White paper

MATS Compliance
An opportunity to build in energy efficiency?

Introduction

Coal-fired generation is under considerable pressure. It faces increasing regulatory constraints regarding emissions and simultaneously an economic challenge from now-plentiful natural gas. Owners of existing coal plants are left with an unappetizing choice between expensive retrofits and decommissioning. However, an alternative has emerged in the form of converting pulverized coal-fired boilers to natural gas.

There are number of reasons that a utility might pursue this option. First, some plants are located in areas where retiring the unit would create the need for significant remediation to maintain proper volt-amps reactive (VAR) support on the local grid. So, there may be a system need to retain generation at a particular location and conversion costs less than outright replacement.

Second, prices for natural gas are expected to remain low and the capital outlays required for conversion to gas compare favorably with the cost of retrofitting coal. At least over the near term, fuel conversion has a viable business case, particularly for plants in the eastern US that burn high-sulfur hard coal and expect to invest heavily to meet compliance rules on emissions.

Of course, fueling a coal-fired boiler with non-design fuel is not the most efficient use of natural gas. However, the reduction in parasitic load and O&M expense associated with gas conversion can at least partially offset the sub-optimal efficiency.

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Figure 1: Clean coal power plant boiler (water condenser)

Still, while pulverizers, primary air fans, sluice pumps, clinker grinders, and conveying system loads go away, large loads in boiler feed pumps, condensate pumps, condenser vacuum pumps, induced draft fans and forced draft fans remain. Together, these remaining auxiliaries on a typical unit can account for 2-4 percent of gross generating capacity.

Maximizing the opportunity to squeeze additional megawatt hours from the unit requires a close examination of the large electrical consumers and an allotment of project dollars to make sure the electrical distribution and automation systems are also a target for improvement. Below we discuss ways to recover some of the efficiency lost in burning non-design fuel. In considering these options, though, it's important to keep in mind that there is no "typical plant." Each facility is different and so any efficiency related allocation should be evaluated relative to the unique characteristics of the plant in question.

That said, fuel conversion projects typically come in between \$20 million and \$50 million per unit, depending on size, proximity to gas supplies and overall site readiness. Fuel conversion, then, represents a relatively low-cost path to essentially instantaneous clean air compliance, a significantly reduced carbon footprint and avoidance of much larger capital expenditures associated with coal retrofits or new-build gas. Energy efficiency improvements can be budgeted as part of the repowering project, and typically account for only 2-5 percent of the overall capital required.

Large motor efficiency improvements

Parasitic load at coal-fired power plants over 20 years old can run as high as 7 to 10 percent of gross MVA generation. Some of the biggest consumers of on-site power are electric motors, which often operate well below their optimal efficiency.

A typical 600MW fossil-fired power plant will have 10-15 large motors (5-25MW), and a somewhat larger complement of medium sized motors (0.1 – 5MW), perhaps 15 to 25 units. As part of the original design of these motors, it's likely that the engineering specification for power and torque were increased to accommodate performance margins and guarantees. An application originally requiring a 2MW motor operating at or near its best efficiency point (BEP) may have been "spec'd up" to 3MW or more. Consequently, the motor operates well away from its BEP, dissipating significantly more power than necessary.

Over a 40 year life, this could waste 56GWh in just one such motor. Multiply that by the cost to produce those GWh, or even worse the lost opportunity to sell them, and it becomes obvious that the cost of the motor itself is dwarfed by the cost of the energy it wastes. Replacement and resizing of motors for best efficiency in major air, fuel and fluid handling systems can easily yield gains of 10 percent of the power consumed by the motor.

Variable frequency drives

In many cases, with older air and fluid pumping systems, the actual operating point of a given motor is well below original design limits. Additionally, retrofits such as back-end flue gas scrubbing may render the originally specified equipment a bit lacking in performance. A variable frequency drive (VFD) can solve a number of operability and controllability issues that arise in these scenarios, and do so in an energy-efficient manner.

It's worth noting too that new VFDs reduce downtime compared with first- and second-generation drives that still exist in many plants. A single avoided plant outage can often pay for a drive retrofit, and improvement in parasitic load will contribute to lower operating cost for as long as the drive is installed.

Figure 2: Variable Frequency Drives (VFDs)

Capacity increases via power factor improvements

For remotely located units, power factors are often set by dispatch at 0.80 to 0.90, depending on network load conditions. These represent capacity losses, as real MW output is sacrificed to create MVAR support. A tighter range of 0.88 to 0.93 would be an improvement over the current range. This allows generating stations to shift MVAR (unsold) production to MW (sold), improving their net efficiency and revenue.

Techniques and equipment exist to make this possible. Within the power station, auxiliary motors can be driven with variable speed drives that include front-end power electronics that improve the Power Factor found on the busses. This in turn makes the station auxiliaries look like less of an inductive load, and reduces the need for additional power factor compensation from the generator. In other situations, a STATCOM or SVC system can take over much of the reactive power generation needs, and restore lost MW capacity for additional revenue.

Obstacles to efficiency improvements

So why haven't these upgrades been done over the years in the absence of MATS compliance projects? There are three contributing factors, each of which can be addressed in the context of current industry conditions.

New Source Review

The new source review (NSR) provision of the Clean Air Act (CAA) requires existing units that undergo "major modifications" to install state-of-the-art pollution controls. Since 1977, debate has continued as to what constitutes a "major modification" but owners have generally avoided projects that expose them to scrutiny.

The decision to switch from coal to gas automatically invokes scrutiny under NSR. Historically, the risk of an energy efficiency project being viewed as "major modification" was largely a function of the possibility that a FGD/SCR/baghouse would need to be installed, a possibility that is taken off the table when natural gas is the fuel source.

ROI predictability

Energy efficiency project returns are inherently difficult to predict because they depend on unpredictable measures like capacity factor and unit cycling. Payback and ROI will float as function as of these two factors, a situation which lends no comfort to capital planners. However, when an energy efficiency project is a tiny fraction of an overall capital project, the justification is somewhat less complex because project success isn't entirely dependent on realized energy savings. The main project driver is compliance.

Figure 3: Clean coal-fired power plant

Project risk

There is risk in "tinkering" with the powering and control of critical fans and pumps. Adding VFDs and replacing motors is not always problem-free. Embarking on a project to do this work based on an inherently unpredictable set of outcomes has sometimes been viewed as "not worth it."

The risk of adding VFDs and replacing inefficient motors, however, is quickly outweighed by replacing coal valves with gas valves, installing a complete gas distribution piping system and modifying control logic in the burner management system. Clearly, adding more components increases the risk somewhat but the major risk-driving decision has already been made out of necessity for compliance.

Other efficiency opportunities

As is probably clear at this point, once the compliance strategy of fuel conversion is set, it opens the door to myriad possibilities for efficiency improvements. In addition to those discussed earlier, plant owners might also consider areas such as:

- Replacement or repair of step-up transformers
- Improving feedwater heater chain efficiency
- Maintaining cooling system hydrogen purity to reduce friction and resistance losses
- Installing state-of-the-art blades in the final stages of LP turbines
- Review and repair/redesign of boiler blowdown systems
- Examination of other parasitic operations and loads such as compressed air systems, steam trap management, etc.

Conclusion

To summarize, building energy efficiency improvements into a coal-to-gas conversion project makes sense from a financial perspective, has only minor implications on the overall project risk profile and helps overcome some of the inherent inefficiency related to burning non-design fuel in a boiler. Conversion projects present an opportunity from a project justification perspective and can help overcome many of the historic objections to pursuing incremental process improvements through capital investment.

Without question, the savings potential of each project will vary by site and load profile of individual units. A complete analysis by a company with expertise to evaluate the potential is critical. A comprehensive plan for efficiency improvements can typically yield multiple percentage point improvements in output at costs far lower than building new units, but that plan will still need to offer a reasonable expectation of payback.

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