THE 2008 FORECAST OF INDIANA COAL PRODUCTION & USE

Prepared for the

Center for Coal Technology Research

Energy Center at Discovery Park

Prepared by

Frederick T. Sparrow

F.T. Sparrow & Associates

West Lafayette Indiana

July 2008

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A. INTRODUCTION AND CURRENT SHIPMENTS

This report presents the results of a study of the likely changes in the use of Indiana coal in Indiana and elsewhere for the period 2008-2025. Five developments are likely to make future use of coal substantially different than historic use:

1) Likely passage of some form of legislation limiting CO_2 emissions;
2) Phases I and II of the Clean Air Interstate Rule (CAIR) going into effect;
3) The dramatic rise in transportation costs for coal;
4) For coal use by the Indiana iron and steel industry, the replacement of by-product recovery coke ovens by non-recovery units; and
5) The near doubling of eastern US coal exports to Europe and elsewhere in response to the withdrawal of China as an exporter of coal, and the resultant run-up in Eastern coal prices relative to Illinois Basin (IB) and Powder River Basin (PRB) coals.

A.1 CURRENT USE

In 2006, according to the EIA[1], over 68 million tons of coal were either delivered to Indiana coal users or exported from Indiana. EIA shipment data, rather than use data were used as a point of reference, since EIA use data does not keep track of the source of coals. Table 1 summarizes the 2006 flows.

As the table shows, of the 52.9 million tons delivered to Indiana utilities, only 30.5 million tons were mined in Indiana, the balance coming from Western mines (14 million tons), other Illinois Basin states (6.5 million tons) and eastern states (1.8 million tons).

Coal shipments to Indiana's iron and steel industry totaled over 6 million tons, all from eastern states, while deliveries to industrial plants totaled an additional 6 million tons, including 2.7 million tons to Alcoa's Warrick electricity generating units.

Finally, 3.4 million tons of coals were exported in 2006, mostly to utilities.

Projections for each of the three uses – electricity generation, iron and steel, and other industrial use – will be discussed in turn.

[1] EIA, "Domestic Distribution of U.S. Coal by Destination State-2006."

Table 1. Total Coal Delivered in Indiana Plus Exports, 2006

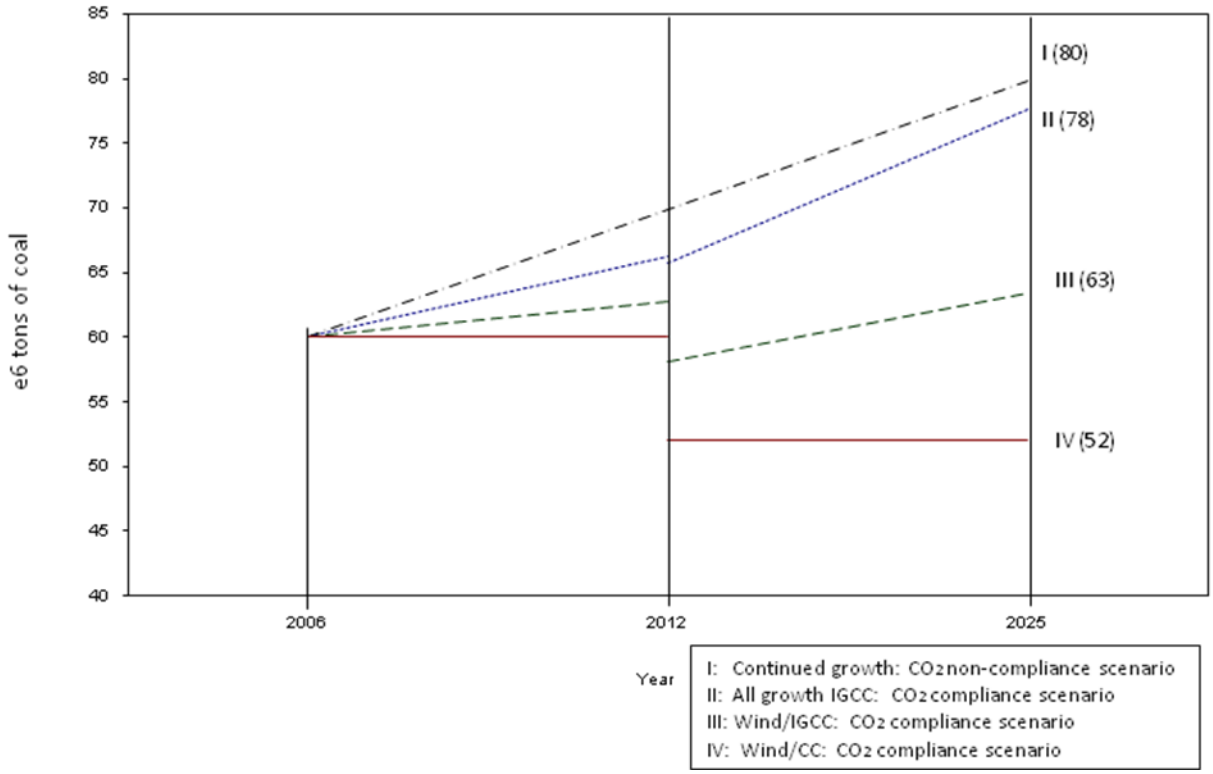
Delivered to Indiana Utilities	30.53 million tons from Indiana mines 5.7 million tons from Illinois mines 0.8 million tons from Kentucky mines 11.7 million tons from Wyoming mines 2.2 million tons from Montana mines 1.1 million tons from Virginia mines 0.7 million tons from other mines **Total: 52.9 million tons**	Source: EIA, "Domestic Distribution of U.S. Coal by Destination State-2006." Note: 52.9 million tons shipped, 60 million tons consumed in 2006; data on use by source not available. Source: EIA, "US Coal Consumption by End Use by State, 2006"
Delivered to Coke Plants	0.9 million tons from Alabama 0.7 million tons from Virginia 4.5 million tons from West Virginia **Total: 6.1 million tons** [amount consumed withheld by EIA]	Source: EIA, "Domestic Distribution of U.S. Coal by Destination State-2006."
Delivered to Industrial Plants	2.4 million tons from Indiana 1.8 million tons from West Virginia 0.8 million tons from Illinois 0.5 million tons from Kentucky 0.4 million tons from other **Total: 5.9 million tons** [5.6 million tons consumed]	Source: EIA, "Domestic Distribution of U.S. Coal by Destination State-2006."
Exports	2.67 million tons to utilities 0.57 million tons to industry 0.17 million tons to other **Total: 3.41 million tons**	Source: EIA, "Domestic Distribution of US Coal by Origin State … 2006"
GRAND TOTAL	Shipments: 65.046 million tons Exports: 3.4 million tons **Total: 68.4 million tons**	Source: EIA, "Domestic Distribution of US Coal by Origin State … 2006"

B. PROJECTIONS OF USE BY UTILITIES

B.1 SUMMARY TABLE

Regarding Indiana and imported coal use by Indiana and other utilities, this report projects a wide range of use trajectories, depending on utility adjustments to likely CO_2 legislation. Figure 1 summarizes the four forecasts developed for the paper. All projections start with Indiana utility coal use (not shipments) in 2006, which totaled 60 million tons.

Figure 1. All Cases, Coal Use, 2006-2025



B.2 CASE I – HISTORICAL GROWTH RATES ASSUMED

If legislation limiting CO_2 emissions were not enacted, the future could be expected to look very much like the past. Trajectory I in Figure 1 is based on extrapolating the 1995-2005 growth rates in the use of coal by Indiana utilities reported by EIA[2]. Extrapolating these historical growth rates into the future shows that coal use could be expected to grow to almost 80 million tons a year by 2025, an increase of 20 million tons from current levels.

B.3 IMPACT OF POSSIBLE CO_2 LEGISLATION

If CO_2 legislation was enacted, two questions must be answered – what legislation and what compliance strategy would be used by utilities? Fortunately, Purdue's State Utility Forecasting Group (SUFG) has just completed a report[3] that discusses the consequences of two possible compliance strategies if the bill eventually passed were to be the Lieberman-Warner Climate Security Act, SB2191 before amendments. Their report considers two compliance strategies – one meeting the CO_2 targets of the bill by construction of IGCC plants with CO_2 sequestering, the other using a combination of wind and gas-fired combined cycle technology. This report adds yet a third compliance strategy – wind in combination with IGCC plants.

In all three cases, the compliance strategy assumes SB2191's "cap and trade" system is adopted, which applies to all fossil-fueled generating units and industrial units which emit more than 10,000 tons per year CO_2 equivalent of greenhouse gases. The cap starts at 5,200 million tons of CO_2 in 2012, dropping to 3,592 tons by 2025, the end of the forecast horizon of the SUFG report. All three strategies assume companies will purchase non-covered offsets up to the specified maximum, and will construct new base load generation capacity to meet the demand growth forecast by SUFG over the horizon as shown in Table 2.

[2] EIA, "U.S. Coal Consumption by End Use Sector, by Census Division and State," *Table 12: Electric Power Sector Consumption Estimates, 1960-2005, Indiana,* 2006.
[3] SUFG/PCCRC Report, "The Projected Impacts of Carbon Dioxide Emissions Reduction Legislation on Electricity Prices in Indiana," 2008.

Table 2. New Indiana Baseload Requirements (units in MW)

Year	Baseload
2006	120
2007	120
2008	240
2009	480
2010	730
2011	1020
2012	2020
2013	2090
2014	2270
2015	2520
2016	2860
2017	3130
2018	3380
2019	3700
2020	4000
2021	4300
2022	4660
2023	5040
2024	5440
2025	5890

Note: MW is cumulative
Source: SUFG/PCCRC report

Since the CO_2 targets cannot be met by just constructing low CO_2 emissions units to meet new demand, additional units must then be retired and replaced in 2012 to meet the cap requirements, as shown in Table 3.

Table 3. New Indiana Baseload Requirements: Retiring Facilities in 2012

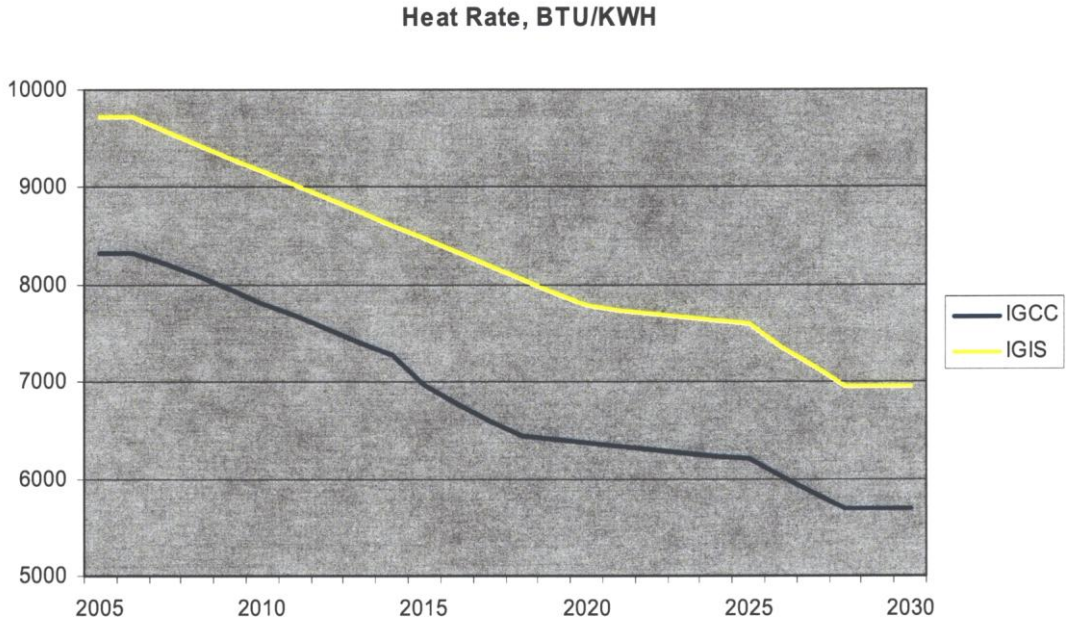
Facility	**Nameplate (units in MW)**
Tanners Creek 1-3 (1.2e6 tons BIT)	519
Eagle Valley/Pritchard 3-6 (0.79e6 tons BIT)	301
Bailly 7, 8 (1.3e6 tons BIT)	615
Edwardsport 7, 8 (0.18e6 tons BIT)	109
Gallagher 1-4 (1.3e6 tons BIT)	600
Wabash River 2-5 (1.65e6 tons BIT)	472
Warrick 4 (1.1e6 tons BIT)	323
TOTAL: ~ 8e6 tons BIT (3.4 non-IN)	**2939 MW retired**

Source: EIA Form 767 data
Note: 2006 Indiana utility coal tonnage is use, not deliveries

B.4 CASE II – IGCC WITH SEQUESTERING COMPLIANCE

If it was assumed that the new units to meet new and replacement base load demand were IGCC plants, then coal use by Indiana utilities could be expected to grow to 78 million tons a year by 2025, assuming the plants operate at a 90% capacity factor. The key to this forecast is determining the increase in the heat rate for the IGCC plants caused by having to use a good portion of the electricity generated to compress, ship, and inject CO_2 into storage areas. This study takes the forecast of IGCC heat rates found in a DOE/NETL 2008 report referenced in Figure 2.

Figure 2. Case II: Calculation of Coal Use Projections by Utilities in Indiana for IGCC Scenario



Source: Repowering Coal-Fired Power Plants for Carbon Dioxide Capture and Sequestration– Further Testing of NEMS for Integrated Assessments, DOE/NETL-2008/1310, January 23, 2008, Fig. 4

As the figure shows, IGCC heat rates with CO_2 injection derating are expected to drop to the 9,750 btu/kwh range by 2015, a bit less than the current average base load heat rate in Indiana. Since the embedded heat rates in existing base load plants are roughly equal to these derated IGCC plants, the retirement and replacement of older capacity in 2012 only slightly alters the trajectory in 2012, when the older units are replaced by the IGCC units.

B.5 CASE III – WIND/IGCC COMPLIANCE

If, on the other hand, compliance was achieved by a combination of wind and IGCC plants, Figure 1 shows use would grow to only 63 million tons a year by 2025. The replacement of the roughly 3,000 MW of coal fired capacity in 2012 necessary to meet the CO_2 limits causes 2012 coal consumption to drop by 4 million tons/year, since the heat rates of the replaced units are higher than the heat rates of the IGCC units, even with the derating necessary for CO_2 injection. This projection is based on the SUFG assumption that each 60 MW of wind generation capacity must be backed up by 50 MW of IGCC generation capacities in order to guarantee the

availability of energy during peak demand periods. This results in the IGCC units operating at only a 48% capacity factor in this case. While the SUFG report estimates that this case releases roughly the same amount of CO_2 as the wind/combined cycle case discussed below, SUFG projects it to be 12% more expensive than the wind/combined cycle case.

B.6 CASE IV – WIND/CC COMPLIANCE

Finally, if the compliance strategy were to be a combination of wind and gas-fired combined cycle plants, coal use could be expected to decrease to 52 million tons a year, well below the current use level of 60 million tons a year. As in the wind/IGCC case, SUFG assumes that each 60 MW of wind must be backed up by 50MW of conventional capacity, in this case gas-fired Combined Cycle (CC) units. As Figure 1 showed, coal use is constant until 2012, since all growth in demand is assumed to be met by a combination of wind and as fired CC units. Coal use drops by 8 million tons in 2012 as a result of the retired coal units being replaced by the combination of wind and natural gas-fired units, and is constant thereafter, since all new demand is assumed to be met by the combination of wind/CC.

B.7 CONCLUSIONS – The perfect forecasting storm

As Figure 1 showed, coal use by Indiana utilities can range from 52 million to 80 million tons a year by 2025, depending on the enactment of CO_2 legislation, and the technologies the utilities use to comply with such legislation. This compares with current use of around 60 million tons/year. Such a wide range of estimates makes the forecast essentially useless for planning purposes. It is no wonder that Indiana coal producers, like those in other states, are reluctant to open new mines until the uncertainty regarding the impact of CO_2 legislation on coal's share of the electricity generation business is reduced. Add to this uncertainty the impact of uncertain higher oil prices on natural gas prices results in a near perfect storm for utility planners.

C. USE OF INDIANA COAL FOR THE GENERATION OF ELECTRICITY

C.1 GENERAL CONSIDERATIONS

What does all this mean for the use of coal mined in Indiana to generate electricity?

Forecasting the use of coal mined in Indiana by Indiana and other utilities is much more speculative than forecasting total utility coal use as was done in the above section, since, in addition to the factors previously discussed which apply to the competition between coal in general and other sources of base load power, it involves first projecting how IB coal will compete with PRB coals, and then projecting how Indiana coals will compete with Kentucky and Illinois coals for their share of the Illinois Basin market.

Since most IB coals are near indistinguishable from one another when mined from the same horizon (some minor differences arise because of differing depths of the deposits as one approaches the middle of the basin), shifts in the three states' market shares of total IB coals are going to be nearly unpredictable. They will be governed by a host of factors including the relative success of each of the three states in encouraging mining and utility coal using activity within their states, movement of coal within the states, encouragement of coal exports from the states, and the like.

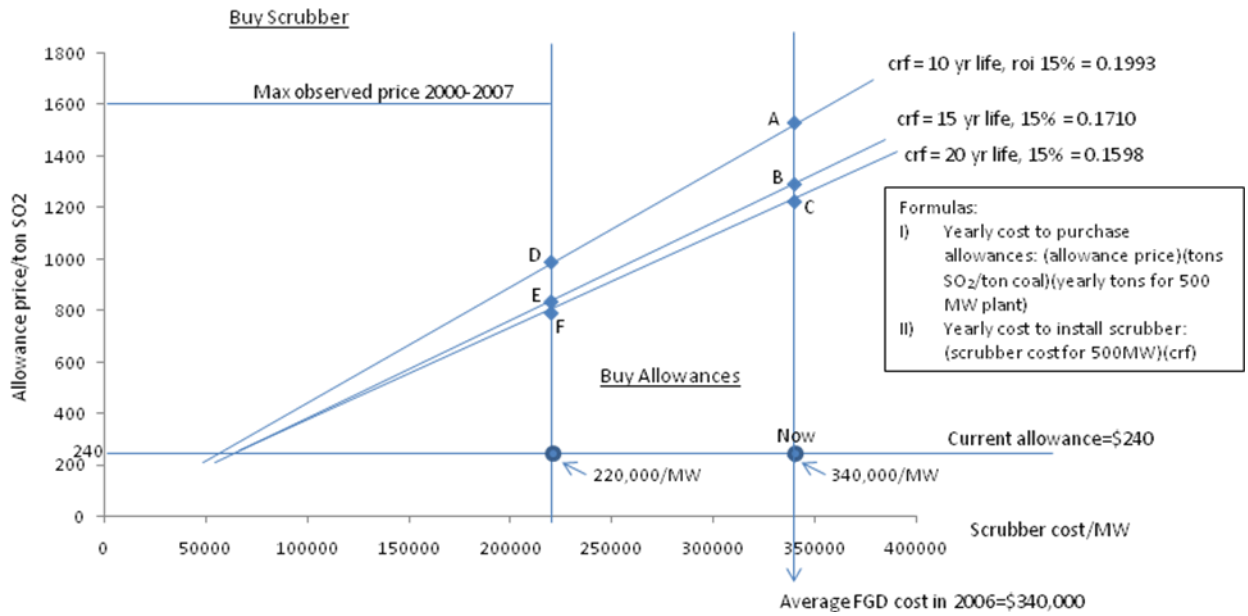
A more tractable question is to examine the impact of the factors mentioned at the beginning of the report on the relative competitiveness of IB coals and Western coals. Starting with the passage of clean air legislation in the mid-1970s, PRB coals have dramatically reduced the markets for IB coals, due chiefly to PRB coals' lower sulfur content and the economics of unit trains. This trend has continued up to the present day; the question is: are there developments which could reverse this trend, and recapture some of the markets IB coals have lost to their PRB competitors?

The answer seems to be a qualified yes, depending on whether coal switching in existing plants or coal choice in new plants is being considered.

C.2 USE OF IB COALS IN EXISTING PLANTS

Regarding coal switching in existing units now using PRB coals, it appears that compliance with Phases I and II of the CAIR legislation will result in existing units buying allowances and continuing to use PRB coals, rather than purchasing scrubbers and switching to IB coals.

Figure 3. PRB Coal User Choice: Buy/Not Buy Scrubber?



Assumptions: 500 MW PC plant, 90% utilization rate, heat rate 10,000 btu/kwh, using PRB coal with 20 lbs/ton CO_2, heat content 8800 btu/lb.

C.2.1 FACTORS DETERMINING SCRUB AND SWITCH VERSUS ALLOWANCE PURCHASE CHOICE

Figure 3 shows the outcome of this decision as a function of the three major factors that enter into the choice – the cost of purchasing allowances, scrubber equipment costs, and the capital recovery factor used to annualize the equipment costs. Figure 3 assumes the existing plant is a 500 MW pulverized coal plant with a heat rate of 10,000 btu/kwh, operated 90% of the time, burning PRB coals with a heat content of 8,800 btu/lb and a sulfur content of 20 pounds/ton. The figure also assumes that the cost per million btu of IB and PRB coals are the same, that if utilities choose to scrub and switch to IB coals, no allowances need to be purchased, and the operating costs for scrubbers are minimal. All these assumptions tend to make IB coals more competitive with PRB basin coals than they really are, so if scrub and switch is not competitive under these circumstances, it will not be competitive with more realistic assumptions regarding these factors.

To construct the figure, the annual costs of the two alternatives for 500 MW plant were calculated as a function of the three key variables. The annual cost of the allowance strategy is simply the forecast allowance price per ton of SO_2 times the tons of sulfur per ton of coal times the tons of coal purchased annually for a 500 MW plant. The yearly cost of the scrubber option is

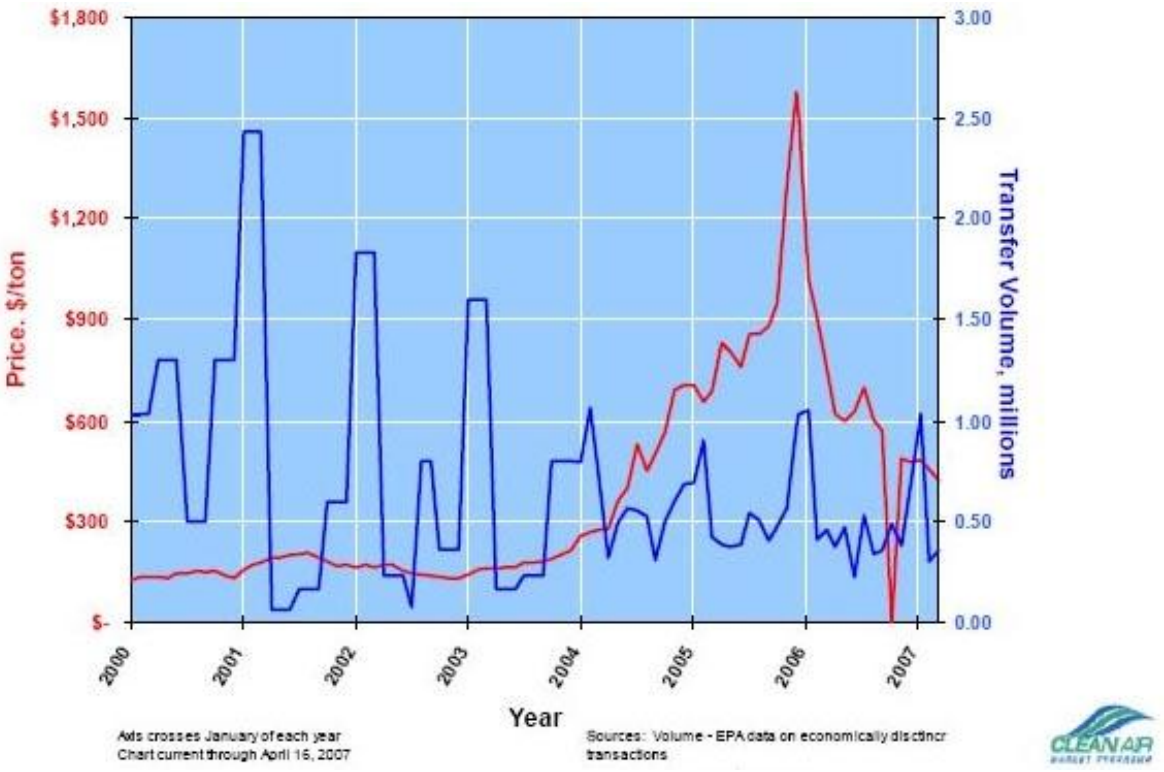
the forecast cost of the scrubber times the assumed capital recovery factor. The diagonal lines divide the space into two areas – areas in the upper-left hand corner of the diagram where the unit would be expected to install scrubbers and switch to IB coals, and areas in the lower right where the units would be expected to continue to use PRB coals by purchasing allowances. The lines themselves represent combinations of input values which make the units indifferent to the use of the two options.

As Figure 3 indicates, given that current allowances are selling at around $240/ton and scrubbers cost well over $300,000/MW, there is little likelihood that units now burning PRB coals will switch. Only if allowance prices rise above $800/ton and scrubber costs drop to below $220,000MW will there is any chance for the scrub/switch option.

C.2.2 HISTORICAL ALLOWANCE PRICES

Figure 4 show that only once in its history has the historical pattern of allowance prices ever exceeded $800; recent costs have stayed below the $500 figure for the last year and a half.

Figure 4. Simplified Historic SO2 Price and Volume



Source: http://www.epa.gov/airmarkets/presentations/docs/EMA2007.pdf

By the same token, there appears to be little likelihood that units which have already invested in scrubbers and are using IB coals will switch to PRB coals, given the dramatic increase in coal transport costs for the 1,200 mile trip from Western mines.

C.2.3 CONCLUSIONS – Utility fuel switching in existing plants

There appears to be little economic gain in any switching from one coal source to another in the foreseeable future; any increase in the use of Indiana coals must come from their use in the new units installed to serve demand growth in the state.

The forecast sees little likelihood that IB coals will replace PRB coals in existing units as a result of adjustments to CAIR rules, since the least cost compliance strategy for utilities now using PRB coals appears to be by a wide margin buying SO_X allowances and continuing to burn PRB.

C.3 USE OF IB COALS IN NEW PLANTS

C.3.1 FACTORS THAT WILL CONTROL USE IN NEW PLANTS

The picture is mixed for the use of IB coals in new plants. All indications are that the first level of competition will be between gas-fired combined cycle units and coal-fired IGCC plants; the days of new coal-fired pulverized coal plants serving Midwest electricity generators seems about over, as utilities anticipate CO_2 legislation by choosing to build CO_2 capture ready IGCC units. Within the IGCC option, the choice of IB or PRB coals will likely be governed by two factors – the persistence of current increases in coal transportation costs, and the growing consensus that IB coals are more suitable for gasification than PRB coals because of their higher heat content and the additional revenue stream available from easily recovered sulfur impurities.

C.3.2 FOUR POSSIBLE TRAJECTORIES

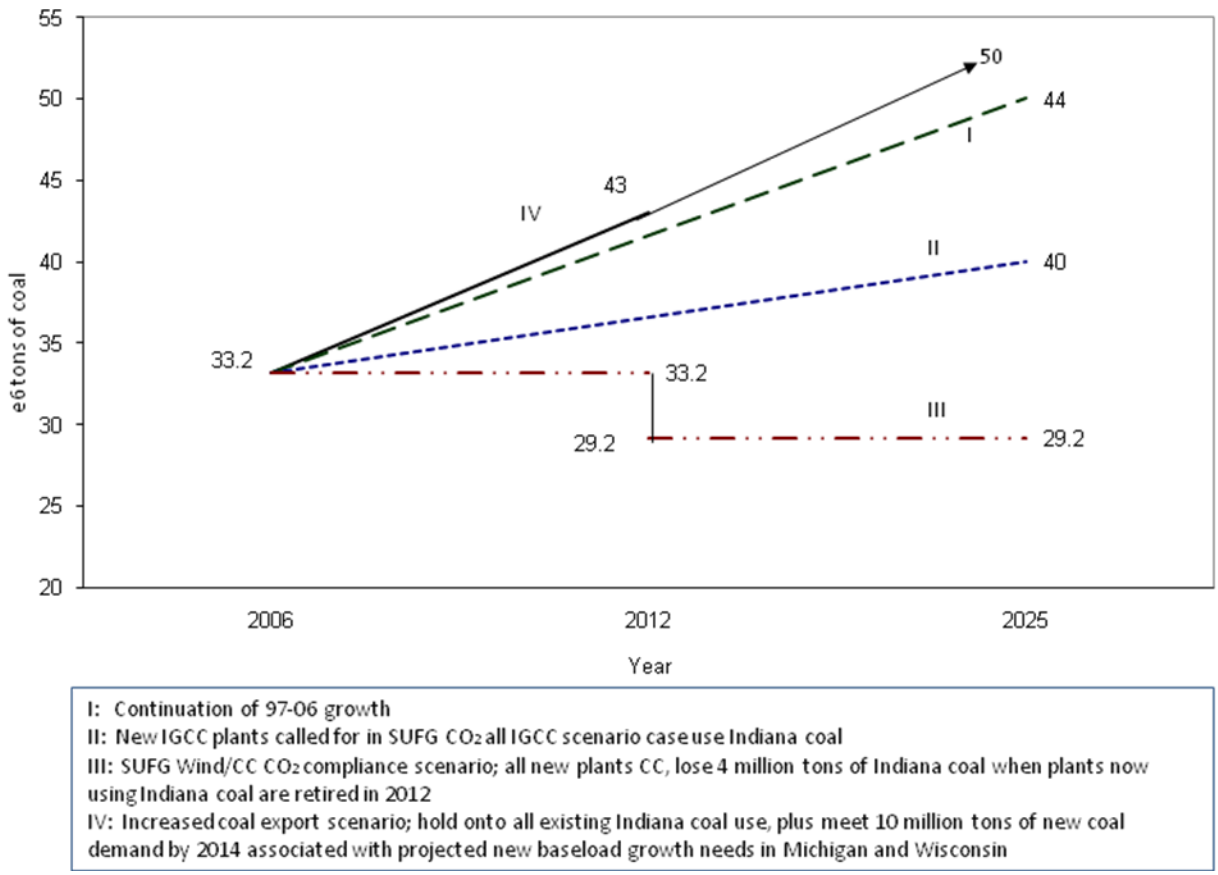
With all this in mind, Figure 5 presents four possible trajectories for future use of IB mined coal to generate electricity.

All four trajectories start with 33.2 million tons of Indiana coal shipped to electricity generating units in 2006, as reported by the EIA[4] 30.5 million tons sent to Indiana generating units, and 2.6

[4] EIA, "Domestic Distribution of U.S. Coal by Destination State-2006."

million tons exported to generation plants outside the state. As Figure 5 indicates, the four scenarios are: (I) a "business as usual" scenario; (II) a scenario which assumes all IGCC plants built in Case II in Figure 1 above – the scenario which assumes all new IGCC plants constructed to meet the CO_2 limits of the Lieberman-Warner bill – will use IB coal; (III) a scenario which assumes the compliance strategy used by utilities will be a combination of wind and combined cycle units; and (IV) an optimistic scenario which assumes that the Case II scenario just described, IB coals recapture a portion of the export markets in Michigan and Wisconsin now served by PRB coals. Each will be discussed in turn, following a discussion of a few issues which cut across all the scenarios.

Figure 5. Forecast Use of IB Mined Coal for Electric Generation



Note: 33.2 million tons shipped to Indiana and out of state utilities
Source: EIA "Distribution of US Coal by Destination, 2006"

C.3.3 CASE I – BUSINESS AS USUAL ASSUMPTION

Turning now to a discussion of Figure 5, Trajectory I is based on the assumption that the factors which controlled the growth in the use of IB coals in the past will continue to govern their use in the future; more specifically, the scenario assumes that the 1.5% per year growth rate for the consumption of IB coals by the electric power sector contained in the latest EIA state statistics[5] for the period 1995-2005 will continue into the future. This scenario is unlikely to take place – it is presented simply as a point of reference for the other forecasts. This assumption results in a forecast of 44 million tons consumed in 2025 – an increase of about 30%.

C.3.4 CASE II – ALL IB COAL USE IN ALL IGCC SCENARIOS

Trajectory II in Figure 5 assumes that the IGCC plants built to satisfy the CO_2 limits of the Lieberman-Warner bill if the utilities choose to meet the emissions limits by constructing nothing but IGCC plants – that is, Case II in Figure 1 above – will use IB coals. If this is the case, then IB coal use in Indiana will grow from 33.2 million to only 40 million tons by 2025. This lower figure is partly due to the fact that 4 million of the 8 million tons of coal being used by the plants retired in 2012 already use IB coals, so the net gain in IB coal use as a result of the retirements is smaller than might be expected.

C.3.5 CASE III – WIND/CC COMPLIANCE SCENARIO

As would be expected, since no coal is used in new units in this scenario, IB coal use is constant until 2012, and then drops by 4 million tons in 2012 as the plants which are retired at that time which are using IB coals are replaced by a combination of wind and as fired combined cycle plants.

C.3.6 CASE IV – INCREASED IB COAL EXPORTS CASE

To end on an optimistic note, this case assumes IB coals successfully recapture some of the export market in Michigan and Wisconsin lost to PRB coals in recent years. Currently, exports of Indiana coal to other states for power generation is very small – about 2.7 million tons, according to EIA figures,[6] this has not always been the case – as recently as 1990, over 9 million tons of coal mined in Indiana was shipped to other states. These markets have been presumably lost to

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[5] EIA, "U.S. Coal Consumption by End Use Sector, by Census Division and State," *Table 12: Electric Power Sector Consumption Estimates, 1960-2005, Indiana,* 2006.
[6] EIA, "Domestic Distribution of U.S. Coal by Destination State-2006."

PRB coals because of cost considerations. Is it possible that with the dramatic increase in unit train transportation costs, IB coals could recapture some of these markets? Regarding the increase in coal transportation costs, the BNSF "Coal and Unit Train and Trainload Mileage Table"[7] indicates that the coal surcharge rate for unit trains has increased from $0.21/mile per carload in March 2007 to $0.48/mile in June 2008, as staggering 130% increase in 15 months! What this means is that the fuel surcharge per ton of coal (not the full transportation cost, just the surcharge) transported 1,200 miles from Wyoming to Michigan is now over $6.00 a ton, a cost greater than current estimates of the cost of mining the coal itself. Add to this the fact that US railroads face a "Congestion Calamity" in the next few years as rail freight capacity cannot keep up with increasing demands, which is forcing rail lines to look for higher margin business to substitute for the low margins received in the transport of commodities such as wheat, coal, lumber, and the like.

Table 4. Export Potential for IB Coal Use by Utilities: Current Use (2004/2006) (e6 tons)

To From	KY	OH	IL	MI	WI	Total
West	7.1/6.0	7.3/20.3	42.2/51.4	28.6/25.4	25.1/26.3	110/129
East (incl E Ky)	4.6/9.4 **	23/37	0.3/0	5.1/7.8	0.2/0.53	34.2/55
IB (incl W Ky)	2.4/1.99 **	0.6/1.6 *	0.4/0.3 *	0/0	0.5/0.3	3.9/4.1
Home	13.8/23.9	14.4/15.1	5.7/4.1	0/0	0/0	33.9/43.1
Totals	29.4/41.4	45.3/74	45.3/56	34.2/33.6	25.9/27.1	

* Non home only ** E & W KY included in home
Source: EIA Distribution of US Coal by Destination

Table 4 shows the origins and destinations for coal imports into the states surrounding Indiana in both 2004 and 2006. The two markets that stand out in the table as likely targets for recapture are the Wisconsin and Michigan markets. In 2006, Michigan imported 20 million tons of PRB coals by unit train, and Wisconsin almost 26 million tons. Neither have any domestic sources of coal, and in the case of Michigan, unit trains from the West must pass through Indiana on their way to

[7] BNSF Rules book 6100-Item 3381, "Coal and Unit Train and Trainload Mileage Table," 2008.

Michigan, and have the longest delivery distance (1,200 miles) for Western coals of any on the five states considered.

Michigan, then, seems to be the logical target for export development. The only problems are getting such a large volume of coal from southern to northern Indiana, and the response of PRB coal producers to the invasion of their markets by IB coals; would they simply reduce their mine mouth prices in the face of developing competition?

In any event, Case IV assumes that in addition to the use of coal in Case II – the case where compliance with the CO_2 limits are met by utilities using just IGCC plants, IB coal producers will capture 25% – 10 million tons – of the combined Michigan/Wisconsin markets from PRB sources. This forecast is probably more a wish than a forecast, but does draw attention to a potential market for IB coals that certainly deserves the careful analysis only the coal companies can give it.

C.3.7 CONCLUSIONS – Use of IB coals in new electricity generating units

As in the case of the forecasts for total use of coal by Indiana utilities, the spread of forecasts in Figure 5 – from 29 million to 50 million tons by 2025 – make the forecast useful only in spelling out the consequences of various assumptions regarding the expansion or contraction of the markets for IB coals.

D. USE OF IB COALS BY THE INDIANA IRON AND STEEL INDUSTRY

D.1 PRESENT USE

In 2006, the EIA[8] reports that 6.1 million tons of coal were shipped to Indiana's iron steel industry, all from eastern states. Coal was used for two purposes; provide the raw material for the states four coke making facilities, and as an injectant into the blast furnaces.

[8] EIA, "Domestic Distribution of U.S. Coal by Destination State-2006."

D.2 POSSIBLE USE OF IB COALS IN COKE OVENS

Coke facilities in Indiana include:

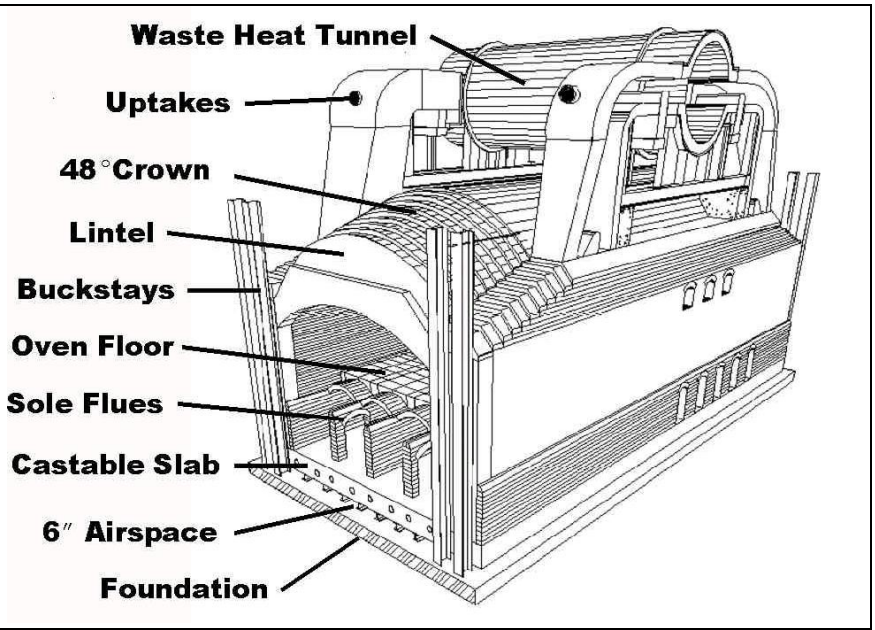
1) The Indiana Harbor Coke Company (Ispat/Inland), a recently constructed non-recovery coke plant which has a coke production capacity of 1.3 million tons/year (approximately 1.8 million tons/year coal input), and a 94 MW electric generation plant;
2) Burns Harbor Coke Plant (Mittal Steel), a by-product recovery coke plant with a coke production capacity of 1.8 million tons/year (2.4 million tons/coal); coke oven and blast furnace gases are used in a 177 MW electric generation unit;
3) Gary Coke Plant (US Steel), a by-product recovery coke plant which has a coke production capacity of 1.6 million tons/yr (2.2 million tons/coal); the coke oven gas is used in various steelmaking processes in the plant;
4) Citizens Gas and Coke plant in Indianapolis, which had a coke production capacity of 500,000 tons/yr until its closure in July 2007.

Figure 6 is a drawing of a non-recovery coke oven, and a picture of the Indiana Harbor Coke Company facility. Rather than capture the coke oven gas for use in other steelmaking processes, as is the case with recovery ovens, non-recovery ovens burn all the gases in the oven itself, a much less polluting process than the recovery ovens. For this reason, the EPA has effectively mandated that all new ovens be of the non-recovery type, which has implications for the future location of such facilities.

Dr. Robert Kramer has completed a study of the possibility of IB coals being blended with stronger eastern coals for coking purposes in order to minimize problems associated with the use of lower strength of IB coals. He and his colleagues have concluded that blends with up to 30% Indiana coal are practical. Thus, if the Indiana coke ovens are operating at capacity, Kramer concluded that up to 2.1 million tons of Indiana coal could be utilized.[9]

[9] "Development of Coking/Coal Gasification Concept," Final Report to CCTR, September 30, 2007, Robert Kramer, Purdue Calumet.

Figure 6. Non-Recovery Oven

Jewell-Thompson Heat Recovery Coke Oven	
Indiana Harbor Coke Co	

Source: http://www.epa.gov/guide/ironsteel/pdf/jewell.pdf

D.3 USE OF IB COALS AS INJECTANTS INTO THE BLAST FURNACE

All three blast furnace complexes now use West Virginia coals as injectants into the furnaces; the amounts vary from 200 to 400 pounds per ton of hot metal produced from the furnaces. Since injected coal can substitute on a pound for pound basis for coke, up to certain limits, there is much current interest in injection, given the extraordinary coke prices that now prevail in world coke markets. (Spot prices are forecast to be in the $700//ton range this fall, five times the $140/ton prices that prevailed in 2003.)[10] Further, the possibility of using IB coals as injectants is being actively explored, since IB coals have not seen the price increases experienced by eastern coals (see Figure 7 below) attributed to rapid expansion of export markets for eastern coals in response to China dropping out of the coal export markets.

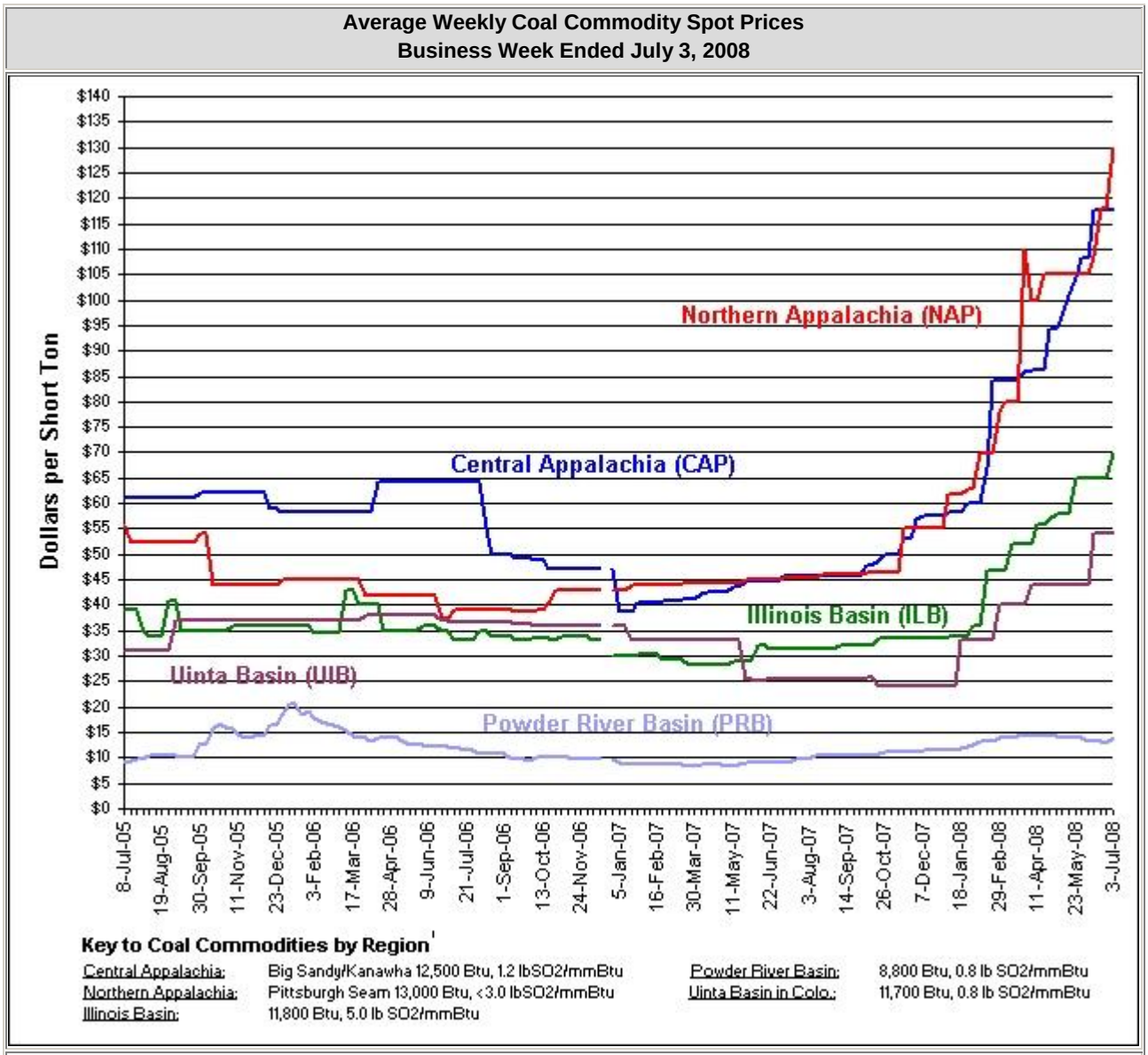
The concept has been around for a long time; interest first peaked in the US during the 1970s when operators were looking around for ways to reduce coke charges in the furnaces. From 1995 to 1998, DOE funded a coal injection demonstration project at the Burns Harbor blast furnace complex which indicated that coal could replace coke on a pound for pound basis up to a limit of around 270 pounds per ton of hot metal, almost 30% of the normal coke charge. The experiment also concluded that a wide range of coal types could be used in addition to the West Virginia low volatile coals used in the demonstration. One problem identified with the use of IB coals is the need to remove moisture from the coals prior to injection. This problem has led blast furnace experts to conclude that a mix of IB and eastern anthracite coals may be the best injectant.

D.4 CONCLUSIONS

If use of IB coals as blends in both the coke making and coal injection processes were to be implemented, up to 2.1 million tons of IB coals could be used in coke blends, and up to 1.3 million tons in blends injected directly into the blast furnaces. This seems to be a very promising new market for IB coals, given the dramatic price increases seen in recent months in the cost of the eastern coals now used for these purposes.

[10] "Development of Coking/Coal Gasification Concept," Final Report to CCTR, September 30, 2007, Robert Kramer, Purdue Calumet.

Figure 7. Average Weekly Coal Commodity Spot Prices (week ending July 3, 2008)



[1] Coal prices shown are for a relatively high-Btu coal selected in each region, for delivery in the "prompt quarter." The prompt quarter is the quarter following the current quarter. For example, from January through March, the 2nd quarter is the prompt quarter. Starting on April 1, July through September define the prompt quarter.

Source: With permission, selected from listed prices in Platts Coal Outlook, "Weekly Price Survey."

Note: The historical data file of spot prices is proprietary and cannot be released by EIA; see http://www.platts.com/Coal/. >Analytic Solutions>COALdat, or >Newsletters> Coal Outlook.

Source: http://www.eia.doe.gov/cneaf/coal/page/coalnews/coalmar.html

E. IB COAL USE BY THE INDUSTRIAL SECTOR

A DOE report[11] indicated that 5.6 million tons of coal were delivered to industrial users in Indiana. Of this total, almost half – 2.7 million tons – were delivered to Alcoa's Warrick electricity generating units, and should be counted in the total of coal delivered to plants for the generation of electricity, and the forecasts for such use presented in previous sections of this report. IDEM reports that of the remainder, 0.9 million tons were used at five cogeneration sites in Indiana, and 0.5 million tons were used in six process steam plants in Indiana. The 1.5 million ton remainder is unaccounted for.

It is likely that all these plants use IB or eastern coals, since the individual volumes are so small as to preclude the use of unit trains from the west. No forecast of IB use for these purposes will be included in this report, except to note that growth in coal use for cogeneration and process stream will be governed by the price of electricity to large industrial users, and the cost of coal and gas for cogeneration and process stream to such users.

F. THE IMPLICATIONS OF THIS FORECAST FOR CCTR PLANNING PURPOSES

There appears to be several important conclusions relating to the design of future CCTR projects that arise from this forecast.

F.1 THE USE OF IB COALS TO GENERATE ELECTRICITY

First and foremost, CCTR needs to take a careful look at the competition between IB and PRB coals in the new environment of dramatically increased transportation costs for all coals. Certainly IB coals have become more competitive, but by how much, and for how long? How will the competition between IB and PRB coals play out when used in IGCC plants with CO_2 injection capabilities? What will PRB coal producers do to offset the decline in their competitive advantage? Will they accept lower margins on the mining of their coals to maintain their market shares?

[11] EIA, "Domestic Distribution of U.S. Coal by Destination State-2006."

Next, CCTR should consider investigating the possibility of IB coals expanding into the export market potential offered in the Michigan and Wisconsin markets, both markets now served by PRB coals. This 10 million ton export market potential identified in this study should give additional impetus to efforts to find a low cost way of moving IB coals from south to north, over and above the markets for Indiana electricity generation and use by the iron and steel industry already identified in this and previous studies.

Finally, CCTR might consider a follow-up study to the SUFG CO_2 compliance report which looks more closely at the least-cost compliance options open to utilities, and the implications for IB coal use in these options. Are scenarios which include widespread use of wind power really realistic here in the Midwest without government mandates requiring their use? If widespread use is likely, how can IB coals take advantage of the fact that back-up power will be needed for such plants, if they are to be used as base load generators?

F.2 THE USE OF IB COALS BY THE IRON AND STEEL INDUSTRY

The continued support of Dr. Kramer's work regarding IB coal use in coke blends is certainly justified. It might be wise to consider expanding the project to include the use of IB coals as injectants into the blast furnaces. Members of Dr. Kramer's team, in particular Dr. Valia, are well qualified to carry out such investigations.

F.3 THE USE OF IB COALS BY THE INDUSTRIAL SECTOR

No CCTR projects seem warranted in this area, except to support the work of IDEM in continuing to track coal consumption in all areas of the state – in particular, the work of IDEM in expanding our knowledge of other industrial uses of coal in Indiana besides use by utilities and the iron and steel industry.

APPENDIX A – CHRONOLOGY OF THE STUDY

In February 2006, in the document "Forecasting Indiana Coal Production," two alternate forecasts of Indiana coal production were presented. The first, based on projecting historical growth rates, forecast a 3% rate of growth in production, resulting in a predicted 62 million tons of production in 2020, a 77% increase over 2004 production. The second, based on a shift share forecasting methodology, projected changes in the shares of the various energy markets that control Indiana coal production – Indiana's share of Illinois Basin coal production, Illinois Basin's share of US coal production, US coal production's share of US energy use, etc. This method arrived at an estimate of 4.8% annual growth in Indiana coal production, or 86 million tons by 2010, a 145% increase. That document also proposed, but did not prepare, a third, disaggregate forecast methodology which would forecast Indiana coal production by end use – Indiana coal use by the utility sector, by the steel industry, and by the industrial sector for process steam.

The 2008 forecast uses the disaggregate approach, for three reasons. First, regardless of the method used, there have been significant developments in the lasts three years which have changed the competitiveness of Indiana coals relative to its substitutes. Second, since 2005, several new EIA reports have been prepared whose results should be incorporated in such an updated coal forecast, including an updating of actual Indiana coal production and deliveries. (The 2006 report was based on 2004 Indiana coal production, the last year such data was available from EIA at the time of the forecast.) Finally, all these developments can best be understood in the context of the disaggregate model, rather than the alternative approaches. Since the budget was limited, the forecast was created by a compilation of the consequences of existing studies that relate to future uses of Indiana coals, not on any original supporting work to be done by the proposer.

The forecast was prepared in phases. Phase I was to forecast the use of Indiana coal by the electricity sector, which now accounts for over 95% of Indiana coal use, but only 58% of the use of all coal used to generate electricity in Indiana. The prospects for expanded use of Indiana coal due to import substitution and to accommodate forecast growth in electricity use in Indiana was explored, as were opportunities for developing the export markets for Indiana coals for use in generating electricity in other states. Major new studies examined included the latest SUFG forecast of Indiana electricity supply and demand, the SUFG white paper on the impact of pending CO_2 legislation on coal use, the CCTR studies regarding the transportation of Indiana coals, new technologies, and the various new studies regarding coal use which have been prepared since the last forecast, including the National Academy study. In preparing this, and other sections of the forecast, the scenario approach was used to emphasize the impact key factors such as the scope and design of CO_2 legislation will have on Indiana coal use. Meetings with key utility decision makers were part of this phase to make sure the forecasts were "ground truthed."

Next, Phase II focused on forecasting the use of Indiana coals by the steel industry, for coking (ore reduction), blast furnace heat, and steam production. Since no Indiana coals are now used in Indiana steel production, this section of the forecast is much more speculative than the utility use forecast, primarily utilizing "what if" forecasts of Indiana coal use by the steel industry. Studies examined included the work for CCTR of Kramer and his colleagues, and the competition between natural gas and coal as a source of heat in the blast furnaces and mills. Again, the forecast was "ground truthed" by discussing the results with key decision makers in the steel industry.

Finally, in Phase III, prospects for growth in the use of Indiana coals by the industrial sector for process steam and heat were examined, a use relatively ignored in past studies. While this sector now accounts for only 5% of total use, there could be resurgence in coal-based cogeneration demand, if natural gas prices continue to increase. Since total use is small, no forecast was presented.

APPENDIX B – TIMELINE OF THE STUDY

The table below gives the dates of the study deliverables. The project was completed by August 2008 in time to be incorporated into the CCTR 2008 coal report.

	JUNE	JULY	AUGUST	SEPTEMBER
PHASE I	Completed in June, interim report at CCTR Bloomington meeting			
PHASE II		Completed in July		
PHASE III		Completed in July		
FINAL REPORT			Completed in August	