0.52	0.66
Indiana	Greene	114	4,466,450	11,063	9.2	1.9	15.0	415	0.085	0.05	0.21	0.20	0.55	0.71
Indiana	Knox	259	2,924,700	11,196	8.7	1.5	14.3	416	0.062	0.05	0.22	0.23	0.58	0.71
Indiana	Parke	46	111,200	11,986	6.5	2.1	11.7	463	0.055	0.06	0.22	0.22	0.57	0.73
Indiana	Pike	161	4,334,497	11,397	9.3	3.1	12.1	230	0.084	0.02	0.13	0.12	0.46	0.55
Indiana	Sullivan	205	1,390,500	10,891	9.2	1.4	15.8	379	0.052	0.04	0.21	0.21	0.56	0.68
Indiana	Vigo	184	3,552,700	10,345	10.5	1.1	17.3	451	0.076	0.06	0.24	0.27	0.61	0.73
Indiana	Warrick	157	3,360,169	11,126	10.1	3.4	12.7	255	0.099	0.03	0.13	0.13	0.47	0.58
Kansas	Crawford	86	0	11,815	13.1	3.3	7.6	1,813	0.066	0.24	0.40	0.49	0.74	0.98
Kansas	Linn	38	402,404	10,952	19.5	4.1	6.9	904	0.125	0.13	0.29	0.33	0.62	0.88
Kentucky	Bell	102	2,682,928	12,635	9.2	1.3	6.0	432	0.096	0.05	0.23	0.25	0.60	0.72
Kentucky	Boyd	16	434,400	12,306	10.8	0.9	7.4	748	0.081	0.14	0.32	0.38	0.73	0.84
Kentucky	Breathitt	200	998,449	11,965	10.2	1.1	8.9	829	0.103	0.14	0.32	0.38	0.72	0.86
Kentucky	Clay	22	538,378	12,399	9.8	1.4	7.6	2,800	0.219	0.39	0.50	0.62	0.84	0.98
Kentucky	Daviess	46	762,970	11,214	9.1	2.8	13.4	204	0.089	0.02	0.12	0.11	0.45	0.51
Kentucky	Estill	5	35,000	12,774	7.3	0.9	7.5	926	0.053	0.17	0.34	0.41	0.75	0.88
Kentucky	Floyd	233	4,572,011	12,194	10.9	1.0	6.9	1,291	0.093	0.23	0.39	0.48	0.79	0.94
Kentucky	Harlan	267	8,615,558	12,814	8.4	1.1	6.4	435	0.084	0.05	0.24	0.26	0.62	0.72
Kentucky	Henderson	108	1,740,717	10,601	13.0	3.4	12.6	231	0.143	0.03	0.12	0.13	0.46	0.56
Kentucky	Hopkins	230	4,878,580	11,466	12.0	2.8	9.5	531	0.087	0.07	0.23	0.23	0.57	0.77
Kentucky	Jackson	3	4,000	12,169	10.5	1.7	7.4	1,871	0.160	0.28	0.43	0.53	0.80	0.98
Kentucky	Johnson	76	1,692,200	12,107	10.5	1.3	6.9	1,049	0.155	0.17	0.35	0.42	0.74	0.91
Kentucky	Knott	412	6,317,410	12,685	8.7	1.1	6.6	1,264	0.093	0.22	0.38	0.46	0.78	0.94
Kentucky	Laurel	8	3,600	11,687	12.4	1.0	9.2	1,971	0.096	0.33	0.46	0.57	0.82	0.98
Kentucky	Lawrence	92	744,800	12,272	9.2	1.0	8.0	1,180	0.144	0.21	0.37	0.46	0.78	0.93
Kentucky	Leslie	206	3,268,782	12,640	8.8	1.1	6.8	1,229	0.074	0.21	0.37	0.46	0.77	0.94
Kentucky	Letcher	313	5,571,516	12,828	8.2	1.2	6.2	1,137	0.094	0.20	0.36	0.44	0.76	0.92

Kentucky	Magoffin	40	624,977	12,266	10.4	1.3	7.4	857	0.100	0.14	0.32	0.38	0.71	0.87
Kentucky	Martin	266	8,973,877	12,125	11.0	0.9	6.4	1,011	0.105	0.19	0.36	0.44	0.77	0.90
Kentucky	McLean	16	109,700	10,377	15.7	3.3	12.4	285	0.079	0.03	0.15	0.16	0.48	0.62
Kentucky	Muhlenberg	55	2,406,040	10,804	14.6	3.2	10.6	261	0.103	0.03	0.14	0.14	0.47	0.59
Kentucky	Ohio	3	114,910	11,045	12.0	3.5	11.6	343	0.110	0.04	0.17	0.17	0.50	0.66
Kentucky	Owsley	23	14,000	12,374	9.6	1.8	6.4	1,949	0.171	0.28	0.43	0.54	0.80	0.98
Kentucky	Perry	542	14,449,505	12,321	10.4	0.9	6.6	1,024	0.071	0.19	0.36	0.44	0.76	0.90
Kentucky	Pike	847	21,071,801	12,651	9.3	0.8	6.5	1,375	0.088	0.26	0.40	0.50	0.80	0.95
Kentucky	Pulaski	10	339,000	12,500	10.0	1.3	6.8	1,005	0.109	0.17	0.34	0.41	0.74	0.90
Kentucky	Union	225	8,861,664	12,059	9.5	2.5	8.9	1,786	0.093	0.25	0.40	0.50	0.77	0.98
Kentucky	Webster	153	6,295,809	12,236	10.3	2.7	6.8	1,821	0.099	0.25	0.40	0.50	0.76	0.98
Kentucky	Whitley	24	224,607	12,190	9.8	1.2	7.6	1,533	0.112	0.25	0.41	0.50	0.79	0.97
Louisiana	De Soto	59	2,105,000	6,936	12.0	0.9	33.5	155	0.093	0.02	0.13	0.10	0.46	0.46
Louisiana	Red River	38	705,000	7,117	12.3	0.7	32.5	161	0.059	0.02	0.14	0.10	0.48	0.47
Maryland	Allegany	29	85,414	11,608	18.5	1.7	4.9	162	0.200	0.02	0.12	0.09	0.44	0.45
Maryland	Garrett	116	3,053,274	12,442	14.3	1.7	5.6	943	0.202	0.14	0.32	0.38	0.70	0.89
Missouri	Bates	30	127,565	10,598	17.2	3.7	10.5	391	0.100	0.05	0.18	0.19	0.52	0.70
Montana	Big Horn	452	23,552,836	9,234	5.1	0.4	24.9	84	0.052	0.02	0.09	0.04	0.41	0.19
Montana	Richland	28	215,300	6,770	7.6	0.5	36.7	200	0.092	0.03	0.18	0.17	0.53	0.53
Montana	Rosebud	35	12,695,800	8,726	8.1	0.7	26.7	38	0.065	0.02	0.04	0.03	0.28	0.10
New Mexico	Colfax	7	472,300	11,962	14.9	0.6	4.7	134	0.055	0.02	0.14	0.09	0.48	0.38
New Mexico	McKinley	206	11,539,043	9,621	15.5	0.6	14.8	157	0.065	0.02	0.15	0.12	0.50	0.45
New Mexico	San Juan	101	15,133,000	9,090	23.8	0.8	10.5	80	0.087	0.02	0.07	0.04	0.39	0.23
North Dakota	McLean	45	7,150,000	6,181	11.4	0.7	37.6	114	0.098	0.02	0.11	0.07	0.43	0.37
North Dakota	Mercer	255	11,159,500	6,703	8.0	0.7	37.0	119	0.075	0.02	0.11	0.07	0.43	0.37
North Dakota	Oliver	68	5,989,200	6,789	9.0	1.0	36.5	188	0.121	0.02	0.14	0.12	0.48	0.51
Ohio	Belmont	422	5,459,600	12,269	10.3	3.8	6.3	486	0.126	0.06	0.20	0.21	0.54	0.75
Ohio	Carroll	3	29,200	12,190	11.8	2.6	6.0	669	0.300	0.10	0.26	0.29	0.61	0.82
Ohio	Columbiana	14	569,561	12,181	10.9	3.8	6.6	1,038	0.484	0.15	0.30	0.35	0.65	0.91
Ohio	Coshocton	49	2,156,500	11,987	7.4	2.7	10.2	825	0.243	0.12	0.28	0.32	0.64	0.86
Ohio	Guernsey	2	400	11,251	14.7	2.1	7.7	698	0.412	0.10	0.28	0.32	0.64	0.83
Ohio	Harrison	192	1,572,509	12,031	11.1	2.8	7.3	1,221	0.288	0.17	0.34	0.41	0.70	0.93
Ohio	Holmes	14	143,230	11,067	13.6	3.1	9.2	762	0.403	0.11	0.27	0.31	0.62	0.85

Ohio	Jackson	34	699,800	10,889	13.0	4.1	10.2	240	0.294	0.03	0.12	0.13	0.46	0.57
Ohio	Jefferson	36	246,800	11,894	11.6	2.3	7.6	741	0.163	0.11	0.28	0.32	0.64	0.84
Ohio	Mahoning	3	13,600	9,741	21.8	3.4	8.5	748	0.373	0.11	0.27	0.31	0.61	0.85
Ohio	Meigs	101	4,553,600	11,194	12.5	3.6	9.8	1,458	0.240	0.20	0.36	0.44	0.70	0.96
Ohio	Morgan	56	1,090,147	11,618	12.6	4.4	7.2	613	0.132	0.09	0.23	0.24	0.56	0.80
Ohio	Perry	91	290,600	11,247	11.6	2.8	9.9	267	0.297	0.03	0.15	0.14	0.48	0.60
Ohio	Tuscarawas	64	290,716	11,511	12.3	3.6	8.0	811	0.233	0.12	0.27	0.31	0.61	0.86
Ohio	Vinton	117	1,198,000	11,260	10.7	3.0	10.5	375	0.192	0.04	0.18	0.18	0.52	0.68
Oklahoma	Haskell	11	641,000	12,304	16.1	3.3	3.6	555	0.451	0.08	0.23	0.23	0.57	0.78
Oklahoma	Latimer	1	116,452	12,697	13.5	3.7	4.2	346	0.680	0.04	0.17	0.16	0.50	0.66
Oklahoma	Le Flore	28	510,000	12,220	16.2	3.4	3.8	498	0.459	0.07	0.21	0.21	0.55	0.75
Oklahoma	Rogers	36	111,704	12,764	10.7	4.0	4.2	2,034	0.075	0.25	0.40	0.50	0.75	0.98
Pennsylvania	Armstrong	20	4,405,083	12,174	13.9	2.7	5.5	1,735	0.388	0.24	0.40	0.49	0.76	0.98
Pennsylvania	Beaver	260	674,300	12,010	12.0	1.6	6.8	726	0.242	0.11	0.29	0.34	0.66	0.84
Pennsylvania	Bedford	8	371	11,633	14.8	1.5	6.9	887	0.418	0.14	0.32	0.39	0.71	0.88
Pennsylvania	Butler	6	135,730	11,029	16.2	2.9	7.4	858	0.298	0.13	0.29	0.34	0.64	0.87
Pennsylvania	Cambria	3	539,600	12,677	12.7	2.0	5.2	1,621	0.297	0.24	0.40	0.49	0.77	0.98
Pennsylvania	Clearfield	6	2,482,840	12,098	15.8	1.8	5.7	1,080	0.442	0.17	0.34	0.41	0.72	0.91
Pennsylvania	Elk	49	153,627	12,547	10.9	1.9	6.2	1,566	0.457	0.23	0.39	0.48	0.77	0.97
Pennsylvania	Fayette	62	516,829	12,639	8.4	1.6	7.8	882	0.162	0.13	0.31	0.37	0.69	0.88
Pennsylvania	Greene	908	23,468,283	13,091	7.7	2.0	6.0	976	0.113	0.14	0.32	0.38	0.70	0.89
Pennsylvania	Indiana	4	3,002,300	12,368	14.4	2.2	5.5	1,707	0.483	0.24	0.40	0.50	0.77	0.98
Pennsylvania	Luzerne	2	1,090,000	12,134	10.3	0.6	7.8	152	0.130	0.02	0.15	0.11	0.50	0.41
Pennsylvania	Lycoming	23	99,760	10,708	23.0	0.7	4.9	902	0.202	0.19	0.36	0.45	0.77	0.88
Pennsylvania	Northumberland	50	908,162	10,880	16.8	0.6	7.9	434	0.132	0.08	0.27	0.31	0.67	0.72
Pennsylvania	Schuylkill	7	123,000	8,913	28.5	0.5	10.2	377	0.180	0.07	0.26	0.31	0.67	0.70
Pennsylvania	Somerset	163	3,070,306	12,922	10.2	2.0	5.7	954	0.177	0.14	0.32	0.37	0.69	0.89
Pennsylvania	Washington	413	5,349,966	13,098	7.3	1.6	6.0	1,084	0.133	0.17	0.34	0.41	0.73	0.91
Pennsylvania	Westmoreland	27	677,091	13,007	8.3	1.6	6.3	1,375	0.216	0.21	0.38	0.46	0.76	0.95
Tennessee	Anderson	12	366,920	12,417	9.2	1.2	7.3	1,028	0.154	0.17	0.35	0.42	0.74	0.90
Tennessee	Campbell	1	878,000	12,277	9.3	1.1	7.8	342	0.126	0.04	0.21	0.21	0.57	0.66
Tennessee	Claiborne	24	473,746	12,890	7.4	1.3	6.6	383	0.105	0.04	0.22	0.22	0.58	0.68
Tennessee	Cumberland	15	258,260	12,508	11.8	0.7	6.7	812	0.049	0.16	0.34	0.40	0.75	0.86

Tennessee	Morgan	1	4,900	12,432	10.8	1.7	6.6	320	0.274	0.03	0.19	0.16	0.53	0.64
Tennessee	Scott	19	457,520	12,415	10.9	1.4	6.0	992	0.128	0.16	0.34	0.41	0.73	0.90
Tennessee	Sequatchie	34	429,140	12,039	13.2	0.8	6.7	1,106	0.069	0.22	0.38	0.47	0.78	0.92
*Texas	Atascosa	34	2,321,987	5,435	24.9	1.7	27.8	903	0.228	0.15	0.34	0.45	0.69	0.89
*Texas	Freestone	32	4,972,000	6,596	15.8	0.7	32.0	368	0.213	0.05	0.24	0.27	0.61	0.69
Texas	Harrison	48	3,627,000	6,511	15.2	1.2	33.5	132	0.299	0.02	0.10	0.09	0.43	0.42
Texas	Leon	12	9,216,000	7,020	18.2	1.1	26.8	222	0.141	0.03	0.16	0.15	0.50	0.57
*Texas	Milam	28	3,820,596	6,717	16.3	1.2	30.6	474	0.255	0.07	0.25	0.29	0.61	0.75
*Texas	Panola/Rusk	85	14,006,000	6,473	13.7	1.1	34.9	163	0.192	0.02	0.12	0.11	0.46	0.48
*Texas	Robertson	87	1,640,000	6,746	16.9	0.9	30.4	128	0.160	0.02	0.11	0.09	0.44	0.41
*Texas	Titus	88	7,536,000	5,994	17.8	0.5	33.8	175	0.399	0.03	0.17	0.17	0.53	0.51
Utah	Carbon	126	7,116,633	11,806	9.8	0.6	7.9	212	0.046	0.02	0.19	0.18	0.56	0.53
Utah	Emery	226	9,213,244	12,028	9.5	0.4	8.3	246	0.057	0.04	0.21	0.22	0.60	0.57
Utah	Sevier	91	2,137,309	11,347	8.3	0.4	10.3	107	0.058	0.02	0.13	0.08	0.47	0.29
Virginia	Buchanan	240	2,866,960	13,105	8.3	0.8	7.1	1,125	0.095	0.21	0.37	0.45	0.78	0.92
Virginia	Craig	18	0	13,969	5.9	0.7	5.5	1,132	0.083	0.23	0.38	0.45	0.78	0.92
Virginia	Dickenson	69	1,160,431	13,089	8.1	0.9	7.1	524	0.077	0.08	0.27	0.30	0.66	0.76
Virginia	Lee	56	3,018,031	12,911	8.1	1.1	6.1	110	0.060	0.02	0.09	0.04	0.41	0.28
Virginia	Russell	136	1,675,932	12,378	14.6	0.7	4.7	611	0.064	0.12	0.30	0.36	0.72	0.80
Virginia	Wise	846	10,775,002	12,852	9.7	1.0	6.3	300	0.086	0.03	0.20	0.19	0.56	0.62
Washington	Lewis	90	3,832,000	7,791	15.2	0.9	25.4	104	0.067	0.02	0.09	0.06	0.41	0.33
West Virginia	Barbour	38	853,922	13,084	9.5	1.4	5.9	1,672	0.157	0.26	0.41	0.51	0.80	0.98
West Virginia	Boone	1190	20,715,607	12,397	11.3	0.8	6.3	1,305	0.091	0.25	0.40	0.49	0.79	0.94
West Virginia	Braxton	8	22,187	12,636	10.3	0.8	6.6	1,338	0.136	0.25	0.40	0.49	0.79	0.95
West Virginia	Brooke	127	1,626,800	12,302	10.4	3.7	6.7	821	0.140	0.12	0.27	0.30	0.61	0.86
West Virginia	Calhoun	4	0	12,505	9.7	1.4	7.0	500	0.100	0.07	0.25	0.27	0.62	0.75
West Virginia	Clay	73	2,537,325	12,286	12.6	0.8	5.4	933	0.138	0.18	0.35	0.43	0.76	0.89
West Virginia	Fayette	166	1,780,810	12,076	13.0	0.9	6.6	1,036	0.098	0.19	0.36	0.45	0.77	0.91
West Virginia	Grant	113	1,146,830	12,403	13.5	1.7	6.1	1,147	0.231	0.18	0.35	0.43	0.73	0.92
West Virginia	Greenbrier	6	52,000	13,102	9.1	0.9	6.5	1,005	0.150	0.19	0.35	0.43	0.76	0.90
West Virginia	Harrison	19	6,038,722	13,244	6.9	2.9	5.7	743	0.090	0.10	0.26	0.29	0.62	0.84
West Virginia	Kanawha	671	11,638,342	12,053	13.5	0.8	6.0	970	0.095	0.19	0.36	0.44	0.77	0.90
West Virginia	Lincoln	24	226,700	11,420	14.4	0.8	7.1	798	0.091	0.15	0.33	0.40	0.74	0.86

West Virginia	Logan	369	4,276,078	12,168	12.4	0.7	6.0	1,051	0.088	0.21	0.37	0.46	0.78	0.91
West Virginia	Marion	13	903,123	13,339	7.1	2.1	5.4	1,294	0.063	0.19	0.35	0.43	0.73	0.94
West Virginia	Marshall	606	11,139,828	12,089	12.1	3.9	6.7	436	0.125	0.05	0.19	0.19	0.53	0.72
West Virginia	Mingo	452	15,413,902	12,123	12.4	0.9	6.5	1,074	0.082	0.20	0.37	0.45	0.77	0.91
West Virginia	Monongalia	516	7,848,526	12,705	10.3	2.1	5.6	858	0.114	0.12	0.30	0.35	0.67	0.87
West Virginia	Nicholas	141	3,237,943	12,286	12.3	0.9	6.1	1,036	0.143	0.19	0.36	0.44	0.76	0.91
West Virginia	Preston	18	1,237,017	13,126	8.8	1.4	6.4	1,768	0.157	0.28	0.42	0.52	0.80	0.98
West Virginia	Raleigh	7	297,700	11,339	17.7	0.9	7.2	797	0.110	0.15	0.33	0.40	0.74	0.86
West Virginia	Upshur	92	2,059,348	12,982	9.7	1.7	4.9	1,004	0.251	0.15	0.33	0.39	0.71	0.90
West Virginia	Wayne	417	5,279,621	11,935	11.5	0.8	7.5	1,027	0.118	0.20	0.37	0.45	0.77	0.91
West Virginia	Webster	268	4,494,014	12,529	12.0	0.9	5.0	1,381	0.121	0.25	0.40	0.50	0.80	0.95
West Virginia	Wyoming	17	622,069	13,471	7.3	0.8	5.2	1,189	0.059	0.23	0.38	0.47	0.79	0.93
Wyoming	Campbell	3819	288,722,919	8,616	5.1	0.3	28.5	129	0.069	0.02	0.15	0.12	0.51	0.38
Wyoming	Carbon	133	2,586,539	10,887	6.3	0.6	13.5	60	0.027	0.02	0.07	0.03	0.35	0.11
Wyoming	Converse	392	18,120,375	8,702	5.5	0.3	26.9	170	0.057	0.02	0.18	0.18	0.56	0.47
Wyoming	Lincoln	105	2,529,000	9,957	5.1	0.8	20.7	135	0.052	0.02	0.12	0.06	0.45	0.38
Wyoming	Sweetwater	116	9,168,000	9,402	9.5	0.5	20.1	102	0.051	0.02	0.11	0.04	0.44	0.29

Notes: Tons from FERC 423 (USEIA, 2003a) or Part 50 (USMSHA, 2004)

Btu, Ash, and Sulfur adjusted to a moist basis using estimated Moisture

Fractional Mercury Capture calculated as the average result of equations listed in table 14 (this report); hESP is hot-side Electrostatic

Precipitator; cESP is cold-side Electrostatic Precipitator; hESP/FGD is hot-side Electrostatic Precipitator with wet Flue Gas

Desulphurization; cESP/FGD is cold-side Electrostatic Precipitator with wet Flue Gas Desulphurization; SDA/FF is Spray Dry Adsorption

with wet Flue Gas Desulphurization.

\* Mercury values revised to higher values after McCall (2004) and Eutizi (2005)



## GLOSSARY

ASTM	American Society for Testing and Materials.
Btu/lb	gross British thermal units per pound coal on a moist, whole-coal basis as reported from the laboratory (multiply by 0.002326 to convert to MJ/kg).
Btu/lb <sub>m,mmf</sub>	British thermal units per pound coal, on a moist, mineral-matter-free basis calculated as, $Btu / lb_{m,mmf} = \frac{100 (Btu / lb - 50 Sulfur )}{(100 - [1.08 Ash - 0.55 S])}$ , where the sulfur, ash and Btu/lb values are on a moist, whole-coal basis.
Btu <sub>net</sub>	Net British thermal units per pound coal, reported on a whole-coal, moist basis. Also called the lower heating value, this calculated value is less than the Btu value reported from the laboratory in proportion to the amount of water vapor in gaseous combustion products. It can be calculated as $= Btu - 92.7(0.1119Moisture + Hydrogen)$ where both Btu and hydrogen are reported on a moist basis, but hydrogen excludes hydrogen in coal moisture.
COALQUAL	Coal quality database from the U.S. Geological Survey.
CTRDB	Coal Transportation Rate Data Base from the U.S. Energy Information Administration.
cESP	cold-side Electrostatic Precipitator. (see ESP)
daf	A dry, ash-free reporting basis, usually noted as a subscript associated with a coal assay value. Dry, ash-free basis values are obtained by multiplying, moist, whole-coal assay values by the factor: $\frac{100}{(100 - Ash - Moisture)}$ , where ash and moisture values are on a moist, whole-coal basis.
DOE	U.S. Department of Energy.
ESP	Electrostatic Precipitator. Called a cold-side ESP (cESP) when installed downstream of the air pre-heater (where temperatures typically range from 140 to 160 °C) and called a hot-side ESP (hESP) when installed before the air pre-heater (where temperatures typically range from 350 to 450 °C).
FGD	wet Flue Gas Desulfurization. An emission control technology designed to remove SO <sub>2</sub> from flue gas, usually installed after a particulate collection device; sulfur is removed as flue gas passes through an aqueous, alkaline solution (typically made with lime or limestone).
FF	Fabric Filter. An emission control device, also called a baghouse, that removes solid particles from combustion flue gas.

hESP	hot-side Electrostatic Precipitator. (see ESP)
EIA	U.S. Energy Information Administration.
EPA	U.S. Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FERC 423	A monthly data set listing the cost and quality of coal delivered to U.S. power plants.
ICR	Information Collection Request. Data collected during 1999 by the EPA to assist the development of any rules to limit mercury emissions from coal-fired utilities. The part 2 data list coal assay data for coal shipments, the part 3 data list measurements of mercury in stack gas
lbs Cl/10 <sup>9</sup> Btu	Pounds of chlorine per billion Btu = $\frac{10^9}{Btu} \times \frac{ppmChlorine}{10^6}$ , where Btu and chlorine values are on the same reporting basis (for example, both dry basis or both moist basis. Multiply by 0.430 to convert to kg Cl/TJ.
lbs Hg/10 <sup>12</sup> Btu	Pounds of mercury per trillion Btu = $\frac{10^{12}}{Btu} \times \frac{ppmMercury}{10^6}$ , where Btu and mercury values are on the same reporting basis (for example, both dry basis or both moist basis). Multiply by 0.430 to convert to kg Hg/PJ.
lbs Hg/TW-h	Pounds mercury per terawatt hour, which is calculated in this report as: $= \frac{10^{12}}{Btu_{net}} \times \frac{ppmMercury}{10^6} \times 10.26$ where both Btu <sub>net</sub> and mercury are reported on a moist basis, and the coefficient, 10.26, corresponds to a nominal heat rate of 35% (exactly 9,750 gross Btu/kilowatt-hour, which is approximately 10,260 net Btu/kilowatt-hour).
lbs S/10 <sup>6</sup> Btu	Pounds of sulfur per million Btu = $\frac{10^6}{Btu} \times \frac{\%Sulfur}{100}$ , where Btu and sulfur values are on the same reporting basis (for example, both dry basis or both moist basis). Multiply by 0.430 to convert to kg S/GJ.
MW	Mega Watt, used to describe the power output from an electric generator.
ppm	parts per million. Equals µg/g or mg/kg.
PRB	Powder River Basin. Refers to coal produced from Campbell, Converse, and Sheridan Counties, Wyoming as well as Big Horn and Rosebud Counties, Montana.
PSU	Pennsylvania State University.
SDA	Spray Dry Adsorption. An emission control technology designed to remove SO <sub>2</sub> from flue gas where gaseous sulfur is converted to a solid sulfate when an alkaline mist is injected into the flue gas; the solids are

subsequently collected in a particulate filter. Usually used for low-sulfur western coal.

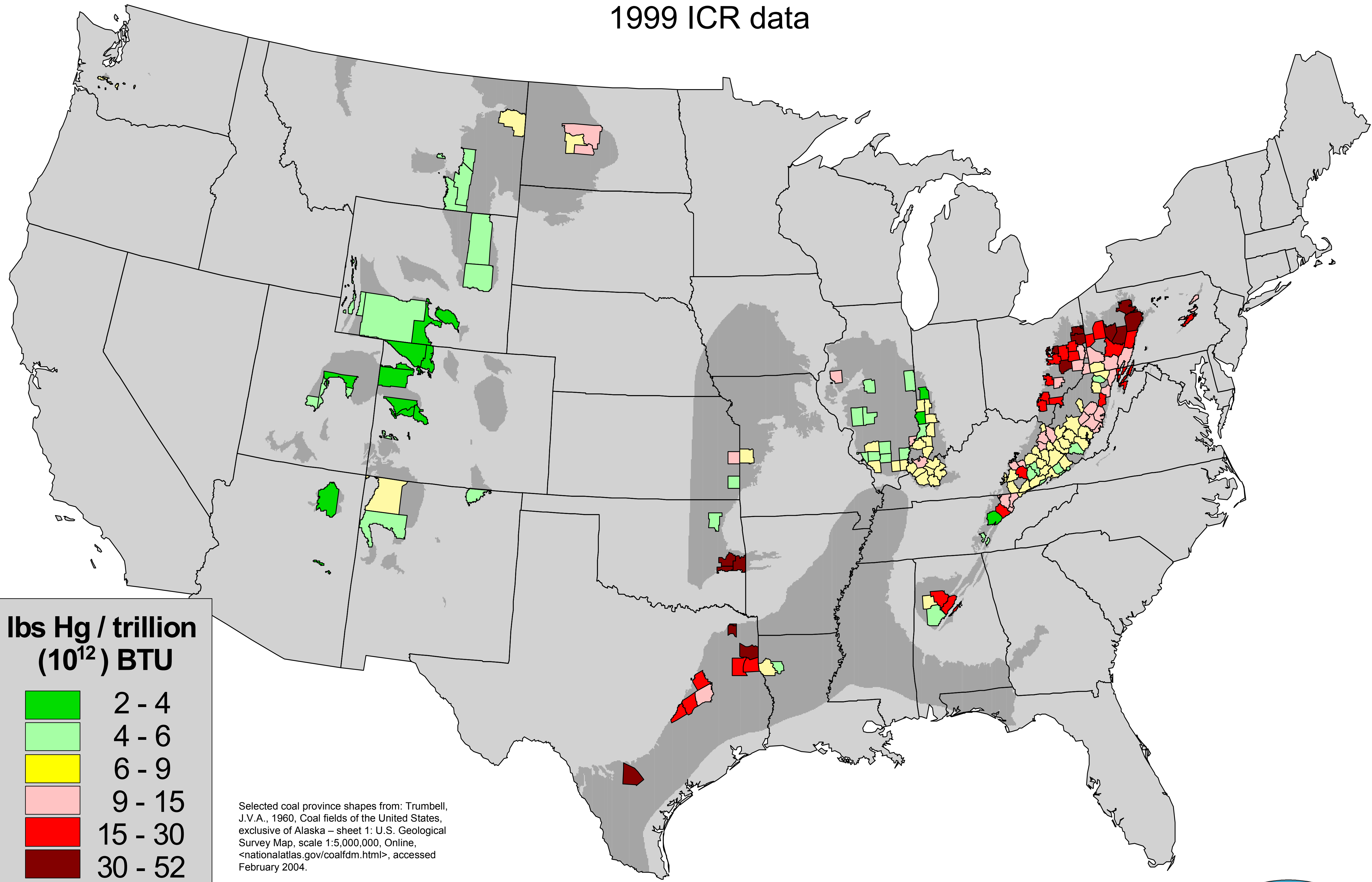
UGS

Utah Geological Survey.


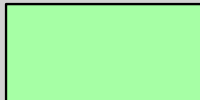

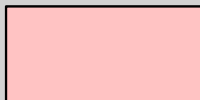



USGS

United States Geological Survey.

# Plate 1. Mercury in Commercial U.S. Coal by U.S. county of origin 1999 ICR data

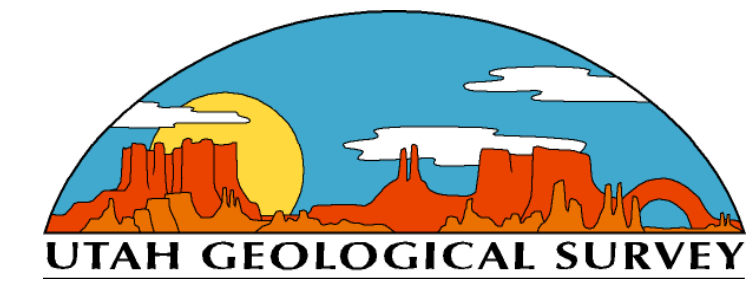


**lbs Hg / trillion  
(10<sup>12</sup>) BTU**

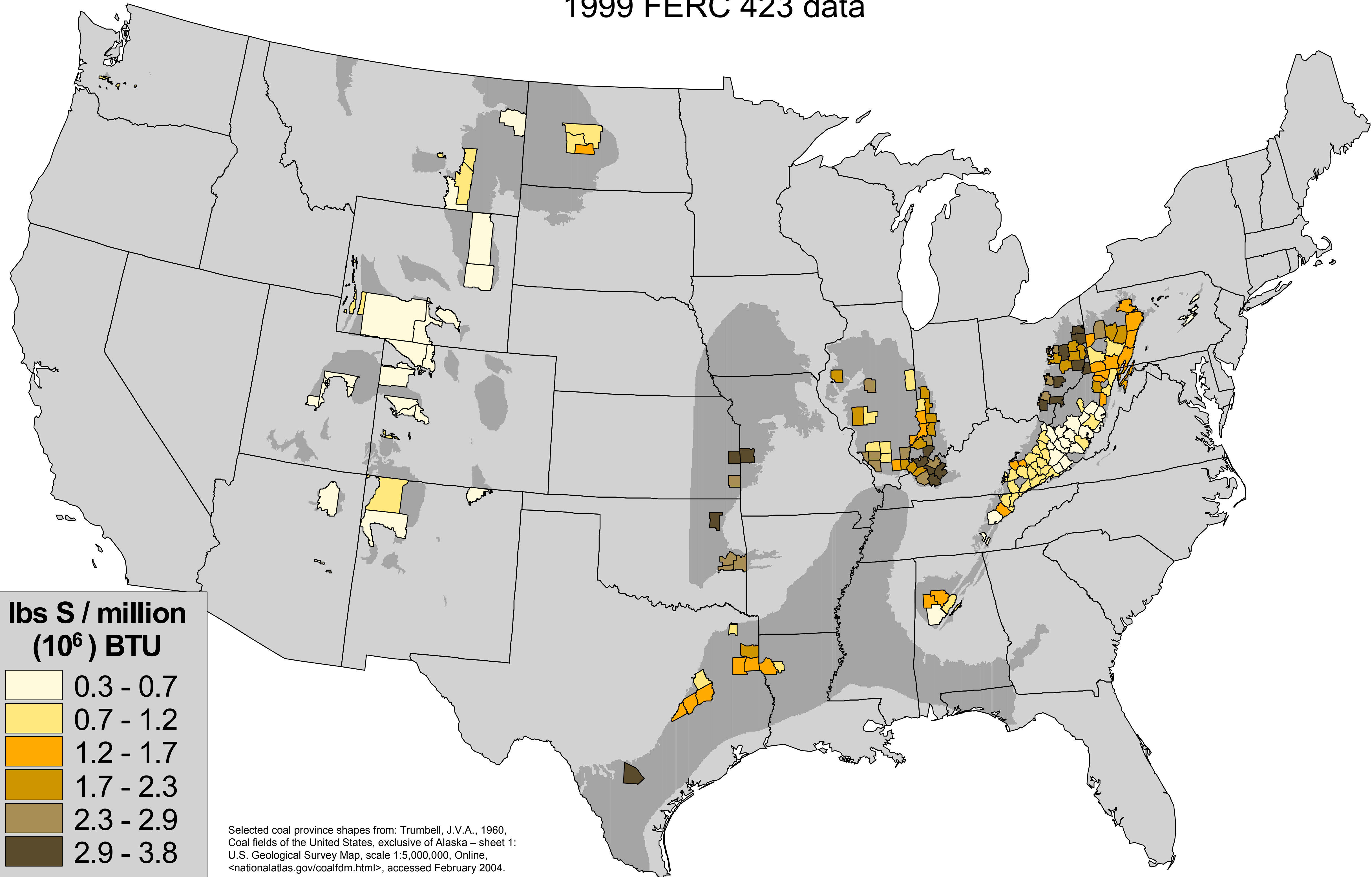
	2 - 4
	4 - 6
	6 - 9
	9 - 15
	15 - 30
	30 - 52
	coal province

Selected coal province shapes from: Trumbell, J.V.A., 1960, Coal fields of the United States, exclusive of Alaska – sheet 1: U.S. Geological Survey Map, scale 1:5,000,000, Online, <[nationalatlas.gov/coalfdm.html](http://nationalatlas.gov/coalfdm.html)>, accessed February 2004.

Selected coal mercury data from: U.S. Environmental Protection Agency. 2003, Unified air toxics website, electric utility steam generating units hazardous air pollutant emission study: Online, <[epa.gov/ttn/atw/combust/utiltox/utoxpg.html](http://epa.gov/ttn/atw/combust/utiltox/utoxpg.html)>, accessed October and November 2003.



# Plate 2. Sulfur in Commercial U.S. Coal by U.S. county of origin 1999 FERC 423 data



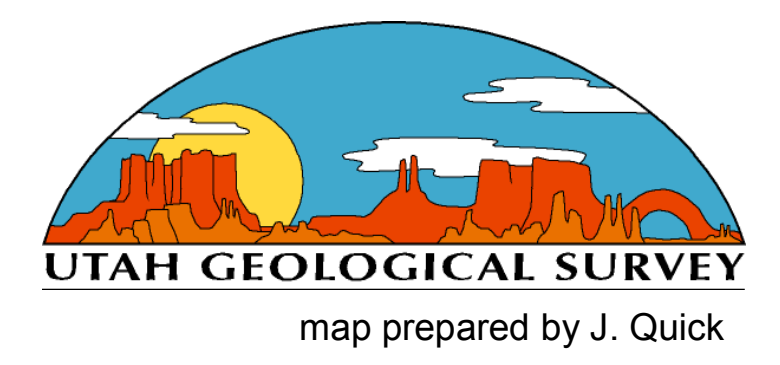
**lbs S / million  
(10<sup>6</sup>) BTU**

Lightest Yellow	0.3 - 0.7
Yellow	0.7 - 1.2
Orange	1.2 - 1.7
Dark Orange	1.7 - 2.3
Brown	2.3 - 2.9
Dark Brown	2.9 - 3.8

coal province

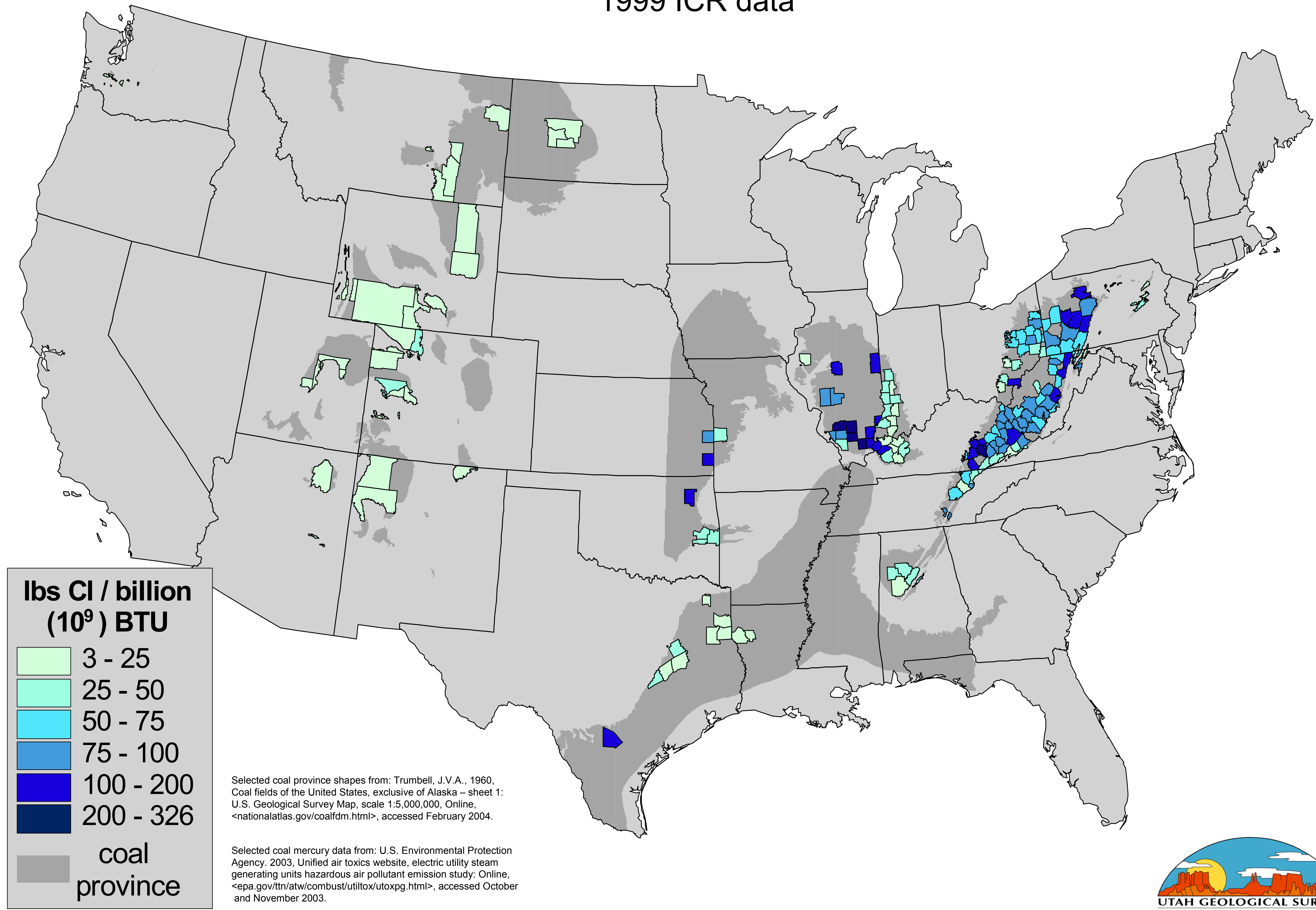
Selected coal province shapes from: Trumbell, J.V.A., 1960, Coal fields of the United States, exclusive of Alaska – sheet 1: U.S. Geological Survey Map, scale 1:5,000,000, Online, <nationalatlas.gov/coalfdm.html>, accessed February 2004.

Selected coal sulfur data from: U.S. Energy Information Administration, 2003, FERC Form 423 Database, Monthly cost and quality of fuels for electric power plants: Online, <eia.doe.gov/cneaf/electricity/page/ferc423.html>, accessed October and November 2003.





# Plate 3. Chlorine in Commercial U.S. Coal by U.S. county of origin 1999 ICR data

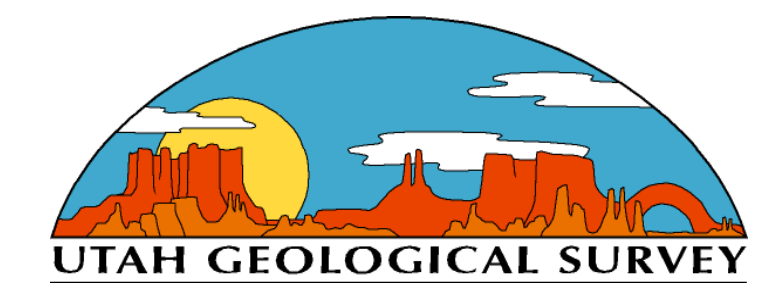


**lbs Cl / billion  
(10<sup>9</sup>) BTU**

Lightest Green	3 - 25
Light Green	25 - 50
Cyan	50 - 75
Blue	75 - 100
Dark Blue	100 - 200
Darkest Blue	200 - 326
Grey	coal province

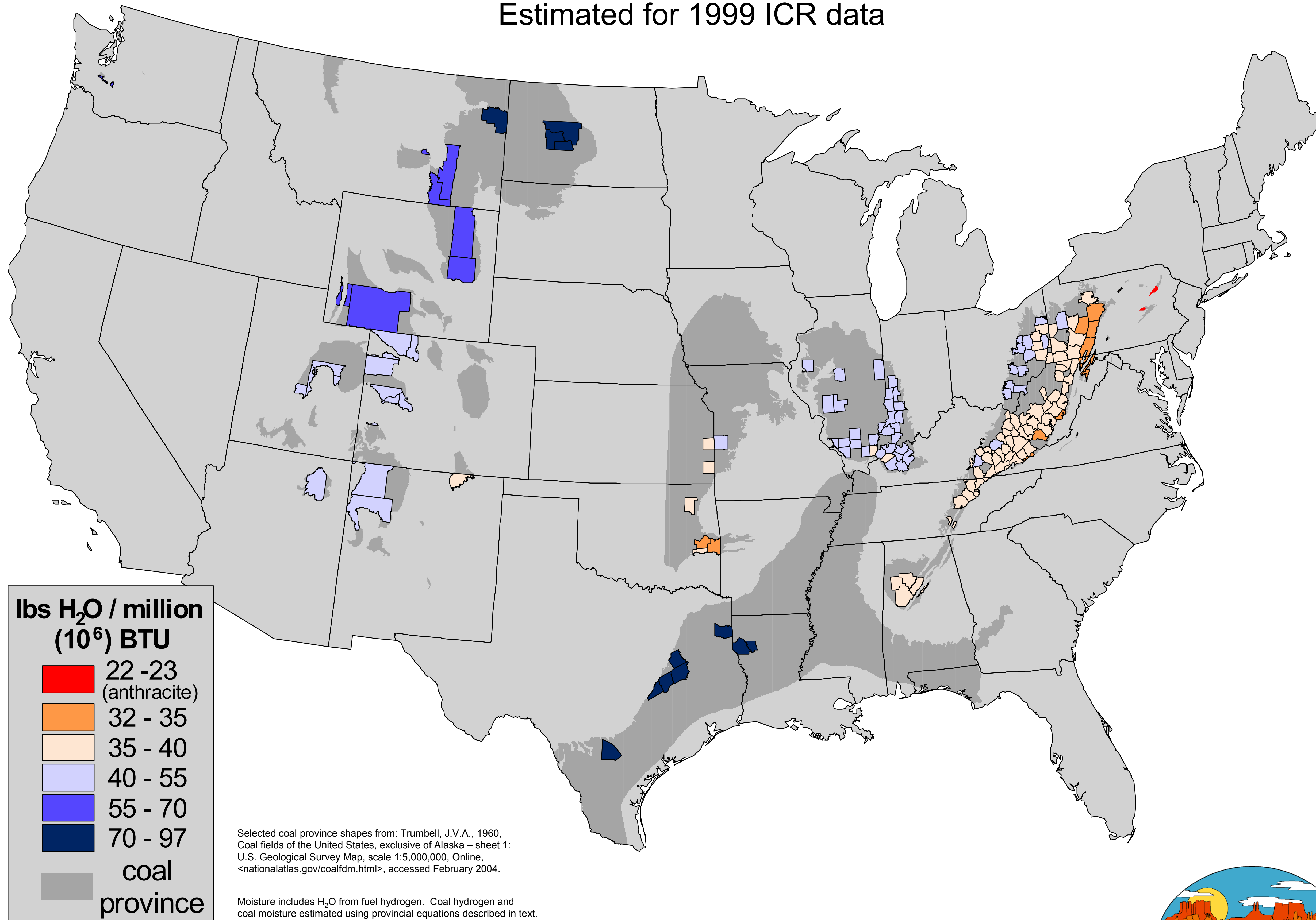
Selected coal province shapes from: Trumbell, J.V.A., 1960, Coal fields of the United States, exclusive of Alaska – sheet 1: U.S. Geological Survey Map, scale 1:5,000,000, Online, <nationalatlas.gov/coalfdm.html>, accessed February 2004.

Selected coal mercury data from: U.S. Environmental Protection Agency. 2003, Unified air toxics website, electric utility steam generating units hazardous air pollutant emission study: Online, <epa.gov/ttn/atw/combust/utiltox/utoxpg.html>, accessed October and November 2003.



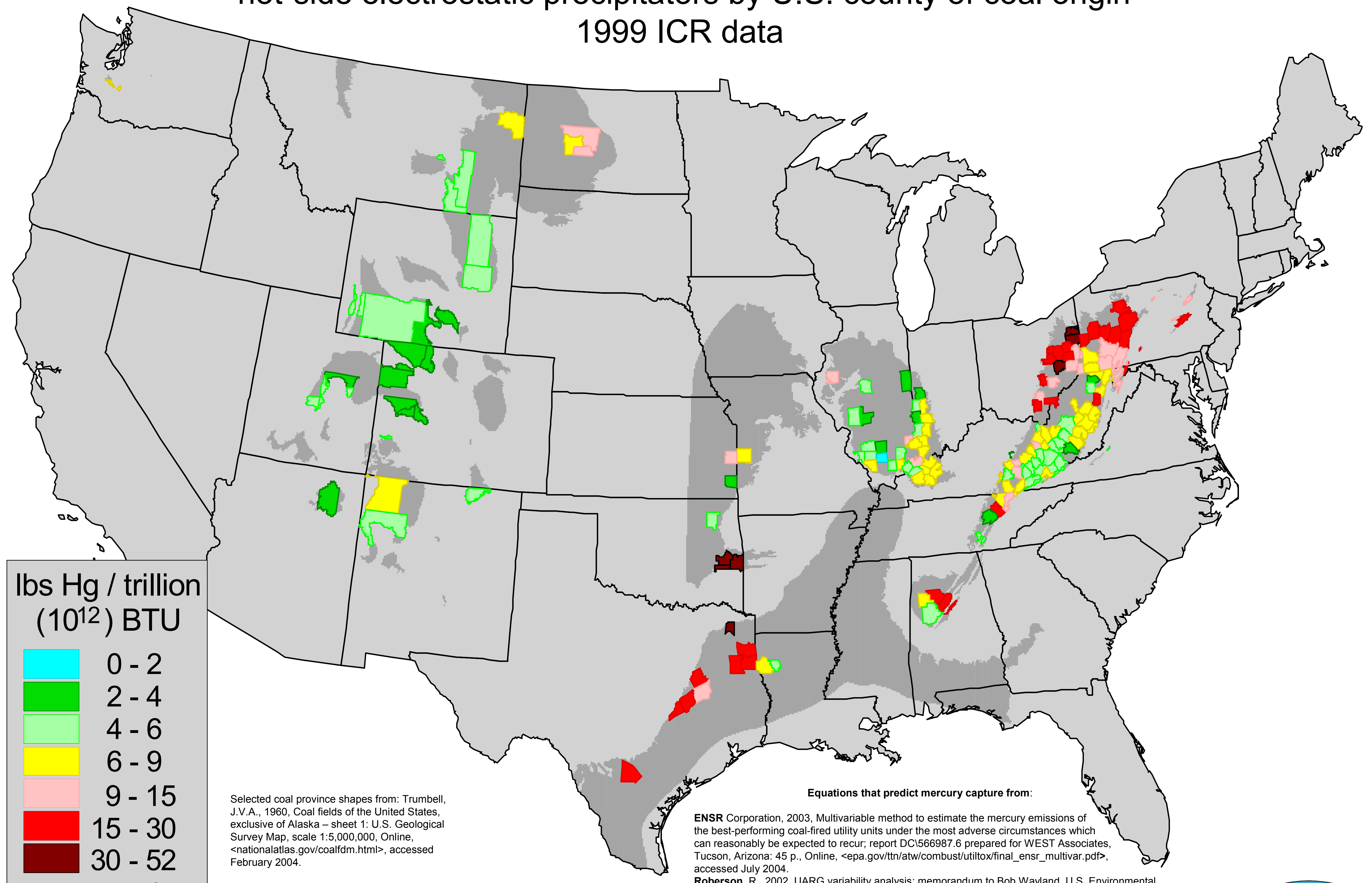
# Plate 4. Moisture in Commercial U.S. Coal by U.S. county of origin

## Estimated for 1999 ICR data





# Plate 5. Mercury emissions from U.S. coal, predicted for utilities with hot-side electrostatic precipitators by U.S. county of coal origin 1999 ICR data



**lbs Hg / trillion (10<sup>12</sup>) BTU**

Cyan	0 - 2
Green	2 - 4
Light Green	4 - 6
Yellow	6 - 9
Pink	9 - 15
Red	15 - 30
Dark Red	30 - 52
Grey	coal province

Selected coal province shapes from: Trumbell, J.V.A., 1960, Coal fields of the United States, exclusive of Alaska - sheet 1: U.S. Geological Survey Map, scale 1:5,000,000, Online, <nationalatlas.gov/coalfdm.html>, accessed February 2004.

Selected coal quality data from: U.S. Environmental Protection Agency. 2003, Unified air toxics website, electric utility steam generating units hazardous air pollutant emission study: Online, <epa.gov/ttn/atw/combust/utitox/utoxpg.html>, accessed October and November 2003.

**Equations that predict mercury capture from:**

**ENSR Corporation**, 2003, Multivariable method to estimate the mercury emissions of the best-performing coal-fired utility units under the most adverse circumstances which can reasonably be expected to recur; report DC\566987.6 prepared for WEST Associates, Tucson, Arizona: 45 p., Online, <epa.gov/ttn/atw/combust/utitox/final\_ensr\_multivar.pdf>, accessed July 2004.

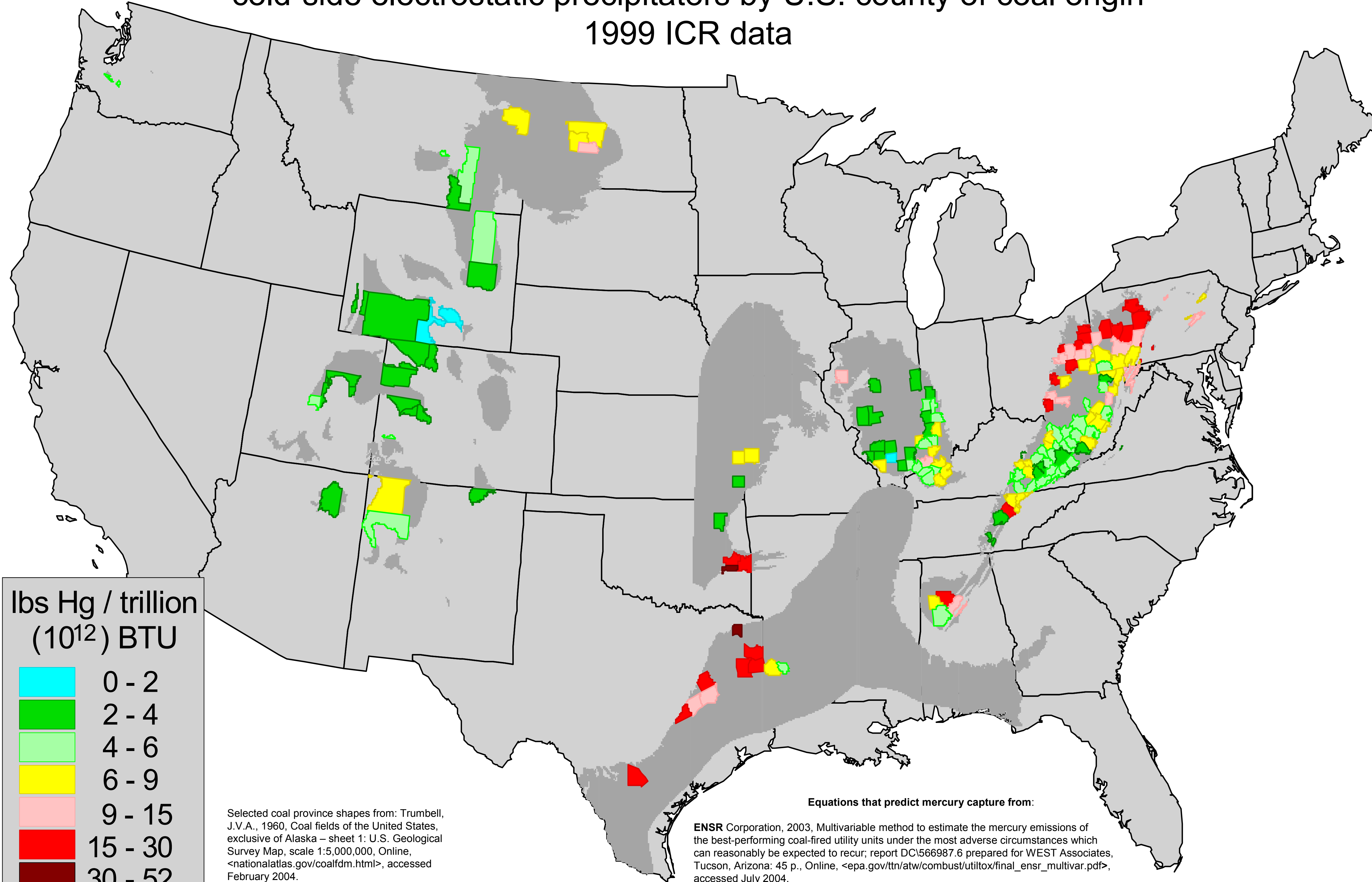
**Roberson, R.**, 2002, UARG variability analysis: memorandum to Bob Wayland, U.S. Environmental Protection Agency, 4 p., Online, <epa.gov/ttn/atw/combust/utitox/epavarifnl.doc>, accessed July 2004.

**Science Applications International Corporation**, 2003, Calculation of possible mercury MACT floor values for coal-fired utilities - influence of variability and approach; report for the U.S. Department of Energy: Reston, Virginia, SAIC Corp., 46 p., 8 appendices, Online, <netl.doe.gov/coal/E&WR/mercury/pubs/DOE\_Report\_v120803.pdf >, accessed August 2004.





# Plate 6. Mercury emissions from U.S. coal, predicted for utilities with cold-side electrostatic precipitators by U.S. county of coal origin 1999 ICR data



**lbs Hg / trillion  
(10<sup>12</sup>) BTU**

Cyan	0 - 2
Green	2 - 4
Light Green	4 - 6
Yellow	6 - 9
Pink	9 - 15
Red	15 - 30
Dark Red	30 - 52
Grey	coal province

Selected coal province shapes from: Trumbell, J.V.A., 1960, Coal fields of the United States, exclusive of Alaska – sheet 1: U.S. Geological Survey Map, scale 1:5,000,000, Online, <nationalatlas.gov/coalfdm.html>, accessed February 2004.

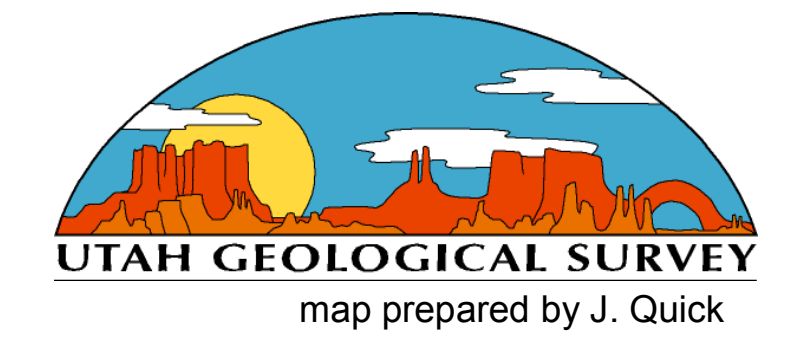
Selected coal quality data from: U.S. Environmental Protection Agency. 2003, Unified air toxics website, electric utility steam generating units hazardous air pollutant emission study: Online, <epa.gov/ttn/atw/combust/utiltox/utoxpg.html>, accessed October and November 2003.

**Equations that predict mercury capture from:**

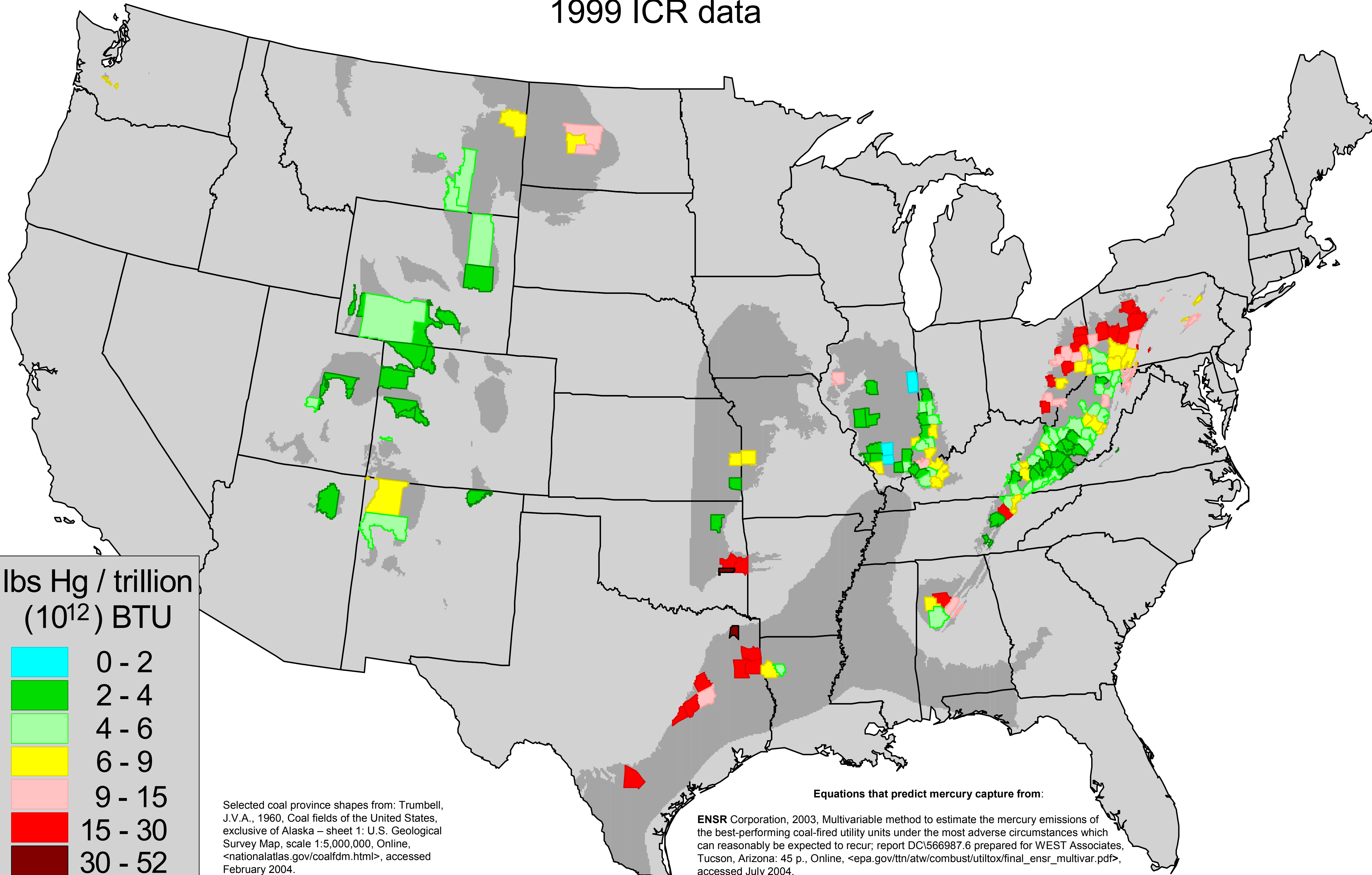
**ENSR Corporation, 2003**, Multivariable method to estimate the mercury emissions of the best-performing coal-fired utility units under the most adverse circumstances which can reasonably be expected to recur; report DC\566987.6 prepared for WEST Associates, Tucson, Arizona: 45 p., Online, <epa.gov/ttn/atw/combust/utiltox/final\_ensr\_multivar.pdf>, accessed July 2004.

**EPRI, 2000**, An Assessment of Mercury Emissions from U.S. Coal-Fired Power Plants. Palo Alto, California, TR-1000608.

**Science Applications International Corporation, 2003**, Calculation of possible mercury MACT floor values for coal-fired utilities - influence of variability and approach; report for the U.S. Department of Energy: Reston, Virginia, SAIC Corp., 46 p., 8 appendices, Online, <netl.doe.gov/coal/E&WR/mercury/pubs/DOE\_Report\_v120803.pdf >, accessed August 2004.



# Plate 7. Mercury emissions from U.S. coal, predicted for utilities with hot-side electrostatic precipitators and wet flue gas desulphurization, by U.S. county of coal origin 1999 ICR data



**lbs Hg / trillion  
(10<sup>12</sup>) BTU**

Cyan	0 - 2
Green	2 - 4
Light Green	4 - 6
Yellow	6 - 9
Pink	9 - 15
Red	15 - 30
Dark Red	30 - 52
Grey	coal province

Selected coal province shapes from: Trumbell, J.V.A., 1960, Coal fields of the United States, exclusive of Alaska – sheet 1: U.S. Geological Survey Map, scale 1:5,000,000, Online, <nationalatlas.gov/coalfdm.html>, accessed February 2004.

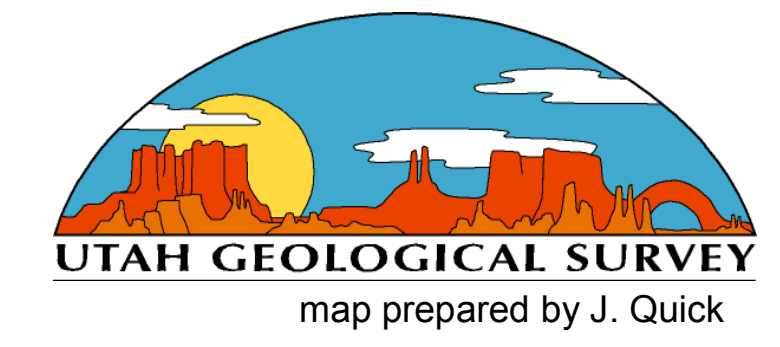
Selected coal quality data from: U.S. Environmental Protection Agency. 2003, Unified air toxics website, electric utility steam generating units hazardous air pollutant emission study: Online, <epa.gov/ttn/atw/combust/utitox/utoxpg.html>, accessed October and November 2003.

**Equations that predict mercury capture from:**

**ENSR Corporation**, 2003, Multivariable method to estimate the mercury emissions of the best-performing coal-fired utility units under the most adverse circumstances which can reasonably be expected to recur; report DC\566987.6 prepared for WEST Associates, Tucson, Arizona: 45 p., Online, <epa.gov/ttn/atw/combust/utitox/final\_ensr\_multivar.pdf>, accessed July 2004.

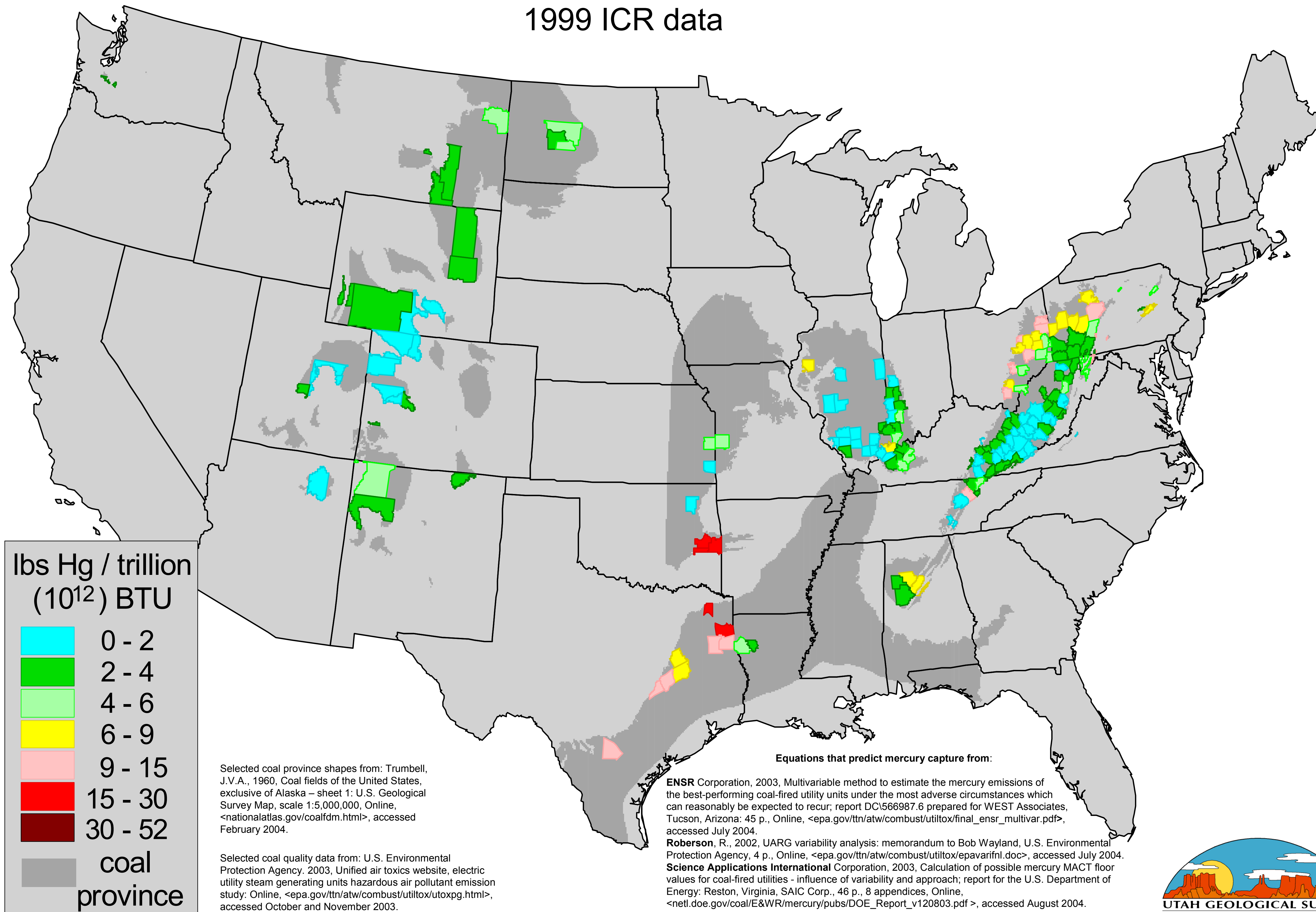
**Roberson, R.**, 2002, UARG variability analysis: memorandum to Bob Wayland, U.S. Environmental Protection Agency, 4 p., Online, <epa.gov/ttn/atw/combust/utitox/epavarifnl.doc>, accessed July 2004.

**Science Applications International Corporation**, 2003, Calculation of possible mercury MACT floor values for coal-fired utilities - influence of variability and approach; report for the U.S. Department of Energy: Reston, Virginia, SAIC Corp., 46 p., 8 appendices, Online, <netl.doe.gov/coal/E&WR/mercury/pubs/DOE\_Report\_v120803.pdf >, accessed August 2004.





# Plate 8. Mercury emissions from U.S. coal, predicted for utilities with cold-side electrostatic precipitators and wet flue gas desulphurization, by U.S. county of coal origin 1999 ICR data



**lbs Hg / trillion  
(10<sup>12</sup>) BTU**

Cyan	0 - 2
Green	2 - 4
Light Green	4 - 6
Yellow	6 - 9
Pink	9 - 15
Red	15 - 30
Dark Red	30 - 52
Grey	coal province

Selected coal province shapes from: Trumbell, J.V.A., 1960, Coal fields of the United States, exclusive of Alaska – sheet 1: U.S. Geological Survey Map, scale 1:5,000,000, Online, <nationalatlas.gov/coalfdm.html>, accessed February 2004.

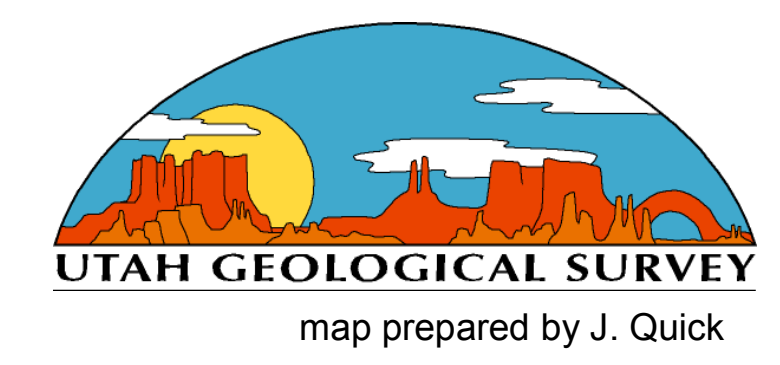
Selected coal quality data from: U.S. Environmental Protection Agency. 2003, Unified air toxics website, electric utility steam generating units hazardous air pollutant emission study: Online, <epa.gov/ttn/atw/combust/utiltox/utoxpg.html>, accessed October and November 2003.

**Equations that predict mercury capture from:**

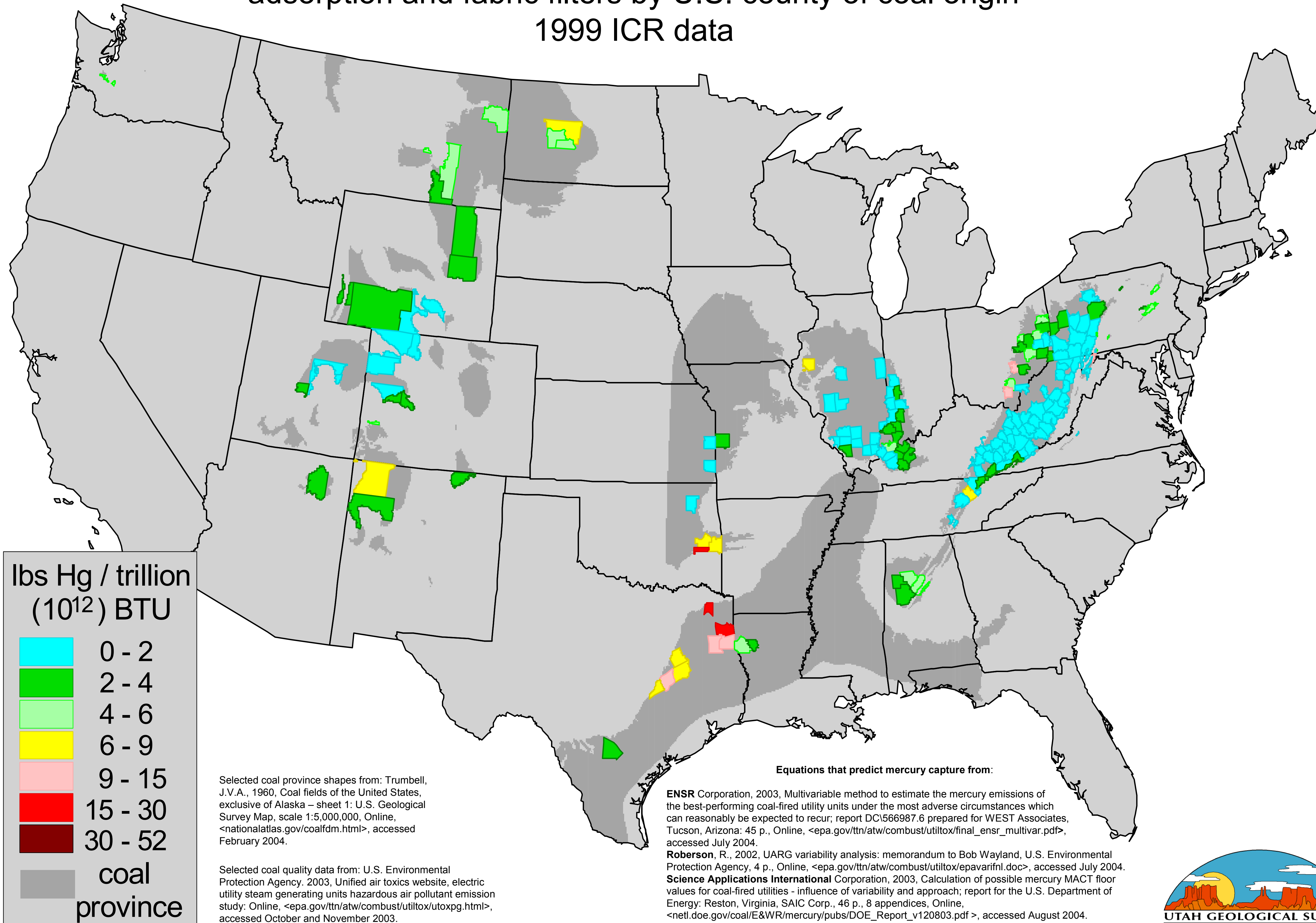
**ENSR Corporation**, 2003, Multivariable method to estimate the mercury emissions of the best-performing coal-fired utility units under the most adverse circumstances which can reasonably be expected to recur; report DC1566987.6 prepared for WEST Associates, Tucson, Arizona: 45 p., Online, <epa.gov/ttn/atw/combust/utiltox/final\_ensr\_multivar.pdf>, accessed July 2004.

**Roberson, R.**, 2002, UARG variability analysis: memorandum to Bob Wayland, U.S. Environmental Protection Agency, 4 p., Online, <epa.gov/ttn/atw/combust/utiltox/epavarifnl.doc>, accessed July 2004.

**Science Applications International Corporation**, 2003, Calculation of possible mercury MACT floor values for coal-fired utilities - influence of variability and approach; report for the U.S. Department of Energy: Reston, Virginia, SAIC Corp., 46 p., 8 appendices, Online, <netl.doe.gov/coal/E&WR/mercury/pubs/DOE\_Report\_v120803.pdf >, accessed August 2004.



# Plate 9. Mercury emissions from U.S. coal, predicted for utilities with spray-dry adsorption and fabric filters by U.S. county of coal origin 1999 ICR data



lbs Hg / trillion  
(10<sup>12</sup>) BTU

- 0 - 2
- 2 - 4
- 4 - 6
- 6 - 9
- 9 - 15
- 15 - 30
- 30 - 52
- coal province

Selected coal province shapes from: Trumbull, J.V.A., 1960, Coal fields of the United States, exclusive of Alaska – sheet 1: U.S. Geological Survey Map, scale 1:5,000,000, Online, <nationalatlas.gov/coalfdm.html>, accessed February 2004.

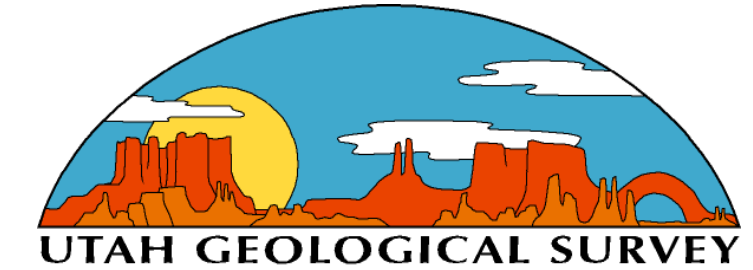
Selected coal quality data from: U.S. Environmental Protection Agency. 2003, Unified air toxics website, electric utility steam generating units hazardous air pollutant emission study: Online, <epa.gov/ttn/atw/combust/utiltox/utoxpg.html>, accessed October and November 2003.

### Equations that predict mercury capture from:

**ENSR Corporation**, 2003, Multivariable method to estimate the mercury emissions of the best-performing coal-fired utility units under the most adverse circumstances which can reasonably be expected to recur; report DC\566987.6 prepared for WEST Associates, Tucson, Arizona: 45 p., Online, <epa.gov/ttn/atw/combust/utiltox/final\_ensr\_multivar.pdf>, accessed July 2004.

**Roberson, R.**, 2002, UARG variability analysis: memorandum to Bob Wayland, U.S. Environmental Protection Agency, 4 p., Online, <epa.gov/ttn/atw/combust/utiltox/epavarifnl.doc>, accessed July 2004.

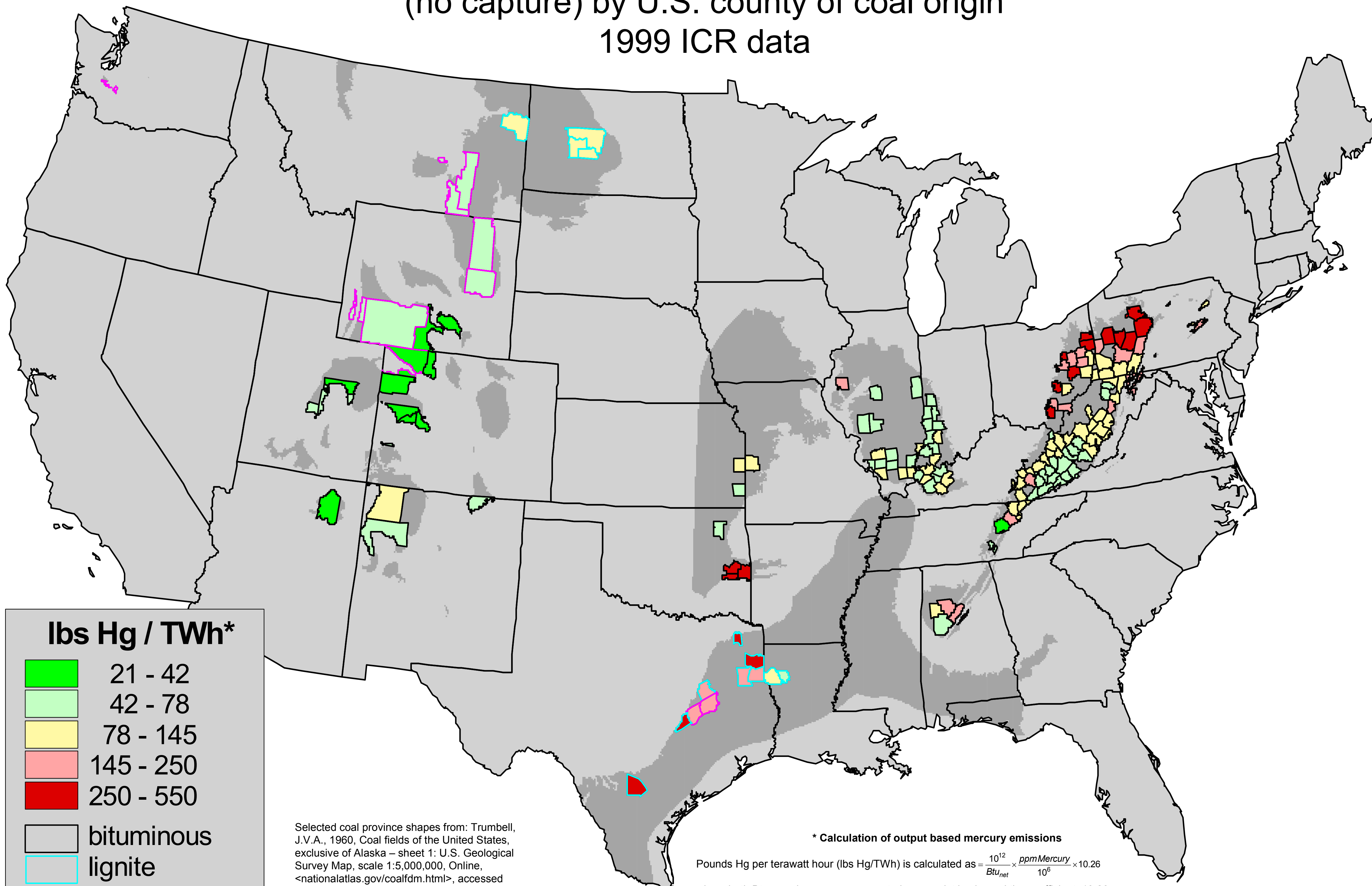
**Science Applications International Corporation**, 2003, Calculation of possible mercury MACT floor values for coal-fired utilities - influence of variability and approach; report for the U.S. Department of Energy: Reston, Virginia, SAIC Corp., 46 p., 8 appendices, Online, <netl.doe.gov/coal/E&WR/mercury/pubs/DOE\_Report\_v120803.pdf >, accessed August 2004.



map prepared by J. Quick



# Plate 10. Potential mercury emission rate of commercial U.S. coal (no capture) by U.S. county of coal origin 1999 ICR data



**lbs Hg / TWh\***

- 21 - 42
- 42 - 78
- 78 - 145
- 145 - 250
- 250 - 550

bituminous  
 lignite  
 subbituminous  
 coal province

Selected coal province shapes from: Trumbell, J.V.A., 1960, Coal fields of the United States, exclusive of Alaska – sheet 1: U.S. Geological Survey Map, scale 1:5,000,000, Online, <nationalatlas.gov/coalfdm.html>, accessed February 2004.

Selected coal quality data from: U.S. Environmental Protection Agency. 2003, Unified air toxics website, electric utility steam generating units hazardous air pollutant emission study: Online, <epa.gov/ttn/atw/combust/utitox/utoxpg.html>, accessed October and November 2003.

**\* Calculation of output based mercury emissions**

Pounds Hg per terawatt hour (lbs Hg/TWh) is calculated as 
$$= \frac{10^{12}}{Btu_{net}} \times \frac{ppm_{Mercury}}{10^6} \times 10.26$$

where both  $Btu_{net}$  and mercury are reported on a moist basis, and the coefficient, 10.26, corresponds to a nominal heat rate of 35% (exactly 9,750 gross Btu/kilowatt-hour, which is approximately 10,260 net Btu/kilowatt-hour). Note that the net Btu value is calculated using estimated moisture and hydrogen values according to  $= Btu - 92.7(0.1119Moisture + Hydrogen)$  where both Btu and hydrogen are reported on a moist basis, but hydrogen excludes hydrogen in coal moisture.

