Andover Technology Partners 978-683-9599
Consulting to the Air Pollution Control Industry

Uncontrolled CO_2 Emission Rates From Selected Electric Generating Units

C-16-2--EDF

to:

Environmental Defense Fund
257 Park Avenue South
New York, NY 10010

August 26, 2016

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Background

In October 2015 US EPA issued their Final Rule - Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units. This rule established performance standards for CO_2 emissions.

EDF has requested that Andover Technology Partners examine reasonable baseline emission rates for new, uncontrolled (no CO_2 capture) supercritical pulverized coal (SCPC) generating units by obtaining performance data from coal-fired power plants that are currently in operation, including plants located outside the U.S.

ATP has conducted a review of data associated with coal fired power plants in Asia, Europe and North America. ATP has also examined the NETL baseline emissions performance for new PC boilers relative to the actual units. This report identifies specific PC plants that have demonstrated low CO_2 emissions performance. For each plant, this report provides the following information, as available:

- Known plant characteristics, including name, location, fuel, pollution control systems, capacity factor, ambient conditions, etc.
- Recent CO_2 emissions performance of the plant in lb CO_2/MWh-g. For comparability with EPA's baselines performance has been determined on a 12-month average basis.
- Identify any factors that affected how the performance of a plant should be compared to the baseline facility chosen by EPA.

Program Results

This study examines the performance of modern pulverized coal power plants as it relates to CO_2 emissions. Case studies of efficient facilities that have been operated for decades as well as the newest and most efficient facilities will be presented. This will demonstrate the evolution of pulverized coal steam generating plants and the resulting improvements in efficiency and emissions.

Various measures of performance

Throughout this document different terminology will be used as indications of performance because different sources of information used different measures. Therefore, it is important to review the different measures of performance, how they relate to one another and how to convert from one measure to another.

Efficiency – Or, *thermal efficiency*. For power plants the efficiency is the amount of electrical energy produced per unit of fuel heat energy input and it is equal to electrical output divided by the heat input. It is typically expressed as a percent and it is therefore important that both the electrical output and heat input be in the same units when calculating efficiency – for example, megawatts of thermal or electrical energy. There are different measures of efficiency based upon whether the electrical output includes the plant auxiliary loads (gross output) or if the output is after subtraction of auxiliary loads (net output) and whether the heat input is on a lower heating value basis (LHV basis) or a higher heating value basis.(HHV). The distinction between LHV and HHV is that HHV includes in the available fuel energy the heat of vaporization of moisture that is present in the exhaust gases while LHV does not include in the available fuel energy the heat of vaporization of moisture that is present in the exhaust gases. This is why the heating value of a fuel expressed as HHV is somewhat higher than that expressed in LHV. Therefore, the efficiency on a HHV basis is somewhat lower than that on an LHV basis. Table 1 shows how to convert efficiency expressed in one form to another form.

Heat Rate - Heat Rate is most commonly expressed in Btu/kWh and is equal to 3412 Btu/kWh divided by the efficiency. Like efficiency, it is important to understand if the heat rate is expressed in terms of net or gross output or fuel LHV or fuel HHV. In the United States heat rate is most commonly expressed in the form of HHV for the fuel and may be either expressed in terms of gross output or net output. Outside the US, however, LHV is frequently the basis of fuel heat input. So, to determine heat rate while knowing efficiency, first convert the efficiency to the form that is of interest (net or gross, HHV or LHV) and then divide 3412 by the efficiency expressed as a fraction (for example, 0.40 for 40%).

Table 1. Converting efficiency expressed in one form into another form.

To ⬇ / From →	Gross, LHV	Gross, HHV	Net, LHV	Net, HHV
Gross, LHV	Equal	Multiply by fuel HHV and divide by fuel LHV	Multiply by gross output and divide by net output	Multiply by gross output and fuel HHV and divide by net output and fuel LHV
Gross, HHV	Multiply by fuel LHV and divide by fuel HHV	Equal	Multiply by gross output and fuel LHV and divide by net output and fuel HHV	Multiply by gross output and divide by net output
Net, LHV	Multiply by net output and divide by gross output	Multiply by net output and fuel HHV and divide by gross output and fuel LHV	Equal	Multiply by fuel HHV and divide by fuel LHV
Net, HHV	Multiply by net output and fuel LHV and divide by gross output and fuel HHV	Multiply by net output and divide by gross output	Multiply by fuel LHV and divide by fuel HHV	Equal

Emission rates – Emission rate can be expressed in terms of either mass per unit of heat input or mass per unit of electricity output. The CO_2 emission rate expressed in mass per unit of electrical output is a direct result of the CO_2 emissions intensity of the fuel, expressed in terms of lb of CO_2 per million Btu of fuel heating value, and the heat rate of the power plant, expressed in terms of Btu/kWh. The heat rate of the power plant is also inversely related to efficiency, expressed as a percent. Because the carbon intensity of a fuel is a function of the fuel type, once the fuel is selected heat rate is the important determinant of the CO_2 emission rate.

For coal, CO_2 emission rates on a heat input basis are generally on the order of 200-220 lb/million Btu (HHV), depending upon the specific coal characteristics. Bituminous coals tend to produce lower CO_2 emissions per unit of heat input than lower rank coals. Emission rates can also be expressed on a pound per megawatt hour of output basis, and it is important to indicate if the output is net or gross (whether or not the output includes auxiliary loads).

Converting from efficiency to emission rate – For most of the overseas facilities performance information was available for efficiency, but not for CO_2 emissions rate. To convert from a reported efficiency to a CO_2 emission rate in pounds per unit of output it is first necessary to have the right form of efficiency. Many overseas facilities tend to report efficiency on a net, LHV basis and emission rates are often expressed on a pound per million Btu (HHV) basis. Some overseas facilities will express CO_2 emissions on a gram per kWh basis. In this case it is important to know if the output is gross output or net output.

- If the emission rate desired is on a gross basis (such as lb/MWh gross), converting efficiency to a gross HHV basis will be required first.
- Then, convert to heat rate (gross, HHV basis) by dividing 3412 by the efficiency expressed as a fraction.
- Next, determine the emission rate for the particular coal (lb/million Btu HHV) based upon the coal properties
- Multiply the heat rate

Example -

A 500 MWg (474 MWnet) power plant has a 40% efficiency (net, LHV). It burns coal that has 11,000 Btu/lb (HHV) and 10,340 Btu/lb (LHV) heating value. The coal also emits 205 lb CO_2 per million Btu (HHV). Determine the CO_2 emission rate on a lb/MWh gross basis.

- First, convert efficiency to a gross, HHV basis:
  - 40% * (500 MWg * 10,340 Btu/lb) /(474 MWnet * 11,000 Btu/lb) = 39.66%
- Next, determine the heat rate on a gross, HHV basis:
  - 3412 Btu/kWh / 0.3966 = 8,605 Btu/kWh
- Next, multiply by the CO_2 emission rate on a heat input basis and convert units
  - 8605 Btu/kWh * 205 lb/million Btu * (1000kWh/MWh)/(10^6Btu/million Btu) = ***1764 lb CO_2/MWh gross***

Using the conversion method shown in Table 1 for different forms of efficiency and the methodology shown in the associated example along with a few assumptions it is possible to characterize the relationship that exists between net thermal efficiency and the CO_2 emission rate. Recalling,

- 3412 Btu/kWh divided by efficiency results in heat rate

- Heat rate times emission rate for the fuel results in emission rate per unit output

Figure 1a shows the relationship between net thermal efficiency (HHV basis) and CO_2 emissions for bituminous and subbituminous coal, assuming that the CO_2 emissions for bituminous coal are 205 lb/MMBtu (HHV) and the CO_2 emissions for subbituminous coal are 215 lb/MMBtu (HHV).[1] Another assumption is that the auxiliary load is 5.2% of gross load, consistent with the NETL baseline study. According to this figure, a facility firing bituminous coal that has a net thermal efficiency of 41% (HHV) would be expected to have a CO_2 emission rate of about 1,706 lb/MWhnet and about 1,617 lb/MWhgross. Similarly, a subbituminous unit with a 40% heat rate would have a CO_2 emission rate of about 1834 lb/MWhnet and about 1,739 lb/MWhgross.

The difference between HHV and LHV heating value will depend upon the specific fuel. For an Illinois Basin bituminous coal with about 12% moisture the HHV fuel heating value may be on the order of roughly 5.8% greater than the LHV fuel heating value and for a PRB fuel with about 30% moisture the difference may be roughly 7.5%. [2] A lower fuel moisture content and lower fuel hydrogen content will result in a smaller difference between the HHV heating value and the LHV heating value. Therefore, efficiency for any given unit when reported on a LHV basis will be somewhat higher than efficiency reported on a HHV basis and the difference will depend upon the fuel used. Figure 1b shows the estimated relationship between net thermal efficiency (LHV basis) and emissions for bituminous and subbituminous coal.

Figure 2 demonstrates the importance of having a high efficiency when using CCS in combination with a pulverized coal plant. This is also discussed in EPA's Final Rule in why they selected highly efficiency supercritical pulverized coal with partial CCS as EPA's Best System of Emission Reduction for coal-fired generation and in the rulemaking docket.[3] As shown, CCS will adversely impact the generating efficiency of a pulverized coal plant. For supercritical units, net efficiency will drop from just over 40% LHV to about 35% LHV. However, as the efficiency of the steam cycle improves and the uncontrolled CO_2 intensity is improved, the adverse impact of CCS on the overall plant efficiency is also reduced. Advanced

[1] US Energy Information Administration, https://www.eia.gov/tools/faqs/faq.cfm?id=73&t=11

[2] This was estimated for two coals using the Constants_CC worksheet of US EPA's CUECOST model.

[3] Federal Register /Vol. 80, No. 205 / Friday, October 23, 2015 /Rules and Regulations 64547
Memo to Rulemaking Docket ID: EPA-HQ-OAR-2013-0495; US EPA Memo, Subject: Achievability of the Standard for Newly Constructed Steam Generating EGUs, July 31, 2015

USC plants with CCS could have efficiencies close to 45% - better than current supercritical plants without CCS.

Figure 1a. Relationship between thermal efficiency (HHV) and CO_2 emissions for bituminous and subbituminous coals.

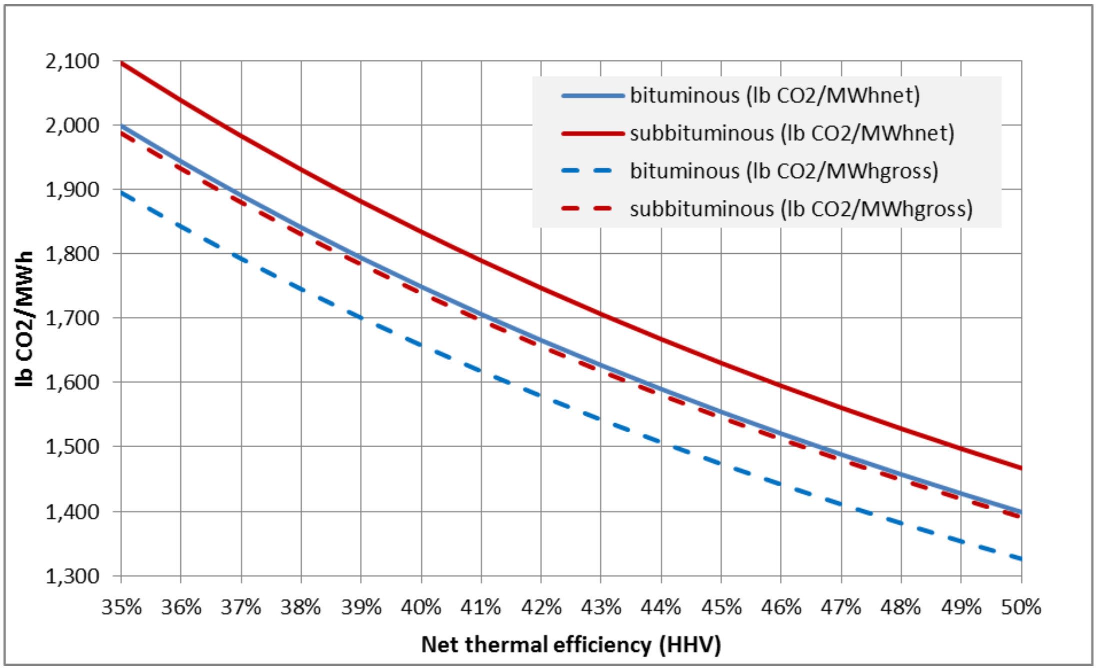


Figure 1b. Relationship between thermal efficiency (LHV) and CO_2 emissions for bituminous and subbituminous coals.

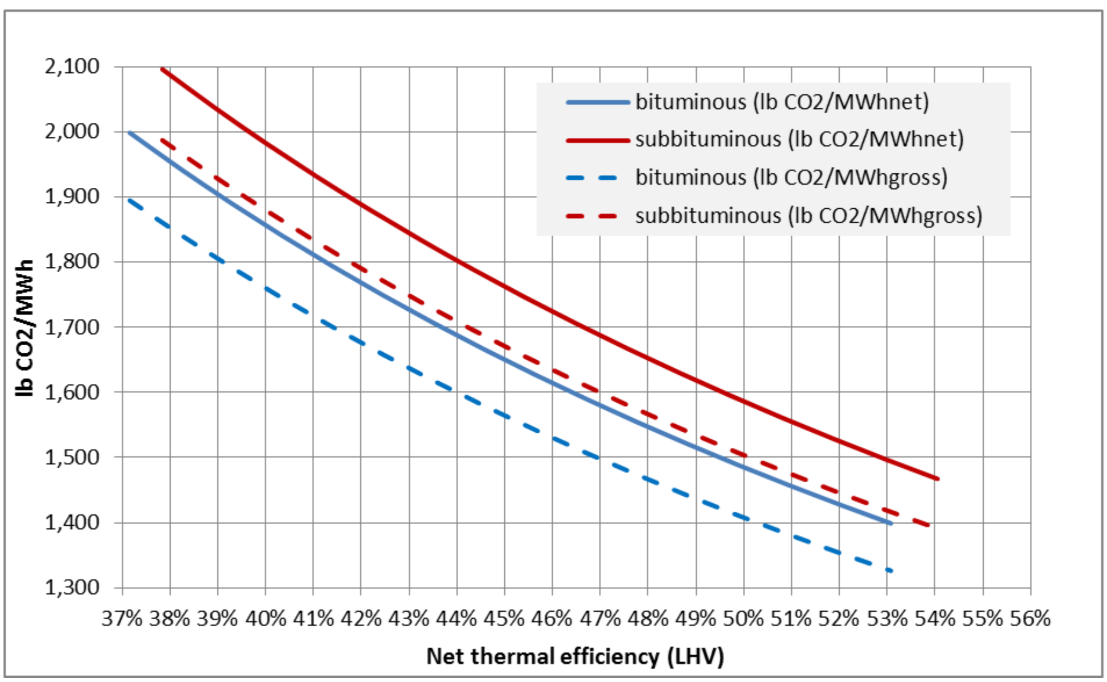
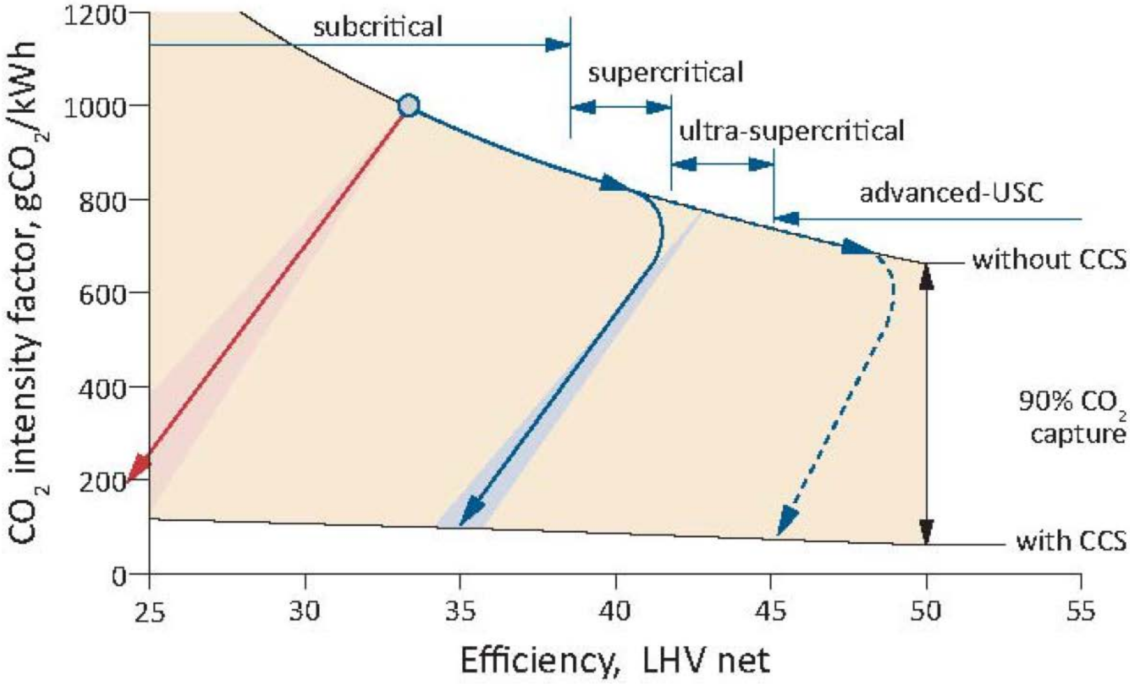


Figure 2. CO_2 Intensity and efficiency of different steam cycles, with and without CCS[4]



[4] Barnes, I., "Upgrading the Efficiency of the World's Coal Fleet to Reduce CO2 Emissions", *Cornerstone Magazine*, http://cornerstonemag.net/upgrading-the-efficiency-of-the-worlds-coal-fleet-to-reduce-co2-emissions/

Advances in Pulverized Coal Power Plant Performance

Modern pulverized coal power plants are more efficient than their predecessors. This is a result of several areas where technology has advanced.

Materials – Advanced alloys permit operation of the steam cycle at higher temperatures and pressures than previously possible. These higher temperatures and pressures enable the steam cycle to be more efficient. Supercritical technology – operation at pressures above the critical point where there is no distinction between liquid and vapor phase – has been available for decades. But, the operating temperatures and pressures of facilities built in the 1970s, for example, were limited by the available materials. Figure 3 is from IEA Coal Research, and shows the evolution of generation technology over time.[5] As shown there and in Table 2, supercritical boilers were built to operate with maximum steam temperature of about 550-560°C (1020-1040°F). Ultra-supercritical boilers can operate in the range of 580-600°C (1075-1105°F) and at higher pressures of about 25 Mpa (3625 psi) or greater. Advanced ultrasupercritical boilers would operate at even greater temperatures and pressures. The US Department of Energy has embarked on major development programs to improve the materials available for boilers as well as for turbines in order to allow for higher temperature and higher pressure systems. [6] These programs include government and industry consortiums with boiler manufacturers (Babcock & Wilcox, Alstom, Foster Wheeler, and Riley Power), turbine manufacturers (GE, Siemens and Alstom), industry groups (EPRI, Energy Industries of Ohio), and government (US DOE, Ohio Coal Development Office[7] A goal of the Advanced USC program is to develop technology to operate at 1,400°F and 4,000-5,000 psi superheater temperature and pressure. The impact of increased superheater temperature is a significant increase in plant efficiency, as shown in Figure 4. In order to achieve the temperatures and pressures of an advanced

[5] Ito, O., "Emissions from coal fired power Generation", Workshop on IEA High Efficiency, Low Emissions Coal Technology Roadmap Date: 29 November 2011 Location: New Delhi

[6] Crosscutting Technology Research Program High Performance Materials: Advanced Ultra-Supercritical (AUSC) Consortium, Program 125, March 2015

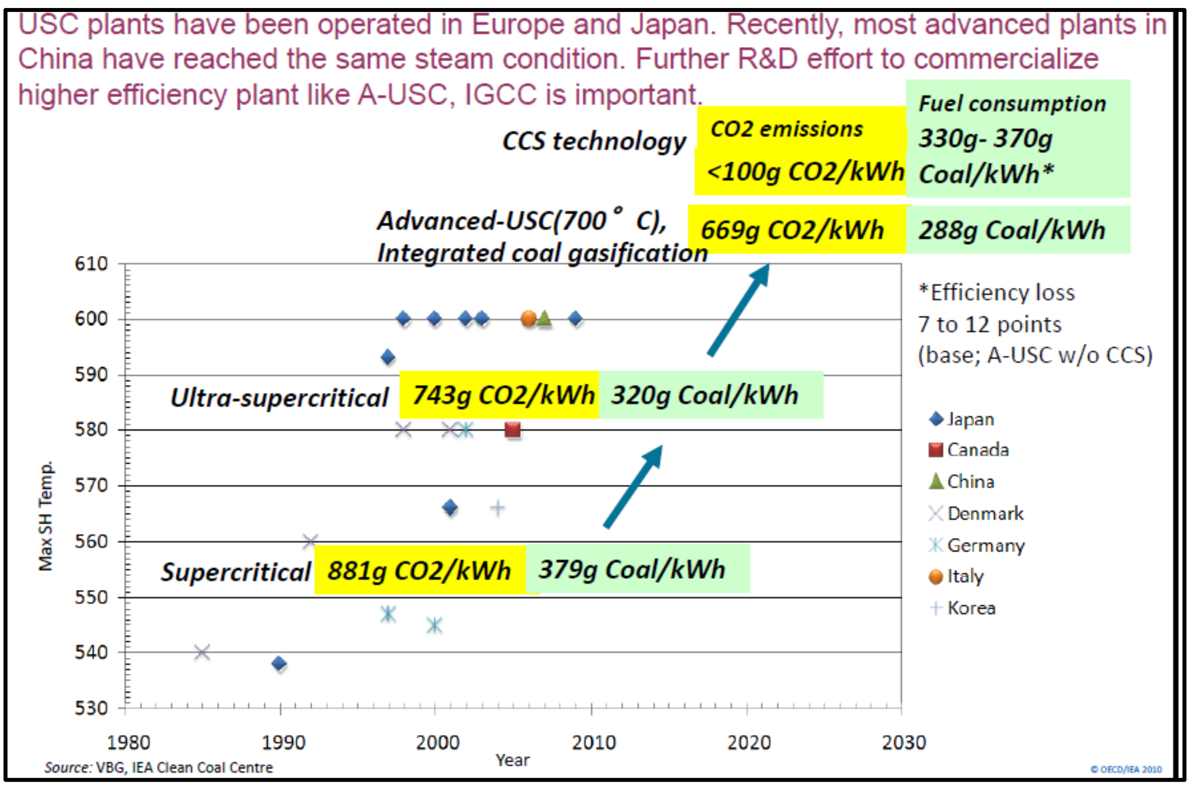
[7] Annual Progress Report, DOE Award Number: DE-FC26-05NT42442, OCDO Grant Number: D-05-02(B), Project Title: Steam Turbine Materials for UltraSuperCritical Power Plants, Date of Report: 12/31/2006, Period Covered by Report: 10/1/2005 - 9/30/2006

Annual Progress Report, Doe Award Number: DE-FC26-05NT42442, OCDO Grant Number: D-05-02(B), Project Title: Steam Turbine Materials for Ultrasupercritical Coal Power Plants, , Electric Power Research Institute, Date of Report: 10/18/2007 PERIOD COVERED BY REPORT: 10/1/2006 – 9/30/2007

Quarterly Progress Report, Doe Award Number: DE-FG26-01NT41175, OCDO Grant Number: D-05-02(A), Project Title: Boiler Materials for Ultrasupercritical Coal Power Plants, Date of Report: 10/15/2007, Period Covered by Report: 7/1/2007 – 9/30/2007 ultrasupercritical plant new American Society of Mechanical Engineers (ASME) design codes must be prepared for the advanced materials. Figure 5 shows allowable stress, in thousand psi, versus temperature for current steels as well as the expected values that were submitted to ASME for the alloys INCO 740 and Haynes 282. A higher allowable stress at a given temperature permits higher steam generator operating pressures. As this figure demonstrates, these two alloys permit operation at much higher temperatures and pressures than steels that are currently used for boiler construction.

Modern Controls and Auxiliaries – Modern control systems and auxiliaries, along with improved energy integration, permit auxiliary load and other losses to be reduced. According to National Energy Technology Laboratory (NETL) baseline studies, the parasitic load for a modern, 580 MW pulverized coal facility is 30 MW, or 5.17% of gross MW.[8]

Figure 3. Evolution of steam generation technology.[9]



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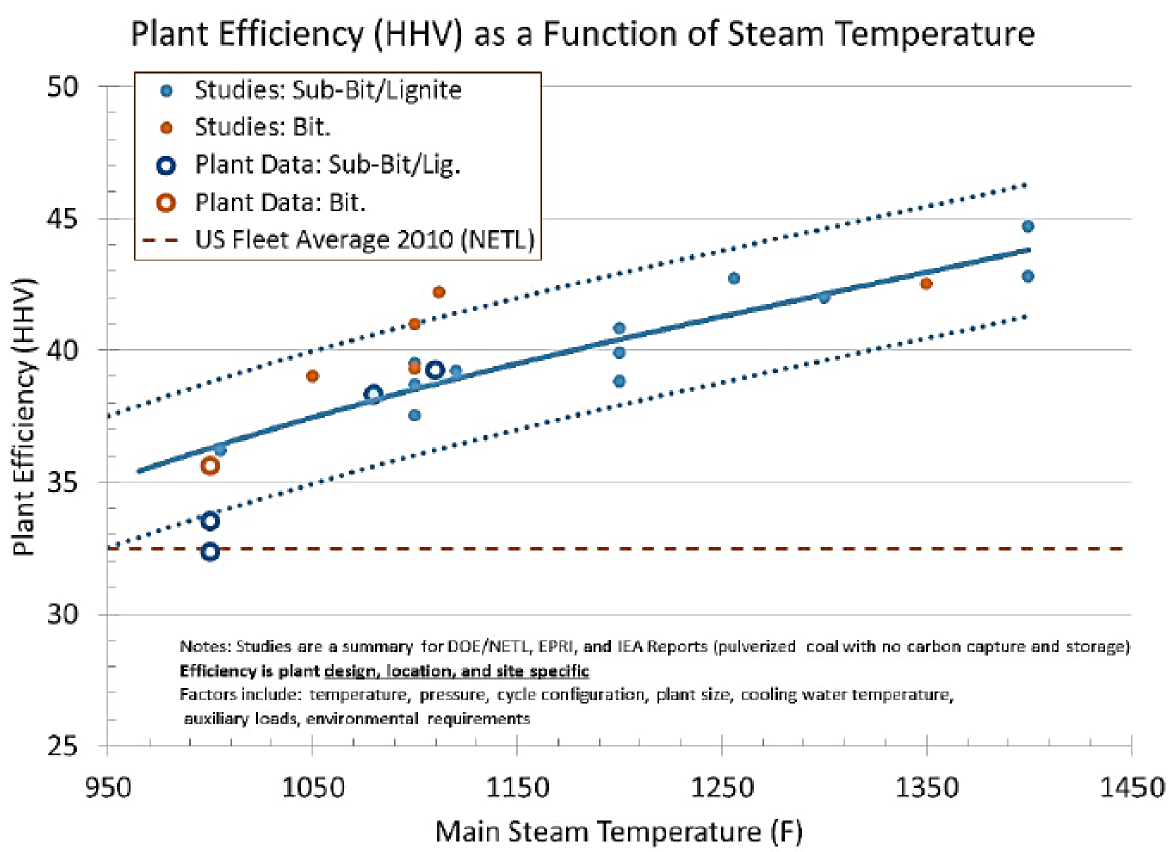
[8] NETL, "Cost and Performance Baseline for Fossil Energy Plants", Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity, Revision 3, July 6, 2015, page 15

[9] Ito, 2011

Table 2. Steam cycle, conditions and efficiency [10]

Nomenclature	Steam Conditions	Net Plant Efficiency (HHV)
Subcritical	2400psig 1000 to 1050ºF	35%
Supercritical (SC)	>3600psig ~1050ºF (550ºC) and above	38%
Ultrasupercritical (USC)	>3600 psig ~1100ºF (600ºC) and above	>42%
Advanced-UltraSupercritical (A-USC)	4000-5000psig 1300-1400ºF (700-760ºC)	>45%

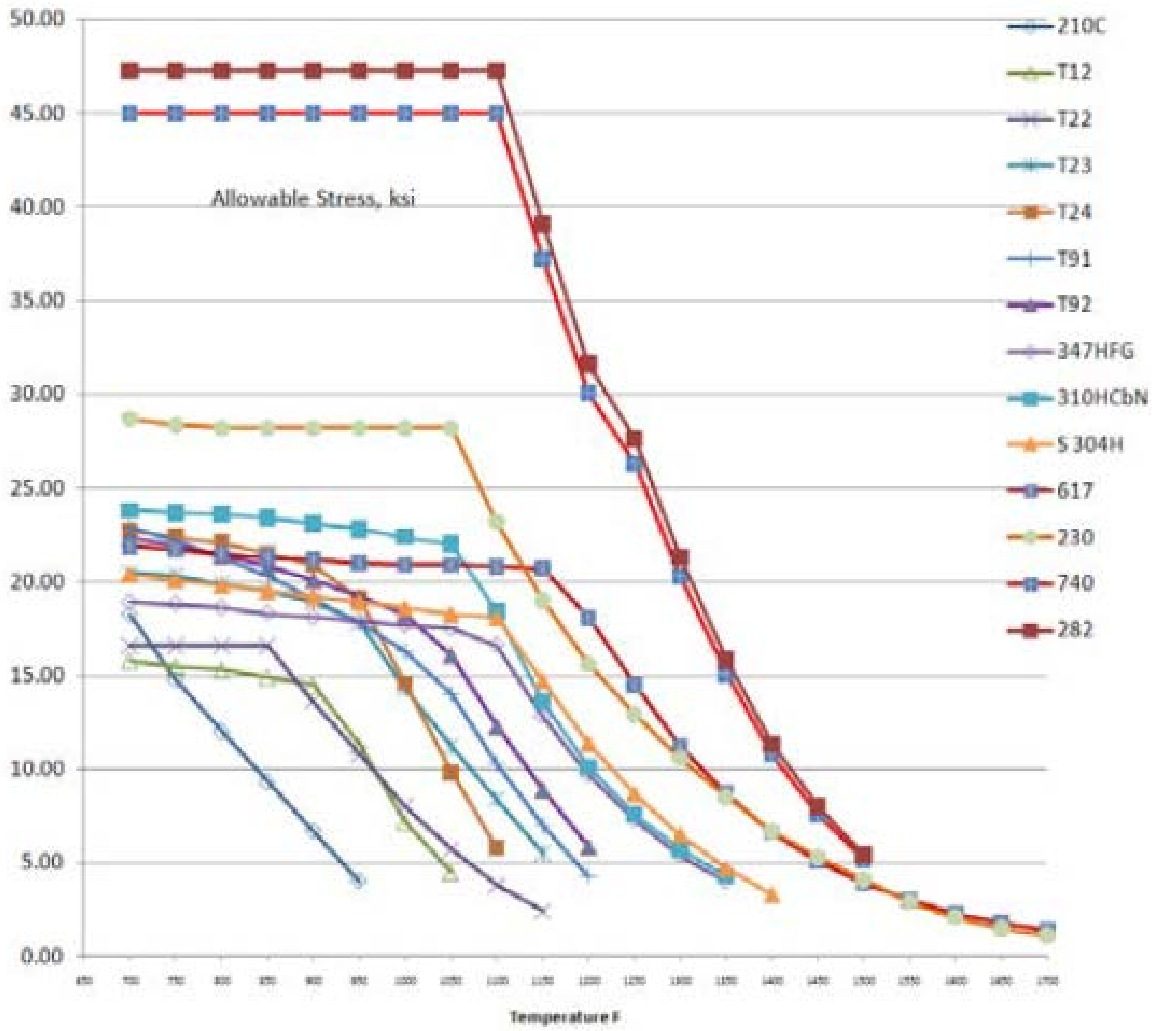
Figure 4. Efficiency as a function of steam temperature [11]



[10] Purgert, B., Shingledecker, J., "Update on U.S. DOE/OCDO Advanced Ultrasupercritical (A-USC) Steam Boiler and Turbine Consortium", DE-FG26-01NT41175OCDO Grant: CDO-D-05-02(A)DE-FE0000234OCDO Grant: CDO-D-05-02(B), DOE-FE Cross-Cutting Review MeetingApril 29, 2015: Pittsburg, PA USA

[11] Ibid

Figure 5. Allowable stress versus temperature for different steels and alloys[12]



[12] Weitzel, P. “Steam Generator for Advanced Ultra-Supercritical Power Plants 700 to 760C”, ASME 2011 Power Conference, July 12-14, 2011

NETL Baseline Studies

The United States Department of Energy's National Energy Technology Laboratory performed system studies to evaluate the capabilities of current coal generation technology as well as technologies with CO_2 capture. They performed studies of power plants utilizing both bituminous and low rank (subbituminous and lignite) coals.[13] The system study is an engineering evaluation of plant designs operating at 85% capacity factor. As described in the baseline study for the bituminous coal,

> *"The methodology for developing the results presented in this report included performing steady-state simulations of the six power plant configurations using the Aspen Plus® (Aspen) process modeling software. The major plant equipment performance and process limits were based upon published reports, information obtained from vendors and users of the technology, performance data from design/build utility projects, and/or best engineering judgment."*[14]

Aspen Plus is a well-established system simulation software tool that is widely accepted within the energy industry. Pulverized coal power plants are well understood technology that use equipment components that are commercially available and well understood. Experience with this equipment is extensive and the Aspen Plus modules are therefore benchmarked. The system performance estimates are therefore expected to be reliable for the assumptions used. Some of the important assumptions and resulting performance are shown in Table 3. More data is shown in the Appendices.

The supercritical bituminous and ultrasupercritical subbituminous baseline studies were used by EPA in the final rule for CO_2 emissions from new units to estimate the uncontrolled emission rates of new units of 1620 lb/MWh and 1740 lb/MWh, respectively.[15]

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[13] US Department of Energy, National Energy Technology Laboratory, "Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity Revision 3", July 6, 2015, DOE/NETL-2015/1723

US Department of Energy, National Energy Technology Laboratory, "Cost and Performance Baseline for Fossil Energy Plants, Volume 3 Executive Summary: Low Rank Coal and Natural Gas to Electricity", September 2011, DOE/NETL-2010/1399

[14] US Department of Energy, National Energy Technology Laboratory, "Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity Revision 3", July 6, 2015, DOE/NETL-2015/1723, pg. 13

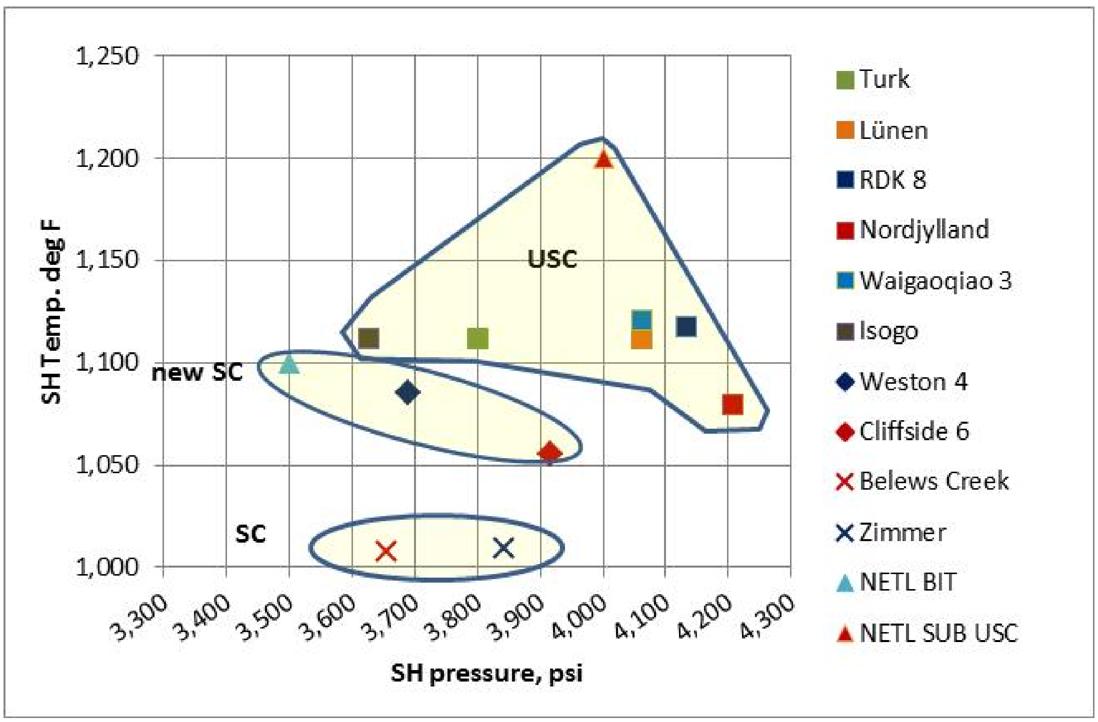
[15] F40 CFR Parts 60, 70, 71, et al. Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units; Final Rule, Federal Register / Vol. 80, No. 205 / Friday, October 23, 2015 / Rules and Regulations, pg. 64562

Table 3. Characteristics of the NETL Baseline Pulverized Coal Plants					
	Bit SC	Subbit SC	Subbit USC	Lig SC	Lig USC
Location	Midwest	Montana	Montana	North Dakota	North Dakota
SH temp	1100	1100	1200	1100	1200
SH press	3500	3500	4000	3500	4000
RH temp	1100	1100	1200	1100	1100
MW gross	580	583	582	585	583
MW net	550	550	550	550	550
Capacity Factor	85%	85%	85%	85%	85%
NOx Control	SCR	SCR	SCR	SCR	SCR
SO2 Control	Wet FGD	Dry FGD	Dry FGD	Dry FGD	Dry FGD
PM Control	Baghouse	Baghouse	Baghouse	Baghouse	Baghouse
Cooling	Recirculating	Recirculating	Recirculating	Recirculating	Recirculating
CO2 emissions, lb/MMBtu	204	215	215	219	219
Efficiency (net, HHV)	40.7%	38.7%	39.9%	37.5%	38.8
Heat Rate, Btu/kWh net	8379	8813	8552	9093	8795
CO_2 emissions, lb/MWh gross	1618	1786	1737	1877	1820
CO_2 emissions, lb/MWh net	1705	1892	1836	1996	1930

Operating Plants

This report examines ten plants in the United States, Europe and Asia that are regarded as extremely efficient units. Some of these units are as much as over 40 years old and demonstrate the potential of supercritical technology that has been available for years. The other units examined in this report are more recently constructed supercritical and ultra-supercritical technology facilities that more closely resemble the state of the art in boiler construction. Figure 6 shows the steam temperature and pressures of these units, and how, over time, technology has evolved to higher temperatures and pressures. Importantly, this figure demonstrates an evolution rather than a step change in superheater temperature and pressure, with some of the newer "supercritical" units having temperatures and pressures approaching those of some of the "ultrasupercritical" units. In any event, as newer materials become available for the boiler and steam turbine, higher pressures and temperatures will be possible in the future, resulting in even higher efficiencies.[16, 17]

Figure 6. Superheater temperature and pressure of units examined [18]



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[16] Purgert, B., Shingledecker, J., "Update on U.S. DOE/OCDO Advanced Ultrasupercritical (A-USC) Steam Boiler and Turbine Consortium", DOE-FE Cross-Cutting Review MeetingApril 29, 2015: Pittsburg, PA USA

[17] Nicol, K., "Status of advanced ultra-supercritical pulverized coal technology" IEA Clean Coal Centre , CCC/229 ISBN 978-92-9029-549-5, December 2013

[18] There was some inconsistency between sources regardng the SH pressure for the Cliffside 6 boiler

For units operating in the United States, data is readily available on CO_2 emissions and electricity generation from US EPA's Air Markets Program Data (AMPD), and the CO_2 emission rate can be directly calculated from that data. Because data to directly calculate CO_2 emission rates are not available for the overseas facilities, it is necessary to estimate CO_2 emission rates from reported heat rates, coal consumption, or efficiency. For any given fuel, the CO_2 emission rate (in lb/MWh) is directly proportional to the heat rate. In the case of most overseas facilities, efficiency – which is the inverse of heat rate - was reported. From reported efficiency it is possible to estimate the CO_2 emission rate using the methodology described earlier in this report.

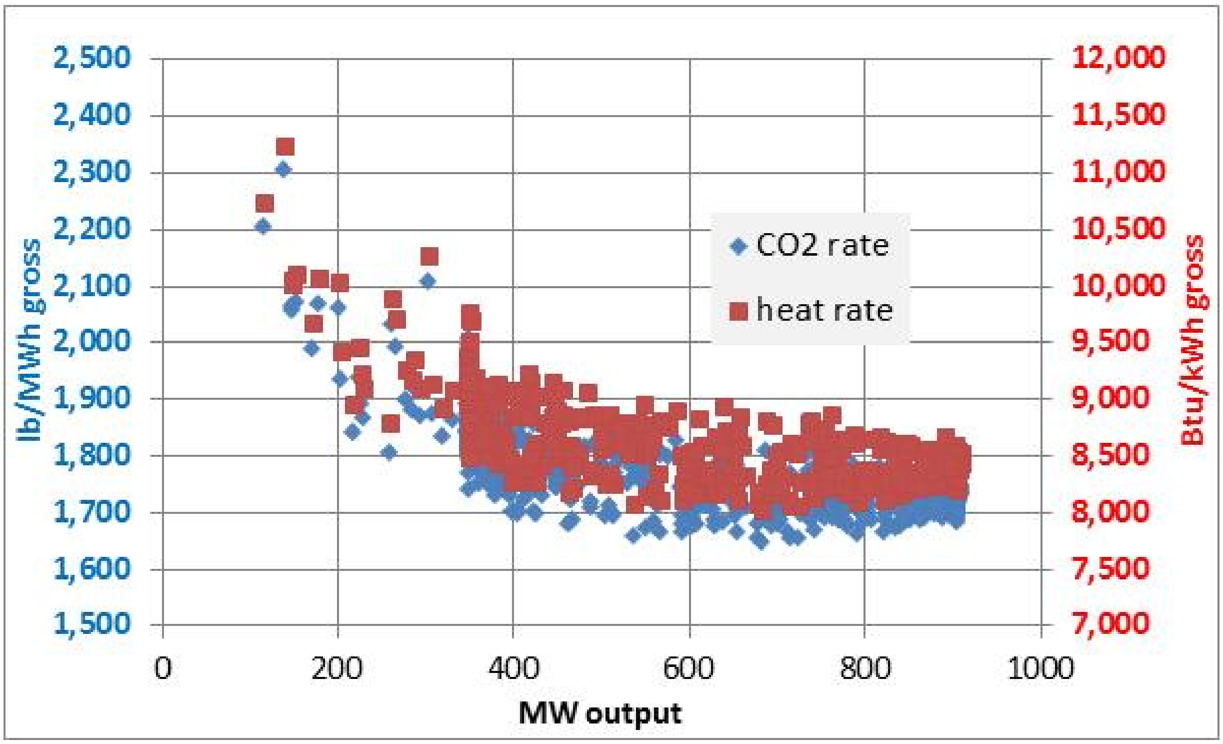
As noted earlier, ten case studies were examined, and the detailed results will be in the next section. In every case for the US-based plants comprehensive operating data was available to determine annual average CO_2 emission rates in lb/MWh gross as well as heat rate.

Capacity factor will play a role in determining the annual heat rate and CO_2 emission rate. Figure 7 shows calculated hourly heat rate and CO_2 emissions rate for Cliffside 6 (now, one of two units at the renamed Rogers Energy Center) for periods where the unit was in operation during the first half of 2016. The data was taken from EPA's AMPD. It shows that as load is decreased, both heat rate and CO_2 emissions rate increase. Over this period, the average heat rate was 8,518 Btu/kWh gross and the average CO_2 emission rate was 1,748 lb/MWh gross. On the other hand, if only periods where load was greater than 800 MWgross are considered, the heat rate was 8,363 Btu/kWh gross and the average CO_2 emission rate was 1,716 lb/MWh gross. Initial performance testing of a power plant is normally performed at or near full load over a period of time to demonstrate reliability and efficiency. The initial testing of the Cliffside 6 boiler demonstrated that it had a heat rate of 8,890 Btu/kWh net.[19] If auxiliary loads are assumed to be 5.2% of total load, this equates to a heat rate of 8,428 Btu/kWh gross, close to the heat rate achieved at high loads during the first half of 2016. Comparing the average heat rate determined from AMPD data over the six month period to that for periods where load was over 800 MW, the average heat rate was 1.8% higher than for only the high load periods. A similar analysis was performed for Weston 4 and Turk power plants. It was found that Weston 4's average heat rate over the first half of 2016 (when it was operating) was 2.8% higher than for when it only operated at 500 MWg or more (8216 Btu/kWh gross versus 7991 Btu/kWh gross and 1723 lb/kWh gross versus 1676 lb/kWh gross). For Turk, that analysis showed that for when

[19] http://www.powermag.com/cliffside-steam-station-unit-6-cliffside-north-carolina/?printmode=1

Turk operated at over 600 MWg, the heat rate was slightly lower than the average for the period (8849 Btu/kWh gross versus 8923 Btu/kWh gross and 1856 lb/MWh gross versus 1871 lb/MWh gross). In 2013 Turk reportedly had a heat rate of 8858 Btu/kWh.[20] Turk plant's design heat rate ia 8730 Btu/kWh net,[21] or roughly 8276 Btu/kWh gross if auxiliary loads are 5.2%. Comparing the 2013 reported heat rate to the design heat rate results in the 2013 heat rate being 1.47% higher than the design heat rate. As the data from these three plants demonstrates, the effect of how the unit operates on the heat rate will vary from plant to plant.

Figure 7. Cliffside 6 hourly heat rate and CO_2 emission rate
Calculated from hourly US EPA AMPD data first half 2016



In the case of all of the overseas plants, efficiencies were reported and CO_2 emission rate was not available. In most cases only the efficiency demonstrated during the performance test was available. In one case – Waigaoqiao 3 – annual average efficiency data was made available as well as capacity factor. The annualized efficiency for the Waigaoqiao 3 plant averaged 44.4% (net, LHV) versus a design basis of 46% over the period of 2011 to 2013. On this basis, in order to estimate the annualized CO_2 emission rate for those overseas units where annual efficiency was not available, the estimated CO_2 emission rate determined from the performance test

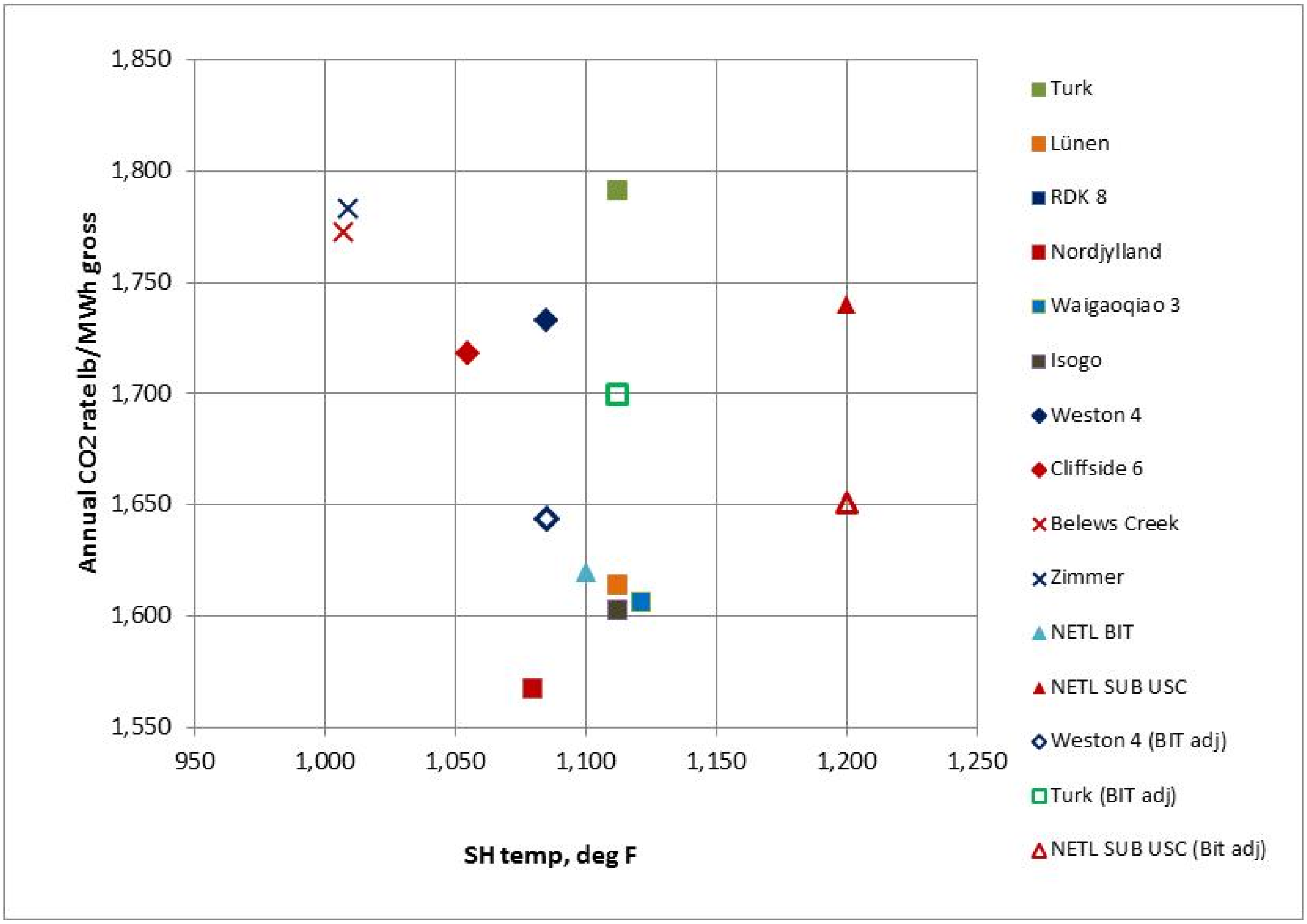
[20] http://www.power-eng.com/articles/print/volume-118/issue-7/features/america-s-best-coal-plants.html
[21] Peltier, R., "AEP's John W. Turk, Jr. Power Plant Earns POWER's Highest Honor", Power Magazine, 8/01/2013

measured efficiency was increased by 3.5%. It is acknowledged that the relationship between average annual CO_2 emission rate and that under design conditions will vary somewhat from unit to unit. However, 3.5% is a reasonable if not high difference to account for off-design operating conditions for new units that are likely to operate at a high capacity factor. It appears to be a conservative assumption considering what has been experienced at Cliffside 6, Weston 4 and Turk.

Adjusting tested heat rate to annual heat rate for the overseas plants by increasing it by 3.5% and assuming a CO_2 emissions level from the coal (as described in each of the case studies), it is possible to estimate the annual CO_2 emissions rate for the overseas plants. For the US plants, the average of the annual CO_2 emissions rate was determined from 2014 and 2015 US EPA AMPD. The annual estimated CO_2 emission rate versus SH temperature is plotted in Figure 8. As shown in Figure 8, the most efficient plants are estimated to have annual emission rates under 1600 lb CO_2 per MWh gross. All of these plants have modern PM, NOx and SO_2 controls. Figure 8 also shows the significance of superheater temperature in allowing lower emission rates, although other factors such as steam pressure and cooling water temperature will also play a role in determining efficiency and CO_2 emissions. Of these plants, except for Turk, Weston 4 and the NETL Subbituminous USC study, which are fueled with subbituminous coal, all of the plants burn bituminous coal. Adjusted values for these three subbituminous plants are also shown as if they had the same heat rate but fired bituminous coal at 204 lb CO_2 per million Btu versus 215 lb CO_2 per million Btu (consistent with CO_2 emission rates assumed in the NETL baseline studies for bituminous and subbituminous coals). The NETL SUB USC CO_2 emission rate when adjusted for bituminous coal still has a higher CO_2 emission rate than the NETL BIT case that has a lower superheater temperature. This is because the heat rate for the NETL SUB USC case is higher than for the NETL BIT case because of higher losses from the PRB coal, and that has not been adjusted for. Nevertheless, it appears from this figure that the annual emission rates of 1620 lb/MWh gross for bituminous units and 1740 lb/MWh gross for lower-rank units appear to be achievable for modern pulverized coal fired power plants with superheater steam temperatures in the range of about 1100°F or more.

Figure 8. Annual CO_2 emission rate versus superheater temperature

US units calculated from US EPA Air Markets Program Data- average of 2014 and 2015 annual rates
For overseas units rate is estimated from reported efficiency data and assumed coal CO_2 emission rate.



Case Studies

- Duke Belews Creek
- Dynegy, W. M. Zimmer
- Duke Cliffside 6
- Wisconsin Public Service Weston 4
- AEP John W. Turk
- Trianel Kohlekraftwerk Lünen, Germany
- Rheinhafen Dampfkraftwerk (RDK) 8, Germany
- Nordjylland Unit
- Waigaoqiao 3
- J-Power Isogo 2

Duke Belews Creek

Belews Creek units 1 and 2, shown in Figure 9, were placed in service in 1974 and 1975, respectively. They are located in North Carolina. Despite their over 40 years in service, the bituminous coal fired units are among the most efficient and lowest emitting coal facilities in the United States. Based upon US EPA's Air Markets Program Data, both units emitted under 1,800 lb CO_2/MWh gross in both 2014 and 2015.

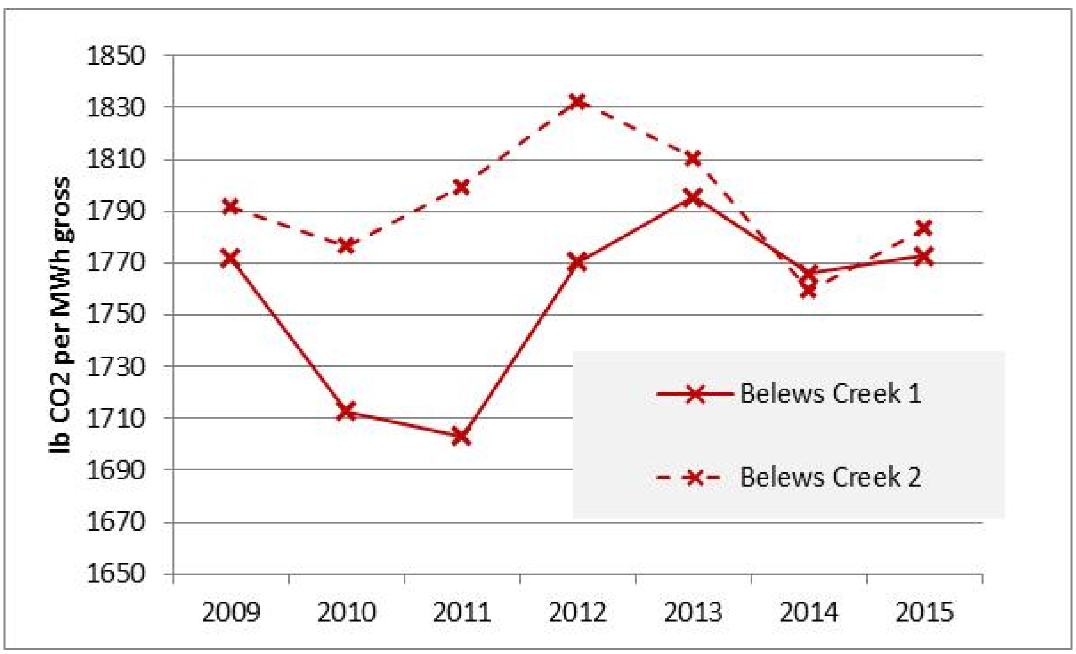
Both units are supercritical units and are equipped with modern emission controls, to include and ESP, SCR and limestone forced oxidation wet FGD system. Cooling water is provided from a man-made lake that was built when the Belews Creek plant was constructed. Table 4 lists some key characteristics of the Belews Creek units and Figure 10 shows CO_2 emissions since 2009. CO_2 emission rate was determined by multiplying the reported tons of CO_2 emitted by 2000 and dividing by the reported MWh gross. The capacity factor was determined by dividing the total gross MWh for the year by 8760 hours/year and dividing that be the reported summer capacity in MW.

Figure 9. Belews Creek 1 & 2

Table 4. Data on Belews Creek 1 & 2
(heat rate and CO_2 rate from AMPD data)

Year in service	1974/5
Net output, MW	1100 MW each
Coal type	bituminous
Superheater exit temperature,	1008 °F
Superheater exit pressure	3655 psi
Reheat temperature	1000 °F
Firing type	Wall
Cooling Water System	Once through, lake
SCR?	Yes
Baghouse or ESP?	ESP
SO_2 Control	Wet FGD
Unit 1 2014 Annual CO_2 rate (capacity factor %)	1,766 lb/MWh gross (78%)
Unit 1 2014 Annual gross heat rate	8606 Btu/kWh gross
Unit 2 2014 Annual CO_2 rate (capacity factor %)	1,760 lb/MWh gross (60%)
Unit 2 2014 Annual gross heat rate	8575 Btu/kWh gross
Unit 1 2015 Annual CO_2 rate (capacity factor %)	1,773 lb/MWh gross (62%)
Unit 1 2015 Annual gross heat rate	8637 Btu/kWh gross
Unit 2 2015 Annual CO_2 rate (capacity factor %)	1,783 lb/MWh gross (67%)
Unit 2 Annual gross heat rate	8693 Btu/kWh gross

Figure 10. Annual CO_2 emissions rate calculated from AMPD data



Sources:

https://www.duke-energy.com/power-plants/coal-fired/belews-creek.asp

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US EPA Air Markets Program Data

EIA Form 860

EIA Form 923

W. M. Zimmer Power Plant

Dynegy's Zimmer Power plant, shown in Figure 11, is located southeast of Cincinnati, OH on the Ohio River. The 1300 MW plant was placed in service in 1991. It is equipped with modern pollution controls, to include an ESP, SCR and wet FGD system using lime. The cooling system type is recirculating with a natural draft cooling tower and cooling water is from the Ohio River.

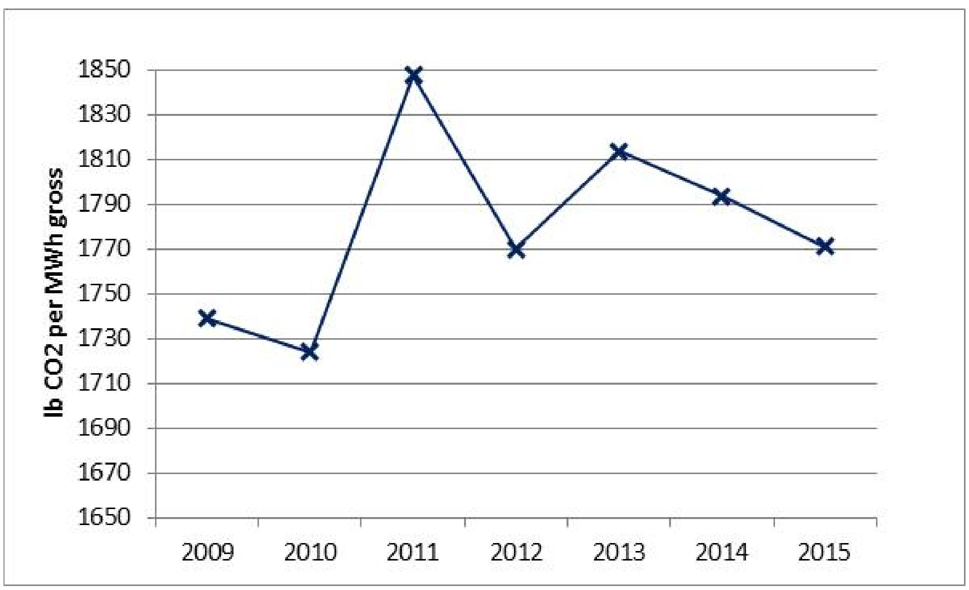
Based upon US EPA AMPD, Zimmer emitted 1,794 lb CO_2/MWh gross in 2014 and 1,771 lb CO_2/MWh gross in 2015. Table 5 lists key characteristics of the Zimmer plant and Figure 12 shows the CO_2 emission rate since 2009. CO_2 emission rate was determined by multiplying the reported tons of CO_2 emitted by 2000 and dividing by the reported MWh gross. The capacity factor was determined by dividing the total gross MWh for the year by 8760 hours/year and dividing that be the reported summer capacity in MW. In 2015 the Zimmer plant was not in service during the months of November or December.

Figure 11. Dynegy's W. M. Zimmer Plant

Table 5. Data on Dynegy's W. M. Zimmer Plant
(heat rate and CO_2 rate from AMPD data)

Year in service	1991
Net output, MW	1300 MW
Coal type	bituminous
Superheater exit temperature,	1009 °F
Superheater exit pressure	3844 psi
Reheat temperature	1000 °F
Firing type	Wall
Cooling Water System	Recirculating, natural draft, river
SCR?	Yes
Baghouse or ESP?	ESP
SO_2 Control	Wet FGD
2014 Annual CO_2 rate (capacity factor %)	1,794 lb/MWh gross (62%)
2014 Annual Gross heat rate	8742 Btu/kWh gross
2015 Annual CO_2 rate (capacity factor %)	1,771 lb/MWh gross (50%)
2015 Annual Gross heat rate	8637 Btu/kWh gross

Figure 12. Zimmer CO_2 emissions rate calculated from AMPD data



Sources:

http://www.dynegy.com/about/power-generation-facilities
Smith, J., "Babcock & Wilcox Company Supercritical (Once Through) Boiler Technology", BR-1658, May 1998
US EPA Air Markets Program Data
EIA Form 860
EIA Form 923

Duke Cliffside 6

Cliffside Power Plant was recently renamed James E. Rogers Energy Complex. Duke's Cliffside 6, shown in Figure 13, was placed in service in 2013 and is located in North Carolina. Cliffside 6 is an 800 MW unit that is equipped with an extensive air pollution control system that includes SCR, dry scrubber, baghouse, and wet scrubber. The unit utilizes closed-loop cooling towers. Water is drawn from the Broad River. The boiler is equipped with sliding pressure control to improve heat rate over the full load range versus throttled control of pressure to the main turbine. The reported steam pressure, depending upon the source, ranged from 3700 psi to 3992 psi.

Based upon information in US EPA's AMPD database, Cliffside 6's CO_2 emission rate was 1700 lb/MWh gross in 2014 and 1736 lb/MWh gross in 2015. Table 6 shows key characteristics of Cliffside 6 and Figure 14 shows CO_2 emission rates since 2012. CO_2 emission rate was determined by multiplying the reported tons of CO_2 emitted by 2000 and dividing by the reported MWh gross. The capacity factor was determined by dividing the total gross MWh for the year by 8760 hours/year and dividing that be the reported summer capacity in MW. In 2015 Unit 6 was not in service during the month of March.

Figure 13. Duke James E. Rogers Energy Complex (Cliffside) 6

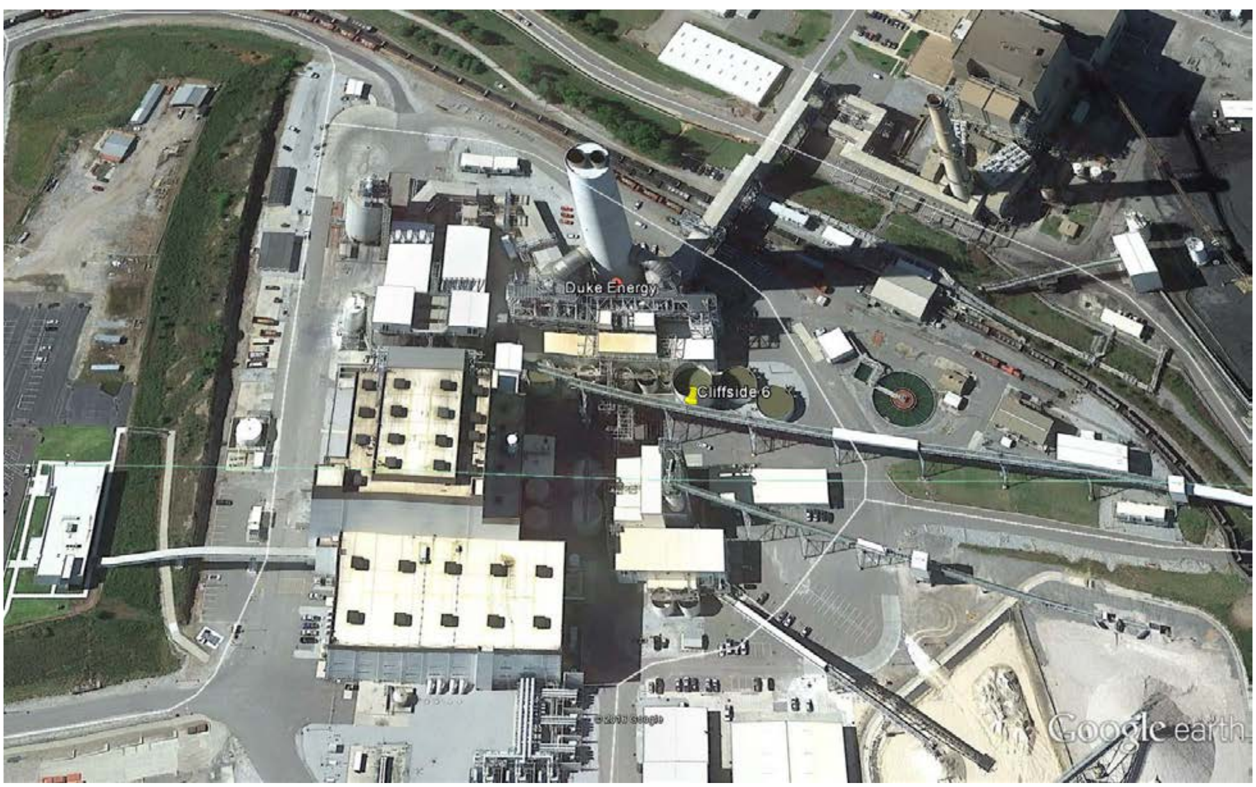
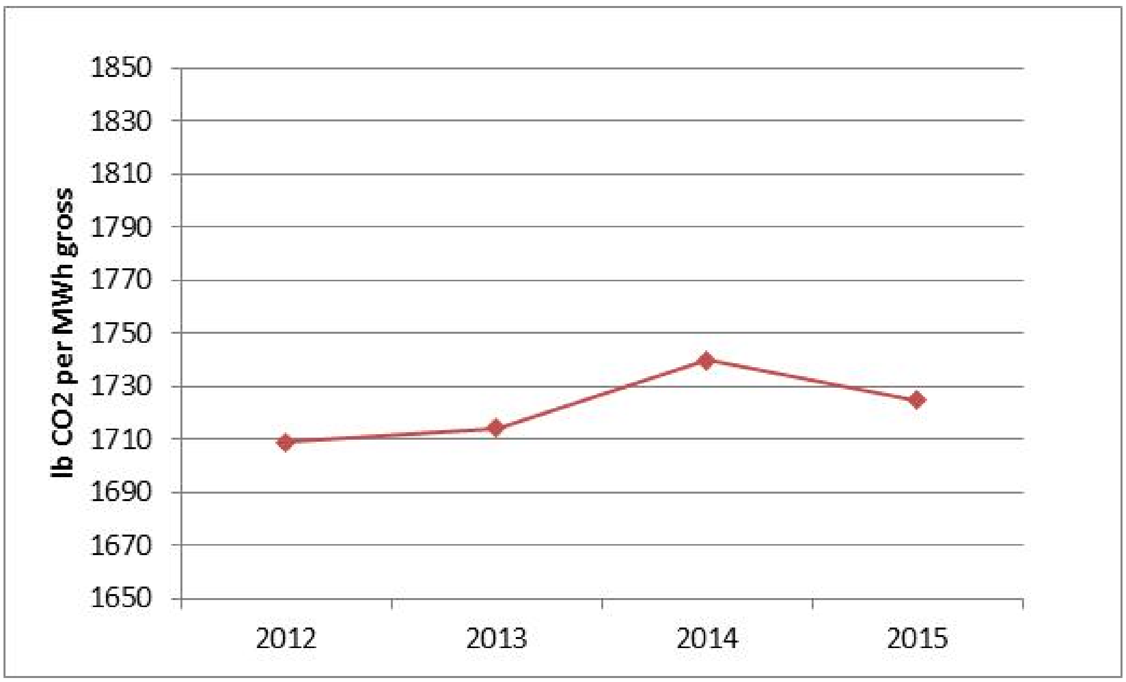


Table 6. Data on Cliffside 6
(heat rate and CO_2 rate from AMPD data)

Year in service	2013
Net output, MW	800 MW
fuel	Bituminous and bituminous-subbituminous blends
Superheater exit temperature,	1008 °F
Superheater exit pressure	3700 – 3992 psi*
Reheat temperature	1055 °F
Pressure Control	sliding
Firing type	Wall
Cooling Water System	Recirculating, river
SCR?	Yes
Baghouse or ESP?	Baghouse
SO_2 Control	Wet FGD, with upstream Dry FGD for SO_3 removal
2014 Annual CO_2 rate (capacity factor %)	1,700 lb/MWh gross (63%)
2014 Annual heat rate	8283 Btu/kWh gross
2015 Annual CO_2 rate (capacity factor %)	1,736 lb/MWh gross (42%)
2015 Annual heat rate	8450 Btu/kWh gross
* This is the range of steam pressures reported from different sources.	

Figure 14. Cliffside 6 CO_2 emission rate calculated from AMPD data



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Duke Energy, Cliffside Modernization Brochure

Overton, T., “Top Plant: Cliffside Steam Station Unit 6, Cliffside, North Carolina”, *Power Magazine*, 10/1/2013

Hitachi Power Systems, America, Ltd., Boiler Cut Sheet.

Lancaster, H., “Cliffside Unit 6 Integrated Air Quality Control System”, 2008 Mega Symposium, Baltimore, MD, August 28, 2008

US EPA Air Markets Program Data

EIA Form 860

EIA Form 923

Wisconsin Public Service Weston 4

Wisconsin Public Service Weston 4, shown in Figure 15, was placed in service in 2008. It is located near Wausau, WI. Weston 4 is a 416 MW unit that is equipped with an SCR, dry scrubber, and baghouse. The unit utilizes recirculating cooling with induced draft cooling towers. The water source is the Wisconsin River.

Based upon information in US EPA's AMPD database, Weston 4's CO_2 emission rate was 1740 lb/MWh gross in 2014 and 1725 lb/MWh gross in 2015 while firing subbituminous coal. If it fired bituminous coal the emission rate would be lower. Using 204 lb CO_2/MMBtu for bituminous coal and 215 lb CO_2/MMBtu for subbituminous coal (both per NETL baseline studies) and assuming that the heat rate does not change, the emissions rate will drop in proportion to the lower CO_2 emission rate for the fuel, or 204/215 or 94.88%. If this is multiplied by 1732 lb CO_2 per MWh gross (average of 2014 and 2015 rates when firing subbituminous coal), it results in 1643 lb CO_2/MWh gross. In practice, the heat rate (on a HHV basis) of a bituminous unit would be slightly better than for a subbituminous unit because of the lower moisture content of the bituminous fuel. Therefore, in practice the emission rate would be somewhat lower than 1643 lb/MWh gross when firing bituminous fuel.

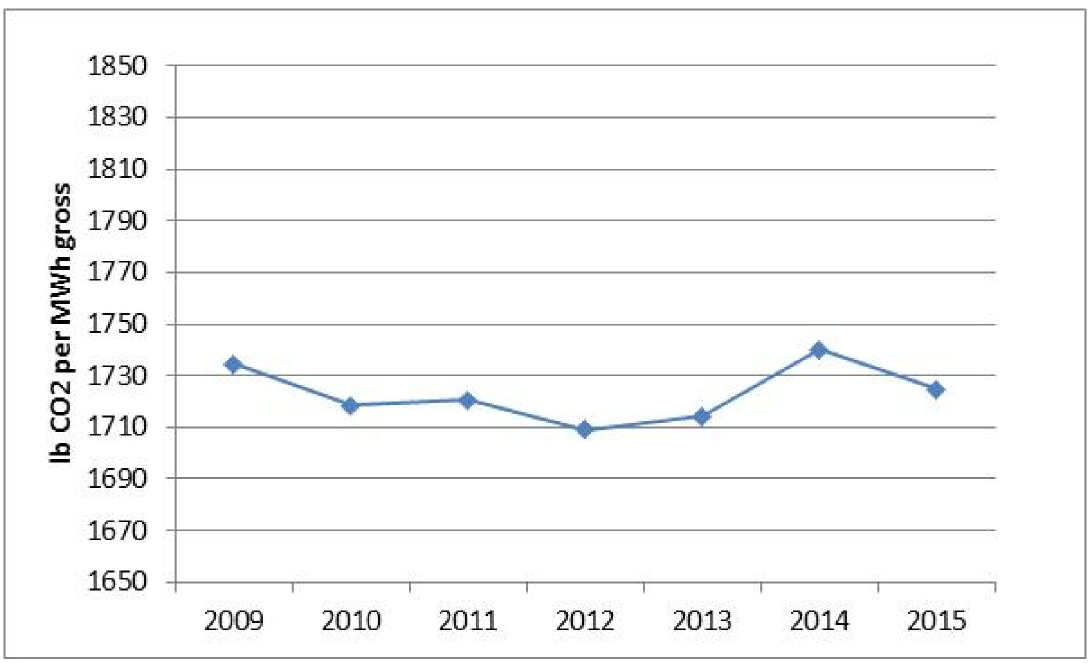
Figure 15. Weston 4

Key characteristics of the plant are shown in Table 7 and Figure 16 shows Weston 4's CO_2 emission rate since 2009. CO_2 emission rate was determined by multiplying the reported tons of CO_2 emitted by 2000 and dividing by the reported MWh gross. The capacity factor was determined by dividing the total gross MWh for the year by 8760 hours/year and dividing that be the reported summer capacity in MW. Weston 4 was out of service October 2015.

Table 7. Data on Weston 4
(heat rate and CO_2 rate from AMPD data)

Year in service	2008
Net output, MW	416 MW
Coal type	subbituminous
Superheater exit temperature,	1085 °F
Superheater exit pressure	3689 psi
Reheat temperature	1085 °F
Firing type	Wall
Cooling Water System	Recirculating, river
SCR?	Yes
Baghouse or ESP?	Baghouse
SO_2 Control	Dry FGD
2014 Annual CO_2 rate (capacity factor %)	1740 lb/MWh gross (68%)
2014 Annual heat rate	8300 Btu/kWh gross
2015 Annual CO_2 rate (capacity factor %)	1725 lb/MWh gross (65%)
2015 Annual heat rate	8229 Btu/kWh gross

Figure 16. Weston 4 annual CO_2 emission rate calculated from AMPD data



Sources:

Peltier, R., “Wisconsin Public Service Corp.’s Weston 4 earns POWER’s highest honor”, Power Magazine, 8/15/2008

http://www.wisconsinpublicservice.com/company/weston.aspx

US EPA Air Markets Program Data

EIA Form 860

EIA Form 923

American Electric Power (AEP) John W. Turk Jr.

AEP's Turk Power Plant, shown in Figure 17, is a 600 MW PRB fueled ultrasupercritical plant located in Arkansas that was placed in service in 2012. It is the first boiler built in the United States that is classified as ultrasupercritical. It is equipped with an SCR, dry scrubber and baghouse. It is also equipped with a recirculating cooling system.[22] The cooling water source is the Little Arkansas River.

Based upon information in US EPA's AMPD database, Turk's CO_2 emission rate was 1765 lb/MWh gross in 2014 and 1817 lb/MWh gross in 2015 while firing subbituminous coal. It is reported to have a 40% HHV efficiency (which equates to a heat rate of 8532 Btu/kWh) and 42% LHV efficiency. Key characteristics of Turk plant are shown in Table 8 and Figure 18 shows Turk plant CO_2 emissions rate since 2012. CO_2 emission rate was determined by multiplying the reported tons of CO_2 emitted by 2000 and dividing by the reported MWh gross. The capacity factor was determined by dividing the total gross MWh for the year by 8760 hours/year and dividing that be the reported summer capacity in MW. Turk plant was out of service October 2015.

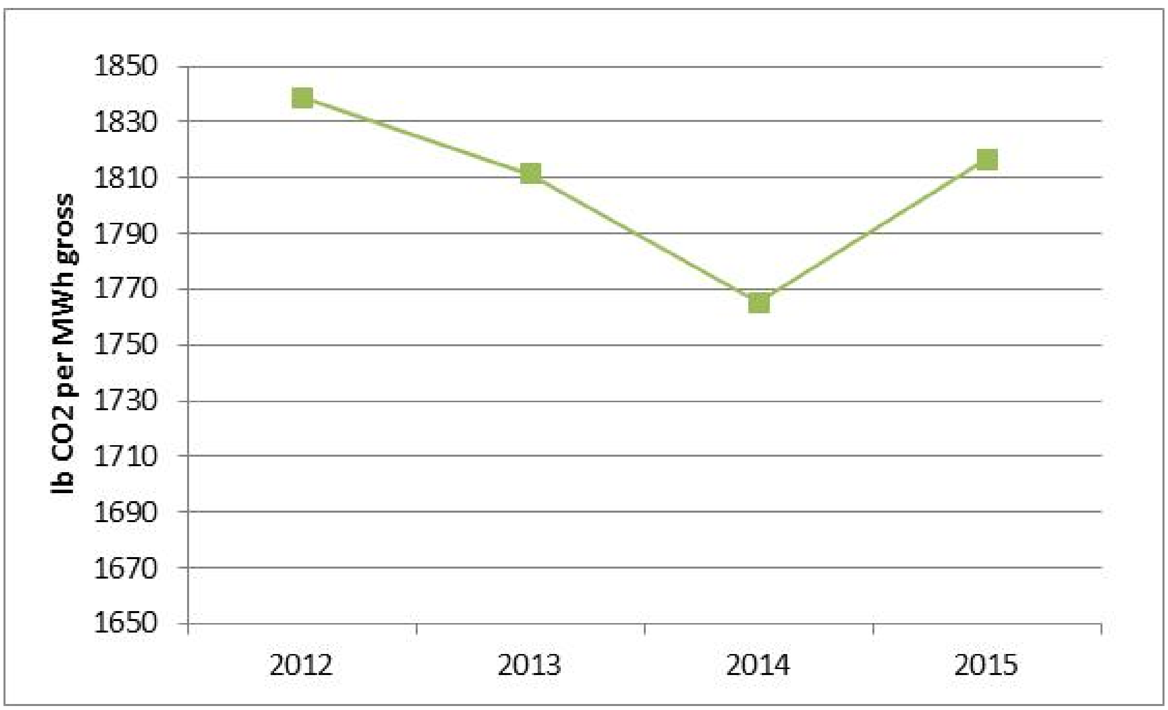
Figure 17. AEP John W. Turk plant

[22] EIA Form 860 indicates induced draft cooling towers although the satellite image suggests possibly forced draft cooling towers.

Table 8. Key characteristics of AEP John W. Turk plant.
(heat rate and CO_2 rate from AMPD data)

Year in service	2012
Net output, MW	600 MW
Coal type	PRB
Superheater exit temperature,	1112 °F
Superheater exit pressure	3800 psi
Firing type	Wall
Cooling Water System	Recirculating, river
SCR?	Yes
Baghouse or ESP?	Baghouse
SO_2 Control	Dry FGD
Design net heat rate	8730 Btu/kWh
2014 Annual CO_2 rate (capacity factor %)	1765 lb/MWh gross (83%)
2014 Gross heat rate (Btu/kWh gross)	8415 Btu/kWh gross
2015 Annual CO_2 rate (capacity factor %)	1817 lb/MWh gross (61%)
2015 Gross heat rate (Btu/kWh gross)	8661 Btu/kWh gross

Figure 18. CO_2 emissions rate for Turk plant calculated from AMPD data



Sources:

Santoianni, D., "Setting the Benchmark: The World's Most Efficient Coal-Fired Power Plants", Cornerstone Magazine, http://cornerstonemag.net/setting-the-benchmark-the-worlds-most-efficient-coal-fired-power-plants/

Sigmon, W., "The Lure of Ultra-Supercritical", Energybiz, Sept/Oct 2008

Peltier, R., "AEP's John W. Turk, Jr. Power Plant Earns POWER's Highest Honor", Power Magazine, 8/01/2013

US EPA Air Markets Program Data

EIA Form 860

EIA Form 923

Overseas case studies.

Higher efficiency power plants were pioneered in Europe and Asia. All of the following power plants, as well as many others not addressed on these pages, are regarded as USC class boilers, and therefore utilize technology that is expected to produce higher efficiencies and lower CO_2 emissions than plants that do not use USC technology.

In the case of the overseas plants, CO_2 emissions data was not directly available as was the case for US-based plants. Therefore, it was necessary to estimate CO_2 emission rates and heat rates from the reported efficiency data.

Trianel Kohlekraftwerk, Lünen, Germany

The 750 MW Lünen ultrasupercritical boiler burns German hard coal and was placed in service in 2012. The Lünen plant is shown in Figure 19. It is equipped with an ESP, SCR and wet FGD. A portion of the exhaust heat is used for district cooling. The balance of waste heat is released to the recirculating cooling system with induced draft cooling. The cooling water source is the Lippe River. The boiler uses a parallel pass design to balance superheater and reheater temperature and the boiler and steam system were built to respond quickly to power changes at 4%/minute and operate over a range of 25%-100% load on coal.

Figure 19. Trianel Kohlekraftwerk Lünen

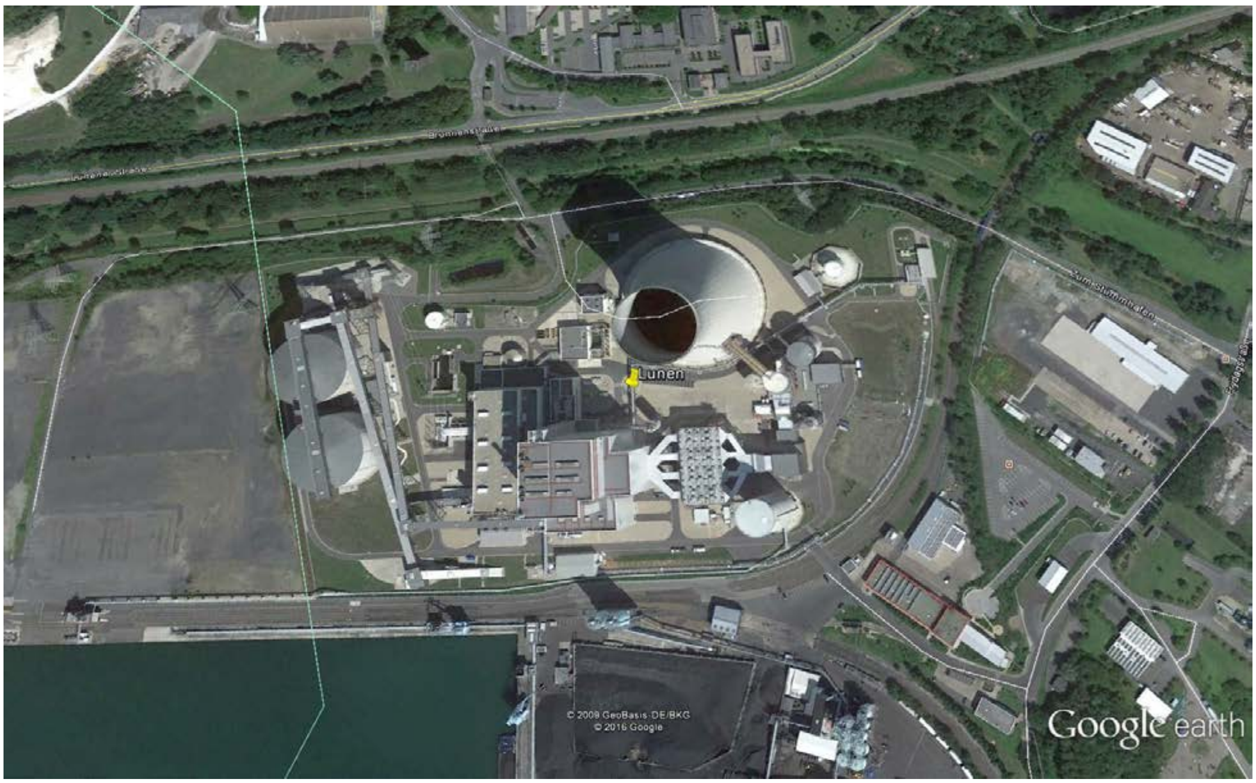


Table 9 shows the characteristics of the coal used at the Lunen plant. Combustion calculations using the Constants_CC sheet of the US EPA's Coal Utility Environmental Cost model determined that this coal produces CO_2 emissions of 211 lb/million Btu (HHV) and there is a 4.7% difference between HHV and LHV of the fuel. Table 10 shows the results of performance testing of the plant. As shown, the design net plant efficiency (LHV) was 45.57% (converted to 43.43% HHV by reducing by the difference between fuel HHV and LHV, 4.7%) and the performance test verified that it achieved 45.87% net plant efficiency LHV (43.71% net HHV, again reducing by 4.7%), or a heat rate of 7805 Btu/kWh, HHV (equal to 3412 Btu/kWh divided by the efficiency as a fraction, or 0.4371). This equates to 1646 lb CO_2 per MWh net (multiply the heat rate of 7805 Btu/kWh times 211 lb CO_2/MMBtu times 1000 kWh/MWh and divide by 1,000,000 Btu/MMBtu). Assuming 5.2% auxiliary loads, this would equate to 1565 lb CO_2 per MWh gross (divide 1646 lb/MWh by 1.052). On a routine operating basis, the emissions would be somewhat higher. Trianel expects Lünen to achieve an 80% capacity factor during its first full year of operation.

Table 11 summarizes the characteristics of Trianel Kohlekraftwerk Lünen.

Table 9. Coal Used at Trianel Kohlekraftwerk Lünen

Item \ Coal			Reference Coal
Heating Value (As Received)	LHV	MJ/kg	25.95
Proximate Analysis (As Received)	Moisture	%	7.5
	Ash	%	12.6
	Volatile Matter	%	24.8
	Fixed Carbon	%	55.0
Total Sulphur		%	0.5
Ultimate Analysis (Dry Ash Free)	Carbon	%	84.2
	Hydrogen	%	4.80
	Nitrogen	%	1.9
	Oxygen	%	8.4
Ash Fusion Temp. (Reducing)	IDT	°C	1250
HGI			49

Table 10. Performance test at Trianel Kohlekraftwerk Lünen

Item		Design Value	Performance Test Result
Boiler Load	%	100	100
Net Output	MW	746.2	755.1
Net Plant Efficiency (LHV Base)	%	45.57	45.87
NOx at Stack Inlet	mg/Nm^3 (Dry, 6%O_2)	100	84
SOx at Stack Inlet	mg/Nm^3 (Dry, Actual O_2)	200	168
CO at Stack Inlet	mg/Nm^3 (Dry, Actual O_2)	200	76
Dust at Stack Inlet	mg/Nm^3 (Dry, Actual O_2)	20	2

Table 11 Key Characteristics of Trianel Kohlekraftwerk Lünen

Year in service	2012
Net output, MW	750 MW
Coal	German Hard Coal
Superheater exit temperature,	1112 °F
Superheater exit pressure	4061 psi
Reheat temperature	1130 °F
Firing type	Wall-Opposed fired
Cooling Water System	Recirculating, induced, river
SCR?	Yes
Baghouse or ESP?	ESP
SO_2 Control	Wet FGD
Efficiency during performance test	45.87% net, LHV
CO_2 emission rate during performance test	1565 lb CO_2 per MWh gross (estimated)

Sources:

Cziesla, F., Bewerunge, J., Senzel, A., "Lünen – State-of-theArt Ultra Supercritical Steam Power Plant Under Construction", POWER-GEN Europe 2009 – Cologne, Germany, May 26-29, 2009

Sato, Y, "Lünen – State-of-the-Art 813MW Coal-Fired USC Boiler with High Efficiency and Flexibility", Power-Gen Asia, 2014, Kuala Lumpur, Malaysia, September 10-12, 2014

Lunen Coal-Fired Power Plant, Germany, *Power-Technology*, http://www.powertechnology.com/projects/lnencoalfiredpowerplant

Johnstone, H., "Germany's Lünen plant receives clean coal award", *Power Engineering International*, http://www.powerengineeringint.com/articles/2015/06/germany-s-l-nen-plant-receives-clean-coal-award.html

Santoianni, D., "Setting the Benchmark: The World's Most Efficient Coal-Fired Power Plants", Cornerstone Magazine, http://cornerstonemag.net/setting-the-benchmark-the-worlds-most-efficient-coal-fired-power-plants/

"Siemens commissions 750 MW Lunen coal-fired power plant", *PennEnergy*, December 11, 2013

Larson, A., "Trianel Coal Power Plant Lünen, North Rhine-Westphalia, Germany", *Power Magazine*, 10/1/14

Rheinhafen Dampfkraftwerk 8 (RDK 8), Germany

Rheinhafen Dampfkraftwerk 8 (RDK 8), owned by EnBW, is reported to have achieved the world record in efficiency at 47.5% (net, HHV).[23] RDK 8 surpassed the previously recognized record holder at the Nordjylland plant in Denmark, which achieved 47.1% net efficiency. The 912 MW facility in Figure 20, burns German hard coal and commenced commercial operation in 2015. It is equipped with an ESP, SCR and wet FGD. It also is equipped with a recirculating cooling system with induced draft cooling. The cooling water source is the Rhine River.

The 47.5% LHV thermal efficiency equates to a 45.37% HHV efficiency, or 7522 Btu/kWhnet heat rate assuming the same 4.7% difference between German hard coal HHV and LHV as determined for Lünen. Using an assumed 211 lb CO_2 per million Btu, this equates to 1587 lb CO_2 per MWh net. Assuming 5.2% parasitic loads, this equates to 1505 lb CO2 per MWh gross. Routine operation would likely result in a somewhat higher CO_2 emission rate.

Table 12 shows the plant characteristics.

Figure 20 Rheinhafen Dampfkraftwerk 8 (RDK 8)

[23] Keller, M., "Supercritical Thinking: To Achieve World's Best Performance, This Coal-Fired Power Plant Applies Bullet-like Pressures To Steam", GE Reports, Jan 20, 2016

Table 12. Characteristics of Rheinhafen Dampfkraftwerk 8 (RDK 8)

Year in service	2015
Net output, MW	912 MW
Superheater exit temperature,	1117 °F
Superheater exit pressure	4134 psi
Reheat temperature	1150 °F
Firing type	tangential
Cooling Water System	Recirculating, river
SCR?	Yes
Baghouse or ESP?	ESP
SO_2 Control	Wet FGD
Efficiency during performance test	47.5% net, LHV
CO_2 emission rate during performance test	1505 lb CO_2 per MWh gross (estimated)

Sources:

Keller, M., "Supercritical Thinking: To Achieve World's Best Performance, This Coal-Fired Power Plant Applies Bullet-like Pressures To Steam", GE Reports, Jan 20, 2016

Stamatelopoulos, G., Lorey, H., "RDK 8 Ultra: Supercritical Boiler A Showcase for the Next CoalFired Plant Generation", VGB Congress "Power Plants 2015", VGB PowerTech, 10 September 2015

https://www.enbw.com/unternehmen/konzern/energieerzeugung/neubau-und-projekte/rheinhafen-dampfkraftwerk-karlsruhe/technik.html

Nordjylland Unit 3, Denmark

Nordjylland Unit 3, shown in Figure 21, was constructed in 1998. For years its owners had claimed the world record for demonstrated net efficiency at about 47.1% (LHV), which is about 44.9% (HHV net). The 411 MWe facility supplies electricity and district heating and burns bituminous or hard coal. Nordjylland Unit 3 uses SNOX technology for NOx and SO_2 reduction, reducing NOx in an SCR reaction and then oxidation of SO_2 to form SO_3 and subsequently sulfuric acid, which is collected and sold. Heat is supplied for district heating and heat is also exhausted in once through cooling to Liim Fiord.

A 44.9% (HHV) net efficiency equates to about 7600 Btu/kWh net or about 1603 lb CO_2/MWhnet or about 1520 CO_2/MWhgross if it is assumed that the coal emits 211 lb CO2/MMBtu (HHV). Since Nordjylland likely has access to world coals (delivered by barge with ocean access), it is possible that lower emitting coals than German hard coals may be used. In any event, for routine operation the plant would likely emit slightly higher emission rates than at the claimed 47% (LHV) efficiency.

Figure 21. Nordjylland Power Plant, Denmark

Table 13 shows characteristics of the Nordjylland Unit 3.

Table 13. Nordjylland Unit 3 Characteristics

Year in service	1998
Net output, MW	411 MW
Superheater exit temperature,	1080 °F
Superheater exit pressure	4206 psi
Reheat temperature	1076 °F
Cooling Water System	Once through, fiord
SCR?	Yes
Baghouse or ESP?	ESP
SO2 Control	SNOX
Performance test efficiency	47.1% net, LHV
CO_2 emission rate during performance test	1565 lb CO_2 per MWh gross (estimated)

Sources:

https://corporate.vattenfall.dk/globalassets/danmark/om_os/nordjyllandsvaerket_english.pdf

Peltier, R., "Plant Efficiency: Begin with the Right Definitions", *Power Magazine*, 2/1/2010

Santoianni, D., "Setting the Benchmark: The World's Most Efficient Coal-Fired Power Plants", Cornerstone Magazine, http://cornerstonemag.net/setting-the-benchmark-the-worlds-most-efficient-coal-fired-power-plants/

Waigaoqiao No 3, China

Waigaoqiao No 3, shown in Figure 22, is the third and most recent generating facility in the Waigaoqiao energy complex near Shanghai. It is owned by Shanghai Waigaoqiao number three Power Generation Company is financed and built by Shenergy (40%), GD Power Development (30%), and Shanghai Electric Power Company (30%). Waigaoqiao 3 has two 1000 MW power boilers that were placed in service in 2007 and uses bituminous coal from China, Indonesia, or Russia. It is equipped with SCR and wet FGD. Cooling is once through with the cooling water from the Yangtze River. Fuel is Shenhua bituminous and Russian and Indonesian coals.

The facility has a designed heat rate of 7320 kJ/kWh (or 6938 Btu/kWh – this is presumably a LHV heat rate and gross output), or roughly a 46% LHV efficiency net.

Figure 22. Waigaoqiao No. 3

Since its initial start in 2007 the annual average efficiency of Waigaoqiao 3 has improved through a series of facility and operating improvements from 41.6% during initial operation to 44.4% (net, LHV), as shown in Figure 23. An efficiency of 44.4% (net LHV) is roughly equivalent to 7687 Btu/kWh (net, LHV) and compares to reported 46% net LHV design efficiency. Assuming a 5% difference between LHV and HHV for the fuel[24] would result in 8,071 Btu/kWh net HHV (divide 3412 Btu/kWh by 8071 Btu/kWh results in 42.27% net HHV efficiency), and assuming 211 lb CO_2/MMBtu for the coal, 1703 lb CO_2/MWh (net) or about 1614 lb/MWh gross if parasitic loads are on the order of 5.2%. Table 14 is a summary of the characteristics of Waigaoqiao 3.

Figure 23. Historical performance of Waigaoqiao No. 3[25]

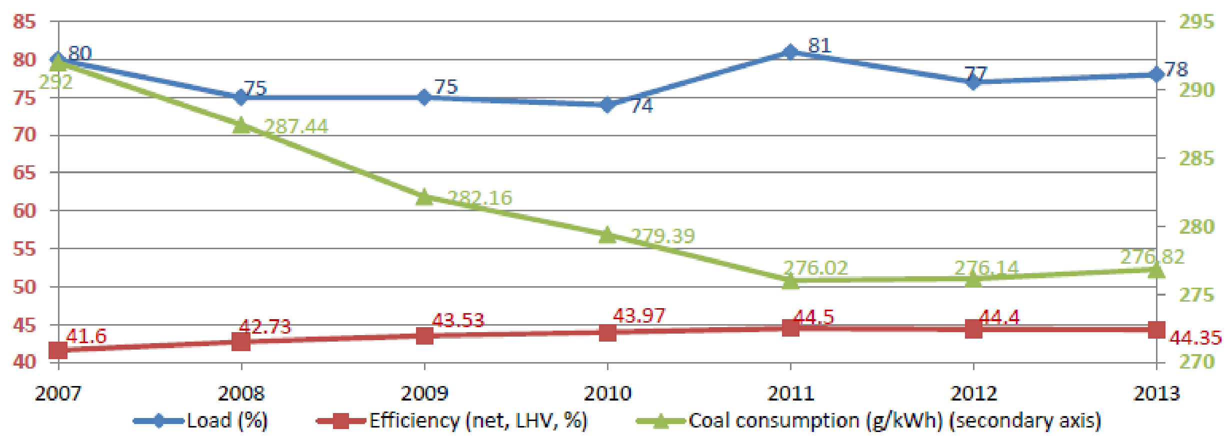


Table 14. Characteristics of Waigaoqiao 3.

Year in service	2007
Net output, MW	2 x 1000 MW each
Superheater exit temperature,	1121 °F
Superheater exit pressure	4061 psi
Reheat temperature	1117 °F
Firing type	Tangential
Cooling Water System	Once through, river
SCR?	Yes
Baghouse or ESP?	ESP
SO2 control	Wet FGD
Design Efficiency	46% net, LHV
Annual demonstrated efficiency	44.4% net, LHV
Annual CO_2 emission rate	1614 lb/MWh gross (estimated)

[24] Indonesian bituminous coal moisture content is typically under 10%, per Belkin, H., and Tewalt, S., "Geochemistry of Selected Coal Samples from Sumatra, Kalimantan, Sulawesi, and Papua, Indonesia", USGS Open File Report 2007-1202. Given that an Illinois Basin coal with 12% moisture has a difference of 5.8%, 5% for the Indonesian coal with under 10% moisture is a reasonable approximation.

[25] Upgrading and efficiency improvement in coal fired power plants, IEA Clean Coal Center, 16-17 Sept, 2014, Shanghai, China, http://upgrading3.coalconferences.org/uploads/Waigaoqiao%20Brochure.pdf

Sources:

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Isogo Power Plant, Japan

Isogo Power Plant is located near Yokohama, Japan. 600 MW Isogo Unit 2 replaced older subcritical units at the same site. Isogo Units 1 & 2, shown in Figure 24, are equipped with ESPs for PM control and control NOx and SO_2 using a ReACT system (Regenerated Activated Coke Technology) that reacts ammonia with the exhaust gas over an activated coke bed. NOx is removed in an SCR-like reaction. SO_2 is removed through formation of ammonium salts and sulfuric acid that are desorbed and make salable products. Mercury is also removed. Cooling water is direct to Yokohama bay.

The gross thermal efficiency of Unit 2, completed in 2009, is 45% (LHV), which would be equivalent to 42.75% (HHV) if the difference between HHV and LHV was 5%.and would be equivalent to 7984 Btu/kWh gross HHV. Assuming bituminous coal similar to US bituminous coal at 205 lb CO_2/MMBtu, this would be equivalent to 1637 lb CO_2/MWh. At 211 lb CO_2/MMBtu, this would be equivalent to 1685 lb CO_2/MWh gross.

Figure 24. Isogo Power Plant, Japan

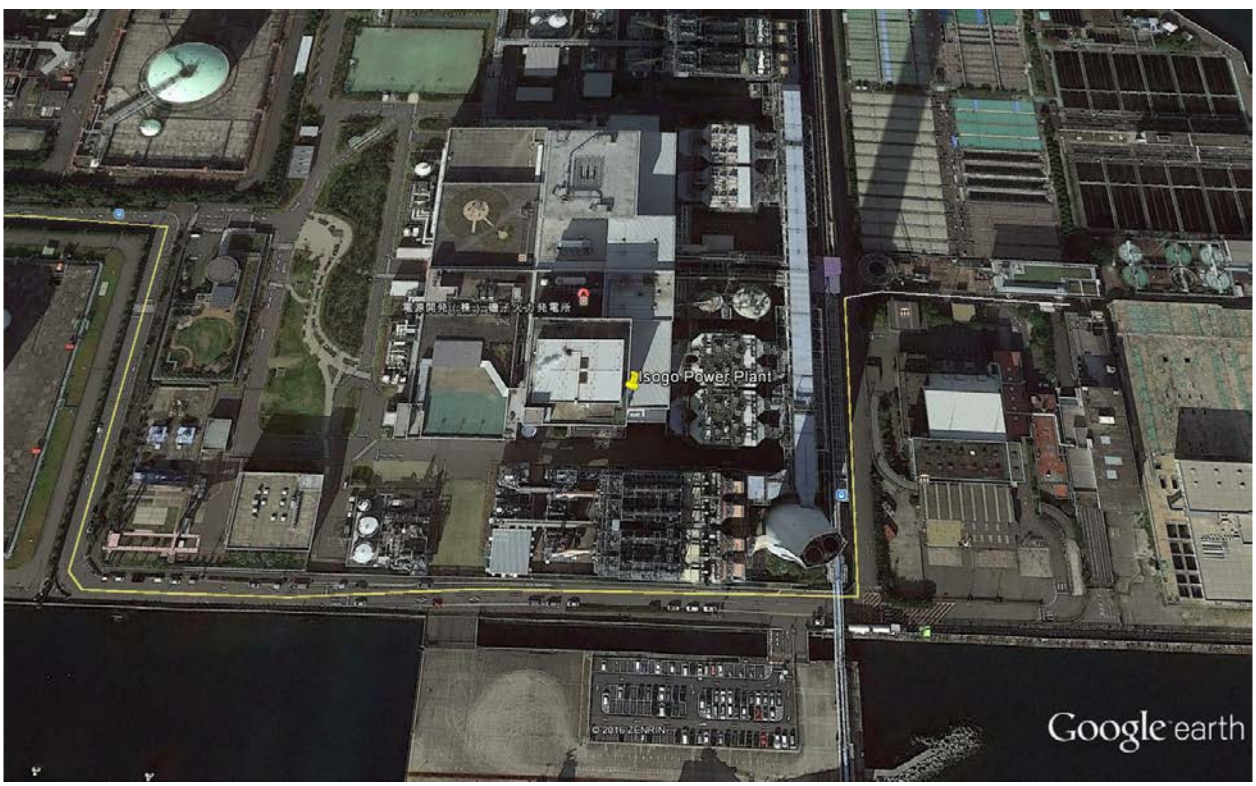

Figure 25 shows how J Power has transitioned to newer technology with higher efficiency since the 1960s. As shown, Isogo Unit 2 is the most recent and most efficient unit that they have built. Figure 26 demonstrates that J Power's average efficiency is much greater than that of the average efficiency for coal power plants in Europe, the United States, China or India. As these figures demonstrate, J-Power has been investing in higher efficiency coal-fired power generation and exceeding the efficiency of national fleets.

Figure 25. Coal fired power generation efficiency at J-Power.[26]

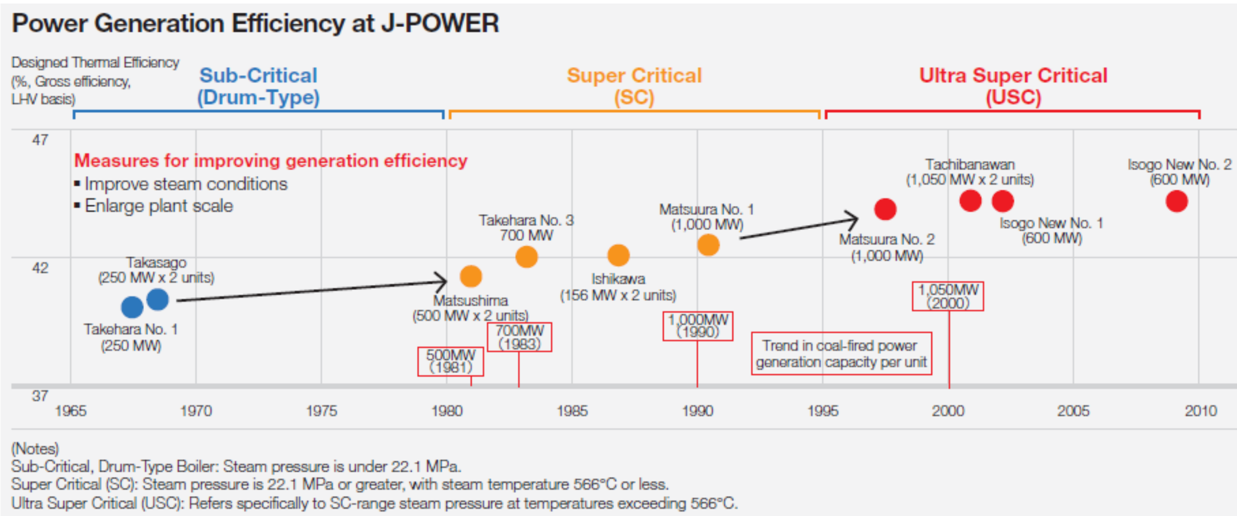

Figure 26. Trends in Coal-Fired Generation Effiiency for J-Power and Rest of World[27]

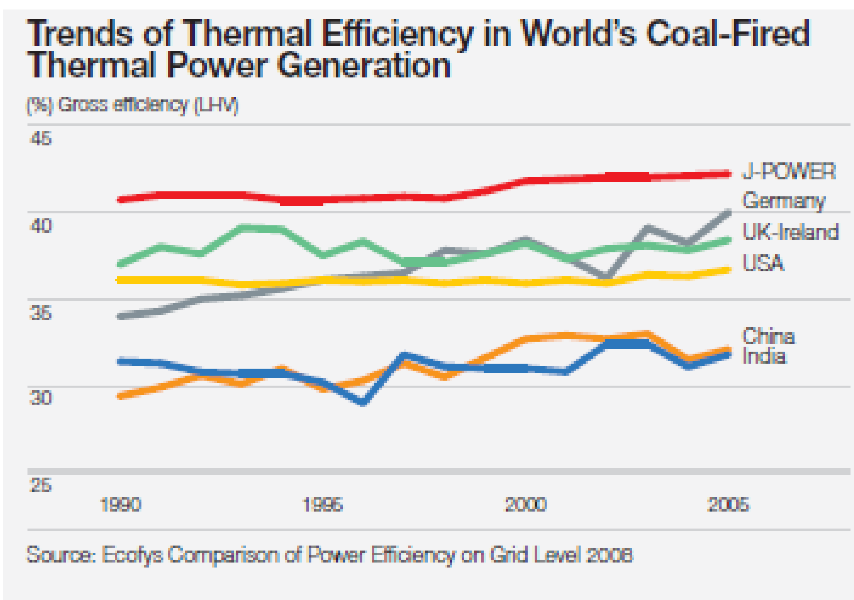

Table 15 shows the characteristics of Isogo Power Plant.

[26] "Replacement Activities completed at Isogo Thermal", http://www.jpower.co.jp/english/ir/pdf/2009-06.pdf
[27] Ibid

Table 15. Characteristics of Isogo Unit 2

Year in service	2009
Net output, MW	600 MW
Superheater exit temperature,	1112 °F
Superheater exit pressure	3626 psi
Reheat temperature	1148 °F
Cooling Water System	Once through, seawater
SCR?	Yes
Baghouse or ESP?	ESP
SO_2 Control	ReACT
Design efficiency	45% gross, LHV
Design CO_2 emission rate	1637 lb CO_2 per MWh gross (estimated from efficiency)

Sources:

Peltier, R., "Top Plant: Isogo Thermal Power Station Unit 2, Yokohama, Japan", Power Magazine 10/1/2010

Santoianni, D., "Setting the Benchmark: The World's Most Efficient Coal-Fired Power Plants", Cornerstone Magazine, http://cornerstonemag.net/setting-the-benchmark-the-worlds-most-efficient-coal-fired-power-plants/

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Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity Revision 3 July 6, 2015 DOE/NETL-2015/1723

Exhibit ES-1 Case configuration summary

Case	Unit Cycle	Steam Cycle, psig/°F/°F	Combustion Turbine	Boiler Technology	CO_2 Separation
B11A	PC	2400/1050/1050	N/A	Subcritical PC	N/A
B11B	PC	2400/1050/1050	N/A	Subcritical PC	Cansolv
B12A	PC	3500/1100/1100	N/A	SC PC	N/A
B12B	PC	3500/1100/1100	N/A	SC PC	Cansolv
B31A	NGCC	2400/1050/1050	2 x State-of-the-art 2013 F-Class	HRSG	N/A
B31B	NGCC	2400/1050/1050	2 x State-of-the-art 2013 F-Class	HRSG	Cansolv

	Pulverized Coal Boiler				NGCC	
	PC Subcritical		PC Supercritical		State-of-the-art 2013 F-Class	
Case Name (Old Case Name)[A]	B11A (9)	B11B (10)	B12A (11)	B12B (12)	B31A (13)	B31B (14)
PERFORMANCE						
Gross Power Output (MWe)	581	644	580	642	641	601
Auxiliary Power Requirement (MWe)	31	94	30	91	11	42
Net Power Output (MWe)	550	550	550	550	630	559
Coal Flow rate (lb/hr)	412,005	516,170	395,053	495,578	N/A	N/A
Natural Gas Flow rate (lb/hr)	N/A	N/A	N/A	N/A	185,484	185,484
HHV Thermal Input (kW_t)	1,408,630	1,764,768	1,350,672	1,694,366	1,223,032	1,223,032
Net Plant HHV Efficiency (%)	39.0%	31.2%	40.7%	32.5%	51.5%	45.7%
Net Plant HHV Heat Rate (Btu/kWh)	8,740	10,953	8,379	10,508	6,629	7,466
Raw Water Withdrawal, gpm	5,538	8,441	5,105	7,882	2,646	4,023
Process Water Discharge, gpm	1,137	1,920	1,059	1,813	595	999
Raw Water Consumption, gpm	4,401	6,521	4,045	6,069	2,051	3,024
CO_2 Capture Rate (%)	0%	90%	0%	90%	0%	90%
CO_2 Emissions (lb/MMBtu)	204	20	204	20	119	12
CO_2 Emissions (lb/MWh-gross)	1,683	190	1,618	183	773	82
CO_2 Emissions (lb/MWh-net)	1,779	223	1,705	214	786	89
SO_2 Emissions (lb/MMBtu)	0.085	0.000	0.085	0.000	0.001	0.000
SO_2 Emissions (lb/MWh-gross)	0.700	0.000	0.673	0.000	0.006	0.000
NOx Emissions (lb/MMBtu)	0.085	0.075	0.088	0.078	0.003	0.003
NOx Emissions (lb/MWh-gross)	0.700	0.700	0.700	0.700	0.020	0.022
PM Emissions (lb/MMBtu)	0.011	0.010	0.011	0.010	0.000	0.000
PM Emissions (lb/MWh-gross)	0.090	0.090	0.090	0.090	0.000	0.000
Hg Emissions (lb/TBtu)	0.363	0.321	0.377	0.333	0.000	0.000
Hg Emissions (lb/MWh-gross)	3.00E-06	3.00E-06	3.00E-06	3.00E-06	0.00E+00	0.00E+00

[A] Previous versions of this report used a different naming convention. The old case numbers are provided here, paired with the new case numbers for reference.

Rank	**Bituminous**	
Seam	**Illinois No. 6 (Herrin)**	
Source	**Old Ben Mine**	
Proximate Analysis (weight %)[A]		
	As Received	**Dry**
Moisture	11.12	0.00
Ash	9.70	10.91
Volatile Matter	34.99	39.37
Fixed Carbon	44.19	49.72
Total	100.00	100.00
Sulfur	2.51	2.82
HHV, kJ/kg (Btu/lb)	27,113 (11,666)	30,506 (13,126)
LHV, Btu/lb (Btu/lb)	26,151 (11,252)	29,544 (12,712)
Ultimate Analysis (weight %)		
	As Received	**Dry**
Moisture	11.12	0.00
Carbon	63.75	71.72
Hydrogen	4.50	5.06
Nitrogen	1.25	1.41
Chlorine	0.29	0.33
Sulfur	2.51	2.82
Ash	9.70	10.91
Oxygen[B]	6.88	7.75
Total	100.00	100.00

[A]The proximate analysis assumes sulfur as volatile matter.
[B]By difference.

Cost and Performance Baseline for Fossil Energy Plants Volume 3 Executive Summary: Low Rank Coal and Natural Gas to Electricity, September 2011, DOE/NETL-2010/1399

	Supercritical Pulverized Coal Boiler				Ultra-supercritical Pulverized Coal Boiler				Supercritical CFB			
PERFORMANCE	**S12A**	**L12A**	**S12B**	**L12B**	**S13A**	**L13A**	**S13B**	**L13B**	**S22A**	**L22A**	**S22B**	**L22B**
CO_2 Capture	0%	0%	90%	90%	0%	0%	90%	90%	0%	0%	90%	90%
Gross Power Output (kW_e)	582,700	584,700	673,000	683,900	581,500	583,200	665,400	675,200	578,400	578,700	664,000	672,900
Auxiliary Power Requirement (kW_e)	32,660	34,640	122,940	133,850	31,430	33,170	115,320	125,170	28,330	28,670	113,990	122,820
Net Power Output (kW_e)	550,040	550,060	550,060	550,050	550,070	550,030	550,080	550,030	550,070	550,030	550,010	550,080
Coal Flowrate (lb/hr)	566,042	755,859	811,486	1,110,668	549,326	731,085	764,212	1,043,879	563,307	745,997	801,270	1,095,812
HHV Thermal Input (kW_{th})	1,420,686	1,465,801	2,036,717	2,153,863	1,378,732	1,417,757	1,918,067	2,024,343	1,413,821	1,446,676	2,011,075	2,125,054
Net Plant HHV Efficiency (%)	38.7%	37.5%	27.0%	25.5%	39.9%	38.8%	28.7%	27.2%	38.9%	38.0%	27.3%	25.9%
Net Plant HHV Heat Rate (Btu/kWh)	8,813	9,093	12,634	13,361	8,552	8,795	11,898	12,558	8,770	8,975	12,476	13,182
Raw Water Withdrawal, gpm	2,649	2,683	7,642	7,817	2,578	2,597	7,117	7,261	2,393	2,379	7,762	7,996
Raw Water Consumption, gpm	2,093	2,125	5,527	5,456	2,035	2,056	5,141	5,060	1,839	1,828	5,713	5,704
CO_2 Emissions (lb/MMBtu)	215	219	21	22	215	219	21	22	213	219	21	22
CO_2 Emissions (lb/MWh_{gross})	1,786	1,877	222	236	1,737	1,820	211	225	1,775	1,865	220	236
CO_2 Emissions (lb/MWh_{net})	1,892	1,996	271	293	1,836	1,930	255	276	1,866	1,963	265	288
SO_2 Emissions (lb/MMBtu)	0.119	0.132	0.002	0.002	0.119	0.132	0.002	0.002	0.102	0.113	0.002	0.002
SO_2 Emissions (lb/MWh_{gross})	0.990	1.130	0.020	0.020	0.960	1.100	0.020	0.020	0.850	0.970	0.020	0.020
NOx Emissions (lb/MMBtu)	0.070	0.070	0.070	0.070	0.070	0.070	0.070	0.070	0.070	0.070	0.070	0.070
NOx Emissions (lb/MWh_{gross})	0.582	0.599	0.723	0.752	0.566	0.581	0.689	0.716	0.584	0.597	0.723	0.754
PM Emissions (lb/MMBtu)	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013
PM Emissions (lb/MWh_{gross})	0.108	0.111	0.134	0.140	0.105	0.108	0.128	0.133	0.108	0.111	0.134	0.140
Hg Emissions (lb/TBtu)	0.597	1.121	0.597	1.121	0.597	1.121	0.597	1.121	0.302	0.482	0.302	0.482
Hg Emissions (lb/MWh_{gross})	4.96E-06	9.59E-06	6.16E-06	1.20E-05	4.83E-06	9.29E-06	5.87E-06	1.15E-05	2.52E-06	4.11E-06	3.12E-06	5.19E-06
COST												
Total Plant Cost (2007$/kW)	1,033,301	1,122,438	1,797,852	1,958,416	1,084,716	1,185,901	1,827,095	1,973,559	1,062,836	1,123,412	1,812,415	1,943,572
Total Overnight Cost (2007$/kW)	2,293	2,489	3,987	4,341	2,405	2,628	4,049	4,372	2,357	2,490	4,018	4,307
Bare Erected Cost	1,530	1,663	2,517	2,750	1,577	1,725	2,530	2,738	1,480	1,563	2,424	2,600
Home Office Expenses	145	157	238	261	149	163	239	259	141	149	230	247
Project Contingency	204	220	406	438	213	231	408	437	210	221	407	435
Process Contingency	0	0	107	112	33	37	144	154	102	110	233	251
Owner's Costs	414	448	718	781	433	472	727	783	425	448	722	773
Total Overnight Cost (2007$x1,000)	1,261,175	1,369,100	2,192,877	2,387,887	1,322,909	1,445,367	2,227,086	2,404,506	1,296,474	1,369,642	2,209,764	2,368,935
Total As Spent Capital (2007$/kW)	2,600	2,823	4,545	4,949	2,742	2,996	4,615	4,984	2,687	2,839	4,580	4,909
COE (mills/kWh, 2007$)[1]	57.8	62.2	107.5	116.4	62.2	67.3	107.7	115.4	61.5	64.6	108.0	115.2
CO_2 TS&M Costs	0.0	0.0	6.0	6.2	0.0	0.0	5.8	6.0	0.0	0.0	5.9	6.1
Fuel Costs	7.8	7.5	11.2	11.0	7.6	7.3	10.6	10.4	7.8	7.4	11.1	10.9
Variable Costs	5.1	6.1	9.3	11.0	5.1	6.1	9.0	10.3	5.3	6.1	9.5	11.0
Fixed Costs	9.0	9.7	14.5	15.7	9.3	10.1	14.7	15.8	9.1	9.5	14.5	15.4
Capital Costs	35.9	39.0	66.5	72.4	40.1	43.9	67.6	73.0	39.3	41.6	67.0	71.9
LCOE (mills/kWh, 2007$)[1]	73.3	78.8	136.3	147.5	78.8	85.3	136.5	146.3	78.0	81.9	136.9	146.0

[1] CF is 85% for PC cases

Exhibit ES-1 Case Descriptions

Case	Gasifier / Boiler	Fuel	Steam Cycle, psig/°F/°F	Sulfur Removal	CO_2 Separation
S1A	Shell SCGP	PRB	1800/1050/1050	Sulfinol-M	-
S1B	Shell SCGP	PRB	1800/1000/1000	Selexol	Selexol 2nd stage
L1A	Shell SCGP	NDL	1800/1050/1050	Sulfinol-M	-
L1B	Shell SCGP	NDL	1800/1000/1000	Selexol	Selexol 2nd stage
S2A	TRIG™	PRB	1800/1050/1050	Sulfinol-M	-
S2B	TRIG™	PRB	1800/1000/1000	Selexol	Selexol 2nd stage
S3A	Siemens SFG	PRB	1800/1050/1050	Sulfinol-M	-
S3B	Siemens SFG	PRB	1800/1000/1000	Selexol	Selexol 2nd stage
L3A	Siemens SFG	NDL	1800/1050/1050	Sulfinol-M	-
L3B	Siemens SFG	NDL	1800/1000/1000	Selexol	Selexol 2nd stage
S4A	CoP E-Gas™	PRB	1800/1050/1050	MDEA	-
S4B	CoP E-Gas™	PRB	1800/1000/1000	Selexol	Selexol 2nd stage
S12A	SC PC	PRB	3500/1100/1100	Spray Dryer FGD	-
S12B	SC PC	PRB	3500/1100/1100	Spray Dryer FGD	Amine Absorber
L12A	SC PC	NDL	3500/1100/1100	Spray Dryer FGD	-
L12B	SC PC	NDL	3500/1100/1100	Spray Dryer FGD	Amine Absorber
S13A	USC PC	PRB	4000/1200/1200	Spray Dryer FGD	-
S13B	USC PC	PRB	4000/1200/1200	Spray Dryer FGD	Amine Absorber
L13A	USC PC	NDL	4000/1200/1200	Spray Dryer FGD	-
L13B	USCPC	NDL	4000/1200/1200	Spray Dryer FGD	Amine Absorber
S22A	SC CFB	PRB	3500/1100/1100	Spray Dryer FGD	-
S22B	SC CFB	PRB	3500/1100/1100	In-bed Limestone	Amine Absorber
L22A	SC CFB	NDL	3500/1100/1100	In-bed Limestone	-
L22B	SC CFB	NDL	3500/1100/1100	In-bed Limestone	Amine Absorber
S31A	NGCC	NG	2400/1050/1050	-	-
S31B	NGCC	NG	2400/1050/1050	-	Amine Absorber
L31A	NGCC	NG	2400/1050/1050	-	-
L31B	NGCC	NG	2400/1050/1050	-	Amine Absorber

Exhibit 2-4 Montana Rosebud PRB, Area D, Western Energy Co. Mine, Subbituminous Design Coal Analysis

Proximate Analysis	Dry Basis, %	As Received, %
Moisture	0.0	25.77
Ash	11.04	8.19
Volatile Matter	40.87	30.34
Fixed Carbon	48.09	35.70
Total	100.0	100.0
Ultimate Analysis	**Dry Basis, %**	**As Received, %**
Carbon	67.45	50.07
Hydrogen	4.56	3.38
Nitrogen	0.96	0.71
Sulfur	0.98	0.73
Chlorine	0.01	0.01
Ash	11.03	8.19
Moisture	0.00	25.77
Oxygen[1]	15.01	11.14
Total	100.0	100.0
Heating Value	**Dry Basis**	**As Received, %**
HHV, kJ/kg	26,787	19,920
HHV, Btu/lb	11,516	8,564
LHV, kJ/kg	25,810	19,195
LHV, Btu/lb	11,096	8,252
Hardgrove Grindability Index	57	
Ash Mineral Analysis		**%**
Silica	SiO_2	38.09
Aluminum Oxide	Al_2O_3	16.73
Iron Oxide	Fe_2O_3	6.46
Titanium Dioxide	TiO_2	0.72
Calcium Oxide	CaO	16.56
Magnesium Oxide	MgO	4.25
Sodium Oxide	Na_2O	0.54
Potassium Oxide	K_2O	0.38
Sulfur Trioxide	SO_3	15.08
Phosphorous Pentoxide	P_2O_5	0.35
Barium Oxide	Ba_2O	0.00
Strontium Oxide	SrO	0.00
Unknown	---	0.84
	Total	100.0
Trace Components		**ppmd**
Mercury[2]	Hg	0.081

[1] By Difference

[2] Mercury value is the mean plus one standard deviation using EPA's ICR data