# 1. Optimize Power Plant Operations

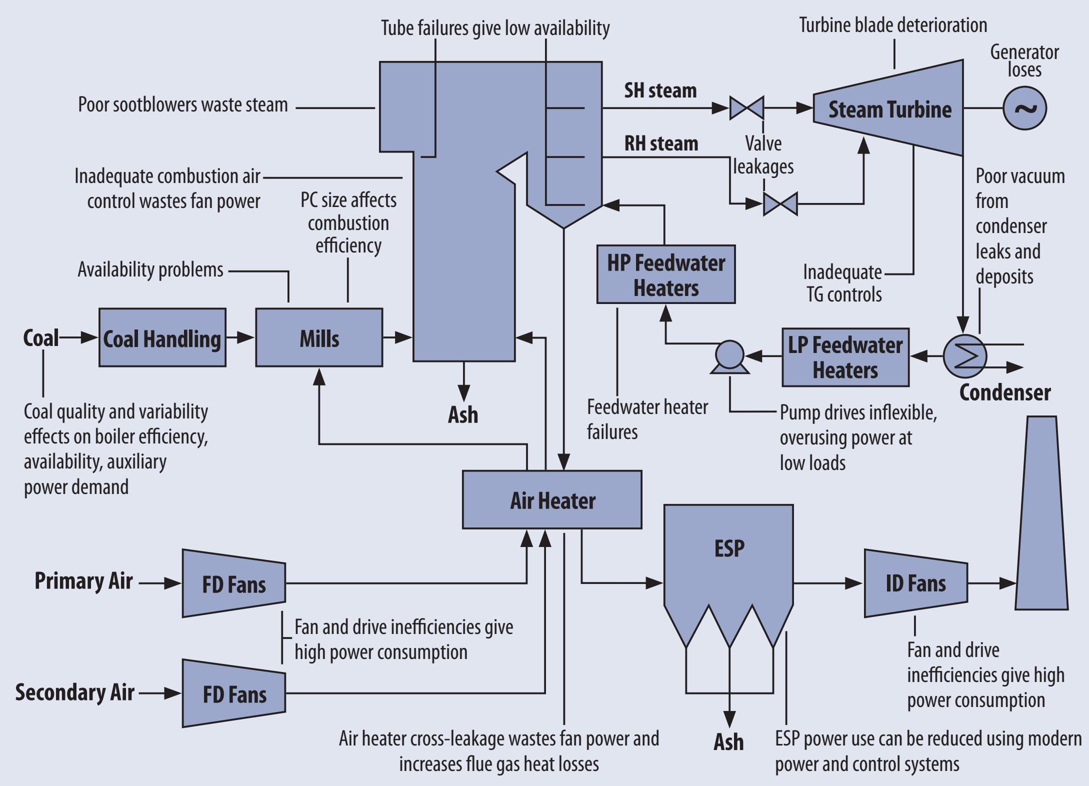
## 1. Profile

The average thermal efficiency of a coal-fired power plant in the United States across all classes of fuel is approximately 32 percent. This level has not changed in many years, as few new coal-fired power plants have been constructed in the last decade.[1] Figure 1-1 illustrates the various components of a power plant and factors that affect its thermal efficiency.

Operating experience reflects that the thermal efficiency of a power plant declines with use. Much of the efficiency degradation can be recovered during maintenance outages such that, over time, a unit's efficiency plotted versus time will have a sawtooth pattern. The level of maintenance undertaken will dictate the amount of efficiency loss that is recovered during each outage but, after a unit is 30 years old, even well-maintained equipment suffers from persistent degradation. Another contributing factor to the loss of efficiency over time is that older units are more likely to operate in a load-following mode, rather than a baseload mode, as newer units take their place

***Figure 1-1***

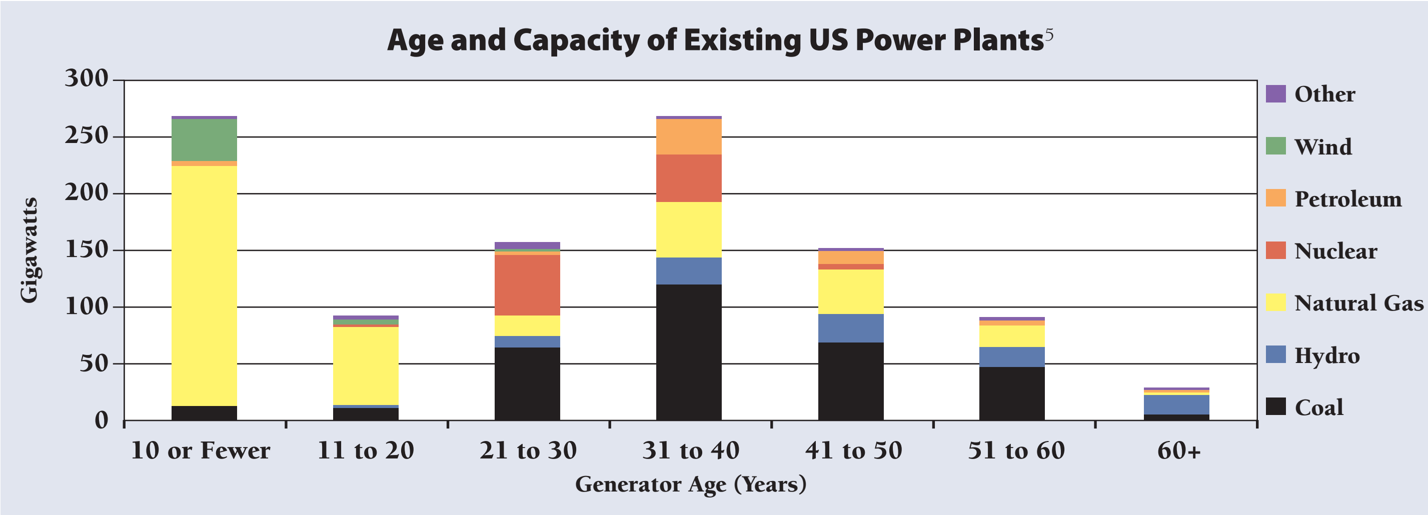
**Areas of a Coal-Fired Power Plant That Give Rise to Efficiency Loss**[2]




1 New coal-fired plants would not necessarily be more efficient than older coal-fired units. New units would be more likely to have high levels of emissions controls that increase the auxiliary load of the unit and reduce net output. New units may also have more restrictions on cooling water resulting in higher condenser pressure, and may be designed to operate flexibly rather than maximizing efficiency for one specific mode of operation. All of these factors would tend to have a negative impact on a unit's thermal efficiency.

2 Henderson, C. (2013, August). *Upgrading and Efficiency Improvement in Coal-Fired Power Plants.* International Energy Agency (IEA) Clean Coal Centre, CCC-221, ISBN 978-92-9029-541-9. Copies can be downloaded for free by member countries at: http://bookshop.iea-coal.org/publishor/system/component_viewbymedia.asp?logdocid=83186&MediaId=2. Registration required first.

*Figure 1-2*




in the dispatch order.[3] The increase in cycling that comes from following load can have a significant impact on overall operating efficiency. The thermal efficiency of an older plant can thus be significantly lower than that which existed at the time it commenced operation.[4] The average age of the US coal fleet is over 30 years, with up to one-third of the units over 50 years old in some regions. Figure 1-2 shows the ages of US fossil-fuel generation by ten-year increments, reflecting that approximately 500 gigawatts (GW) of total generation are produced by power plants that are 31 years old or older.

Using actual data from existing coal-fired power plants, the top ten percent of units have a thermal efficiency of 37.6 percent. This level is more than five percentage points higher than the average efficiency, and imputes a fuel consumption rate that is 15 percent lower than the average.[6] Table 1-1 breaks out unit level thermal efficiency by equal-weighted capacity deciles.[7] The table reflects that units with lower thermal efficiency have lower capacity factors, meaning that they operate for fewer hours in a given year, and that inefficient units are also smaller. Nearly 200 units comprise the least thermally efficient decile, whereas 53 units comprise the most thermally efficient decile. This profile suggests two key points: (1) inefficient units burn more fuel per megawatt hour (MWh) of generation and have higher fuel costs relative to other

3 "Baseload" generating units operate at fairly constant output levels near their maximum rated capacity, except when they are down for maintenance. These units tend to be the ones that are most thermally efficient or that have low operating costs for other reasons. "Load-following" generating units cycle their output levels up or down in response to a "dispatch" signal from a system operator, as needed to match total system-wide generation to the varying system-wide demand for electricity. Load-following units usually have higher operating costs than baseload units because they are less thermally efficient or for other reasons.

4 Boiler design is critical to the efficient operation of a power plant. Boiler design life is predicated on adherence to good fluid dynamics and heat transfer principles. Layout of the plant's ductwork and piping aims to minimize turns and bends and have large diameter ducts to minimize pressure drops, to maximize the thermal efficiency of the plant, and to avoid extra energy demand just to move flue gases from one point to another. Critical to this are well-mixed flue gases, which depend on adequate retention time in the combustion chamber to complete chemical reactions, achieve maximum heat transfer, and minimize the formation of air pollutants. Well-mixed flue gases also ensure that duct velocities are uniform from top to bottom and side-to-side. Doing so helps to assure that flue gas temperatures are as uniform as possible. Flue gas hot spots can cause duct deformation, and flue gas cold spots can cause corrosion if the temperatures drop below the acid dew point.

5 US Energy Information Administration (EIA). (2011, June 16). *Today in Energy.* Available at: http://www.eia.gov/todayinenergy/detail.cfm?id=1830.

6 US Department of Energy (DOE). (2008, July). *Reducing $CO_2$ Emissions by Improving the Efficiency of the Existing Coal-Fired Power Plant Fleet*. National Energy Technology Laboratory (NETL), DOE/NETL-2008/1329. This report is no longer available online.

7 A decile is any one of nine numbers that divide a frequency distribution into 10 classes such that each contains the same number of individuals; also: any one of these 10 classes.

*Table 1-1*

**Generation-Weighted Thermal Efficiency**[9]

| Decile | Number of Units | Capacity (GW) | Capacity Factor | 2008 Total Generation (Billion kWh)[10] | 2008 Generation-Weighted Efficiency (HHV)[11] |
|---|---|---|---|---|---|
| 1 | 194 | 30.5 | 62% | 165 | 27.6% |
| 2 | 102 | 30.3 | 67% | 179 | 29.9% |
| 3 | 88 | 30.7 | 65% | 176 | 30.8% |
| 4 | 86 | 30.6 | 69% | 185 | 31.6% |
| 5 | 75 | 30.7 | 70% | 189 | 32.2% |
| 6 | 83 | 30.8 | 66% | 178 | 32.9% |
| 7 | 71 | 31.0 | 68% | 186 | 33.8% |
| 8 | 79 | 30.6 | 68% | 183 | 34.7% |
| 9 | 61 | 30.8 | 67% | 181 | 35.7% |
| 10 | 53 | 30.7 | 74% | 201 | 37.6% |
| **OVERALL** | **892** | **307** | **69%** | **1823** | **32.5%** |

units, and (2) less thermally efficient units operate more as peaking or cycling units.[8]

Onsite improvements to the power plant boiler and associated equipment can apply mature technologies and operating practices to reduce greenhouse gas (GHG) emissions by four to seven percent, on average. Older plants built between the 1950s and the 1970s have the greatest potential for improvement. Applications of these technologies also reduce fuel consumption, improve plant profitability, and reduce criteria pollutant emissions. Innovative new options have also been demonstrated that add onsite renewable generation to a coal-fired power plant site, further reducing GHG emissions by directly offsetting generation at the plant site or by using the renewable generation to help recover heat losses from the cooling system or flue gas.

The potential improvement that can be achieved by any given coal-fired generating unit will depend on at least three factors. First, some of the technologies and processes that improve thermal efficiency may be less feasible or effective owing to the design or operational requirements of the unit. For example, some of the possible improvements in steam turbine design will be less durable for units that operate with frequent start and stop cycles. Second, some units will have already implemented some of the available options and will have less room for improvement than an average unit. And third, the *capital* costs of improvement projects can be hard to recover through reduced *operating* costs for units that operate less frequently than an average unit. Nevertheless, there are many options to be considered.

This chapter explores a variety of boiler optimization technologies and processes, including those that:

- Optimize the combustion of coal;
- Recover waste heat from cooling systems;
- Recover waste heat from flue gases;

8 Very efficient units (e.g., supercritical units) require higher capital investments to build than less efficient units (e.g., subcritical units). The higher capital costs can be justified if the unit is expected to operate at a high capacity factor, whereas less efficient, less expensive designs make more sense when a unit is expected to operate at a lower capacity factor.

9 US DOE. (2010, February). *Technical Workshop Report: Improving the Thermal Efficiency of Coal-Fired Power Plants in the United States.* National Energy Technology Laboratory. Available at: http://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/ThermalEfficCoalFiredPowerPlants-TechWorkshopRpt.pdf.

10 One thousand kilowatt hours (kWh) is equal to one megawatt hour (MWh).

11 Higher Heating Value (HHV) is one of two common ways to express the amount of heat released when a given amount of fuel is combusted. This column shows the efficiency based on HHV values.

- Optimize soot blower operation;
- Improve turbine design;
- Use turbine inlet cooling (TIC) technologies for natural gas-fired power plants;
- Supplement coal-fired generation with onsite renewable generation; and
- Reduce auxiliary power consumption (i.e., the electricity used onsite to operate the power plant – sometimes referred to as "house load").[12]

Another option to improve boiler efficiency — better coal quality through drying or other beneficiation techniques — is covered separately in Chapter 4.

## 2. Regulatory Backdrop

The emphasis of this GHG reduction option is to improve the heat rate and thermal efficiency of the power plant through techniques that optimize the operation of the boiler or reduce heat losses from the flue gas and cooling systems, or to complete other techniques that reduce fuel consumption or auxiliary equipment energy consumption.

The US Department of Energy (DOE) National Energy Technology Laboratory (NETL) found consistent support among utilities for implementing onsite efficiency improvements, as there are direct financial benefits that accrue to the plant itself after such improvements have been completed. Lower fuel costs mean improved profit margins for the utility or plant operator. Improved thermal efficiency results in lower heat rates (less fuel burned per kilowatt hour (kWh) of generation), and also improves the ability of an individual unit to be dispatched by the electricity grid operator, which again can help improve the profitability of the particular unit.[13] NETL further found that the five boiler optimization options it considered in the cited study can be completed without requiring additional legislation or regulations. However, these kinds of changes at a power plant may require the owner/operator to obtain a new or modified air pollution permit. NETL found that uncertainty and risk associated with the permitting process has been a barrier to higher penetration of boiler optimization projects.

Hesitancy exists among air pollution regulators as well. Despite the fact that Prevention of Significant Deterioration regulations require the applicant and the permitting authority to assess energy, environmental, and economic factors to establish Best Available Control Technology (BACT) emissions limits, states and the US Environmental Protection Agency (EPA) have not always taken advantage of the expansive definition of BACT to encourage new or modified power plants to operate as efficiently (thermally) as possible. Standard practice has instead been to set a specific point source concentration-based emissions limit grounded in an assessment of the boiler type and fuel combusted, for example, X pounds of nitrogen oxides ($NO_X$) per million British thermal units (BTU[14]) or Y parts per million (ppm) of $NO_X$. A few states have made more concerted efforts to incorporate thermal efficiency considerations in BACT analyses. For example, an advisory board to the Virginia Department of Environmental Quality issued a report in 2011 that lays out a recommended process for that state to follow in determining BACT for GHG emissions.[15]

The EPA has more explicitly considered thermal efficiency in a number of rulemakings over the last decade. To begin with, the New Source Performance Standards for Electric Utility Steam Generating Units now include output-based emissions standards for particulate matter (PM), $NO_X$, and sulfur dioxide ($SO_2$) that are expressed as "pounds per MWh" limits. Most older federal regulations included input-based emissions standards only, for example, standards limiting the pounds of emissions per million BTUs (MMBTU) of energy input into a coal-fired boiler. Output-based emissions standards inherently promote thermal efficiency because it is easier

12 Waste heat recovery strategies are also featured in Chapters 2 and 3 of this document. Here in Chapter 1, the discussion of waste heat recovery is limited to the potential to capture heat that is produced at power plants as an inherent byproduct of generating electricity, and then using the captured heat onsite to improve the net heat rate of the generating unit. Other applications of waste heat recovery are considered in Chapters 2 and 3.

13 Supra footnote 6.

14 A BTU is the amount of heat required to increase the temperature of a pint of water (which weighs exactly 16 ounces) by one degree Farenheit.

15 State Advisory Board on Air Pollution. (2011, November). Energy Efficiency Measures as Best Available Control Technology for Greenhouse Gases. Available at: http://www.deq.virginia.gov/Programs/Air/StateAdvisoryBoardonAirPollution/StateAdvisoryBoardReports.aspx.

to comply with a "pounds per MWh" standard if less fuel is combusted to generate each MWh. With input-based standards, an inefficient boiler that requires more fuel (more BTUs) to generate each MWh can legally emit more pounds of air pollutant per MWh.

In September 2013, the EPA released proposed New Source Performance Standards similarly limiting GHG emissions from new electric generating units. The proposed rule would set separate, output-based standards for certain natural gas-fired stationary combustion turbines and for fossil fuel-fired utility boilers and integrated gasification combined-cycle units. It would require affected natural gas combined-cycle units to meet output-based standards of 1000 pounds of carbon dioxide ($CO_2$) per gross MWh (for units with a heat input rating of greater than 850 MMBTU per hour) or 1100 pounds of $CO_2$ per MWh (for units smaller than 850 MMBTU per hour). The corresponding standards for fossil fuel-fired boilers and integrated gasification combined- cycle units would be set at 1100 pounds of $CO_2$ per MWh over any 12-month period, or 1000 to 1050 pounds of $CO_2$ per MWh over an 84-month period.[16]

In addition to this new emphasis on output-based emissions standards, the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Industrial Boilers rule that the EPA promulgated in 2012 requires affected facilities to complete energy assessments that produce "a comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments." The Industrial Boiler NESHAP does not specifically require facilities to act on the recommendations in these assessment reports. This energy assessment concept was not replicated in the EPA's 2012 NESHAP for Coal and Oil-Fired Electric Utility Steam Generating Units (also known as the Mercury and Air Toxics Standards, or MATS), but the MATS rule does rely on output-based standards and those standards, according to the EPA, were developed after consideration of the potential for thermal efficiency projects to reduce emissions.

Boiler optimization techniques are also a central component of the emissions guidelines for GHG emissions from existing power plants that the EPA proposed on June 2, 2014 (a.k.a. the Clean Power Plan). The EPA determined that the "best system of emissions reduction" for this category of sources is one that consists of a combination of four "building blocks" determined to have been adequately demonstrated to reduce $CO_2$ emissions, with due consideration for impacts on the cost of electricity and electricity system reliability. The first of those four building blocks consists of practices that reduce the output-based emissions rate (pounds of $CO_2$ per net MWh) of affected power plants through heat rate improvements. The proposed emissions guidelines include a GHG reduction obligation for each state that is based in part on the EPA's analysis that heat rates of coal-fired power plants can be improved by six percent on average.[17] This rate of improvement is based on analysis conducted on a suite of hundreds of coal-fired power plants. The EPA acknowledges that individual plant heat rate improvements will differ; some may achieve greater than a six-percent improvement and some may achieve less, based on the individual characteristics at each plant.

This chapter focuses on the state of power plant efficiency today to provide support for states that want to evaluate how improved thermal efficiency can be part of a GHG emissions reduction plan. It is worth noting, however, that the engineering consulting firm Sargent & Lundy, in a 2009 report to the EPA, found that regulatory and economic barriers tilt the dynamics toward replacing the entire power plant, rather than overhauling and rebuilding equipment at existing plants.[18] This conclusion

16 The proposed standards for natural gas combined-cycle plants are equivalent to or less stringent than the limits noted in the EPA's RACT/BACT/LAER Clearinghouse (RBLC) for some recently issued permits, viz. Calpine Russell City Energy Center, California (1100 lb/MWh); Interstate Power and Light, Marshalltown, Iowa (951 lb/MWh); or Berks Hollow Energy Associates, Ontelaunee, Pennsylvania (1000 lb/MWh). The proposed standards for coal-fired plants, however, are premised on the implementation of at least partial carbon capture and storage and are about one-half the value of the $CO_2$ limit in the draft permit for the Wolverine Power Supply Cooperative, Michigan (2100 lb/MWh). Wolverine was the only coal-fired unit included in the EPA RBLC as of July 3, 2014.

17 US EPA. (2014, June 18). *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units.* Available at: https://www.federalregister.gov/articles/2014/06/18/2014-13726/carbon-pollution-emission-guidelines-for-existing-stationary-sources-electric-utility-generating#h-72 at Section VI(B)(2).

18 Sargent & Lundy. (2009, January). *Coal-Fired Power Plant Heat Rate Reductions.* SL-009597. Available at: http://www.epa.gov/airmarkets/resource/docs/coalfired.pdf.

would appear to be at odds with the conclusions the EPA reached in its analysis for the Clean Power Plan, although it is not clear whether Sargent & Lundy would reach the same conclusions today that it reached in 2009. In any event, it will not be surprising if, in response to the Clean Power Plan, some operators choose to completely replace power plants while others opt for just a subset of the boiler optimization options described here.

## 3. State and Local Implementation Experiences

Evidence of the effectiveness of boiler optimization projects can be found in the previously cited NETL reports. A power plant in the western United States completed upgrades to its turbines and control system. Its average thermal efficiency improved from 32 to 35 percent. A power plant in the northeastern United States also completed upgrades to its turbines and improved the performance of its fan blades and pumps. Each of the three units at this plant improved thermal efficiency by three to eight percent.[19] Although these are but a few examples of projects already undertaken, NETL has found that obtaining comprehensive, detailed, and robust data is difficult, as many utilities consider the results of such projects to be confidential.[20]

Nevertheless, the International Energy Agency's (IEA) Clean Coal Centre, based in London, United Kingdom, published a report that includes several more case studies from the United States. The JH Campbell plant in Michigan converted from burning Eastern bituminous coal to a blend of 30-percent Powder River Basin (PRB) subbituminous and 70-percent Eastern bituminous coal. A comprehensive overhaul of plant equipment was completed to adjust to the lower-sulfur, higher-ash PRB coal. Steps taken included: additional overfire air ports, new furnace roof tubes, new superheater and economizer surfaces, new primary air heaters, and new primary air fans. Prior to the upgrade, plant $NO_X$ emissions were 2.42 pounds per MWh. After the changes were completed, $NO_X$ emissions were reduced to 1.01 pounds per MWh. The IEA case study did not include information about heat rate improvements at this plant.[22]

The Dairyland Power Cooperative JP Madgett plant in Alma, Wisconsin, undertook a turbine retrofit project in 2004. During the same time period as a major boiler maintenance project, the turbine unit was retrofitted with new blades and inner casing. As a result, the efficiencies of the high-pressure turbine increased by eight to ten percent, that of the intermediate pressure turbine by two to four percent, and overall output of the plant increased by 20 to 27 MW.

Installation of a continuous combustion management system at the Progress Energy Crystal River plant in Florida improved boiler efficiency by 0.5 percent and also reduced the fan energy requirements.[23]

Intelligent soot blowing systems were installed at the 780-MW Jeffrey Energy Center in St. Marys, Kansas, and the 574-MW Allen King Unit 1 in Bayport, Minnesota. Both plants burn PRB coal. The heat rate was improved by 0.87 percent at the Jeffrey plant and by 1.8 percent at the Allen King plant.[24] A neural network soot blower optimization system installed at the Big Bend Power Project in Texas reduced $CO_2$ emissions by 58,400 tons per year and $NO_X$ by 3000 tons per year. The Deseret Power Bonanza Station in Utah installed neural network controls on its burners to improve boiler efficiency by one percent.[25]

TIC refers to a suite of technologies that can be used to cool the ambient air before it enters a natural gas-fired power plant's combustion chamber. Gas turbines operate at high thermal efficiency at an ambient temperature of 59 degrees Fahrenheit (F) and 60 percent relative humidity (so-called "standard conditions"). Thermal efficiency losses

19 DiPietro, P. (2009, November). *Improving Efficiency of Coal-Fired Power Plants for Near-Term $CO_2$ Reductions.* National Energy Technology Laboratory. Available at: http://netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/ImprovEfficCFPPNearTermCO2Reduct.pdf.

20 Supra footnote 9.

21 Supra footnote 3. Note that a second phase of the JH Campbell plant included a conversion to 100-percent PRB coal and installation of Selective Catalytic Reduction for additional $NO_X$ reductions.

22 Supra footnote 2.

23 Ibid.

24 Ibid.

25 Asia-Pacific Economic Cooperation (APEC) Energy Working Group, Expert Group on Clean Fossil Energy. (2005, June). *Costs and Effectiveness of Upgrading and Refurbishing Older Coal-Fired Power Plants in Developing APEC Economies.* Energy Working Group Project EWG 04/2003T. Available at: http://www.egcfe.ewg.apec.org/Documents/Costs%26EffectivenessofUpgradingOlderCoal-FiredPowerPlantsFina.pdf.

*Figure 1-3*

**Cameo Generating Station, Grand Junction, Colorado, with Parabolic Solar Trough Installation**

*Photo: Xcel Energy, Public Service of Colorado, 2011.*

increase with increased ambient temperature. Compared to standard conditions, turbine power output declines by 7 percent at an ambient temperature of 25 degrees Celsius (C) (77 F), and declines by 15 percent at an ambient temperature of 36 C (97 F).[26] In many parts of the United States, peak electricity demand occurs during periods of hot weather, when air conditioning demand from homes and businesses rapidly increases. TIC technologies include chillers, wet compression, fogging, and evaporative cooling.[27]

Fewer data are available on the potential to supplement coal-fired generation with onsite renewable generation, but at least one demonstrated example exists. The Xcel Energy Cameo plant near Grand Junction, Colorado, shown in Figure 1-3, installed parabolic trough concentrating thermal solar technologies to provide supplemental heat to the coal-fired power plant's heat exchanger. The Xcel project was performed as part of a demonstration with the National Renewable Energy Laboratory to show the potential to combine renewable technologies with coal-fired plants to improve their thermal efficiency and to reduce GHG and criteria pollutant emissions. The project lasted one year (2010) and produced positive results. No coal unit outages were experienced. The coal-based heat rate declined by more than one percent. Coal savings were calculated to be 524,760 pounds for the one-year test period.[28]

## 4. GHG Emissions Reductions

If all types of boiler optimization projects are completed, plant operators can improve a plant's thermal efficiency in the range of four to seven percent. Because improved thermal efficiency means lower fuel or auxiliary power consumption, these translate into a similar range of GHG reductions at the plant site. Supplementing coal-fired generation with renewable generation can further reduce emissions. The EPA's Clean Power Plan analysis for heat rate improvement found that best operating practices can improve the heat rate of coal-fired power plants by four percent on average and, in addition, upgrades to equipment can improve heat rate by up to two percent.[29]

It should be noted that the prime purpose of boiler optimization projects completed in the United States has been to reduce fuel consumption and criteria pollutant emissions. Although GHG emissions are also reduced, this result has not been a primary objective to date; GHG emissions reductions have been a co-benefit of projects designed to reduce $NO_X$ or $SO_2$ emissions. This may change with the promulgation of the EPA's Clean Power Plan guidelines for existing power plants, and future optimization projects will more likely seek to jointly and simultaneously reduce criteria, toxic, and GHG emissions.

Three recent reports describe projects to improve boiler efficiency. Data from DOE's NETL and from the Xcel Energy solar demonstration project are summarized in Table 1-2.

A subsequent 2014 research report by NETL also examined the effects of "off the shelf" technology options for coal pulverizer and combustion control improvement, condenser improvement, and steam turbine upgrades on

26 Chacartegui, R. (2008, August). *Analysis of Combustion Turbine Inlet Air Cooling Systems Applied to an Operating Cogeneration Power Plant.* Energy Conversion and Management, Volume 49, Issue 8, 2130–2141.

27 Turbine Inlet Cooling Association. (2014, June). *Technology Options to Increase Clean Electricity Production in Hot Weather.*

28 Xcel Energy, Public Service of Colorado. (2011, March). *Final Report: Innovative Clean Technology: "The Colorado Integrated Solar Project."* Docket No. 09A-015E. Available at: http://www.xcelenergy.com/staticfiles/xe/Corporate/Environment/09A-015E%20Final%20CISP%20Report%20Final.pdf.

29 US EPA. (2014, June). *Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units.* Docket ID No. EPA-HQ-OAR-2013-0602.

*Table 1-2*

| Reported Efficiency Increase from Actual Efficiency Improvement Projects[30] | | |
|---|---|---|
| **Efficiency Improvement Technology** | **Description** | **Reported Efficiency Increase** |
| **Combustion Control Optimization** | Combustion controls adjust coal and air flow to optimize steam production for the steam turbine/generator set. However, combustion control for a coal-fired EGU is complex and impacts a number of important operating parameters, including combustion efficiency, steam temperature, furnace slagging and fouling, and $NO_X$ formation. The technologies include instruments that measure carbon levels in ash, coal flow rates, air flow rates, carbon monoxide levels, oxygen levels, slag deposits, and burner metrics as well as advanced coal nozzles and plasma-assisted coal combustion. | 0.15% to 0.84% |
| **Cooling System Heat Loss Recovery** | Recover a portion of the heat loss from the warm cooling water exiting the steam condenser prior to its circulation through a cooling tower or discharge to a water body. The identified technologies include replacing the cooling tower fill (heat transfer surface) and tuning the cooling tower and condenser.[31] | 0.2% to 1% |
| **Flue Gas Heat Recovery** | Flue gas exit temperature from the air preheater can range from 250° F to 350° F, depending on the acid dew point temperature of the flue gas, which is dependent on the concentration of vapor phase sulfuric acid and moisture. For power plants equipped with wet flue gas desulfurization systems, the flue gas is further cooled to approximately 125° F as it is sprayed with the flue gas desulfurization reagent slurry. However, it may be possible to recover some of this lost energy in the flue gas to preheat boiler feedwater through the use of a condensing heat exchanger. | 0.3% to 1.5% |
| **Soot Blower Optimization** | Soot blowers intermittently inject high velocity jets of steam or air to clean coal ash deposits from boiler tube surfaces in order to maintain adequate heat transfer.[32] Proper control of the timing and intensity of individual soot blowers is important to maintain steam temperature and boiler efficiency. The identified technologies include intelligent or neural-network soot blowing (i.e., soot blowing in response to real-time conditions in the boiler) and detonation soot blowing. | 0.1% to 0.65% |
| **Steam Turbine Design** | There are recoverable energy losses that result from the mechanical design or physical condition of the steam turbine. For example, steam turbine manufacturers have improved the design of turbine blades and steam seals, which can increase both efficiency and output (i.e., steam turbine dense pack technology).[33] | 0.84% to 2.6% |
| **TIC** | Several technologies can be used to cool inlet air during hot weather to increase the thermal efficiency of a natural gas combined cycle plant. These include: chillers, wet compression, fogging, and evaporative coolers. | 8% to 26%[34] |
| **Integrated Renewable Energy and Coal** | Parabolic solar thermal troughs provide supplemental heat to the plant's heat exchanger to improve thermal efficiency. | 1.33% |

30 Data in this table for Turbine Inlet Cooling are from: Turbine Inlet Cooling Association. (2012, July). *Turbine Installation Data.* Available at: http://www.turbineinletcooling.org/data/ticadatap.pdf. Data for Integrated Renewable Energy and Coal are from: Xcel Energy, Public Service of Colorado. (2011, March). Final Report: Innovative Clean Technology: *"The Colorado Integrated Solar Project."* Docket No. 09A-015E. Available at: http://www.xcelenergy.com/staticfiles/xe/Corporate/Environment/09A-015E%20Final%20CISP%20Report%20Final.pdf. All other data in this table are from: US DOE. (2008, July). *Reducing $CO_2$ Emissions by Improving the Efficiency of the Existing Coal-Fired Power Plant Fleet.* National Energy Technology Laboratory, DOE/NETL-2008/1329. The NETL study clarifies that reported efficiency improvement metrics are "adjusted to common basis by conversion methodology assuming individual component efficiencies for a reference plant as follows: 87 percent boiler efficiency, 40 percent turbine efficiency, 98 percent generator efficiency, and 6 percent auxiliary load. Based on these assumptions, the reference power plant has an overall efficiency of 32

two hypothetical coal-fired power plants. One of the hypothetical power plants was assumed to have a 1968-vintage, 550 MW unit with a heat rate of 10,559 BTU/kWh. The other hypothetical power plant also had a 550 MW unit, but was newer (1995-vintage) and more efficient (9,680 BTU/kWh heat rate). An emerging solar-assisted feedwater heating option was also evaluated.[35] NETL's 2014 report concluded that the "off the shelf" technologies could reduce $CO_2$ emissions at the two hypothetical power plants by 1.7 to 6.9 percent. Emissions at the retrofitted plants might be as little as one percent greater than the emissions expected from a new subcritical pulverized coal unit. In addition, the solar-assisted feedwater heating option could, by itself, potentially reduce $CO_2$ emissions 1.7 to 7.1 percent.

The IEA Clean Coal Centre report referenced earlier also provides data on the potential improvements in plant efficiency in several different areas, as shown in Table 1-3.

Sargent & Lundy's 2009 report to the EPA on possible projects to improve the heat rate at coal-fired power plants provides data based on small-, medium-, and large-sized electric generating units. These data, summarized in Table 1-4, represent a range based on Sargent & Lundy's industry surveys, discussions with equipment vendors, and review of operating experience at selected plants.[36]

For the data cited in Table 1-4, Sargent & Lundy used

*Table 1-3*

**Potential Efficiency Improvements for Power Plants in the United States**[37]

| Area of Improvement | Efficiency increase, percentage points |
|---|---|
| **Air heaters** (optimise) | 0.16–1.5 |
| **Ash removal system** (replace) | 0.1 |
| **Boiler** (increase air heater surface) | 2.1 |
| **Combustion system** (optimise) | 0.15–0.84 |
| **Condenser** (optimise) | 0.7–2.4 |
| **Cooling system performance** (upgrade) | 0.2–1 |
| **Feedwater heaters** (optimise) | 0.2–2 |
| **Flue gas moisture recovery** | 0.3–1.5 |
| **Flue gas heat recovery** | 0.3–1.5 |
| **Coal drying** (installation) | 0.1–1.7 |
| **Process controls** (installation/improvement) | 0.2–2 |
| **Reduction of slag and furnace fouling** (magnesium hydroxide injection) | 0.4 |
| **Soot blower optimisation** | 0.1–0.65 |
| **Steam leaks** (reduce) | 1.1 |
| **Steam turbine** (refurbish) | 0.84–2.6 |

percent and a net heat rate of 10,600 BTU/kWh. As a result, if a particular efficiency improvement method was reported to achieve a one-percent increase in boiler efficiency, it would be converted to a 0.37-percent increase in overall efficiency. Likewise, a reported 100-BTU/kWh decrease in net heat rate would be converted to a 0.30-percent increase in overall efficiency."

31 Replacing tower fill and tuning the tower and condenser improve the components' ability to reject heat to the atmosphere, thereby potentially reducing condenser backpressure and improving turbine thermal efficiency.

32 Soot blowers can also help clean the air preheater exchange surfaces.

33 Efficiency recovery from existing turbine components is also possible; this generally entails removing deposits from turbine blades, repairing damage to turbine blades, and straightening and sharpening packing teeth.

34 The reported data for turbine inlet cooling indicate the typical percentage power increase at specific plants. A few of the hundreds of power plants featured in the database reflect power increases greater or less than the range shown.

35 US DOE. (2014, April). *Options for Improving the Efficiency of Existing Coal-Fired Power Plants.* National Energy Technology Laboratory, DOE/NETL-2013/1611. Available at: http://netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/Efficiency-Upgrade-Final-Report.pdf.

36 Supra footnote 18.

37 Supra footnote 2.

*Table 1-4*

**Potential Heat Rate Reductions (BTU/kWh) from System or Equipment Modifications for a Typical Coal-Fired Power Plant[38]**

| System or Equipment Modified | Power Plant Size 200 MW | 500 MW | 900 MW |
|---|---|---|---|
| Economizer | 50–100 | 50–100 | 50–100 |
| Neural Network | 50–150 | 30–100 | 0–50 |
| Intelligent Soot Blowers | 30–150 | 30–90 | 30–90 |
| Air Heater and Duct Leakage Control | 10–40 | 10–40 | 10–40 |
| Acid Dew Point Control | 50–120 | 50–120 | 50–120 |
| Turbine Overhaul | 100–300 | 100–300 | 100–300 |
| Condenser | 30–70 | 30–70 | 30–70 |
| Boiler Feed Pumps | 25–50 | 25–50 | 25–50 |
| Induced Draft (ID) Axial Fan and Motor | 10–50 | 10–50 | 10–50 |
| Variable Frequency Drives (VFD) | 20–100 | 20–100 | 20–100 |
| Combined VFD and Fan | 10–150 | 10–150 | 10–150 |

an average boiler heat rate of 10,400 BTU/kWh. Although most of the above projects are discrete, the "combined VFD and fan" row represents a sum of the "ID axial fan" and the "VFD" projects. If all of the projects above were to be completed, and if all achieved the maximum possible heat rate improvement, thermal efficiencies could possibly be improved by more than ten percent. However, these data are based on discussions with equipment vendors. Sargent & Lundy was not able to exhaustively survey US coal-fired power plants and, like the NETL and IEA data cited earlier, was able to locate actual case examples for only a subset of the plant inventory.

## 5. Co-Benefits

In the examples described above, the prime purpose of boiler optimization projects was to reduce fuel consumption and criteria pollutant emissions. GHG reductions were a co-benefit of these projects. Boiler optimization projects, considered after EPA promulgates its Clean Power Plan emissions guidelines for existing power plants, are more likely to evaluate the benefits and compare tradeoffs between criteria, toxic, and GHG emissions.

The direct relationship between improved thermal efficiency and reduced fuel consumption reduces a plant's $SO_2$, $NO_X$, PM, and mercury emissions. Reductions in $SO_2$ and PM emissions will generally be proportional to the heat rate improvement, as the amount emitted is dictated by the sulfur and ash content of the fuel consumed. With $NO_X$ emissions, nonlinear improvements are possible because most of the nitrogen comes from the combustion air rather than the fuel. For example, improvements in boiler efficiency achieved by replacing burners and installing new air supply can disproportionately reduce $NO_X$ emissions. At a 550-MW plant, Siemens installed new burners and air supplies and saw $NO_X$ emissions decrease from 1200 mg/m3 to 300 mg/m3. The plant also increased boiler efficiency by 0.42 percent and reduced fan power consumption by 900 kW.[39] The Deseret Power neural network controls reduced $NO_X$ emissions by 20 percent and improved the plant's thermal efficiency by 1 percent, even with changes to different coals.[40]

The public health benefits associated with reductions in criteria and hazardous air pollutants are well documented across decades of published literature. In several recent rulemaking dockets, the EPA has consistently identified these co-benefits as constituting a substantial portion of the total benefits associated with reducing GHG emissions. For example, in the Regulatory Impact Analysis that the EPA published in conjunction with the Clean Power Plan proposal, air pollution health co-benefits represent more than half of the total calculated benefits under most of the analyzed scenarios.[41]

38 Supra footnote 18.

39 Supra footnote 2.

40 Supra footnote 25.

41 The EPA analyzed costs and benefits under a range of different assumptions. The results, summarized in Table ES-8 of the Regulatory Impact Analysis, show health benefits exceeding climate benefits in almost every scenario. Refer to: US EPA. (2014, June). *Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants.* Available at: http://www2.epa.gov/sites/production/files/2014-06/documents/20140602ria-clean-power-plan.pdf.

Other types of co-benefits can also be significant. The full range of co-benefits that can be realized through boiler optimization are summarized in Table 1-5.

## 6. Costs and Cost-Effectiveness

It is difficult to make generalized statements about the cost of boiler optimization projects. Large utility-sized boilers are typically custom fabricated on a power plant site. The fuel handling system and boiler nozzles themselves are designed for particular fuel types. Coals – even within the same rank – have different properties, with varying heating values, ash content, and sulfur content. Also, the costs of many of the inputs used in boiler optimization projects, from copper wire and cement to the design and construction labor, can fluctuate significantly. Data confidentiality is often a further complication, as the cost of boiler optimization projects can be a sensitive topic. Consequently, much of the cost data cited herein comes from NETL, Sargent & Lundy, and the IEA Clean Coal Centre, and is based on generalized data from a broad range of coal-fired power plants. As a result, the cost data cited here should be interpreted as a guide or estimate only, and not strictly applicable to a particular future project.

Complete upgrades to a boiler to maximize efficiency improvement, including replacement of turbine blades, air preheaters, and all of the optimization tasks outlined in the IEA Clean Coal Centre report are estimated to range from $100 to $200 million.[42] However, boiler efficiency improvements of two to three percent can be achieved for a fraction of these costs through economizer, neural network, and intelligent soot blower projects.

Sargent & Lundy reflects that neural networks (artificial intelligence) have been installed at more than 300 US power plants. Boiler efficiencies have been improved by 0.3 to 0.9 percent, with an average improvement of 0.6 percent. Boilers using PRB coals have observed improvements of up to 1.5 percent. The average cost to install neural networks is $300,000 to $500,000, with annual operating costs of approximately $50,000.[43] Actual experience has shown that, in order to sustain the improved levels of thermal efficiencies over the long-term, various equipment that was previously manually controlled or adjusted, such as actuators, must be controlled by instruments and routinely maintained.[44]

The Allen King Plant reported a payback period of less than six months to recover costs from the improved soot blowing system.[45] At the Big Bend example referenced earlier, the upgraded soot blowing system cost $3 million and produced annual cost savings of $908,000, resulting in a payback period of slightly more than three years.[46] The

*Table 1-5*

**Types of Co-Benefits Potentially Associated With Boiler Operation**

| Type of Co-Benefit | Provided by This Policy or Technology? |
|---|---|
| **Benefits to Society** | |
| Non-GHG Air Quality Impacts | Yes |
| $NO_X$ | Yes |
| $SO_2$ | Yes |
| PM | Yes |
| Mercury | Yes |
| Other | Yes |
| Water Quantity and Quality Impacts | Maybe |
| Coal Ash Ponds and Coal Combustion Residuals | Yes |
| Employment Impacts | Maybe |
| Economic Development | No |
| Other Economic Considerations | No |
| Societal Risk and Energy Security | No |
| Reduction of Effects of Termination of Service | No |
| Avoidance of Uncollectible Bills for Utilities | No |
| **Benefits to the Utility System** | |
| Avoided Production Capacity Costs | Maybe |
| Avoided Production Energy Costs | Yes |
| Avoided Costs of Existing Environmental Regulations | Yes |
| Avoided Costs of Future Environmental Regulations | Yes |
| Avoided Transmission Capacity Costs | No |
| Avoided Distribution Capacity Costs | No |
| Avoided Line Losses | No |
| Avoided Reserves | No |
| Avoided Risk | Maybe |
| Increased Reliability | Yes |
| Displacement of Renewable Resource Obligation | No |
| Reduced Credit and Collection Costs | No |
| Demand-Response-Induced Price Effect | Maybe |
| Other | |

42 Supra footnote 2.

43 Supra footnote 18.

44 Personal communication, James Staudt, April 2014.

45 Supra footnote 2.

46 Supra footnote 25.

heat rate at this plant was improved by 0.1 to 0.4 percent.[47]

The APEC Energy Working Group report, from which some of the case examples described here have been extracted, provides methodologies to assess the costs and benefits of various types of boiler optimization projects. Sample spreadsheets include default assumptions for unit level data on operating and capital costs and electricity revenues. Results are provided in terms of increased electricity revenue, reductions in fuel and ash costs, and emissions reductions.[48]

*Table 1-6*

**Capital, Fixed O&M, and Variable O&M Costs of Boiler Optimization Projects**[49]

| System or Equipment Modified | Cost Item | Power Plant Size 200 MW | 500 MW | 900 MW |
|---|---|---|---|---|
| **Economizer** | Capital ($ million) | 2–3 | 4–5 | 7–8 |
| | Fixed O&M ($/yr) | 50,000 | 100,000 | 150,000 |
| | Variable O&M ($/yr) | 0 | 0 | 0 |
| **Neural Network** | Capital ($ million) | 0.5 | 0.75 | 0.75 |
| | Fixed O&M ($/yr) | 50,000 | 50,000 | 50,000 |
| | Variable O&M ($/yr) | 0 | 0 | 0 |
| **Intelligent Soot Blowers** | Capital ($ million) | 0.3 | 0.5 | 0.5 |
| | Fixed O&M ($/yr) | 50,000 | 50,000 | 50,000 |
| | Variable O&M ($/yr) | 0 | 0 | 0 |
| **Air Heater and Duct Leakage Control** | Capital ($ million) | 0.3–0.5 | 0.6–0.7 | 1–1.2 |
| | Fixed O&M ($/yr) | 50,000 | 75,000 | 100,000 |
| | Variable O&M ($/yr) | 0 | 0 | 0 |
| **Acid Dew Point Control** | Capital ($ million) | 1.5–3.5 | 2.5–10.0 | 3.5–18 |
| | Fixed O&M ($/yr) | 50,000 | 75,000 | 100,000 |
| | Variable O&M ($/yr) | 170,000–350,000 | 425,000–850,000 | 750,000–1,500,000 |
| **Turbine Overhaul** | Capital ($ million) | 2–12 | 4–20 | 5–25 |
| | Fixed O&M ($/yr) | 0 | 0 | 0 |
| | Variable O&M ($/yr) | 0 | 0 | 0 |
| **Condenser** | Capital ($ million) | 0 | 0 | 0 |
| | Fixed O&M ($/yr) | 30,000 | 60,000 | 80,000 |
| | Variable O&M ($/yr) | 0 | 0 | 0 |
| **Boiler Feed Pumps** | Capital ($ million) | 0.25–0.35 | 0.5–0.6 | 0.7–0.8 |
| | Fixed O&M ($/yr) | 0 | 0 | 0 |
| | Variable O&M ($/yr) | 0 | 0 | 0 |
| **Induced Draft (ID) Axial Fan and Motor** | Capital ($ million) | 6–6.5 | 9–11 | 15–16 |
| | Fixed O&M ($/yr) | 50,000 | 85,000 | 130,000 |
| | Variable O&M ($/yr) | 0 | 0 | 0 |
| **Variable Frequency Drives (VFD)** | Capital ($ million) | 1.5–2 | 3–4 | 5–6 |
| | Fixed O&M ($/yr) | 20,000 | 30,000 | 50,000 |
| | Variable O&M ($/yr) | 0 | 0 | 0 |
| **Combined VFD and Fan** | Capital ($ million) | 6–6.5 | 9–11 | 15–16 |
| | Fixed O&M ($/yr) | 25,000 | 38,000 | 60,000 |
| | Variable O&M ($/yr) | 0 | 0 | 0 |

47 US DOE. (2007, September). *Clean Coal Technology: Power Plant Optimization Demonstration Projects.* Topical Report Number 25. Available at: http://www.netl.doe.gov/File%20Library/Research/Coal/major%20demonstrations/ppii/topical25.pdf.

48 Supra footnote 25. Detailed examples are provided in Chapter 8 of this report.

49 Supra footnote 18.

Reduct, a consultancy focusing on improved utility boiler performance, indicates that their experience, based on a study of approximately 1150 power plants in North America, reflects that a one- to three-percent improvement in boiler efficiency can be achieved at savings equal to $600,000 to $1,700,000 for a 450-MW power plant.[50]

Sargent & Lundy also assessed the capital costs, fixed operations and maintenance (O&M) costs, and variable O&M costs associated with the boiler optimization projects identified in Table 1-4. These cost data are shown in Table 1-6.[51]

Finally, the previously cited 2014 NETL report examined the costs of efficiency retrofits and compared those to the cost of building a new power plant.[52] The combined retrofit cost for the "off the shelf" technologies studied in that report was found to be just over $36 million dollars, or $66/kW, for each of the two hypothetical power plants. Considering both the capital cost and the O&M costs, NETL concluded that the cost of electricity at each power plant could increase by nearly 1 percent in the worst case, or decrease by as much as 3.5 percent. But perhaps more importantly, NETL also determined that the cost of electricity that results from deploying these technologies at either the older or the newer hypothetical power plant is 22 to 25 percent below the cost of building and operating a new, subcritical pulverized coal unit. According to NETL, "This could be a strong incentive for performing efficiency upgrades at coal units, as a strategy for reducing $CO_2$ emissions from the existing power generation fleet."

Costs for TIC technology installed as retrofits to existing natural gas combined cycle plants range from $30/kW for wetted media to $375/kW for chillers. The Turbine Inlet Cooling Association estimates a cost of $28.1 million to install chillers at a 500-MW gas-fired power plant. The chillers are estimated to increase the capacity of the plant by 75 MW during periods of the highest ambient temperatures.[53]

## 7. Other Considerations

Improving the heat rate reduces fuel consumption and a plant's operating costs. Although improved profitability might be an incentive to significantly improve a plant's thermal efficiency, depending on the degree of changes made and their effects on emissions a plant may be subject to New Source Review permitting requirements, including BACT review. In some cases, the BACT process can stretch out for months, especially if the state does not receive a complete permit application from the source. If emissions decrease, as is typically the case shown with the examples provided in this chapter, then any changes to the boiler and associated equipment may only require adjustments to the plant's operating permit or may be considered a minor modification. The plant owner or operator would of course consult with the appropriate permitting authority before undertaking any significant changes to the plant. In states with vertically integrated utilities, the owner would also consult with the state public service commission to determine if any of the expenses associated with the improved thermal efficiency projects could be recovered through appropriate rate-making or cost-recovery proceedings under the Commission jurisdiction.

Although permitting issues can present challenges, reducing fuel costs and improving the dispatch ability of the plant are well understood by plant owners and operators as reasons to consider these techniques. Even a one-percent improvement in thermal efficiency can change the order in which a plant is dispatched by the regional transmission operator. Improved heat rates relative to other generating units reorder the dispatch stack; the unit that has upgraded its boiler has a higher probability of running, and can increase its capacity factor and its profitability.

Improved thermal efficiency also means less discharge to water and solid waste streams. Less coal burned per MWh of generation means less ash generation. The life of the associated emissions control equipment can also be extended, with less corrosion and fouling.

50 Reduct and Lobbe Technologies, British Columbia. More information at http://www.reduct.com.

51 Supra footnote 18.

52 Supra footnote 35.

53 Turbine Inlet Cooling Association. (2014, June). *FAQ About Turbine Inlet Cooling Technologies.* Note that the 500 MW plant in the example above would *not* have a peak capacity of 500 MW at an ambient temperature of 100 F. It is more likely that the capacity would be in the 400-425 MW range (reflecting a 15-20% loss of capacity), and that the TIC technologies would be one way to restore the capacity lost by natural gas combined-cycle plants during high ambient temperature conditions.

## 8. For More Information

Interested readers may wish to consult the following reference documents for more information on boiler optimization:


- Campbell, R. (2013, December). *Increasing the Efficiency of Existing Coal-Fired Power Plants.* Congressional Research Service. Available at: http://www.fas.org/sgp/crs/misc/R43343.pdf.
- Henderson, C. (2013, August). *Upgrading and Efficiency Improvement in Coal-Fired Power Plants.* International Energy Agency (IEA) Clean Coal Centre, CCC-221, ISBN 978-92-9029-541-9.
- Sargent & Lundy. (2009, January). *Coal-Fired Power Plant Heat Rate Reductions.* SL-009597. Available at: http://www.epa.gov/airmarkets/resource/docs/coalfired.pdf.
- Storm, R., & Reilly, T. (1987). *Coal-Fired Boiler Performance Improvement Through Combustion Optimization.* Prepared for American Society of Mechanical Engineers. Available at: http://www.stormeng.com/pdf/Coal%20Fired%20Boiler%20Performance%20Improvement%20Through%20Combustion%20Optimization.pdf.
- US DOE. (2008, July). *Reducing $CO_2$ Emissions by Improving the Efficiency of the Existing Coal-Fired Power Plant Fleet.* National Energy Technology Laboratory, DOE/NETL-2008/1329. This report is no longer available online.
- US DOE. (2012, January). *Improve Your Boiler's Combustion Efficiency.* Advanced Manufacturing Office. Available at: http://www1.eere.energy.gov/manufacturing/tech_assistance/pdfs/steam4_boiler_efficiency.pdf.
- US DOE. (2014, April). *Options for Improving the Efficiency of Existing Coal-Fired Power Plants.* National Energy Technology Laboratory, DOE/NETL-2013/1611. Available at: http://netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/Efficiency-Upgrade-Final-Report.pdf.
- Doyle, B. W. (2003, June). *Combustion Source Evaluation Student Manual.* Air Pollution Training Institute, Course 427, Third Edition. Available at: http://www.4cleanair.org/APTI/427combined.pdf.
- US EPA. (2010, October). *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Coal-Fired Electric Generating Units.* Office of Air and Radiation. Available at: http://www.epa.gov/nsr/ghgdocs/electricgeneration.pdf.


## 9. Summary

Boiler optimization and improved thermal efficiency are standard procedures that have been used for many decades. The recent development and maturity of artificial intelligence and neural networks to automatically adjust key variables and parameters de-emphasizes the role of human intervention, and helps to assure that the boiler performs at optimal efficiency levels at all times. Electricity load growth in the United States is at a steady one percent per year, and is expected by the Energy Information Administration to remain at those levels through 2040.[54] Energy efficiency continues to be the most cost-effective means to procure additional resources to meet electricity load growth. Thus there are few opportunities in the United States to construct new coal-fired power plants that achieve the thermal efficiency levels observed in China at their supercritical and ultra-supercritical power plants (up to 44- to 47-percent thermal efficiency, effectively combusting up to 50 percent less coal per MWh than the typical 32-percent thermal efficiency American plant). As a result, boiler optimization efforts in the United States must necessarily focus on ways to get the most generation (MWh) possible from each ton of coal combusted. The techniques described here will permit a plant to improve thermal efficiencies by up to four to seven percent, reducing coal combustion and GHG emissions by an equivalent quantity. Such techniques offer co-benefits in the form of lower criteria pollutant emissions, especially for $NO_X$ and $PM_{2.5}$. Compared to previous performance at the same plant, reduced water and land discharges also result from improved efficiency. The interesting Colorado solar integration project showcases possibilities to achieve additional onsite efficiency improvements by using renewable technologies that provide supplemental heat to a plant heat exchanger.

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54 US EIA. (2014, May). *Annual Energy Outlook 2014 – Market Trends: Electricity Demand.* Available at: http://www.eia.gov/forecasts/aeo/MT_electric.cfm.