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Near-Term Technologies for Retrofit CO_2 Capture and Storage of Existing Coal-fired Power Plants in the United States

White Paper for the MIT Coal Retrofit Symposium

May, 2009

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Summary

Coal-fired power plants, as large point sources of CO_2, are the logical choice for CO_2 mitigation, via CO_2 capture and storage (CCS) and other options. However, continuing life extension of the relatively old and inefficient fleet of existing United States (U.S.) coal power plants undermines potential CO_2 mitigation efforts.

New coal power plants, with CO_2 capture and geologic storage will slow the rate of growth of CO_2 emissions but the large existing fleet of coal power plants needs to be replaced with lower CO_2 power sources or retrofitted with CCS to significantly lower CO_2 emissions. In the near-term, and perhaps medium-term, there are inadequate non-coal, low- CO_2 emitting alternatives to replace the existing 50% coal-based electricity in the U.S. and 40% worldwide. Therefore to become serious about major CO_2 reductions, consideration should be given to CCS retrofits of existing coal power plants.

Existing coal plants represent approximately 33% of total U.S. CO_2 emissions. As such, the retrofit or rebuild of U.S. existing coal power plants with CCS represents significant opportunities for major CO_2 reductions. Retrofits and rebuilds, however, face many technical, economic and political challenges. The low cost electricity from these mostly paid-off (fully amortized) existing coal plants leads to very high CO_2 avoidance costs.

In addition, the simpler and less capital-intensive retrofit add-on for post-combustion CCS leads to large net efficiency and capacity losses. This type of retrofit will likely favor the newer supercritical steam cycle coal units that already have good SO_2 and NO_x controls. Rebuilds of the older subcritical steam cycle coal units have added advantages and flexibility. Due to the lower efficiency and generally higher SO_2, NO_x, Hg and particulate emissions of the older existing subcritical coal units, rebuilds can avoid most net efficiency and capacity losses while reducing all emissions to near zero. This is an important advantage. Rebuilds can come in the form of a state-of-the-art supercritical coal boiler steam cycle of post- or oxy- combustion CCS or an integrated gasification combined cycle (IGCC) for pre-combustion CCS. Combined cycle repower rebuilds can also be fueled with natural gas (without CCS) or off-site CCS based on coal gasification to synthetic natural gas or H_2. This enables major repowering capacity increases and CO_2 reductions at old coal plant sites considered hopeless for retrofit CCS.

Why Focus on Existing Coal-fired Power Plants?

A key conclusion in the 2001 SFA Pacific private multi-client CO_2 Mitigation Analysis was that coal-based electric power generators, as large single point sources of CO_2, would be forced to meet a disproportionate share of any anthropogenic CO_2 reductions. CO_2 reductions from vehicles are especially problematic and CO_2 emitting industries have, unfortunately, the opportunity to re-locate in countries that do not subscribe to major CO_2 reduction mandates. Various graphics describing the existing U.S. coal-fired power plant fleet are presented in the attached PowerPoint slides. These simple bar-chart graphics include sorts by age, unit sizes, locations (by state), owners, emissions and capital cost of retrofit add-on flue gas desulfurization SO_2 emission control by coal power plant size.

The existing U.S. coal power plant fleet has a summertime capacity of about 314 GWe or about 30% of total capacity yet generates about 50% of the entire U.S. annual electricity. Existing coal-fired power plants are relatively old, and have generally lower efficiency and higher emissions than proposed new state-of-the-art coal-fired power plants. For example, the typical existing coal-fired power in the U.S. as of 2005 EIA data was about 35 years old (on a capacity-weighted average), 33% efficiency (HHV) and only about 40% of this total capacity had SO_2 controls. The average CO_2 emissions are about 0.97 metric tons CO_2 per MW-hour of net electricity or about 20% higher than a new state-of-the-art coal power plant at 39-40% net HHV efficiency.

Most existing U.S. coal-fired power plants are pulverized coal (PC) boilers with subcritical steam cycles. The typical unit size is 500-700 MWe. Due to the age, many of these units were not originally built with SO_2 or NO_x controls. The 1990 Clean Air Act Amendments (CAAA) and the 2005 Clean Air Interstate Rule (CAIR) have led to a number of SO_2 scrubber flue gas desulfurization (FGD), and NO_x controls via selective catalytic reduction (SCR) retrofit additions to these existing coal-fired power plants. This is significant, as many CO_2 capture systems require removal of SO_2 before CO_2 capture or to meet CO_2 pipeline specifications. In addition, some post-combustion CO_2 capture systems favor SCR to reduce NO as it reacts with the CO_2 removal chemical solutions.

CO_2 mitigation poses unique issues and challenges for existing coal-fired power plants. The CO_2 avoidance costs for existing plants can be significantly higher than those for new power plants and, without policy or technology options existing plants will face high CO_2 taxes sufficient to incentivize CO_2 reductions via fuel switching or CO_2 capture and storage (CCS).

Coal-fired power plant locations present additional challenges to existing plants and complicate CCS options, as many plants are not located near good geologic formations for effective CO_2 storage. Costs and successful permitting of long CO_2 pipelines in the higher population density States east of the Mississippi River (where most existing U.S. coal power plants are located) are a major challenge. Furthermore, many of these existing coal-fired power plants have serious space limitations. Space limitations are most severe for existing coal power plants that have already added retrofit or require additional flue gas SO_2 and NO_x control retrofit before adding post-combustion CO_2 capture add-on retrofit.

Status of the Existing U.S. Coal-fired Power Plants

After renewable wind and nuclear power, coal-based power plants generally have the lowest marginal load dispatch power costs. Even older, less efficient existing coal power plants normally have lower power dispatch costs that the most efficient new natural gas combined cycle (NGCC) power plant. This is due to the much lower fuel energy price (dollars per million BTU) of coal compared to natural gas. Less than 10% of U.S. installed coal capacity is under 20 years old; as such the high capital costs associated with original plant construction have been paid off, making the total cost of coal-fired electric power quite low. The coal-based fleet's age and its large power generation share give the U.S. some of the lowest electric power prices in the world.

The current political climate of continuing uncertainty regarding long-term CO_2 mitigation further encourages life extension of existing coal-fired power plants. Existing plant owners face substantial revenue losses and opportunities to accumulate CO_2 reduction credits if they shut down older plants in advance of CO_2 reduction mandates. That is especially true if CO_2 mitigation develops as a "cap and trade" system with large, low-cost, CO_2 allocations to existing coal-fired power generators (as in the past with U.S. SO_2 reduction system).

As such, most existing coal power plant sites, with established locations, cooling water, permits, rights of way, proximity to coal and power delivery infrastructures, are simply too valuable to abandon. In fact, many of the old coal plants are strategically located in the existing electric grid transmission and distribution system. In addition, the time, cost and effort associated with developing new "greenfield" coal power plants sites is likely much greater than to ultimately upgrade or recycle these existing power plant sites. Most existing coal power plant modification, upgrades, retrofits or rebuilds significantly reduce the site emissions, making permitting and pubic acceptance very favorable.

The new U.S. EIA 2009 Annual Energy Outlook projects cumulative retirements of only 2.3 GWe (just 0.7%) of the existing 314 GWe coal power plant capacity in the U.S over the next 20 years assuming business as usual (no CO_2 reduction mandates). This continuing life extension of the old existing coal power plants is politically and economically logical. The key issue is how these old coal power plant sites are best utilized if CO_2 reduction mandates develop.

CO_2 Mitigation Options for Existing Coal-fired Power Plants

In addition to nuclear and renewable hydro/wind/solar replacement of coal-based power, there are three general options for existing coal power plants CO_2 mitigation as follows:

1. Replace coal with a lower carbon fuel like biomass or especially natural gas.
2. Increase the efficiency of the coal-to-electricity generation.
3. CO_2 capture and storage (CCS) from coal utilization

Each option has its own attributes and special issues specific to existing coal-fired power plant applications.

Replacement of coal with biomass is most likely the lowest *capital* cost option. This option, however, has high *fuel* costs and faces potential limits on biomass supplies. Annual supplies of sustainable biomass at reasonable collection, transportation and storage costs are a major

challenge, especially for existing coal power plants. This generally limits coal replacement with biomass at existing coal power plants to seasonal co-firing at relatively small amounts (perhaps 5-10% of total annual energy). Biomass based power likely favors new power plants strategically located relative to existing biomass sources and improved new biomass production. Even then, year-round supply limits, high transportation and storage costs plus economy-of-scale generally favor co-processing with coal. More effective biomass utilization also favors fluidized bed combustion (FBC) boilers due to their advantages processing high moisture and hard to feed biofuels plus superior fuel flexibility. Finland has become the world leader in fuel-flexible biomass, peat and coal FBC boiler power generation.

Replacement of coal with natural gas repowering has much greater potential than the biomass option. This generally favors 100% coal replacement and requires more capital to "brownfield" rebuild the old coal plant into a clean, high efficiency natural gas combined cycle (NGCC). NGCC repowering can increase the old coal steam cycle capacity by 300%. However, the long-term natural gas supply and price risks are large. Major coal replacements with NGCC would stress natural gas supplies. *Replacing all the current coal generation in the United States with natural gas would require 17 trillion cubic feet per year of additional natural gas or a 60% supply increase.* That would lead to higher natural gas prices with marginal supplies and prices set by imported LNG. Recent LNG contracts in Korea and Japan are at world oil price energy price parity and reliable estimates of future world oil prices are impossible to predict. More importantly, many believe that if a carbon constrained world develops the big surge in natural gas demand for coal power generation replacement would drive natural gas energy prices to even higher levels than crude oil. That is because the CO_2 generated per unit of energy of natural gas is over 20% lower than of crude oil.

Increasing coal-to-electric efficiency can be achieved in many ways but can be economically, politically and technically complex. The simplest option is a minor upgrade of the old coal-fired power plant to slightly higher steam quality (mainly higher steam superheat and reheat temperatures) plus rebuilding the steam turbine and electric generator for the higher quality steam. This upgrade can increase the net absolute efficiency by about 2% (perhaps from 33% to 35%) at moderate costs. However, the relative efficiency increase and CO_2 reduction per MW is only about 6%. More problematic, a minor upgrade such as this may trigger the New Source Review provisions of the Clean Air Act, necessitating major emissions upgrades. Adding a new higher efficiency wet FGD and SCR would greatly increase costs and CO_2 emission due to increased parasitic power (reducing net efficiency) and increased CO_2 emissions from the limestone reaction in the FGD.

A more expensive but higher efficiency option is a total coal power plant rebuild at the existing old PC site to a clean, high efficiency supercritical PC boiler steam cycle or integrated gasification combined cycle (IGCC). Current capital costs and availability estimates would likely favor the supercritical PC boiler steam cycle along with effective flue gas SO_2 and NO_x controls. A coal power plant rebuild can increase the net absolute efficiency by 6-8% (from perhaps 33% to 40%) for a "relative" efficiency increase of about 20%. Nevertheless, the large capital costs for only a 20% CO_2 reduction usually results in very high costs of CO_2 avoidance, discussed in a later section.

Highest efficiency improvements would be achieved through the replacement of separate direct heat uses and central power plants with effective cogeneration or combined heat and power (CHP). This can increase power generation efficiency from 33% to over 80%. The potential market size and efficiency potential of effective cogeneration can be larger than is generally appreciated. For example consider a 1991 study in Japan by the Japan Gas Association. The study estimated that by just converting existing Japanese industrial steam boiler capacity to heat recovery steam generators (HRSG) behind gas turbine power generation, the cogeneration electric power would represent a 16% national energy saving relative to separate Japanese industrial boilers and central power plants. The CO_2 reduction was estimated at 50 million metric tons per year.

Effective cogeneration is, however, economically, technically and politically complex. To have significant annual benefit cogeneration requires large baseload "heat hosts". Distributed power generation applications are usually small and just seasonal cycling load cogeneration. The available big baseload heat hosts are limited but do exist at select, large energy intensive industrial applications such as large oil refineries, chemical plants and especially steam stimulation heavy oil production. For example, cogeneration power has increased in just 8 years from only 5% to over 28% of total electric power generation in Alberta, Canada due to deregulations and cogeneration of steam for oil sands steam assisted gravity drain (SAGD) production. Effective cogeneration also favors the use of gas turbines over steam turbines since cogeneration is usually heat host "limited". For a given heat host, gas turbines can generate 5-10 times more electricity than with a steam turbine in total high efficiency cogeneration (no heat to a condenser or cooling tower). This also greatly reduces the water requirements.

Gas turbine based cogeneration generally means the use of natural gas. "Syngas" generated through coal gasification can also be used in gas turbine based cogeneration. Most commercial gasification plants are utilized for just high value H_2 or H_2/CO based chemicals (like ammonia) or premium fuels (like SNG, gasoline, jet fuel or diesel). Effective polygeneration of large cogen power sales to the grid and syngas chemicals is possible and would improve economics. However this would generally require new coal gasification facilities at the site of the big industrial heat hosts and unprecedented cooperation of coal-based electric generators with oil and chemical companies. Traditional electric utilities prefer to control and own their power generators, especially big revenue baseload capacity.

The final CO_2 mitigation option and focus of this white paper is CO_2 capture and storage (CCS). There are three key steps in CCS:

1. Separating, recovering or capturing the CO_2 into a relatively pure gas stream
2. Compressing this relatively pure CO_2 gas stream to high-pressure supercritical conditions where it is very dense and has physical properties more like liquid than gas.
3. Pipeline transportation and well injection of this supercritical CO_2 into geologic formations much like pipeline transport and well injection storage of natural gas.

The costs of CCS are generally 50% for capture, 25% for compression and 25% for transportation, injection and monitoring. The CO_2 compression and transportation, injection and monitoring steps and costs are very similar for all CO_2 capture options. However, there are three very different process options to CO_2 capture:

1. Post-combustion
2. Pre-combustion
3. Oxy-combustion

Post-combustion is the simplest and generally considered the first choice for CO_2 capture add-on retrofit to existing coal-fired power plants. It is generally viewed as similar to common flue gas desulfurization (FGD) add-on retrofits to existing coal power plants. However, there is 50-500 times more CO_2 than SO_2 in coal combustion flue gas. More importantly, CO_2 capture requires much more energy and parasitic power than FGD. The overall net efficiency and capacity losses of post-combustion CO_2 capture are high, currently in the range of 30%. This means an existing coal power plant at 33% net efficiency and 300 MWe net capacity drops to only about 23% efficiency and 210 MWe by adding post-combustion CCS (including the CO_2 compression parasitic power).

As the name implies, post-combustion CCS is a flue gas CO_2 capture process. After coal combustion with air, the nitrogen-rich flue gas is normally at low atmospheric pressure and still contains several percent of oxygen. The CO_2 is scrubbed out of the flue gas with a liquid chemical solvent. This is usually called the CO_2 absorber and is about the same size as a wet SO_2 FGD absorber. The low CO_2 partial pressure (volume fraction CO_2 in and especially out times total absolute pressure) in the flue gas requires a strong chemical reaction solvent. The chemical is usually a basic amine to react with the acidic CO_2. The presence of oxygen limits the choice to just a select few amines and requires a special additive for high CO_2 loading of the amine. Also most amines will react and degrade with any SO_2 or NO in the flue gas. Thus essentially all the SO_2 and NO_x are removed from the raw flue gas before post-combustion CCS. SO_2 removal is usually via a conventional wet limestone FGD followed by a second special caustic wash to remove the last few percent of SO_2.

The amine leaving the CO_2 absorber, now rich in CO_2, is then heated to regenerate the amine and drive off the captured CO_2 at near atmosphere pressure. This requires a significant amount of low-pressure steam as the heat source and is called the CO_2 stripper. This steam is extracted from the low-pressure section of the big reheat steam turbine to minimize the steam cycle efficiency losses. There is also heat exchange between the CO_2 lean and rich amine going to and from the CO_2 absorber and stripper. Nevertheless, the 1-2 tons of low-pressure steam per ton CO_2 capture leads to a significant loss in the steam turbine output and overall plant efficiency.

Pre-combustion is basically using gasification to convert the coal into first H_2 and CO, and then reacting the CO with H_2O to mostly H_2 and CO_2 — called the water-gas CO shift reaction. Coal gasification to H_2 with nearly total CO_2 capture (removal) is commercially well proven, used in over 30 GWt (thermal syngas capacity) of coal-based hydrogen and ammonia plants worldwide.

Similar to natural gas replacement of coal, the conversion of coal into hydrogen for pre-combustion CCS favors the use of this clean (but expensive) fuel gas in a modern gas turbine based combined cycle. Grafting pre-combustion CCS onto an existing coal-fired power plant would require an almost total brownfield site rebuild into an IGCC with an H_2-rich syngas-fired gas turbine. Thus this is a high capital cost, complex and highly integrated option. Also the commercial experience of combusting H_2-rich syngas in modern high temperature (F class) gas turbines is limited to just a few oil refineries and chemical plants. Therefore, pre-combustion

CCS IGCC is viewed as a developmental, chemically complex, and high risk technology by most existing coal power plant owners.

The economics of coal gasification generally favor high pressure operating with oxygen (not air). This is due to capital saving with half as much volume of raw syngas to be processed in expensive gasifiers, syngas coolers and syngas conditioning if oxygen blown. This also means the CO_2 partial pressure (volume fraction CO_2 in and especially out times total absolute pressure) is very high and the CO_2 absorber vessels are quite small. The high pressure CO_2 absorber also enables the use of physical solvent to capture the CO_2. This means little or no stripping steam, dry CO_2 and CO_2 stripping/flashing at slight pressure to slightly reduce the CO_2 compressor power. Thus the CO_2 capture net efficiency and capacity losses are noticeably lower for pre-combustion than post combustion CCS.

Oxy-combustion, as the name implies, is simply combustion of coal with pure oxygen in place of air. However, that requires massive oxygen production, about 2.5 times more pure oxygen than required for pre-combustion CCS. The electric power requirements for large cryogenic air separation units (ASU) to produce oxygen, lead to a large loss in net efficiency and net capacity, about the same as for post-combustion at 30% loss. Oxy-combustion is the least developed of the three CCS options. Nevertheless oxy-combustion is of great interest by many existing coal power plant owners due to its lack of chemical processes and "theoretical" potential of avoiding SO_2, NO_x and Hg controls by geologic storage of a "dirty" CO_2.

The general approach of oxy-combustion CCS for existing coal-fired power plant retrofit is to recycle enough CO_2-rich flue gas to match the mass flow of the original air-fired boiler. This should minimize changes in existing heat-transfer profile and equipment. However, this large flue gas recycle may create issues associated with increased SO_2 and H_2O in the boiler that may require their removal from the recycle flue gas. There are also challenges associated with compressing as well as pipeline standards and storage issues of dirty CO_2. The general view is that the 1-3% O_2 plus H_2O, SO_2, NO_x and Hg will have to be recovered from the dirty raw CO_2 flue gas before compression. In addition, the several percent N_2 in the CO_2 from the negative pressure boiler air leakage and the air separation leads to higher slightly higher CO_2 compression for supercritical CO_2.

Rebuilds versus Retrofits

As briefly mentioned in the previous section, some of the CO_2 mitigation options require major rebuilds, not just add-on retrofits. Specifically, conversion of an existing coal-fired power plant to natural gas (with or without CCS) or continuing coal use via pre-combustion CCS requires major brownfield site rebuilds to NGCC or IGCC. These rebuild conversions from the existing coal steam cycle to a combined cycle are commonly referred to as repowering even when the old steam turbine and generator is replaced.

In addition, post- and oxy- combustion CCS can sometimes favor major rebuilds over simple retrofits. Retrofits require significantly less total capital. However, retrofits also suffer from significant loss of net efficiency and capacity. The costs and source of that lost generation capacity replacement must ultimately be accounted for. Furthermore, retrofitting means that most of the power plant key equipment is still relatively old.

Rebuilding the old subcritical PC units into state-of-the-art supercritical PC boiler or IGCC, both with CCS may have a key advantage. Specifically it minimizes or even avoids any net efficiency or capacity losses of adding CCS. That is because of the higher efficiency and capacity of the new supercritical PC or IGCC (before adding CCS) compared with the relatively low efficiency of the old subcritical PC power plants. That might be a very important advantage to gain public support for CCS. Non Governmental Organizations (NGOs) dislike converting a low efficiency (say 33%) coal power plant into embarrassingly low efficiency (say 22%) retrofit coal plant with CCS. The rebuild option can avoid capacity and efficiency losses relative to the existing coal power plant, while at the same time reducing all emissions. Rebuilds also assure that the entire power plant is new, not just the CCS.

Economics of CO_2 Mitigation for Existing Coal Power Plants

The single most important issue is the cost of CO_2 mitigation. The electricity cost, especially from existing coal-fired power plants, will significantly increase for any meaningful CO_2 reduction. In fact, due to the lower electricity cost from existing paid-off coal power plants, CO_2 avoidance costs are likely higher for these old coal power plants than for proposed new coal power plants.

Attached are two sets of comparative screening analysis spreadsheet outputs calculating costs and performance of various CO_2 reduction options for a baseline existing paid-off subcritical PC boiler power plants. Feedstock options include coal and natural gas both without and with CCS as well as simple retrofit add-on and major rebuilds. All key input assumptions and results are clearly shown to assure maximum objectively via relative transparency. By maintaining the same coal feedrate (even for rebuilds) the absolute performance of retrofit versus rebuild as well as without versus with CCS is directly apparent. The natural gas option was set at the same net capacity as the baseline existing coal plant and its feedrate was also kept constant to show the losses of CCS.

The assumed natural gas price is always a key issue when analyzing the costs of CO_2 mitigation versus coal options. Natural gas prices were varied to "breakeven" prices where the power costs are the same for both coal and natural gas. This means at higher natural gas market prices than these breakeven prices, coal is a cheaper option.

Key inputs and results are shown on the first page summary sheet for each of the two model runs. The following pages are more detailed data for each specific option. The details for each option include a simple process flow diagram (with major energy, mass and volume flows), capital cost build-up from the process units costs and product electric costs (including a simple annual capital charge rate of 15% or a 6.7 year payback of all new capital costs). A key assumption is that the baseline existing coal power plant is paid-off, thus it has relatively low power costs due to the lack of capital charges. The baseline power costs and CO_2 emissions strongly influence CO_2 mitigation costs.

The first run of the comparative screening model assumes no CO_2 emissions tax and is used to calculate the CO_2 avoidance cost of each option. CO_2 avoidance is very useful as it is the CO_2 tax required for each specific CO_2 mitigation option to start becoming economical. This is the easiest way to rank the many options, as the lower CO_2 avoidance costs are the more economical

options relative to the baseline. The CO_2 avoidance formula where (b) is the baseline and the other cost and emission units are for each specific option as follows:

$$\$/\text{mt } CO_2 \text{ avoidance} = [\text{mt } CO_2/\text{MWh(b)} - \text{mt } CO_2/\text{MWh}] / [\$/\text{MWh} - \$/\text{MWh(b)}]$$

The CO_2 avoidance results show that all CO_2 options significantly increase power costs due to the low cost power baseline of a paid-off coal unit. Of the CCS cases, the simple retrofit post-combustion add-on was slightly cheaper than the more capital intensive but better performance rebuilds. However, this model does not take into account the lost generation capacity and shorter remaining life of the retrofit versus rebuild. Nevertheless, this lowest CCS CO_2 avoidance cost was still relatively high at $74 per metric ton (mt) CO_2. CO_2 avoidance costs for new coal plant baseline are typically $30-50 per ton CO_2. The lower CO_2 avoidance costs are mainly due to the much higher baseline power costs of a new coal plants with large capital charges. Of the cases without CCS, the NGCC rebuild was competitive with coal adding CCS until the natural gas price is above $8.31 per million Btu (as per cost model run two). Cost model run one of $7.65 per million Btu NG price is just where NGCC and rebuilt PC has the same power cost without a CO_2 tax. The supercritical PC rebuild without CCS was the most expensive CO_2 avoidance cost due to the relatively low CO_2 reduction for a moderately large capital investment.

The second run of the screening model includes an input CO_2 tax based on the lowest coal-based CO_2 avoidance cost from the first cost model run of $74 per metric ton CO_2 emissions. This makes all the power costs high whether doing nothing but paying the CO_2 tax, converting to natural gas or adding CCS. The economic ranking of options is the same as the first run. However this model run makes it clearer why higher CO_2 taxes are required to economically encourage existing coal-fired power plant owners' to reduce CO_2 emissions.

Another important result of this second model run is the "triple point", which is where the power costs are the same (at the input CO_2 tax and natural gas price) for the three key options:

1. Doing nothing - continue using coal as is without CCS but pay the high CO_2 tax. This is low capital, low risk but has high operating costs due to the high CO_2 emissions.
2. Convert to natural gas without CCS but pay about a 60% less CO_2 tax. This is a low capital cost option to a clean, efficient, new power plant but has the risk of future natural gas supplies and prices.
3. Continue using coal but add CCS to avoid most of the CO_2 tax. This is high capital cost option, especially rebuilding to a new more efficient coal power plant. There is also long-term CO_2 storage liability risk but this option provides low operating costs and the largest CO_2 reduction.

The natural gas breakeven price for this triple power was only $8.31 per million Btu. This is quite low as the breakeven natural gas triple point for new coal power plant baseline is usually greater than $12 per million Btu. The low natural gas breakeven price appears mostly due to the high CO_2 tax required to economically encourage existing coal power plants to reduce CO_2.

Again, this second model run does not take into account the lost generation capacity and shorter remaining life of the retrofit versus the rebuilt power plant. This means the lowest cost retrofit add-on of post-combustion CCS to an old coal power plant may not be the best in the longer

term. As discussed previously, the higher capital plant rebuilds avoid most of the efficiency and capacity losses.

Outlook for Existing Coal-Fired Power Plant CCS

Existing coal-fired power plants are commonly ignored in the analysis of CO_2 mitigation and CCS. This is because they are so technically and economically challenging plus very site specific. Nevertheless, this simple analysis suggests several important conclusions relative to existing coal power plants:

- The existing U.S. coal power plant fleet is relatively old, inefficient and dirty. However, the current surge of retrofit add-on SO_2 and NO_x controls due to the 2005 CAIR will greatly reduce SO_2 and NO_x emissions. Nevertheless, these retrofits will also reduce the existing coal fleet's over-all efficiency from about 33 to 32% plus there is added CO_2 emission from the limestone used in FGD for an even higher CO_2 per MWh of electricity.
- The new EIA AEO 2009 projects that from now to 2030 with business as usually only 2.3 GW of existing coal power plant retirements and 24.8 GW of new coal power plants will be added for net coal capacity increase of 7%. However, coal based power generation is projected to increase by 18%. This clearly suggests that uncertainty in future CO_2 mandates and the low marginal load dispatch costs of coal units encourage both life extension and increased generation from our aging inefficient existing coal fleet.
- Most existing coal power plant sites are likely too valuable to ever abandon due to location, existing permits and infrastructure. The issue is whether to continue life extending forever with just retrofit add-on flue gas controls as mandated or rebuild to a modern higher efficiency and capacity coal or NGCC power plant.
- The cost of CCS is high due to the large investment plus significant loss of net efficiency and capacity. CCS also has the added challenge for existing coal power plant sites that in many cases are not near good CO_2 storage sites.
- CO_2 avoidance costs appear higher and breakeven natural gas price alternatives (convert from coal to gas) appear lower for existing coal power plants than for proposed new coal power plants. This appears mostly due to the low baseline power costs from paid-off coal power plants.
- Retrofit of existing coal power plants with add-on post combustion CCS has the lowest capital and CO_2 avoidance costs of all the CCS options if the impact of the roughly 30% efficiency and capacity losses and shorter remaining plant life are ignored. Post-combustion CCS has big space requirements, which could be a major limitation.
- Rebuilding (supercritical PC or IGCC) with added CCS on older existing coal power plant sites can avoid most of the net efficiency and capacity losses (relative to the old, less efficiency subcritical PC). It can also solve the space limitation issues of added on retrofit. However these are higher total capital costs options.

Policies and technologies for mitigating CO_2 emissions from existing plants where CCS is not an economically feasible option, should be a high priority. These are the many existing coal power plants situated in locations that are too far from good CO_2 storage sites. In addition many existing coal power plants are located in urban population areas where permitting even short CO_2 pipelines to good CO_2 storage sites make CCS impossible. There are also relatively

small coal power plants that are just too small for CCS. For example, there are 22 GW of less than 100 MW size plants and 42 GW of just 100-200 MW size existing coal power plants.

These sites may present the best opportunities for natural gas repowering which can reduce the CO_2 emission per MWh by about 60% while also increasing capacity by a factor of 3. In addition, to control long-term natural gas prices and supply risks synthetic natural gas from coal with CCS could be considered. This would be similar to the commercial Dakota coal gasification SNG plant but with better gasifiers. As these industrial gasification plants have a large pure CO_2 vent regardless of the CO_2 mitigation issue, the incremental costs of CCS are much less than for coal power plants.

Retrofits favor the newer supercritical coal units. Newer coal plants have higher efficiency, longer life spans and most already have good SO_2 and NO_x controls. Options for these plants will be defined by their locations relative to good storage sites and the availability of space to add the post combustion add-on CO_2 absorbers plus the CO_2 stripper and compressor as well as the added cooling towers. The CCS space requirements appear to be similar to add-on FGD. Reviewing several studies suggests a 500 MW gross or 350 MW net (after CCS losses) retrofit post-combustion CCS requires about 4-5 acres. There are ways to minimize space requirements, but they come at higher costs; options include placing the CO_2 absorber in the base of a new wet stack, which is sometimes done for FGD retrofits tight on space.

Rebuilds favor older subcritical coal units. Although the added new capital costs of rebuilds are much higher than retrofits, the CO_2 avoidance costs of rebuilds are closer to those of retrofits. More importantly, the rebuilds with CCS avoid most of the efficiency and capacity losses at the same time they enable the conversion of an existing site to a new coal power plant with almost zero emissions; there is significant cost and value associated with the ease of permitting of such rebuilds relative to those associated with a new greenfield plant with CCS, and with the lower costs of existing coal, water and transmission infrastructures.

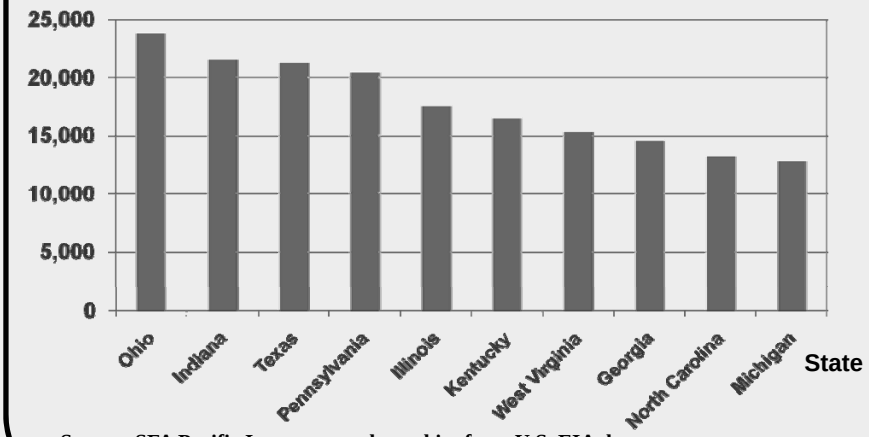
Rebuilds can also avoid space limitations and even increase capacity at existing coal plant sites in addition to avoiding most of the efficiency losses of CCS. There are many rebuild options. For post and oxy combustion rebuilds the steam cycle should be converted to state-of-the-art supercritical for the large gain in efficiency over the old subcritical steam cycle. Post combustion CCS can stack SO_2 and CO_2 absorbers in the base of the new stack to save space. Oxy combustion CCS can locate the large air separation unit oxygen plants off-site with a short oxygen pipeline.

Post combustion CCS – H_2-fired IGCC has the added rebuild potential of even off-siting the location of all but the repowered combined cycle. A pipeline of high pressure H_2 (and N_2, if needed) could be transported a moderate distance with the gasification plant located at an optimal site for CO_2 storage or CO_2 pipeline permitting.

Existing U.S. Coal-Fired Power Plants by Top Capacity States

Top 5 states account for 33% of total U.S. coal capacity

Top 10 states account for 50% of total U.S. coal capacity



Source: SFA Pacific Inc. generated graphics from U.S. EIA data

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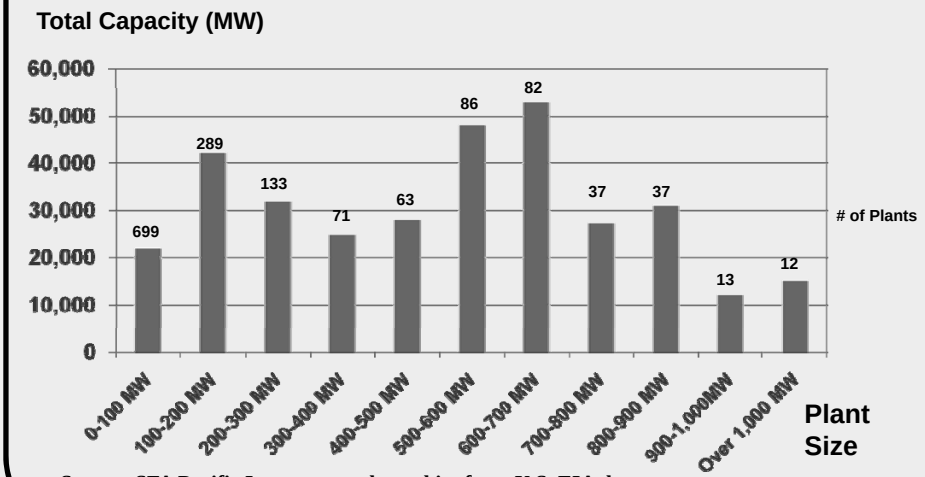
Existing U.S. Coal-Fired Power Plant Unit Sizes



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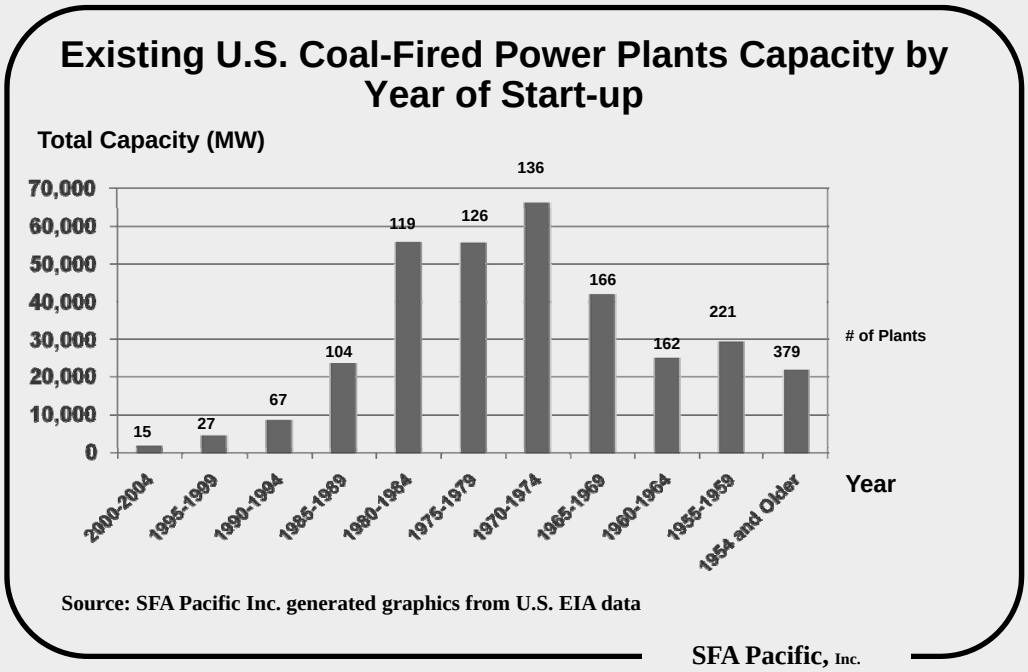
Existing U.S. Coal-Fired Power Plants Capacity by Year of Start-up
Total Capacity (MW)
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
15
27
67
104
119
126
136
166
162
221
379
# of Plants
2000-2004
1995-1999
1990-1994
1985-1989
1980-1984
1975-1979
1970-1974
1965-1969
1960-1964
1955-1959
1954 and Older
Year
Source: SFA Pacific Inc. generated graphics from U.S. EIA data
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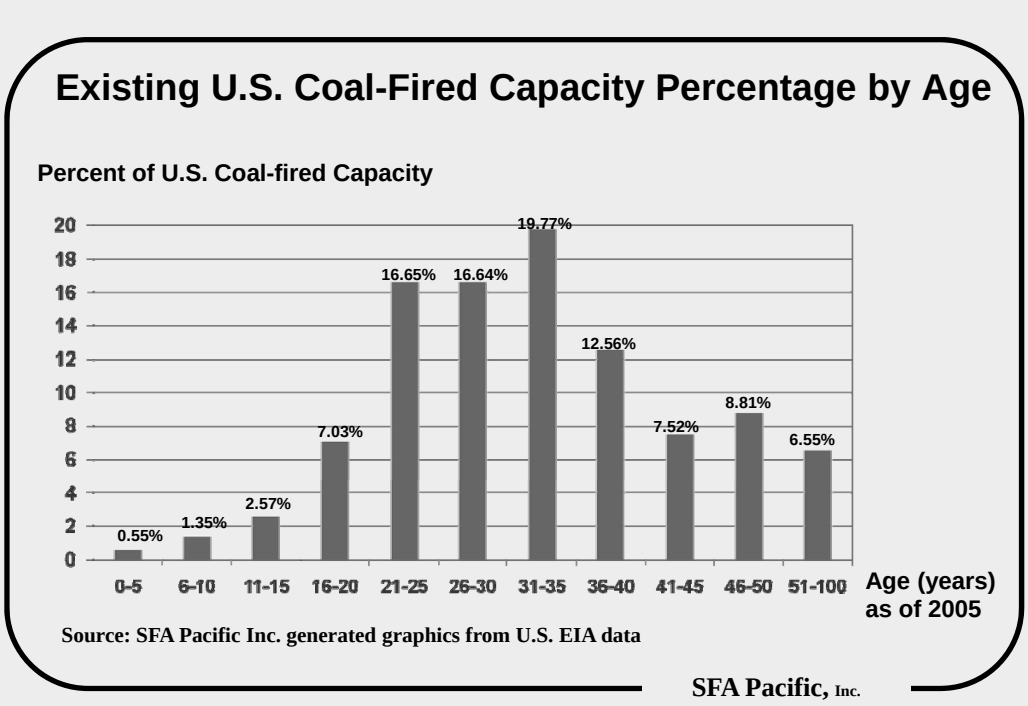
Existing U.S. Coal-Fired Capacity Percentage by Age
Percent of U.S. Coal-fired Capacity
20
18
16
14
12
10
8
6
4
2
0
0.55%
1.35%
2.57%
7.03%
16.65%
16.64%
19.77%
12.56%
7.52%
8.81%
6.55%
0-5
6-10
11-15
16-20
21-25
26-30
31-35
36-40
41-45
46-50
51-100
Age (years) as of 2005
Source: SFA Pacific Inc. generated graphics from U.S. EIA data
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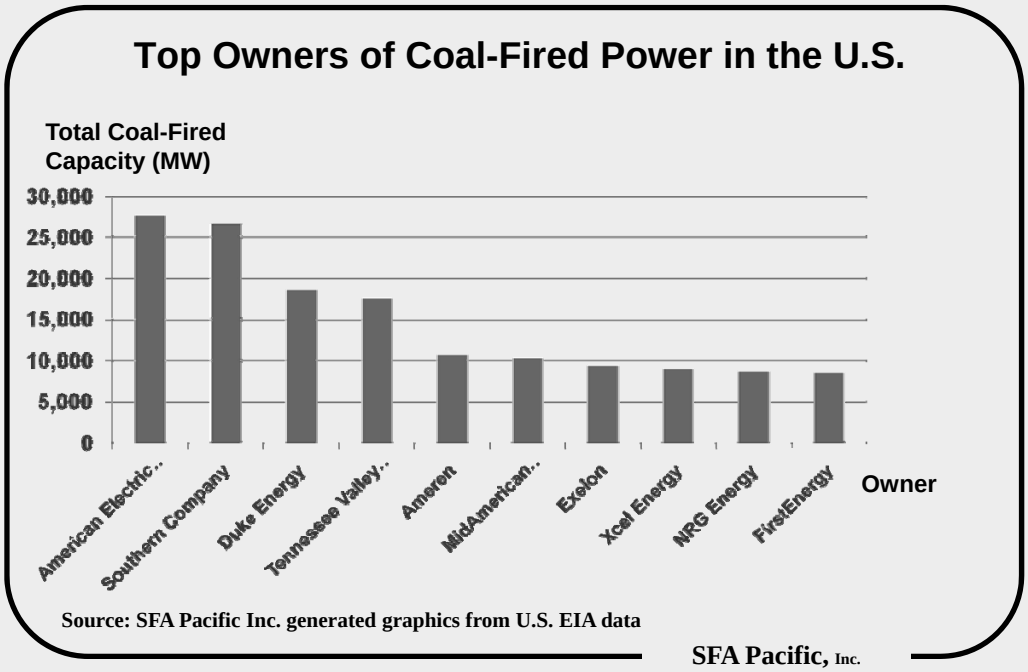
Top Owners of Coal-Fired Power in the U.S.
Total Coal-Fired Capacity (MW)
30,000
25,000
20,000
15,000
10,000
5,000
0
American Electric..
Southern Company
Duke Energy
Tennessee Valley..
Ameren
MidAmerican..
Exelon
Xcel Energy
NRG Energy
FirstEnergy
Owner
Source: SFA Pacific Inc. generated graphics from U.S. EIA data
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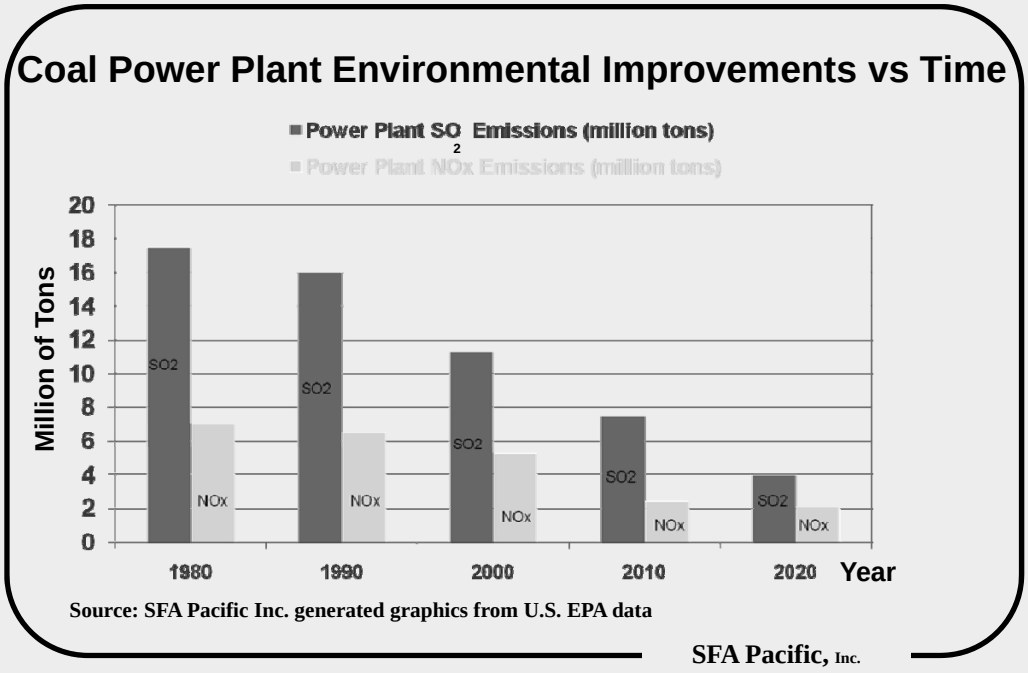
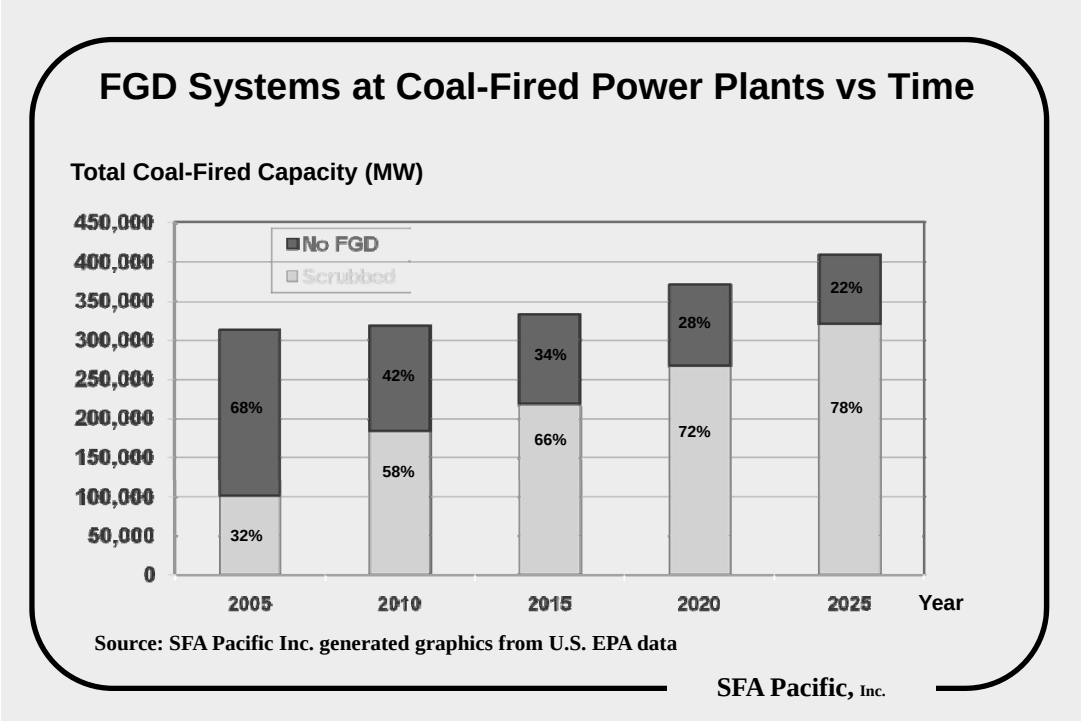
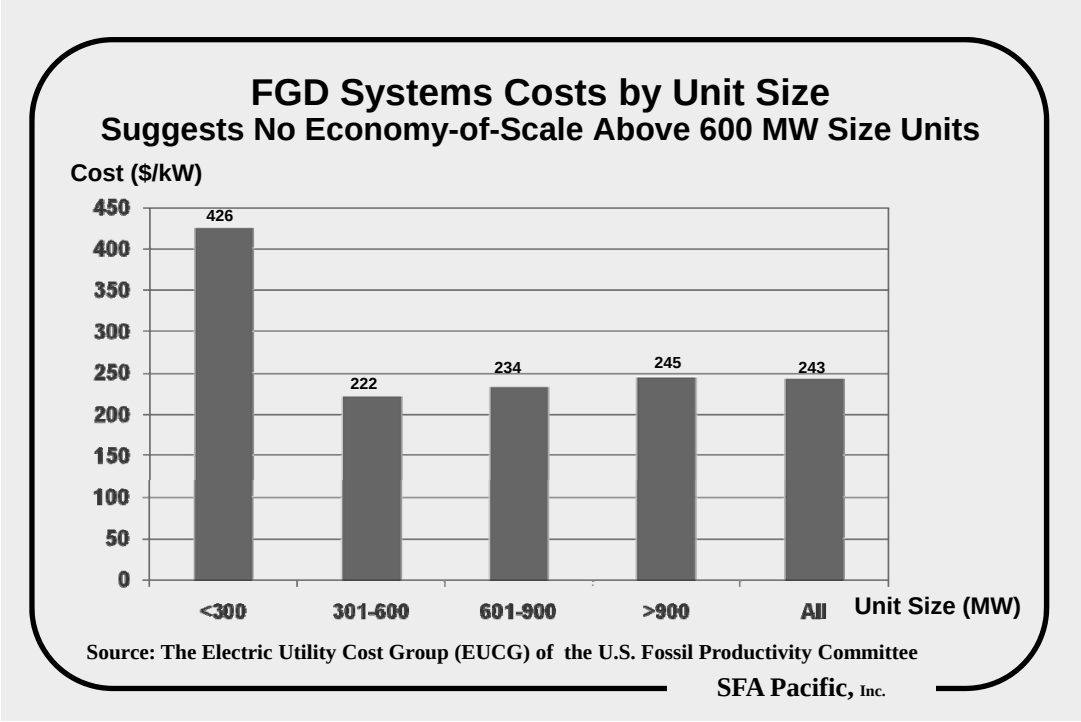

Coal Power Plant Environmental Improvements vs Time
Power Plant SO2 Emissions (million tons)
Power Plant NOx Emissions (million tons)
Million of Tons
20
18
16
14
12
10
8
6
4
2
0
SO2
NOx
1980
1990
2000
2010
2020
Year
Source: SFA Pacific Inc. generated graphics from U.S. EPA data
SFA Pacific, Inc.


FGD Systems at Coal-Fired Power Plants vs Time
Total Coal-Fired Capacity (MW)
450,000
400,000
350,000
300,000
250,000
200,000
150,000
100,000
50,000
0
No FGD
Scrubbed
68%
32%
42%
58%
34%
66%
28%
72%
22%
78%
2005
2010
2015
2020
2025
Year
Source: SFA Pacific Inc. generated graphics from U.S. EPA data
SFA Pacific, Inc.


FGD Systems Costs by Unit Size
Suggests No Economy-of-Scale Above 600 MW Size Units
Cost ($/kW)
450
400
350
300
250
200
150
100
50
0
426
222
234
245
243
<300
301-600
601-900
>900
All
Unit Size (MW)
Source: The Electric Utility Cost Group (EUCG) of the U.S. Fossil Productivity Committee
SFA Pacific, Inc.

Largest Coal-Fired Power Plants of Top Coal-Based U.S. Electric Utilities

Company/ Entity	Plant Name	State	County	Units and In-Service Dates	Total Capacity Plant	2007 CO2 Emissions (tons)	2006 CO2 Emissions (tons)	2006 SO2 Emissions (tons)
American Electric Power	John E. Amos	WV	Putnam	816 MW 816 MW 1,300 MW 1971 1972 1973	2,933 MW	15,300,000	18,798,261	117,299
	Rockport	IN	Spencer	1,300 MW 1,300 MW 1984 1989	2,600 MW	16,600,000	20,181,545	83,543
	Gavin	OH	Gallia	1,300 MW 1,300 MW 1974 1975	2,600 MW	18,700,000	16,997,449	24,787
	Conesville	OH	Coshocton	162 MW 842 MW 444 MW 444 MW 1962 1973 1976 1978	1,891 MW	9,060,000	9,459,016	90,540
	Cardinal	OH	Jefferson	615 MW 650 MW 1967 1977	1,880 MW	10,100,000	10,985,695	86,880
Southern Company	Scherer	GA	Monroe	891 MW 891 MW 891 MW 891 MW 1982 1984 1987 1989	3,564 MW	25,300,000	25,298,499	74,205
	Bowen	GA	Bartow	806 MW 789 MW 952 MW 952 MW 1971 1972 1974 1975	3,499 MW	20,500,000	22,756,191	206,442
	Miller	AL	Jefferson	706 MW 706 MW 706 MW 706 MW 1978 1985 1989 1991	2,822 MW	20,600,000	23,466,022	53,379
	Gaston	AL	Shelby	272 MW 272 MW 245 MW 952 MW 1960 1961 1962 1974	2,013 MW	12,200,000	12,345,695	130,494
	Wansley	GA	Heard	952 MW 952 MW 1976 1978	1,904 MW	11,900,000	13,612,838	96,200
Duke Energy	Gibson	IN	Gibson	668 MW 668 MW 668 MW 668 MW 668 MW 1975 1976 1978 1979 1982	3,340 MW	20,400,000	21,447,980	155,057
	Belews Creek	NC	Stokes	1,080 MW 1,080 MW 1974 1975	2,160 MW	13,600,000	14,034,728	95,290
	Marshall	NC	Catawba	350 MW 350 MW 648 MW 648 MW 1965 1966 1969 1970	1,996 MW	12,600,000	11,425,788	85,050
	W.H.Zimmer	OH	Clermont	1,426 MW 199 1	1,426 MW	8,597,000	8,518,481	22,054
	Miami Fort	OH	Hamilton	100 MW 163 MW 557 MW 558 MW 1949 1960 1975 1978	1,378 MW	7,546,000	7,694,156	62,028
Tennessee Valley Authority (U.S. gov't)	Cumberland	TN	Stewart	1,300 MW 197 3	2,600 MW	19,600,000	19,049,068	18,352
	Paradise	KY	Muhlenberg	704 MW 1,150 MW 1963 1970	2,558 MW	14,500,000	15,497,610	82,926
	Widows Creek	AL	Jackson	141 MW 141 MW 141 MW 1952 1953 1954	1,969 MW	9,976,000	10,793,074	33,507
	Shawnee	KY	McCracken	175 MW 175 MW 1953 1954	1,750 MW	9,852,000	10,527,302	35,715
	Kingston	TN	Roane	175 MW 200 MW 1954 1955	1,700 MW	10,100,000	10,995,365	55,473
Ameren	Labadie	MO	Franklin	574 MW 574 MW 621 MW 621 MW 1970 1971 1972 1973	2,389 MW	16,400,000	17,459,154	51,445
	Rush Island	MO	Jefferson	621 MW 621 MW 1976 1977	1,242 MW	6,828,000	8,646,702	28,674
	Newton	IL	Jasper	617 MW 617 MW 1977 1982	1,235 MW	7,799,000	7,943,291	20,922
	Joppa	IL	Massac	183 MW 183 MW 183 MW 1953 1954 1955	1,100 MW	9,222,000	9,318,296	26,408
	Sioux	MO	St. Charles	550 MW 550 MW 1967 1968	1,099 MW	6,043,000	6,273,478	44,148
MidAmerican Energy	Jim Bridger	WY	Sweetwater	578 MW 578 MW 578 MW 578 MW 1974 1975 1976 1979	2,318 MW	16,500,000	15,884,734	20,055
	George Neal	IA	Woodbury	147 MW 349 MW 550 MW 1964 1972 1975	1,686 MW	5,974,000	7,043,476	37,979
	Hunter	UT	Emery	488 MW 488 MW 496 MW 1978 1980 1983	1,472 MW	10,600,000	10,703,732	7,338
	Huntington	UT	Emery	498 MW 498 MW 1974 1977	996 MW	6,170,000	6,133,031	17,405
	Council Bluffs	IS	Pottawattamie	49 MW 82 MW 726 MW 1954 1958 1978	856 MW	6,010,000	5,786,096	17,523
Exelon	Eddystone	PA	Delaware	354 MW 196 0	707 MW	4,128,000	3,720,279	6,454
	Cromby	PA	Chester	188 MW 195 4	188 MW	1,129,000	1,062,055	5,588
NRG Energy	Parish	TX	Fort Bend	734 MW 734 MW 615 MW 615 MW 1977 1978 1980 1982	2,697 MW	20,000,000	21,076,082	56,438
	Big Cajun2	LA	Pointe Coupee	626 MW 626 MW 619 MW 1981 1982 1983	1,871 MW	14,300,000	14,300,000	44,556
	Limestone	TX	Limestone	893 MW 813 MW 1985 1986	1,706 MW	13,300,000	13,055,769	15,917
	Huntley	NY	Erie	80 MW 100 MW 100 MW 100 MW 218 MW 218 MW 1942 1948 1953 1954 1957 1958	816 MW	3,659,000	3,301,283	12,299
	Indian River	DE	Sussex	82 MW 82 MW 177 MW 442 MW 1957 1959 1970 1980	782 MW	3,558,000	3,572,468	20,705
FirstEnergy	Bruce Mansfield	PA	Beaver	914 MW 914 MW 914 MW 1976 1977 1980	2,741 MW	17,400,000	17,400,000	24,882
	W.H. Sammis	OH	Jefferson	190 MW 190 MW 190 MW 190 MW 334 MW 680 MW 1959 1960 1961 1962 1967 1969 680 MW 197 1	2,456 MW	13,800,000	15,761,762	86,392
	Eastlake	OH	Lake	123 MW 123 MW 208 MW 680 MW 1953 1954 1956 1972	1,257 MW	6,355,000	8,730,503	82,705
	R.E. Burger	OH	Belmont	63 MW 63 MW 103 MW 156 MW 1944 1947 1950 1955	541 MW	1,635,000	2,038,037	62,558
	Bay Shore	OH	Lucas	141 MW 141 MW 218 MW 1959 1963 1968	499 MW	3,979,000	5,393,977	15,207

Source: SFA Pacific, Inc from U.S. EIA and EPA data