Exhibit 1

NATIONAL PETROLEUM COUNCIL

POWER GENERATION EFFICIENCY SUBGROUP
OF THE
DEMAND TASK GROUP
OF THE
NPC COMMITTEE ON GLOBAL OIL AND GAS

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Power Plant Efficiency Outlook

Power Plant Efficiency

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Executive Summary

Power plant efficiencies are typically defined as the amount of heat content in (Btu) per the amount of electric energy out (kWh), commonly called a heat rate (Btu/kWh). In the EIA and IEA outlooks both show power plant efficiencies improvements over time. These expected improvements mainly come from the substitution of old plants with new plants that have better efficiencies. The existing unit efficiency is flat. This indicates some efficiency improvement since many of the existing units will likely install environmental controls. Installation of environmental control systems will add internal energy requirements reducing the efficiency of the plant. There are a few changes one can make to make an existing unit more efficient. However these changes typically will only result in a few percentage point improvements to efficiency.

The efficiency of a new power plant is largely a function of economic choice. The technology is well understood in order to produce a highly efficient plant. In order to produce higher efficiencies, higher pressure and temperatures are required. This increases the cost of the plant as special alloy materials will be needed. Technology improvements could assist by lowering the cost of these special materials through discovery and better manufacturing process.

Coal efficiency merit much focus since coal represents over 50% of current generation in the US. Many countries in the world from Germany to Japan have demonstrated coal plants with heat rates of less than 9,000 Btu/kWh. The US has also demonstrated such technology since the 1950's. However the US coal fleet current operating heat rate is nowhere near those levels, 10,400 Btu/kWh. The US fuel diversity, relative abundance of various fuels, competitive landscape, the age of industry, and focus on reliability has lead to less efficiency in our coal fleet relative to other countries.

In the developing countries there is an opportunity to introduce much higher efficient units in the beginning. Power plants can have lifetimes greater than 40 years, so it becomes important to introduce the efficient units early in the development of the infrastructure. According to the EIA, China is expected to have slightly better coal power plant fleet efficiency as in the US by 2030.

Power plant efficiency can add value by reducing the amount of fuel used and thereby the amount of CO_2 emitted. With the increased efficiency in the EIA forecast the US fleet reduced CO_2 emissions by 261 million tons in the year 2030 versus holding current heat rates.

Power Plant Efficiency Outlook

1. Overview of Methodology

Information was generated from publicly available reports on power generation efficiency. The reports used herein are (in order as they appear):

1. Developments in Pulverized Coal-Fired Boiler Technology J.B. Kitto Babcock & Wilcox April 10-12, 1996Energy Information Agency International Energy Outlook
2. GT World, Handbook 2006
3. Black & Veatch, Supercritical Technology Overview, February 2004, presented at the CSX Coal Forum
4. National Energy Technology Laboratory, 2006 Cost and Performance Baseline for Fossil Energy Plants, February 5, 2007
5. Energy Information Administration, Assumptions to the Annual Energy Outlook 2006, March 2006, Table 38 http://www.eia.doe.gov/oiaf/aeo/assumption/index.html
6. Coal Utilization Research Council, CURC/EPRI Technology Roadmap Update, September 20, 2006, page 10 http://coal.org/PDFs/jointroadmap2006.pdf
7. Electric Light and Power Magazine, November/December 2005, page 44
8. Coal Utilization Research Council, CURC/EPRI Technology Roadmap Update, September 20, 2006, page 10 http://coal.org/PDFs/jointroadmap2006.pdf
9. US EPA Integrated Planning Model, http://www.epa.gov/airmarkets/progsregs/epa-ipm/
10. Lange, Ian and Allen Bellas. Policy Innovation Impacts on Scrubber Electricity Usage. US EPA, National Center for Environmental Economics.
11. Braitsch, Jay. DOE/Fossil Energy Carbon Sequestration Program. September 20, 2005. http://www.ostp.gov/PCAST/agenda_9_20_05_files/Braitsch_DOE-Csequest_PCAST_20Sep05.pdf
12. IEA Greenhouse Gas R&D Programme, http://www.co2captureandstorage.info/whatisccs.htm
13. US Geological Survey. http://ga.water.usgs.gov/edu/wupt.html
14. US Department of Energy, NETL. Energy Penalty Analysis of Possible Cooling Water Intake Structure Requirements on Existing Coal-Fired Power Plants. October 2002
15. General Electric GER- 3696D, Upgradable Opportunities for Steam Turbines, 1996
16. *Electric Light & Power*, Operating Performance Rankings Showcase Big Plants Running Full Time Nancy Spring, managing editor November, 2005
17. The Energy Development Report of China, Edited by M. Cui, etc., Social Sciences Academic Press of China, 2006
18. Energy Information Administration/International Energy Outlook 2006, Appendix F - Reference Case Projections for Electricity Capacity and Generation by Fuel
19. Energy Information Administration Report #:DOE/EIA-0484(2006), Release Date: June 2006, Figure 52 Coal Consumption in China by Sector, 2003, 2015, and 2030

2. Background

Stationary efficiency is an important topic as it relates to power generation for many reasons. By definition high efficiency creates less waste, yielding higher output for any given input. Much of the discussion surrounding power plant efficiency will focus on the heat rate (Btu/kWh). This is an ideal measure of efficiency since it defines the ratio of the input as fuel (Btu) to output as power (kWh).

Efficiency improvements can have broader impacts than simple monetary gains for the plant operator. Improvements can be viewed as a fuel supply. By increasing efficiency (i.e. decreasing the heat rate), less fuel is required to generate each kWh. In effect, more fuel supply is now available than would be otherwise. In large enough volumes, this could have market impacts to fuel costs. Likewise an increase in efficiency has an impact on the level of emissions a plant releases. Since less fuel is required to generate a given kWh, fewer emissions are released for that given kWh. Again, in large enough quantities this could impact emissions markets. However, the reasons for not adopting higher efficiency technologies are that they are not necessarily comparable to existing technology. As an example, the ultra-supercritical plant has unique characteristics from higher capital cost to the unit not being able to cycle as sub-criticals historically have been able to.

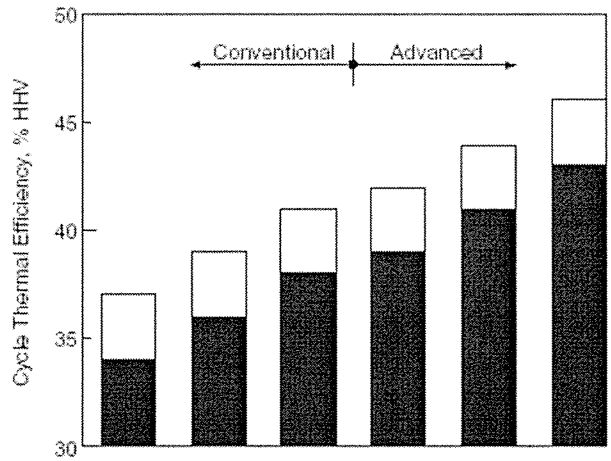
The discussion will focus on current and future factors affecting stationary efficiency. Both efficiency increases and decreases and their impacts will be examined as they pertain to the future of US, world and Chinese power markets.

3. Discussion

Factors Affecting Efficiency

The following factors affect the efficiency of a given power plant.

> *Design choices.* Designs for natural gas and coal-fired power plants represent a trade off between capital cost, efficiency, operational requirements, and availability. For example, a steam turbine system that operates at a higher temperature and pressure can achieve a higher efficiency (see figure 1).



Pressure, psi	2400	3500	3500	4500	4500	6000
SH Temp, F	1000	1000	1000	1000	1100	1200
RH Temp, F	1000	1000	1025	1025	1050	1100
2RH Temp, F			1050	1050	1050	1100
Pressure, bar	16 6	24 1	24 1	31 0	31 0	41 4
SH Temp, C	538	538	538	538	593	649
RH Temp, C	538	538	552	552	566	593
2RH Temp, C	—	—	566	566	566	593

Figure 1[1]: Efficiency as a function of temperature and pressure

The higher temperatures and pressures, however, require more exotic materials of construction for both the boiler and turbine, thus the capital cost goes up. The technology has been proven and demonstrated since the 1950s. The problems were severe superheater material wastage, unacceptable creep, and thermal fatigue cracking experienced when metal temperatures exceeded approximately 1,025°F.[1] The issue was corrosion and strength at these extreme conditions. Heat integration represents another trade off. Rather than transferring cooling water to a process stream that needs to be cooled down and steam to another process stream that needs to be heated up, the work can be partially accomplished by bringing the two streams into thermal contact via a heat exchanger. There is a significant efficiency benefit, but process-process heat exchangers can cause operational problems, especially during transient phases and in the event of fouling or fluid leakage across the exchanger. Thus heat integration represents a trade off between efficiency and availability. Unit role, peaking, base loading, etc, affect design and operational practices of using units for a role other than which they were designed. Old base load design units are often used for cycling duty. The supercritical to ultra-supercritical units are not capable of cycling without reducing longevity and ultimately the efficiency for which was the ultimate purpose of additional investment.

[1] Developments in Pulverized Coal-Fired Boiler Technology J.B. Kitto Babcock & Wilcox April 10-12, 1996

Operational Practices. Efficiency can be improved by pressing over fire air to the minimum, fully utilizing heat integration systems, staying after steam leaks and exchanger fouling, and a large number of other practices. Operating at full load capacity continuously will enhance efficiency. However the reality is that load is ever changing and the requirements of market based systems focus on reliability and leads to the inability to always run at full load.

Fuel. Among coals the higher ranking coals enable higher efficiency because they contain less ash and less water. However additional coal production is largely focused on the Powder River Basin which is sub-bituminous.

Pollutant control. The level of pollutant emission control (including thermal) effects efficiency. NO_x reduction units and SO_x scrubbers represent parasitic loads that decrease net generation and thus reduce efficiency. This issue is further discussed in latter parts of the report.

Ambient conditions. Colder water and ambient air achieves higher efficiency. Additionally, higher altitudes have lower ambient pressure which affects compression and expansion. For example, gas turbines produce lower power at elevations above sea level. The power output loss is a function of the loss in ambient pressure. All else equal, lower altitude enables higher efficiency.

The actual operating efficiency of a power plant is the summation of a lot of factors. The numbers presented for various types of power plants represent typical performance.

Table 1 presents data on the efficiency of commercially available power plant technology at full load and normal temperatures. This does not account for operational issues as discussed above. Estimates for coal technology range from 7,757 – 9,275 btu/kWh (44% - 37% efficient HHV). This range offers significant improvement over the existing coal plants, if units could actually run at full load, without maintenance or outage situations and standard ambient conditions.

Natural gas combined cycle (NGCC) power plant efficiency estimates range from 6,333 – 6,800 btu/kWh (50-54% efficient HHV, see box at right) at full load. Typical combustion turbine (CT) heat rates are 9,650 – 10,400 btu/kWh (33-35% efficient HHV).[2] The CT plants

Definition: LHV and HHV Efficiencies

It is important to define the efficiency terms higher heating value (HHV) and lower heating value (LHV). HHV assumes H2O is in liquid state and contains the energy of vaporization. LHV assumes gas state for all combustion products. The efficiencies of coal-fired power systems are most often reported in HHV in the U.S., much of the rest of the world uses LHV. Tthe efficiencies of natural gas-fired power systems are most often reported in LHV. We report all efficiencies here in HHV for consistency.

The difference can be estimated by 1055Btu/Lb * w, where w is the lbs of water after combustion per lb of fuel. To convert the HHV of natural gas, which is 23875 Btu/lb, to an LHV (methane is 25% hydrogen) would be: 23875 – (1055*0.25*18/2) = 21500. Because the efficiency is determined by dividing the energy output by the input, and the input on an LHV basis is smaller than the HHV basis, the overall efficiency on an LHV basis is higher.

So using the ratio: 23875/21500 = 1.11 you can convert the HHV to an LHV. So the the range of 50-54% translates to 56 – 60% LHV.

[2] GT World, Handbook 2006

do have a very necessary role in the US. The CC and Coal plants cannot cycle – meaning they cannot turn off and on within a few hours. The load shape and reliability require the use of CT units throughout the year. However typically they will have very low capacity factors. Over the past few years, depending on plant location, gas plants were not competitive with coal units and even combined cycle units. As a result, more cycling was required than anticipated.

Three conclusions can be drawn from the data in Table 1.

- Utility companies and other electricity suppliers can choose from a wide range of efficiencies when deploying a coal or natural gas-fired power plant.

- The average efficiency of U.S. power plants will improve as new units come online. The impact of fleet efficiency, as in cars but much longer due to longer operating lifetime, will take many years before any significant change is seen. Significant improvements in the average efficiency of U.S. power plants could be achieved via incentives to accelerate capital stock turnover. However, the ramifications of such incentives do not necessarily result in replacing the retired plant with a particular fuel and technology.

- The current stock of U.S. generation assets is not operating as efficiently as they could be, due largely to operational and economical issues. For example, the existing stock of coal plants is operating well below the efficiency of a new sub-critical plant (10,410 versus 9,276 btu/kWh). If efficiency was the goal gas plants should run over coal plants (8,000 vs 10,400 Btu/kWh). An industry-wide review of operational procedures and audit of lingering maintenance issues could produce a significant, near-term step change in average heat rate.

Collaborative industry/government research and development efforts seek to improve the efficiency of natural gas and coal-fired power plants above the level of commercially available systems. The goals of the U.S. Department of Energy are to demonstrate by 2012 at the pilot scale a coal-fired power plant with a heat rate of 6,824 btu/kWh (50% efficiency HHV). The technologies that enable that performance include H_2S removal from syngas at 'warm' temperatures (500-700°F), membrane-based oxygen supply, advanced turbine materials, and electrochemical synthesis gas combustion. A subset of these technologies can be adopted for natural gas systems to enable a NGCC heat rate of 5,785 (59% efficiency HHV). Such systems could be online commercially in the 2015-2020 timeframe.

Table 1: Coal and Natural Gas Power Plant Efficiency at Full Load, Current Technology and Existing Plants

Description	Order year	Capital cost ($/kW)*	Heat rate (btu/kWh)	Source
COAL				
PC, Ultra sc (5500 psig, 1300F)	2006		7,757	B&V[3]
PC, Adv sc (4710 psig, 1130F)	2006		8,126	B&V[2]
IGCC, Shell, F class	2006		8,304	NETL[4]
IGCC	2005	$1,443	8,309	EIA[5]
IGCC, E-gas, F class	2006		8,681	NETL[3]
PC, super (3500 psig, 1,100 F)	2006		8,712	NETL[3]
PC/IGCC range	2005		8,750 – 9,000	CURC[6]
PC	2005	$1,249	8,844	EIA[4]
IGCC, GE, F class	2006		8,922	NETL[3]
PC, sub (2,400 psif, 1,050 F)	2006		9,276	NETL[3]
Median, Top 20 efficient U.S. coal power plants, 2004			9,400	ELP[7]
Average, all U.S. coal power plants, 2005			10,410	EIA[8]
NATURAL GAS				
Advanced NGCC	2005	$575	6,333	EIA[4]
NGCC, F class	2006		6,719	NETL[3]
Conventional NGCC	2005	$584	6,800	EIA[4]
Conventional CT	2005	$407	10,842	EIA[4]
Average Gas Plant 2005			7,920	EIA[7]
Average, all U.S. NGCC, 2004			not available	EIA[7]
*Overnight capital cost including contingency. Does not include regional multipliers or interest expense.				

Parasitic Load

Beginning with the Clear Air Act of 1970, the number of power generating units that have flue gas desulphurization (FGD or scrubber) and selective catalytic reduction (SCR) units has been increasing. Recent legislation such as the Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR) has lead to a rapid increase of capacity with a scrubber or SCR. With cap-and-trade programs in place for SO_x, NO_x, and mercury the number of units with scrubbers and/or SCRs is expected to rapidly increasing over the

[3] Black & Veatch, Supercritical Technology Overview, February 2004, presented at the CSX Coal Forum
[4] National Energy Technology Laboratory, 2006 Cost and Performance Baseline for Fossil Energy Plants, February 5, 2007
[5] Energy Information Administration, Assumptions to the Annual Energy Outlook 2006, March 2006, Table 38 http://www.eia.doe.gov/oiaf/aeo/assumption/index.html
[6] Coal Utilization Research Council, CURC/EPRI Technology Roadmap Update, September 20, 2006, page 10 http://coal.org/PDFs/jointroadmap2006.pdf
[7] Electric Light and Power Magazine, November/December 2005, page 44
[8] Coal Utilization Research Council, CURC/EPRI Technology Roadmap Update, September 20, 2006, page 10 http://coal.org/PDFs/jointroadmap2006.pdf

next 10-15 years. The obvious environmental benefits of these emission abatement programs come at the detriment of power efficiency. Scrubbers and SCRs, like any auxiliary equipment in a power plant, require electricity to run. This electricity is obtained from the generating unit that is being controlled. This power loss is known as parasitic load. Just as heat rate is a measure of efficiency by calculating the amount of fuel needed for each kWh of power, parasitic load is an efficiency loss because a certain number of kWhs generated must be used for internal power plant use and cannot be sent to the grid to meet consumer demand.

Figure 2 shows the current and forecasted capacity (GW) that will have either a scrubber or SCR installed according to the EPA Integrated Planning Model 2006.[9] Scrubbed capacity is forecasted to increase from 100 GW currently to over 250 GW by 2020. Likewise, SCR installations are expected to rise from 85 GW to 220 GW over the same timeframe.

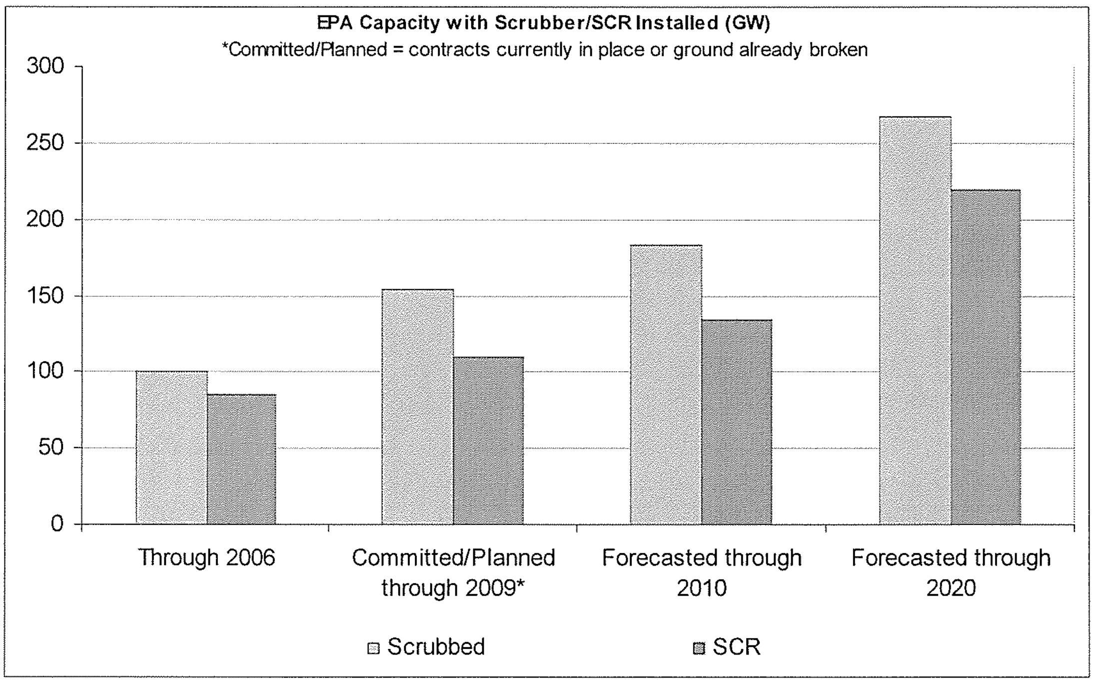


Figure 2: EPA Forecasted Capacities Installing Scrubber/SCR

Of course with parasitic load, each scrubber or SCR installation will, in effect, lower the amount of realizable capacity that can be used to meet consumer demand. Most documentation cites a 2% parasitic load for scrubber installations.[10] Similar documentation and anecdotal evidence suggests SCRs require about 1% parasitic load. Figure 3 shows the amount of capacity lost due to parasitic load based upon the EPA's projected installations and 2% loss for scrubbers and 1% loss for SCRs. By 2020, over 5

[9] US EPA Integrated Planning Model, http://www.epa.gov/airmarkets/progsregs/epa-ipm/

[10] Lange, Ian and Allen Bellas. *Policy Innovation Impacts on Scrubber Electricity Usage.* US EPA, National Center for Environmental Economics.

GW and 2 GW of capacity are lost due to scrubber and SCR installations respectively. Emission control installations can be viewed as a load growth of 1-3% (3% if BOTH scrubber and SCR installed) or directly as efficiency loss to those units. The net effect is that new generation will be required to meet any given demand as the number of emission controls increases. Figure 3 includes current scrubber and SCR installations. Current parasitic load is being accounted for such that companies or ISOs meet reserve margins, etc. By subtracting current (through 2006) capacities from the 2020 forecasted capacities, we obtain the capacity that will be either retrofitted or new build capacity with control equipment. Assuming 2% loss for scrubbers and 1% loss for SCRs, these values come to 2.0 GW and 0.85 GW lost due to parasitic load for scrubber and SCR installations respectively. Nearly 3 GW of total new capacity will be required to meet parasitic load from scrubber and SCR installations through 2020.

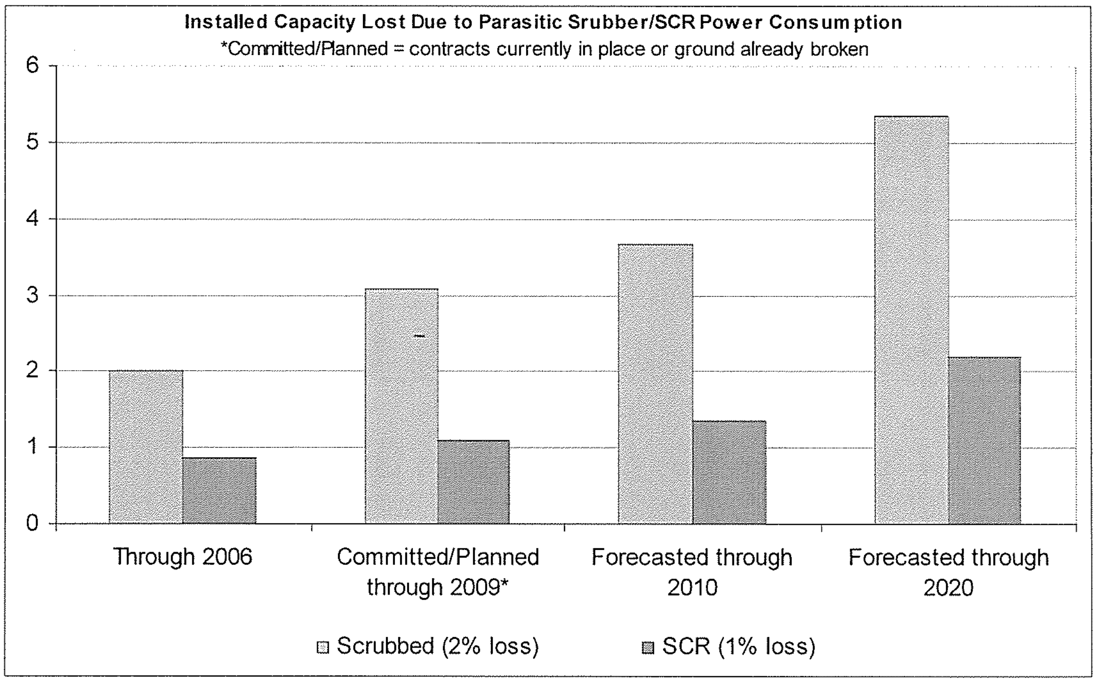


Figure 3: Calculated Total Capacity Loss from Parasitic Load (from EPA data)

Like SO_x and NO_x, carbon dioxide seems likely to be regulated at some point during the next decade. Carbon capture and sequestration has remained the focal point for reducing carbon emissions. This technology is still relatively new and remains very costly from a capital and energy perspective. According to the DOE, parasitic load for carbon capture currently ranges from 5-30%.[11] The IEA Greenhouse Gas R&D Programme estimates a 10-15% reduction in efficiency from carbon capture.[12] These values are ONLY associated with carbon capture. No public data is available on the load required for sequestration. These would include transportation (pipeline, etc) and compression/underground pumping. The sequestration portion would be expected to be

[11] Braitsch, Jay. *DOE/Fossil Energy Carbon Sequestration Program*. September 20, 2005. http://www.ostp.gov/PCAST/agenda_9_20_05_files/Braitsch_DOE-Csequest_PCAST_20Sep05.pdf
[12] IEA Greenhouse Gas R&D Programme, http://www.co2captureandstorage.info/whatisccs.htm

very costly for parasitic load since transportation and compression are relatively energy intensive processes.

Assuming a 15% efficiency loss for carbon capture, this would cause a typical 10,500 Btu/kWh steam cycle plant to perform as a 12,000 Btu/kWh plant. A typical combined cycle unit with a 7,000 Btu/kWh heat rate would now operate as an 8,000 Btu/kWh unit. With over 70% of US power generation coming from coal and natural gas (i.e. the primary CO_2 emitters), any significant amount of carbon capture retrofits on existing plants could have a major impact to the overall system heat rate. Likewise, new plants with carbon capture technology will not reach their full efficiency potential due to significant losses required for carbon capture.

Overall, as emission control installations continue to increase, less power is available to meet consumer demand from the same amount of Btu fuel consumption, leading to an overall efficiency loss. This will require the installation of more capacity to meet this parasitic load.

Water Utilization Energy Penalty

The Clean Water Act amendments of 1977 placed certain limitations on water intake and discharge at certain facilities which included steam power plants. Water is used in large amounts as the method to cool the effluent steam from the steam turbine. Cooling water is used from an external source such as a river or lake to condense this exiting steam. In 2000 approximately 195,000 million gallons per day (MGD) were used to produce electricity in thermal plants alone (i.e. excluding hydroelectric facilities).[13] There are currently three major methods of cooling steam turbine effluent (in order of most to least water consumed):

(1) *once-through cooling systems* which intake water, pump it through the condenser and directly back into the environment.
(2) *wet cooling tower* in which the cooling water is constantly re-circulated from the condenser to a cooling tower where it cools by evaporation and convection; makeup water is added to account for water loss due to evaporation
(3) *indirect dry cooling tower* in which cooling water is constantly re-circulated from the condenser to a cooling tower where it cools by forced air convection via metal fins

The National Energy Technology Laboratory (NETL) at the Department of Energy studied the effects of cooling water systems on power generation.[14] The temperature of the cooling water as it enters the condenser can have significant impacts on turbine performance by changing the vacuum at discharge from the steam turbine. In general terms, cooler water will create a larger vacuum allowing more energy to be generated. Conversely, warmer water creates lower vacuum and impedes generation. This effect is known as the energy penalty.

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[13] US Geological Survey. http://ga.water.usgs.gov/edu/wupt.html
[14] US Department of Energy, NETL. *Energy Penalty Analysis of Possible Cooling Water Intake Structure Requirements on Existing Coal-Fired Power Plants.* October 2002

The NETL modeled a retrofit of a once-through cooling system to both wet and dry cooling tower systems for a 400 MW unit. The annual average energy penalty for conversion to a wet cooling tower ranged from 0.8-1.5%, while the penalty was 4.2-8.8% with a dry cooling tower. Additional simulations were run for peak ambient temperatures, which also coincide with peak power demand. For the peak case the energy penalties range from 2.4-4.0% and 8.9-16.0% respectively. This is a significant amount of capacity loss during peak demand, when generating capacity is most critical.

It is important to note the potential impacts of water cooling systems on new builds, particularly west of the Mississippi. Many of future coal new builds will be built in this region due to the rise of Powder River Basin coal. Due to the arid climate, this western region is expected to have strict limitations on cooling water systems, with dry cooling towers likely being the system required. As shown above these systems can demonstrate significant efficiency losses. It is important to note that the proposed efficiencies provided in the subsequent sections may not be achievable due to the cooling water system requirements.

Efficiency Improvement Possible From Refurbishing and Upgrading Existing Coal-Fired Power Plants.

Existing coal-fired power plants worldwide do not achieve the highest efficiency possible based on their design. The loss of efficiency can be categorized as controllable or non-controllable. Controllable losses are generally due to poor operation and maintenance practices. Non-controllable losses are due to environmental conditions (i.e. cooling water temperature, etc), dispatching requirements (i.e. customer demand) and normal deterioration.

Deterioration naturally occurs, and if left unchecked it can become substantial. Therefore, some amount of deterioration, *normal* deterioration, will always be present and non-controllable. Most of the normal deterioration can be recovered with regularly scheduled maintenance intervals, the frequency of which determines the average based on the resulting saw-tooth curve shown in figure 4. [15] There is a gradual increase in the unrecoverable portion as the unit ages which would require a replacement rather than a refurbishment to eliminate. Poor maintenance practices regarding the timing of the intervals and the amount of refurbishment may result in *excessive* deterioration and is controllable.

[15] General Electric GER- 3696D, Upgradable Opportunities for Steam Turbines, 1996

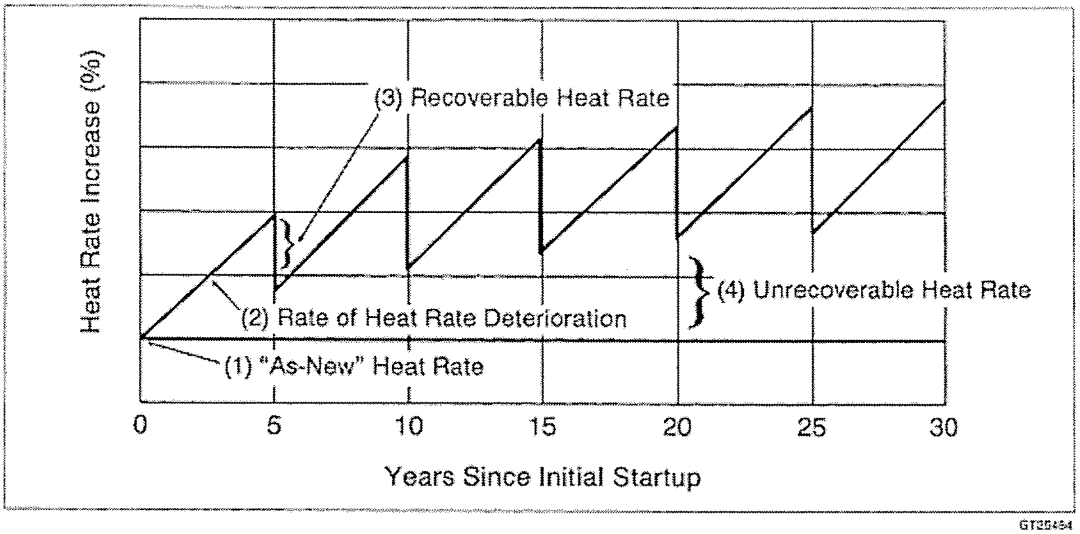

Figure 4[15]: Change in heat rate over time

Poor operation is a controllable loss. It includes operating off-design (i.e. temperatures too low), running redundant equipment, particularly at part load, excessive startups due to poor reliability, unit controls not properly tuned and off role operation. Off role operation may be using a unit designed for load following (with a control stage) for base load or one designed for base load (without a control stage) for load following.

Dispatching requirements determine the generation level of the unit and is not controllable. Since efficiency drops with load, this loss can be substantial (5-10% at half load).

To summarize, starting from the unit's full load design heat rate, add in the typical losses to get to the operational (or reported) heat rate as follows

Design Full Load Heat Rate +
Environmental Conditions [loss or gain] [non-controllable] +
Loading [loss] [non-controllable] +
Normal Deterioration [loss] [non-controllable] +
Excessive Deterioration [loss] [controllable] +
Poor O&M practices [loss] [controllable] =
Operational Heat Rate

The last two items on the list are recoverable through routine refurbishment and correction of poor O&M practices. These categories are generally acknowledged to be on the order of 500 Btu/kWh for an average plant and can reach 1000+ in some of the more poorly run plants.

Beyond refurbishment, replacement in kind is the next step. This resets normal deterioration loss to 'as-new' values and addresses maintenance reliability problems that can impact heat rate. Replacement opens up the possibility of upgrade. Why not replace a part that may be 20 to 60 years old with today's technology and end up better than the original design? Turbine upgrades are prime examples. Controls, condensers and air heaters are other popular upgrades. Table 2 quantifies typical turbine upgrades and breaks the gains down between recovery (in-kind replacement) and that due to the advanced design.[15] Table 3 shows typical improvements for non-turbine equipment.

Table 2[15]: Efficiency gains for turbines

	Heat Rate Improvement - %	Output Increase - %
HP Section		
Advanced Design	0.40 to 0.60	0.70 to 1.00
Recovery of Aging	0.25 to 0.40	0.40 to 0.70
HP Section Total	0.65 to 1.00	1.10 to 1.70
IP Section		
Advanced Design	0.30 to 0.40	0.30 to 0.40
Recovery of Aging	0.10 to 0.20	0.10 to 0.20
IP Section Total	0.40 to 0.60	0.40 to 0.60
LP Section Without Last Stage		
Advanced Design	0.45 to 0.55	0.45 to 0.55
Recovery of Aging	0.10 to 0.20	0.10 to 0.20
LP Section Total	0.55 to 0.75	0.55 to 0.75
Last Stage		
Advanced Design	0.70 to 1.30	0.70 to 1.30
Recovery of Aging	0.05 to 0.15	0.05 to 0.15
Last Stage Total	0.75 to 1.45	0.75 to 1.45
Longer Last Stage Bucket	1.00 to 1.60	1.00 to 1.60
Total for Advanced Design	2.85 to 4.45	3.15 to 4.85
Total Recovery of Aging	0.50 to 0.95	0.65 to 1.25
Potential Improvement	3.35 to 5.40	3.80 to 6.10

GT25485

Table 3: Efficiency gains on various plant equipment

Equipment (other than Turbines)	Description of Efficiency Loss	Cycle Efficiency Impact	Type of Change	Source
Pulverizers	Fly ash carbon content of 1% - 30%, Impact of 30%	0.2% to 0.5%	Recovery	APEC document
Air Heaters	Excessive leakage, High delta P	0.2%– 1.5%	Recovery & upgrade of seals	APEC document
Forced Draft, Primary Air, and Induced Draft Fans	Does not match current system design.	2% - 8%*	Up-grade to match current system design	APEC document
Condenser	Air in leakage, Fouling, Original design	2%	Recovery & up-grade of design	Intek, Inc abstract for January 2007

	of air removal equipment			EPRI Heat Rate Improvement Conference
Control and Instrumentation				
Overall Unit	Controllable Losses	5%-10%		Storm Technologies abstract for January 2007 EPRI Heat Rate Improvement Conference
* This range of values is predominately capacity rather than heat rate. The cause is most likely higher pressure drops caused by scrubber and/or SCR retrofits. Only what is lost can be recovered, so it should not be assumed that the maximum value can be applied to more than a small number of units. There may be some heat rate improvement due to advanced design replacement fans, but that is relatively small compared to the capacity recovery.				

The text below is taken directly from a report, Costs And Effectiveness Of Upgrading And Refurbishing Older Coal-Fired Power Plants In Developing Apec Economies, published in June of 2005 by APEC (Asia Pacific Economic Cooperation) Energy Working Group. It describes a number of unit operations in a power plant that typically contribute to sub-standard efficiency. A given power plant generally will not have one big issue affecting efficiency, but rather several big issues and a large number of small refinements.

> For the past ten years, U.S. AID has been conducting efficiency audits at power plants in India and China. An audit requires the purchase of several hundred thousand dollars worth of diagnostic equipment and evaluation of 4-6 experienced professionals working onsite at the power plant for up to six months. It is a significant undertaking, but based on the experiences of AID, well worth the effort.
>
> Beginning in 2007 the Asia-Pacific partnership plans to initiate a 6-country peer review of power plant efficiency practices. The participating countries are the U.S., China, India, Australia, Japan, and Korea. The effort is being coordinated by EEI (Edison Electric Institute).

Equipment Refurbishing and Upgrading Options (taken from APEC document, June 2005)

Air Heaters

Air heaters heat combustion air and cool boiler exit flue gas. Boiler efficiency is improved and the hot air needed for drying coal and obtaining proper combustion is provided to the pulverizers and burners. The two types of air heaters used most often are the regenerative and tubular air heaters.

Air heater operating deficiencies include excessive leakage of combustion air into the boiler exit flue gas flow, low air temperatures to the pulverizers and burners, excessive air and flue gas pressure loss. These problems cause lower boiler efficiency, reduced gas and air flows, reduced air temperatures, and reduced coal input that can limit boiler output. Pollutant emissions often increase because lower boiler efficiency requires increased coal consumption. Air leakage results in increased flue gas flows that consequently reduce precipitator collection efficiency.

Performance improvement depends on the design and the current performance of the existing air heater. Flue gas leaving some operating air heaters has exceeded the design value by 5 °C to 20 °C and air leakage to into the flue gas flow may reach 40%. As a result of these conditions, boiler efficiencies can decrease in the range of 0.2% to 1.5%. These deficiencies can be corrected by air heater improved surface cleaning, air to gas path seal improvements, and other upgrading and refurbishment.

Pulverizers
Pulverizers dry and process coal to a fine powder that is required in the burners. Improved and refurbished pulverizers often reduce unburned carbon, which is wasted fuel. Fly ash carbon content in the range from 1% to over 30% has been encountered. A 30% fly ash carbon content will cause a loss of boiler efficiency in the range of 0.2% to 0.5%.

Pulverizer upgrading and refurbishment can also reduce the amount of ash slag (iron, silica, calcium and other coal ash constituents) that collects on furnace walls, superheaters, and reheaters, thereby improving heat transfer and boiler efficiency. These ash accumulations may also cause overheating and corrosion of boiler tubes, causing failures that require boiler shutdown for repairs.

Burners
Burners mix coal and primary air with secondary air for injection into the furnace. With improved burners and instrumentation more complete combustion of the coal with lower NOx emissions is possible. In addition, with new burners and instrumentation, operators can adjust air and coal flow for complete combustion and lower unburned carbon, and reduce water wall slagging and superheater/reheater slagging and fouling. These improvements result in better heat transfer within the furnace and improved boiler efficiency. Improved coal feeders and pulverizers may also be needed to achieve the benefits of improved boiler efficiency. As noted above for improved pulverizers, the impact on boiler efficiency can be significant.

Burner Furnace Sootblowing Upgrades
Improved or additional sootblowers increase furnace, superheater, and reheater heat absorption leading to increased boiler efficiency, reduced coal consumption, and lower emissions by maintaining these tube surfaces reasonable clear of ash accumulations that reduce heat transfer.

Steam Turbines
Steam turbines convert the boiler steam energy into rotating energy for turning the generator.

Improving steam turbine performance by refurbishing will result in significant performance improvements. Refurbishments include removing deposits that cause a reduction in blade aerodynamic performance, repairing or replacing the first stage turbine blades that have been damaged by boiler tube scale, replacing or adjusting blade and shaft seals, and other activities. In addition, major performance improvements can be implemented on many turbines with newer, more efficient turbine blades and other components. These improvements are possible because current turbine designs perform more efficiently than the designs that were available ten to twenty years ago.

Condensers
Condensers receive steam from the steam turbines where cooling water flowing through tubes cools and condenses the steam. Condensing lowers steam turbine exhaust pressure and increases turbine efficiency. Also, condensing the steam allows pumping and recycling the high quality water to the boiler.
Scaling on the water-side of the condenser tubes decreases the heat transfer coefficient and higher condenser pressures result. Increased condenser pressure will significantly reduce steam turbine output and efficiency. Air leakage into the condenser can also increase condenser pressure and will lower the quality of the recycled water.

Forced Draft, Primary Air, and Induced Draft Fans
Forced draft (FD) fans supply air to the burners and in some systems to the pulverizers. With a pressurized furnace, the forced draft fans provide sufficient pressure for the flue gas flow through the furnace, air heater and flue gas cleanup equipment to the chimney. Some boilers have primary air fans that supply air to the pulverizers, whereas some boilers have blowers or exhausters on each pulverizer. Induced draft (ID) fans move flue gas from the furnace through the air heaters and flue gas cleanup equipment to the chimney.

Increased fan flow and pressure are required for various reasons:

- Changes in the coal quality and moisture.
- Air heater and other equipment pressure losses have increased.

- Air pollution control or burner modifications have increased air and flue gas pressure losses.
- The original design pressures and flows for the fans were not adequate for the current actual operating situation.

Unit output reductions from fan performance deficiencies have been encountered that have reduced unit output in the range of 2% to 8%.

Control and Instrumentation
Control and instrumentation improvements can reduce total fuel consumption due to quicker and more coordinated startups, and provide better control of fuel and air during normal operation. The main impacts of improved controls are improved operating efficiency due to better control of excess air and steam pressure and temperature, as well as faster load changes in response to the generating system requirements. In addition, boiler and turbine stresses are reduced because startup and load changing is coordinated to reduce temperature and pressure variations. This often provides higher unit availability because of the decrease in thermal stresses and inadvertent unit trips during generating system transients, which, in turn, lead to turbine, boiler and other equipment failures. (end of APEC document)

Advancement in design opens up another possibility, modifying the original design of a unit. This can be as "simple" as resizing the backend of the turbine to increase flow capability or reduce losses due to being undersized in the original economic analysis (low fuel prices) or as complicated as totally replacing major pieces of equipment and modifying the cycle. In some cases, such as turbine nozzles, the replacements can be designed to have a lower rate of deterioration. In the extreme, this type of upgrade can become a repowering option where the boiler is replaced by combustion turbines, a new boiler or converted (CFB). Significant efficiency and fuel changes are possible. To summarize, deterioration can be addressed as follows:

- Refurbishment
- Replacement in kind
- Upgrade with advanced design
- Modify original design
- Repowering
- Retirement with replacement by new construction

Given the large aggregate capacity of existing coal-fired power plants and their long useful life, efforts to improve the average efficiency of the existing stock by one or two percent could have a significant near term impact on fuel consumption rates and greenhouse gas emissions. Every plant, based on age, condition and economics will fall at one of the levels on the above list, with most of them in the top 3 categories. Different pieces of equipment might be at different levels for the same plant. The amount of gain is also a function of the plant's design and situation. Finally, when all is considered, most plants will fall in the 3-6% range of possible improvement. The practical or economic values will be lower. The newer plants might be in the 2-4% range and a certain population might be 2% or less because they were already upgraded.

Forecasted Efficiency

Two primary sources for analyzing the past and the future of power generation efficiency are the Energy Information Administration's (EIA) Annual Energy Outlook 2007 and the International Energy Agency's (IEA) World Energy Outlook. The overall measure of power plant efficiency comes from the heat rate (Btu/kWh). This accounts for the total heat (i.e. fuel) required to generate each kWh. Highly efficient units will require less heat/fuel to generate each kWh. Heat rates were calculated from the provided data for each report to develop trends in power plant efficiency. This analysis is centered on fossil fuel generation. General consensus is that petroleum generation will continue to decline, so we will further focus our discussion on only natural gas and coal-fired generation.

United States

Figure 5 shows historical and forecasted heat rates from US natural gas and coal-fired power plants. Historical calculations are based upon EIA data. The post-war boom of the late 1940s and 1950s saw a large increase in new power plants. However, these were, by today's standards, highly inefficient plants, with the overall fleet heat rate starting in 1949 at nearly 15,000 Btu/kWh. By the end of the 1950s, more efficient plant constructions drove the fleet heat rate to approximately 10,300 Btu/kWh, where it remained relatively unchanged until the end of the century.

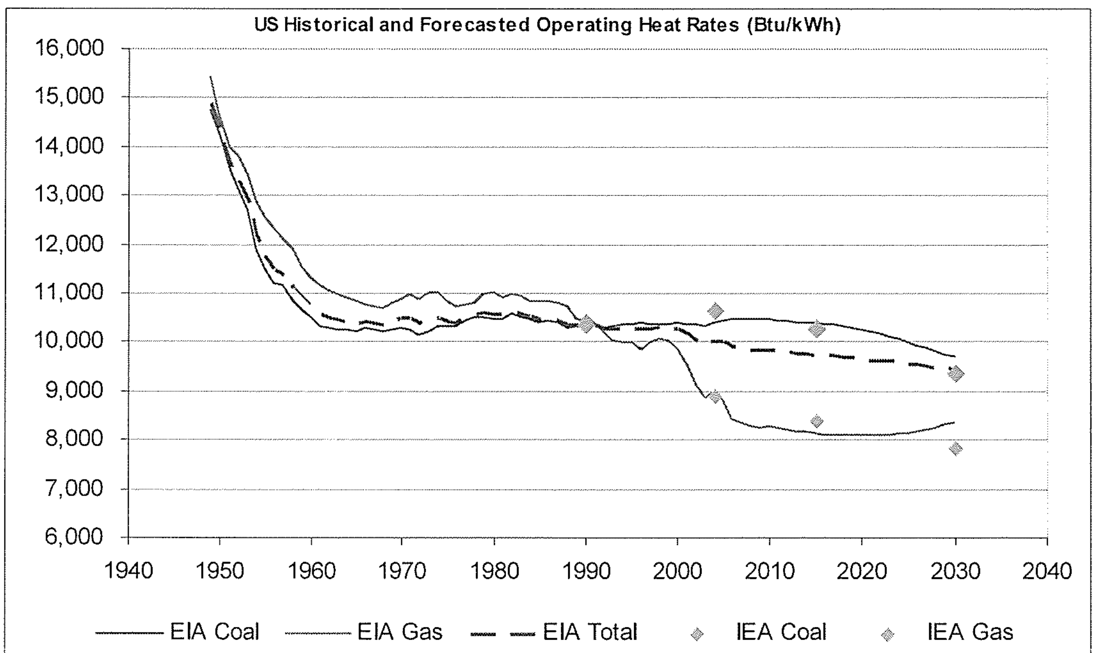

Figure 5: Historical and forecasted heat rates from EIA and IEA

The overbuild of natural gas combined cycle units in the late 1990s decreased the natural gas fleet heat rate below 9,000 Btu/kWh, where it currently resides. However with the recent higher natural gas prices, coal generation still represents over 50% of current US power generation. Therefore overall US fleet heat rate was not impacted by the large combined cycle build since coal-fired heat rates remain around 10,400 Btu/kWh.

The EIA is projecting the natural gas fleet heat rate to continue to decline. Around 2023, generation from gas units decreases faster than consumption, resulting in a slight increase to 8,300 Btu/kWh. Currently, best technology combined cycle units can achieve ~5,700 Btu/kWh [General Electric H-System]. The gas heat rate includes CT plants which could have heat rates as high as 13,000 and as low as 8,550 Btu/kWh in the future according to the EIA. These types of units will continue to be needed as they have the ability to turn on and off over a small time period leading to increase system stability.

The EIA is forecasting moderate improvements in the coal fleet heat rate, achieving 9,700 Btu/kWh by 2030. In terms of percentage improvement it is approximately the same trend as gas units. This indicates many more new coal plants as compared to new gas plants in the projection. To see any appreciable improvement in fleet heat rate, a large number of new, efficient units would need to replace a large number of old, inefficient units and/or existing units would have to be retrofitted. With 40 year life spans and high capital costs (vs. gas plants) to construct, and risk of a CO2 constrained environment, this is not achieved very quickly. The difference in fuel price (coal vs. gas) is another major driver for increased efficiencies in gas plants compared to coal plants. Major increases in combined cycle efficiencies will make those units more competitive with coal in dispatch. With coal's current fuel pricing advantage, there is less incentive to make wholesale improvements in efficiency versus focusing on availability. Table 4 shows the EIA assumptions for new build heat rates for 2005, nth-of-a-kind in the future and the best observed heat rates to date. Observed data for combustion turbines is not provided since efficiency is not their primary role in the supply stack. These units are used primarily as peakers, where efficiency is not of utmost concern.

Table 4: EIA heat rate assumptions (all values Btu/kWh)

Technology	Heat Rate in 2005	Heat Rate nth-of-a-kind (% improvement from 2005)	Best Current (2004)[16]
Scrubbed Coal	8,844	8,600 (2.8%)	8,842*
IGCC	8,309	7,200 (13.3%)	N/A
IGCC w/ carbon sequestration	9,713	7,920 (18.5%)	N/A
Conv. CC	7,196	6,800 (5.5%)	6,335*
Adv. CC	6,752	6,333 (6.2%)	N/A
Adv. CC w/ carbon sequestration	8,613	7,493 (13.0%)	N/A
Conv. CT	10,842	10,450 (3.6%)	N/A
Adv. CT	9,227	8,550 (7.3%)	N/A
** Coal = TVA, Bull Run Plant; CC = Sempra, Elk Hills Power*			

[16] *Electric Light & Power*, Operating Performance Rankings Showcase Big Plants Running Full Time Nancy Spring, managing editor November, 2005

The EIA forecasted heat rates for new builds seem reasonable when compared to the best operational CCs and coal units in 2004. In fact, the forecasted CC heat rate may be a bit conservative, considering new technology (GE H-System) has exhibited heat rates around 5,700 btu/kWh. The forecasted coal heat rate is slightly less than current operational technology, so the EIA is assuming technology advances. In light of the cooling water system requirements (especially in the west), the forecasted heat rate may not be achievable without future technology advances.

Historical EIA and IEA generation and fuel consumption varied slightly for the US, while the IEA provides fuel consumption for combined power and heat plants. To mitigate this discrepancy, it was assumed that historical EIA data for the US was correct. The 1990 IEA data was then normalized to the EIA data. Each normalization factor was used to scale the forecasted IEA data, so it could be directly compared with the EIA forecasted data. Figure 5 shows the IEA forecasted heat rates for both coal and gas-fired plants. The IEA and EIA forecast very similar coal-fired heat rates, but differ slightly in 2030 with EIA forecasting 9,700 Btu/kWh and IEA projecting 9,400 Btu/kWh. The forecasts slightly diverge in gas-fired heat rates, with the EIA having the anomaly decrease (rise of heat rate) in efficiency starting in 2023.

According to the EIA Annual Energy Outlook, the coal-fired fleet heat rate shows improvement over the forecast horizon. To determine how much of this improvement comes from new generation versus improvements to existing units, the heat hates for each were back calculated. Table 5 shows the methodology used in calculating the heat rate of existing units. Equation 1 shows the calculation used for determining weighted-average heat rates for existing and new units. Total generation, total coal heat rates and the mixture of pulverized/IGCC new builds are all available from the EIA Annual Energy Outlook. From those given values, all other values necessary to derive future heat rates for units existing in 2007 can be obtained. Solving Equation 1 for HR_{exist} yields the value we are seeking. New build capacity by year is available in the Annual Energy Outlook. The EIA assumed new pulverized coal units have a heat rate of 8,600 Btu/kWh, while new IGCC units have a heat rate of 7,200 Btu/kWh. Assuming a capacity factor of 80% for all new coal generation, the amount of total generation from existing and new units can be calculated. According to the Annual Energy Outlook 2006, coal new builds in 2015 were 72% pulverized and 28% IGCC. The mixture in 2030 was 40% and 60% respectively. This data is not yet available for the 2007 report, so the new build mixture is assumed unchanged from the 2006 report. For the years 2015-2030, the ratio of pulverized and IGCC new builds was linearly interpolated to get a curve for new pulverized and IGCC generation. Using a weighted-average heat rate calculation based on the above information, the heat rate for existing units was calculated and is shown in Figure 6. Heat rates remain relatively flat through 2030.

Table 5: Methodology for back calculation of existing unit heat rates

ID	Value	Formula	Notes
[1]	Total Generation (MWh)	given	Provided EIA AEO
[2]	Cumulative New Build Generation - 80% CapFact	=NewBuildCoalCapacity*8760*0.80	NewBuildCoalCapacity Provided EIA AEO
[3]	% New Coal Pulverized	linearly interpolated over 2015-2030	Provided EIA AEO 2006
[4]	% New Coal IGCC	linearly interpolated over 2015-2030	Provided EIA AEO 2006
[5]	New Pulverized Generation	=[3]*[2]	
[6]	New IGCC Generation	=[4]*[2]	
[7]	Existing Unit Generation	=[1]-([5]+[6])	
[8]	Total Heat Rate	given	Calculated EIA AEO
[9]	New Heat Rate	see Eq. 1	
[10]	Existing Unit Heat Rate	see Eq. 1	

$$\frac{(HR_{exist} \times Gen_{exist}) + (HR_{new} \times Gen_{new})}{Gen_{exist} + Gen_{new}} = HR_{total} \qquad \text{Eq. 1}$$

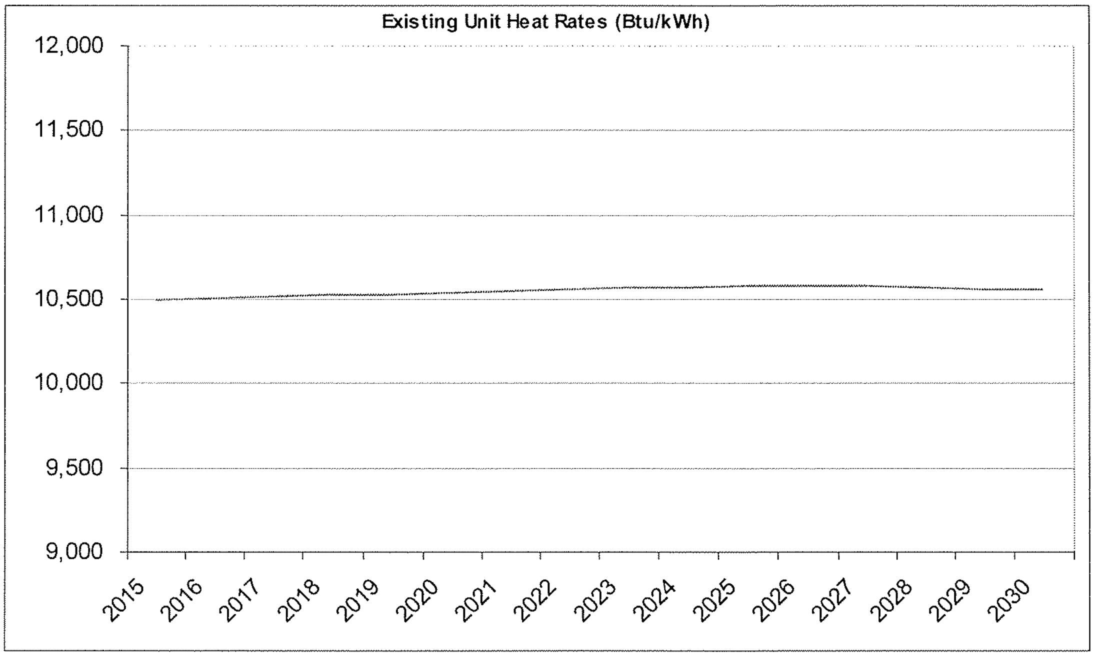

Figure 6: Heat rate at existing coal units according to EIA

According to the EPA, as discussed above, nearly 270 GW will be scrubbed by 2020. This amounts to nearly 90% of all coal units, including new builds which are all assumed to be built with scrubbers and SCRs. By 2020 about 18% of existing coal units will be retrofitted with a scrubber (this does not include units that currently have scrubbers in 2006). The net change in heat rates through 2030 is nearly 0%. This means that any loss due to parasitic load must be identically offset by improvements in efficiency through other retrofits or refurbishing. Based on scrubber retrofits alone, (18%*2% parasitic load) this means that the coal fleet efficiency improvement is 0.36% for existing units. SCRs are not taken into account in this analysis since they are installed on gas units as well. Also, SCR and scrubber installations are not mutually exclusive, as many coal units will install both. Assuming the fleet heat rate would still remain flat with SCR installations, an even larger improvement would be required to identically offset the parasitic load losses. This value is between 2-3% (scrubber = 2%, SCR = 1%). The improvement to existing unit heat rates is not attributed to the retirement of less efficient units (i.e. "addition by subtraction"). By 2030, retired coal capacity is only 1.29% of the entire coal fleet capacity. Considering this 1.29% would have lower capacity factors than the units replacing them, their impact is considered negligible to the observed efficiency improvement.

CO_2 Impact in United States

Using the EIA forecasted heat rates, CO_2 emissions were calculated using standard emission rates of 205 lb/mmtbu and 115 lb/mmbtu for coal and gas units respectively. Five scenarios were compared:

1. CO_2 Locked at Current HR – 2007 HRs are used in perpetuity
2. CO_2 at EIA Forecasted HR – forecasted decrease in HR is used
3. CO_2 If 1/2 Coal Goes to Gas – 50% of coal generation goes to gas generation
4. CO_2 with 2x Coal Turnover – the percentage of coal fleet that is new build is doubled (i.e. by 2030 65% is new build as opposed to the EIA base of 32.5%)
5. CO_2 with 5% Improvement to Current HR – current heat rates improved 5%

Figure 7 shows the 2030 CO_2 emissions for each case. As might be expected the scenario in which 50% of coal generation goes to gas generation yields the lowest CO_2 emissions. This is accounted for by the double reduction effect of heat rate and emission rate. Coal units have higher heat rates and emissions rates. Reducing 50% of that generation by *both* heat rate and emission rate has a multiplicative effect on total CO_2 emissions. Below is a simple illustration of the effect on CO_2 by replacing coal generation with gas generation

$$\textit{Coal}: \frac{205\text{ lb CO}_2}{\text{mmbtu}} \times \frac{10.5\text{ mmbtu}}{\text{MWh}} \times \frac{\text{ton CO}_2}{2000\text{ lb CO}_2} = \frac{1.08\text{ ton CO}_2}{\text{MWh}}$$

$$\textit{Gas}: \frac{115\text{ lb CO}_2}{\text{mmbtu}} \times \frac{7.0\text{ mmbtu}}{\text{MWh}} \times \frac{\text{ton CO}_2}{2000\text{ lb CO}_2} = \frac{0.40\text{ ton CO}_2}{\text{MWh}}$$

By replacing 1 MWh of coal generation with gas, only 37% as much CO_2 is emitted. Figure 8 shows the total CO_2 emission savings for the timeframe 2007-2030. As expected, replacement of coal generation with gas generation has the largest impact followed by replacement of old coal generation with new coal generation.

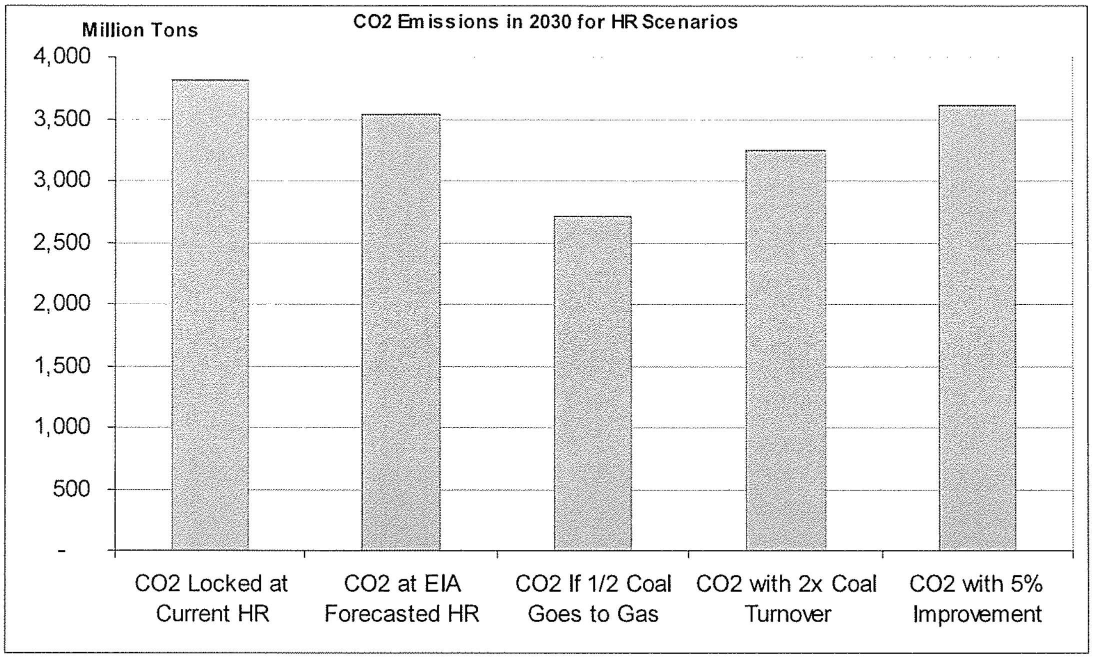

Figure 7: CO_2 emissions in 2030 for various scenarios calculated from EIA Annual Energy Outlook

As always, there are trade-offs. In a carbon constrained world it would be easy to suggest the '1/2 Coal Goes to Gas' scenario. However, the amount of natural gas consumption jumps dramatically to meet this excess demand. With coal accounting for 50% of power generation, this is a significant shift – 25% of total generation moving to gas. Figure 9 shows gas consumption for power generation in 2030 for the given scenarios. With over 3 times the gas consumption for the '1/2 Coal Goes to Gas' scenario as the EIA base forecast, significant price changes in natural gas would occur. This would make coal more attractive, thus increasing CO2 emissions until a final equilibrium is obtained. The above scenarios are simply illustrations of the potential impacts that efficiency can have on CO_2 emissions and gas consumption. In reality, market forces will act to temper extremes toward equilibrium.

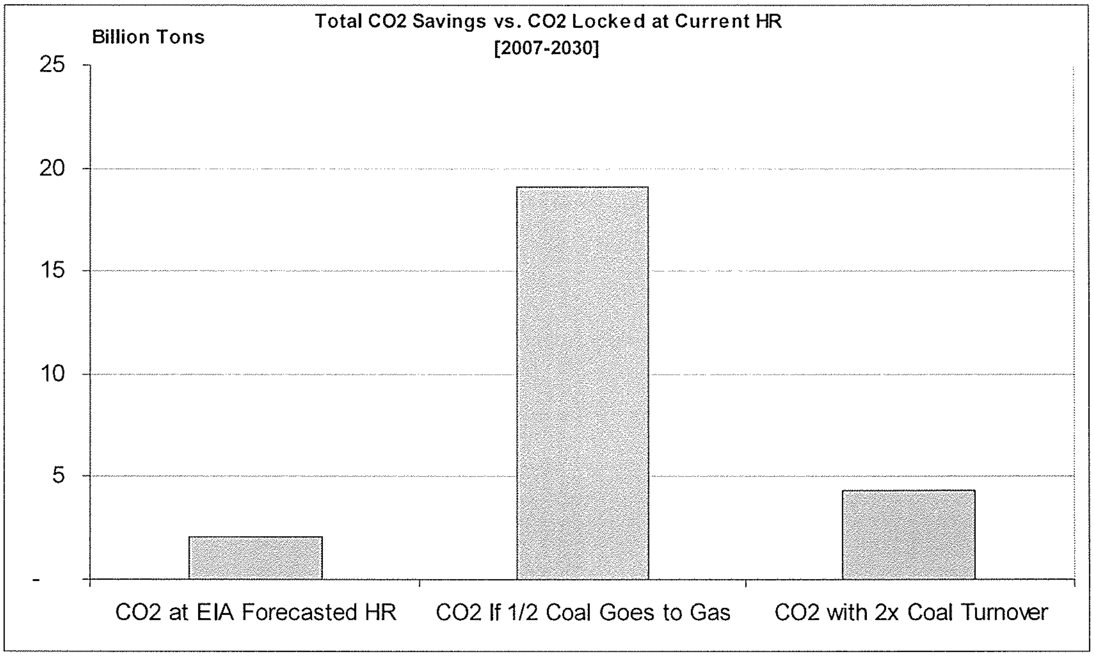

Figure 8: Total CO_2 emission savings vs. the total emitted if 2007 HRs locked in perpetuity

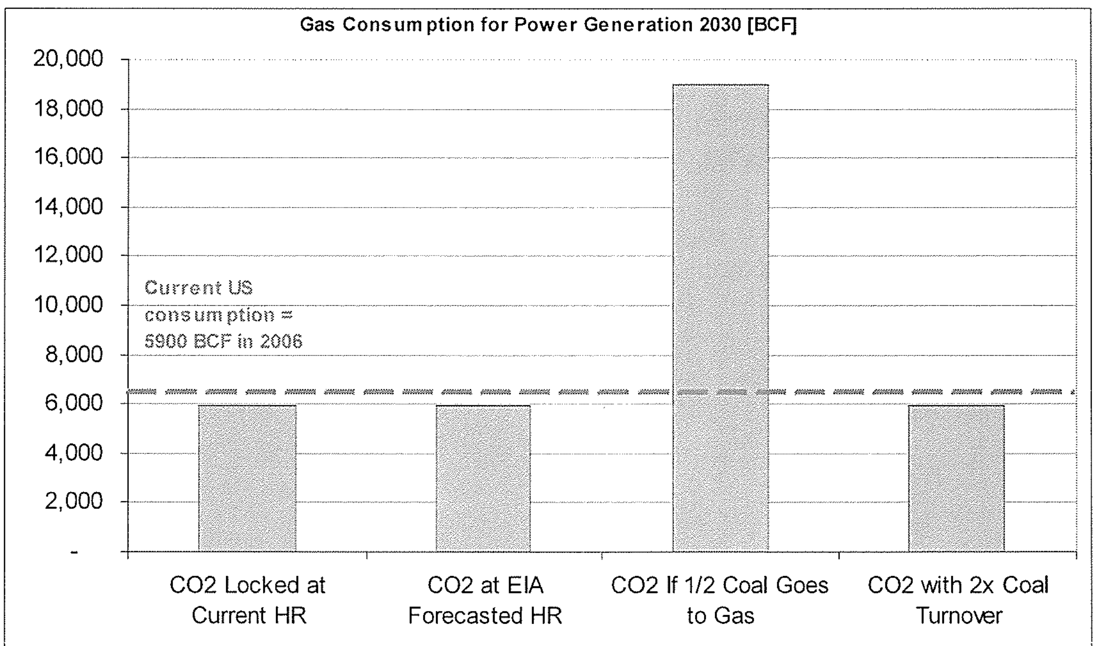

Figure 9: Gas consumption in 2030 for various scenarios calculated from EIA Annual Energy Outlook

World and China

Since historical data does not align properly between EIA and IEA, heat rate improvements were examined for the world and China, as opposed to absolute heat rate values. Figures 10-12 show the percentage improvements in heat rate for EIA and IEA from each agency's base year. As one might expect, heat rate improvements in China are expected to outpace worldwide improvements. Rapidly growing power demand is expected to drive a large increase in the number of new builds. With a larger percentage of fleet capacity coming from newer, efficient units, it is expected that overall improvements would increase rapidly in China. Worldwide heat rate improvements are forecasted to increase moderately for both gas and coal plants according to both EIA and IEA. Again, this is the result of gradual replacement of older, inefficient units with new, efficient ones. The slower pace of this replacement leads to the slower increase in efficiency when compared with China alone.

An important distinction to note between the EIA and IEA forecasts is the heat rate improvements of coal vs. gas. The EIA forecasts gas improvements for the world and China to greatly outpace improvements to coal-fired generation. Inversely, the IEA forecasts coal to improve more rapidly than gas-fired plants. There are two schools of

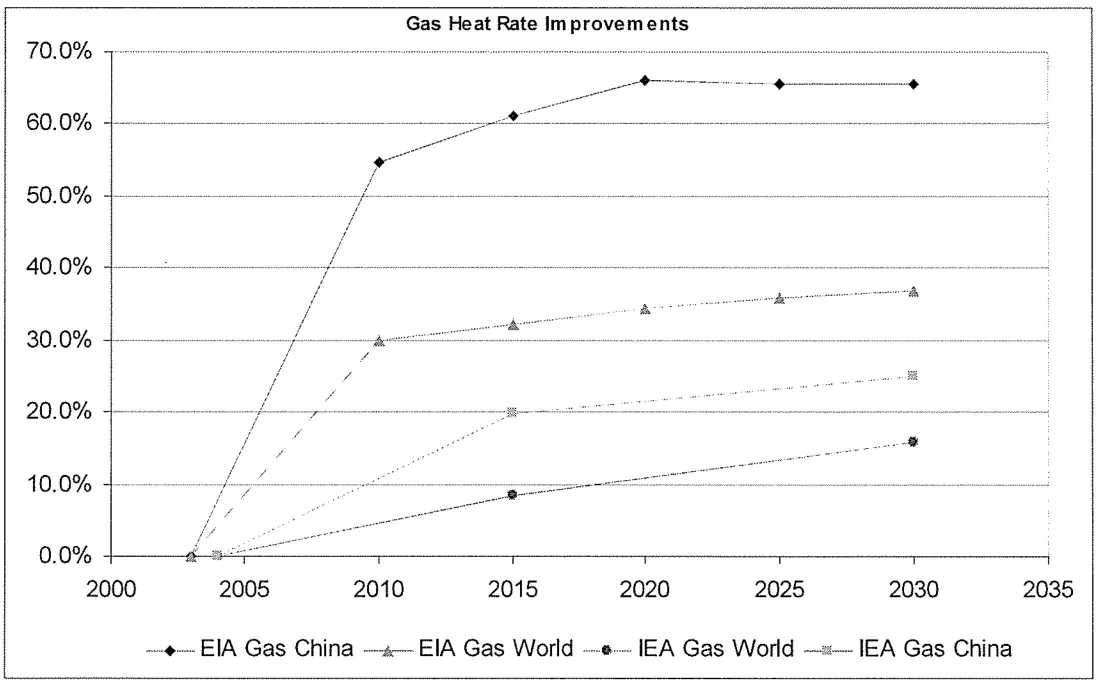

Figure 10: Gas heat rate improvements

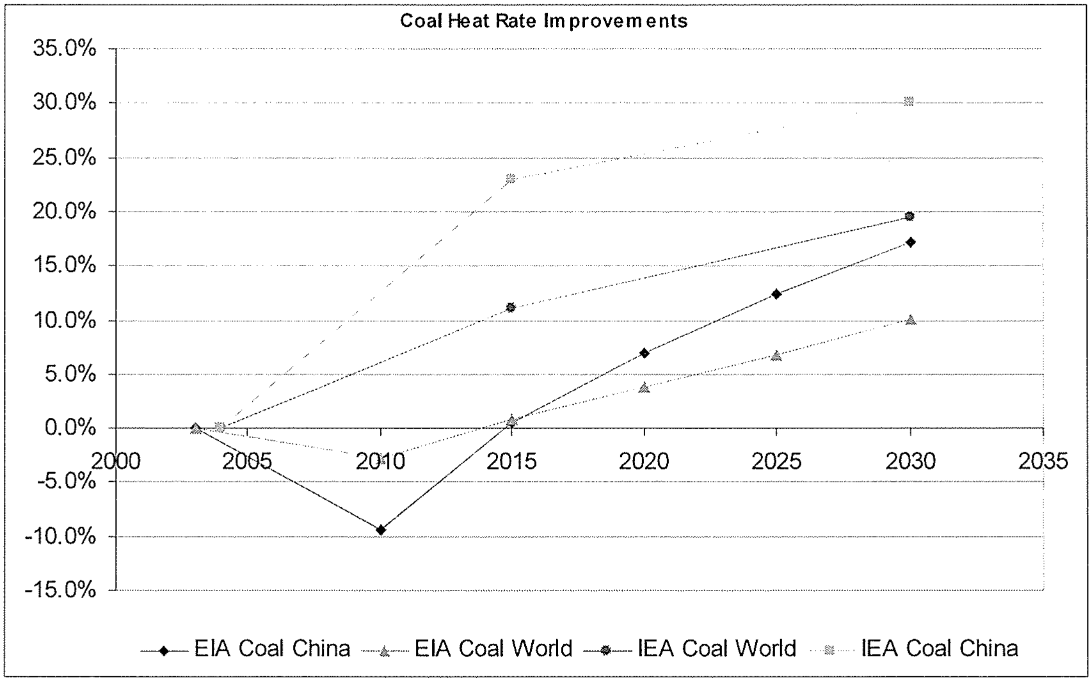

Figure 11: Coal heat rate improvements

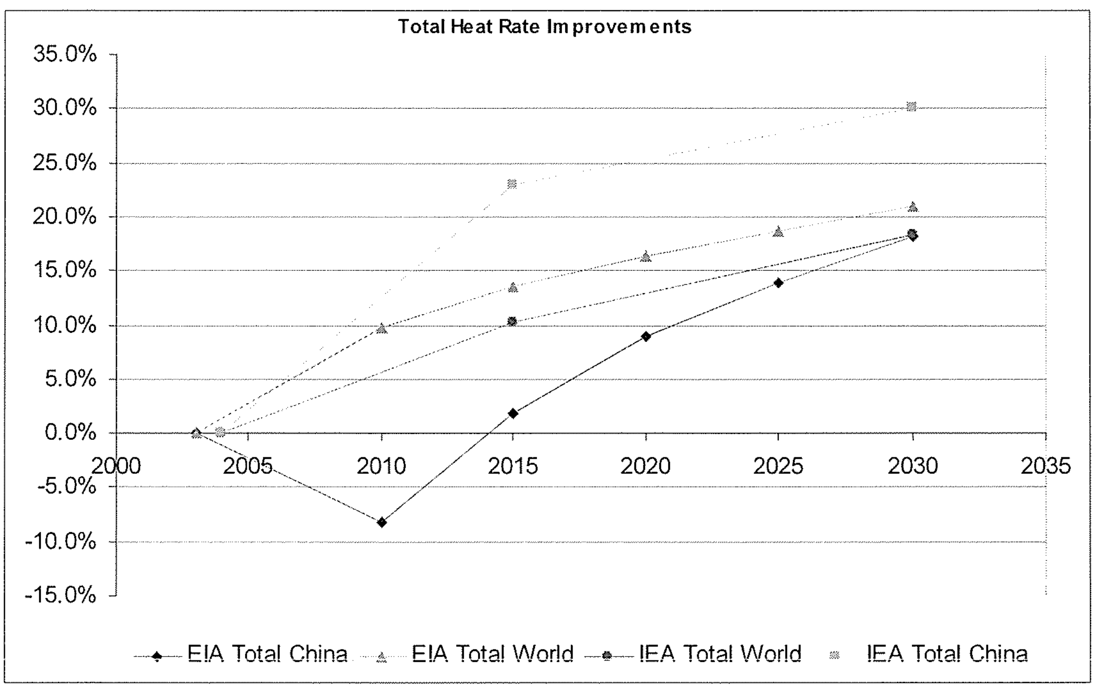

Figure 12: Total heat rate improvements

thought that can justify either scenario. One could argue that gas heat rates are expected to rapidly improve due to a large buildup of highly efficient combined cycle units. This is the same phenomenon that was seen in the United States during the 1990s. With a rapid increase of combined cycle units, the gas heat rate quickly declines. The large improvements in coal-fired heat rates could be justified by determining that gas-fired heat rates are asymptotically approaching their maximum achievable efficiency (though not achievable, 100% efficiency is 3,412 Btu/kWh). Steam cycle coal units theoretically have more room for improvement since they are less efficient from the start.

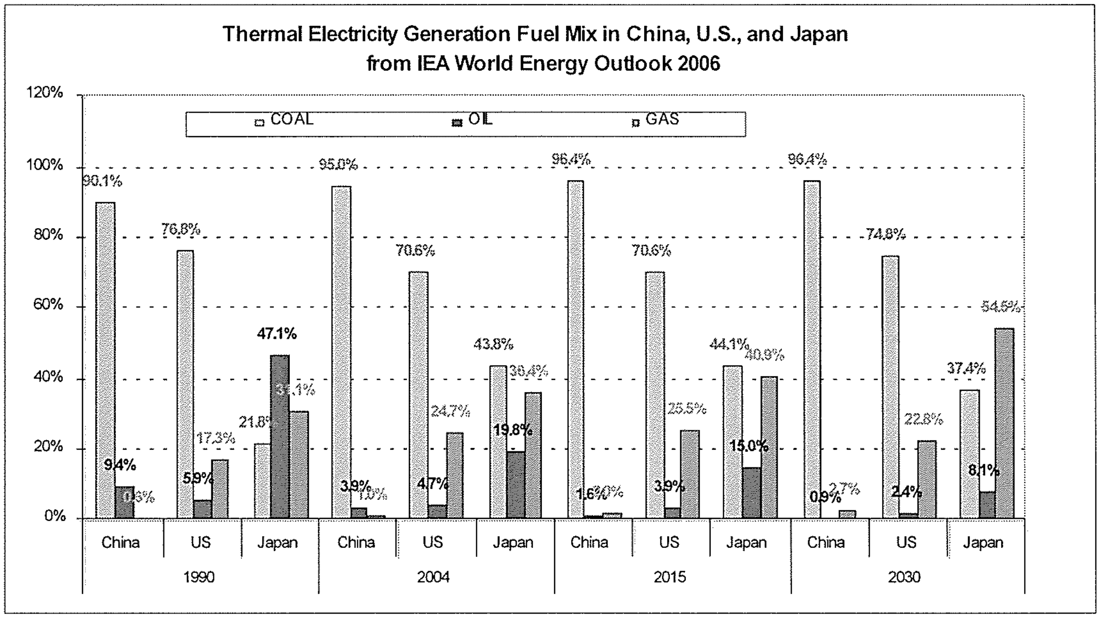

Figure 13: Fuel mix for thermal power plants in China, U.S., and Japan

Recently, a blue book of energy of China[17] reported historical heat rates for Chinese power plants. The blue book data on Chinese coal-fired power plant efficiencies are not consistent with those forecasted by the Energy Information Administration. In its reference case, EIA forecasted electricity generation, coal consumption and coal-fired generation in China, as listed in Table 6. Based on the EIA data, the heat rates for coal-fired power plants in China are calculated and listed in Table 6, and the calculated heat rates for 2003 and 2015 are much higher than those for 2002 reported by the blue book, as shown in Table 7. From Table 6, coal-fired generation in 2015 almost doubles that of 2003, which indicates that about 50% of electricity will be generated from new coal-fired plants built after 2003. However, the average heat rate only decreases 0.4% from 2003 to 2015. These new-builds will have an average heat rate of 11,426 Btu/kWh with assumptions of no retirement of old plants and constant capacity factor for all plants. If the retirement of old plants and higher capacity factors for the new builds are taken into consideration, the new builds' average heat rate will be higher than 11,426 Btu/kWh. This value seems much too high considering US new builds are currently achieving heat rates lower than 9,000 Btu/kWh. As a comparison, the average heat rates of U.S. coal-fired power plants from EIA are listed in Table 6. Because of scarcity of reliable data, the

[17] The Energy Development Report of China, Edited by M. Cui, etc., Social Sciences Academic Press of China, 2006

uncertainty of the efficiencies of coal-fired power plants in China exists and is not ready to be solved at present. Also, this uncertainty has a huge impact on estimating CO_2 emissions from Chinese coal-fired plants. The CO_2 emissions from Chinese coal-fired plants for 2003 will be 8.2%, or 137 million tons, less if the average heat rate of 10,580 Btu/kWh in Chinese coal-fired plants from the Blue book is used, than that calculated from average heat rate of 11,530 Btu/kWh from the EIA. In a less-conservative way, if 17.1% decrease in the average heat rate from 11,530 Btu/kWh in 2003 to 9,560 Btu/kWh in 2030 for Chinese coal-fired power plants from the EIA is applied to the derived average heat rate of 10,580 Btu/kWh from the Blue book, there are 422 million tons of CO_2 emissions less than that based on the EIA forecasted 9,560 Btu/kWh. These calculations indicate that it is important to improve the data collection on CO_2 emissions issue before a reliable conclusion should be made.

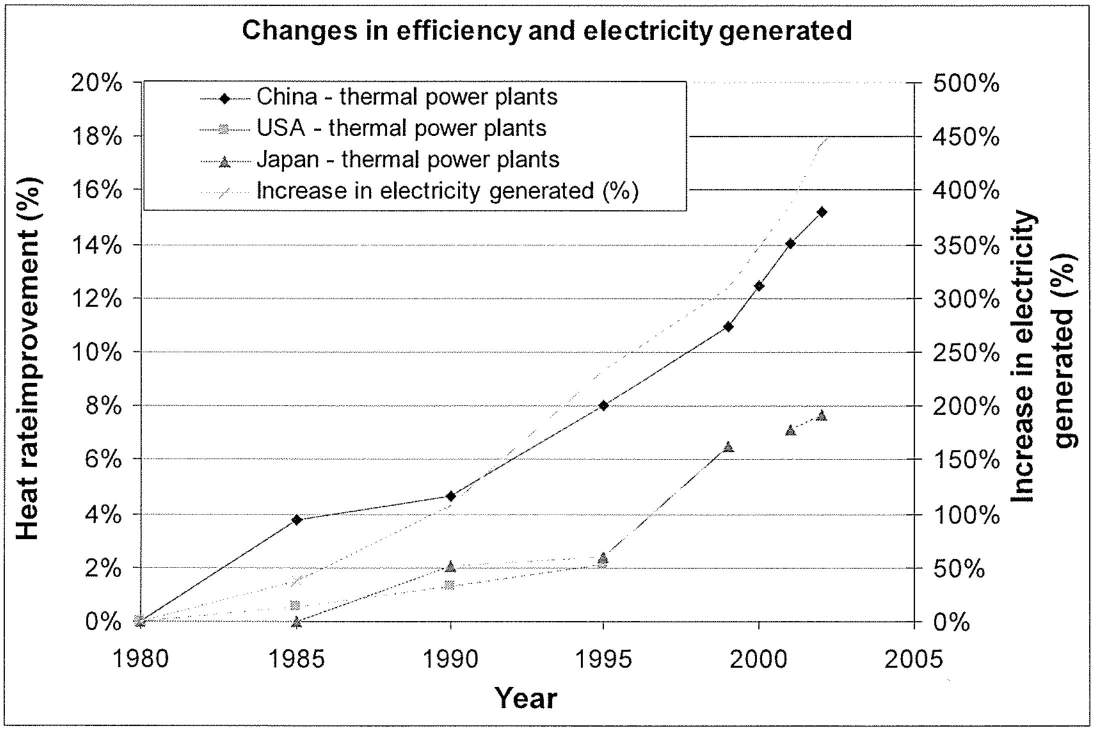

Figure 14: Historical efficiency improvements according to The Energy Development

Table 6: Electricity generation coal consumption and coal-fired generation in China

Year	2003	2015	2030
Generation (Billion kwh)[18]	1414	2788	5243
Coal consumption (Quadrillion Btu)[19]	16.3	32	50.1
Calculated average heat rate (Btu/kWh)	11,530	11,480	9,560
U.S. average heat rate (Btu/kWh)	10,310	10,370	9,670

[18] Energy Information Administration/International Energy Outlook 2006, Appendix F - Reference Case Projections for Electricity Capacity and Generation by Fuel

[19] Energy Information Administration Report #:DOE/EIA-0484(2006), Release Date: June 2006, Figure 52 Coal Consumption in China by Sector, 2003, 2015, and 2030

Table 7: Comparison of coal-fired heat rates in Btu/kwh from different sources

Year	**2002**	**2003**
The Blue Book[17]	10,580	
EIA		11,530

Improvement in coal-fired power plant efficiency in China has a great impact on the CO_2 emissions. If the coal-fired power plants in China kept their efficiency unchanged at the 2003 level, Chinese coal-fired power plants would emit 1 billion tons more CO_2 in 2030 under an assumption of 205 lb CO_2/mmBtu than it would if it had the 2030 forecasted heat rate of 9,560 Btu/kWh. To yield the Chinese forecasted heat rate of 9,560 Btu/kWh, all new coal plants built after 2003 would need to average 8,830 Btu/kWh. This highlights the imperative nature of the need to start installing more advanced coal plants in China versus their historically installed plant technology.

Overall, the EIA and IEA are forecasting fleet improvements to power plant efficiencies. The need for more efficient gas units in addition to technology improvements requires market influence. With gas prices at much higher levels relative to coal prices the need to increase efficiency becomes greater for a gas plant to make up the fuel price difference to a coal plant in dispatch. With an increasing amount of generation coming from coal-fired plants, the overall system fleet heat rate decreases at a slower rate than is seen for gas units alone. This is the weighted-average effect of coal-dominated generation.

4. Policy Recommendation

Promoting efficiency seems to be an obvious choice, but the implementation of a policy needs to be cognizant of the cost and operational sensitivity of the utility industry. Over 50% of current US power generation comes from coal, which shows the most room for efficiency improvement. However, reliability will continue to be important over efficiency. Retrofitting and refurbishing of the aging US fleet will likely yield only minimal efficiency improvements (5-10%). Counteracting this, emission control retrofits will lead to a decrease in efficiency due to their parasitic load.

- Technology research in advanced materials will be required to lower the capital costs of higher efficient units that require exotic materials of construction
- Increasing fleet turnover will yield the greater efficiency improvements by replacing older, less efficient units with newer, more efficient ones. However, without considering a balanced generation mix, a larger dependence on foreign fuel will occur, in particular LNG
- For the world and China, it is imperative that better data be obtained to understand the ramification of future power markets
- Construction of highly efficient plants is critical particularly in developing countries where the fleets have large room to grow. With 40+ year lifespans, it is important that new units be as efficient as possible with balancing the reliability concerns.