Power Generation
Energy Efficient Design of Auxiliary Systems in Fossil-Fuel Power Plants

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The Smart Grid begins with Efficient Generation
Energy Efficient Design of Auxiliary Systems in Fossil-Fuel Power Plants

A technology overview for design of drive power, electrical power and plant automation systems

ABB, Inc.
in collaboration with Rocky Mountain Institute, USA

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Introduction
Energy Efficient Design of Fossil-Fuel-Fired Steam Power Plant Auxiliary Systems

"It is the greatest of all mistakes to do nothing because you can only do a little" Sydney Smith (1771–1845)

Energy efficiency is the least expensive way for power and process industries to meet a growing demand for cleaner energy, and this applies to the power generating industry as well.

> In most fossil-fuel steam power plants, between 7 to 15 percent of the generated power never makes it past the plant gate, as it is diverted back to the facility's own pumps, fans and other auxiliary systems.

This auxiliary equipment has a critical role in the safe operation of the plant and can be found in all plant systems. Perhaps the diversity of applications is one reason why a comprehensive approach to auxiliaries is needed to reduce their proportion of gross power and to decrease plant heat rate.

This handbook takes a comprehensive view of auxiliary systems and describes some common approaches to energy efficient design which can be applied in retrofit and new plant projects. This handbook reviews drive-power concepts, and provides useful design and engineering guidelines that can help to improve energy efficiency. The extent of these energy savings are shown in fully worked-out numerical examples and in actual plant case histories throughout the text.

This handbook may be used as part of a training course for managers and technical staff in operating and engineering service companies, and may also be used in mechanical or electrical engineering university programs. This handbook complements existing best practices for power plant engineering and is not a substitute for detailed plant design and safety guidelines published by standards bodies and industry associations. The relevant sources for detailed guidelines are listed in the **References** section.

Scope

Technologies Scope

This handbook defines plant 'auxiliaries' to include all motor-driven loads, all electrical power conversion and distribution equipment, and all instruments and controls. Process chemical and thermodynamic efficiency is not directly within the scope of this handbook. The controllable losses which are within the reach of automation systems are of interest, as are methods of recovering waste heat or energy from the cycle using drivepower technologies.

Some industry sources may use the overly-narrow term 'auxiliary' to refer only to certain fan and pump systems. An overly-broad term that includes all auxiliary systems (and much more) is 'balance of plant': (BoP). Starting from this level, we can define three categories of auxiliary systems:

- A subset of BoP that encompasses drive power components such as pumps, fans, motors and their power electronics such as variable-frequency drives. These provide drive power for fuel handling, furnace draft, and feedwater pumping. **These systems and components will be referred to as 'Drivepower'.**
- A subset of BoP that encompasses only the electrical power system's conversion, protection, and distribution equipment, excluding motors and variable-frequency drives. This subset includes power transformers and LV and MV equipment. **These systems and components will be referred to as Eelectrical BoP ('EeBoP') or 'Electric Power Systems.'**
- A subset of BoP that encompasses only the instruments, control, and optimization systems. These provide boiler-turbine and other control functions. **These systems and components will be referred to as 'I&C' or simply 'Automation'**

Some examples of auxiliary equipment from these categories are shown on the cutaway view of a plant on the following page. A common aspect of auxiliary technologies is that they handle all the electrical power and control signals throughout the entire plant.

All the technologies discussed are commercially available and the engineering practices described in this handbook are non-proprietary. Some newer technologies and their energy efficiency potential are reviewed in the final module of the handbook.

Industry and Plant Scope

The material and guidelines in this handbook are generally applicable to all power generation and process industries. These industries generally are more energy-intensive than the discrete manufacturing sector. Material which is industry-specific for particular version of the handbook is shown in a blue box.

Plant Type Scope

The focus of this handbook version is on fossil-fuel-fired electrical power generating plants that have a steam cycle. The fuels these plants use include coal, oil, gas, biomass, and solid waste. Pulverized coal (PC) sub-critical boiler plants receive special attention in this handbook due to the large number of existing plants (and continued construction of them globally), their heavy-duty cycle as base-loaded plants, their poor average efficiency, and their considerable carbon dioxide emissions. PC plants also use up to twice as much auxiliary power as compared to liquid or gas-fueled plants

Industrial boilers and co-generation systems share many of the same technologies and designs as their counterparts in utility power generation. An industrial power generation facility is sometimes referred to as a 'power house' to distinguish it from the larger power plants used by power generation companies. The term 'utility' includes all operators of large-scale power generation facilities, regardless of the form of ownership.

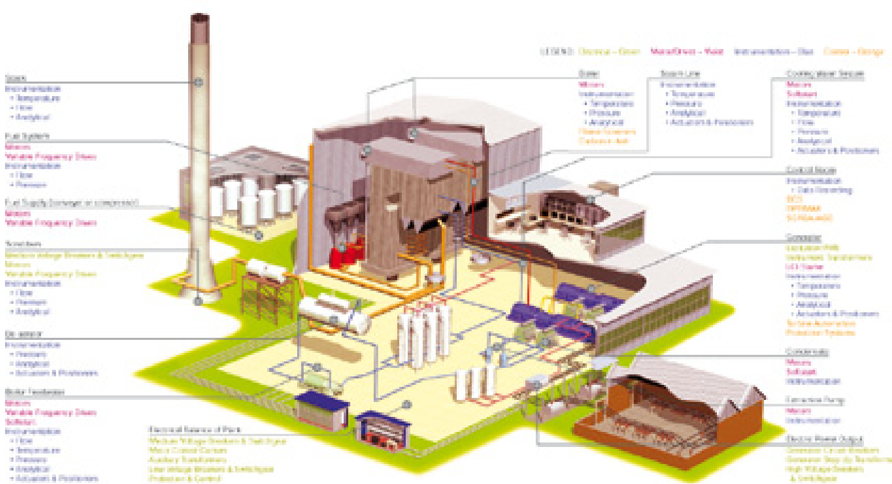


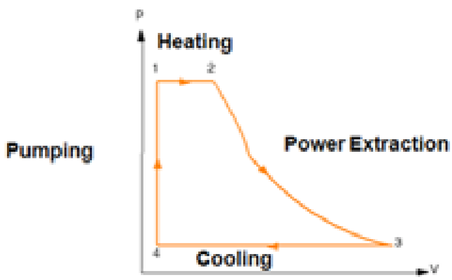
Figure I.1 - Plant cutaway showing location and type of auxiliary equipment (ABB Inc. USA Products for Power Generation Industry)

Why Focus on Auxiliaries?

Role of Auxiliaries in Operation

In power plants, auxiliaries serve to keep the steam-water cycle safely circulating, and to return it to its thermodynamic starting point. Without these auxiliary systems, the steam-water cycle would suffer either an immediate collapse or a dangerous and non-sustainable expansion. The basic thermodynamic shape and efficiency of the cycle, shown on a Pressure-Volume diagram below, is the job of the cycle designer. The main purpose of the auxiliary systems is to preserve the designed shape of this cycle across a wide range of conditions and over time, using a minimum of input energy and with a maximum of availability.

In power plant terminology, auxiliary power is sometimes referred to as 'station load', 'house load' or even 'parasitic load'.



Auxiliaries Consume High-Quality Power

Auxiliaries consume the highest quality energy in the plant, namely electrical energy. The power supplied to in-house loads is power that could otherwise have been saved (or sold, in the case of a power plant operating at full load). The convenience and controllability of electrical power is behind the trend towards electric motors displacing other forms of auxiliary drive power, such as steam for turbine-driven pumps.

Auxiliary power consumption is 'downstream' power; efficiency improvements in auxiliary loads have a multiplier effect as one moves upstream to the primary energy source, within or outside the plant.

Based on the typical 33 percent thermal efficiency that many older power plants achieve, the generated electricity is at least three times the price of the input fuel energy, when all the added fixed and financial costs of electricity generation are also included.

The share of auxiliary drivepower of total plant power has been increasing for other reasons too, mainly from the installation of mandatory anti-pollution equipment, increased fuel variability, and general performance degradation due to the accumulated effects of aging on plant equipment.

Auxiliaries Impact on Reliability has Energy Consequences

No other resource affects plant availability and the bottom line like reliable electrical power. What may not be so apparent is the energy efficiency dimension of reliability problems. Many metrics exist to account for planned or unplanned (forced outage) downtime, but the general assumption has always been that downtime does not affect plant energy efficiency, which is normally calculated under some steady state operating condition.

Long periods of unsalable production (or power generation in the case of power plants) during unit startup and shutdown caused by reliability-related downtime events should be considered as the reduced efficiency of a 'reliability asset.' The efficiency of this virtual asset is proportional to reliability percentage, at plant, unit, and equipment levels. A temporary de-rating due to a reliability issue will have energy efficiency consequences as well. The energy costs of poor reliability have been hiding behind the much greater opportunity costs of downtime and now deserve a proper accounting, as shown in the **Energy Accounting for Reliability** section.

Auxiliaries Enable New Duty Cycles

Perhaps the most compelling reason to address auxiliary systems design is the movement of the power generation industry towards deregulation, more renewable supply, and carbon dioxide emissions limits. All these factors can turn the duty cycle of today's fleet of plants on its head, with the workhorse base-loaded coal-fired units moving into mid-range or even peaking duty, and lower-emissions combined-cycle plants being base-loaded instead. Auxiliary systems design improvement is important to prop up the older plants efficiency under all load scenarios, to improve control response (ramp rate) for more rapid load changes, and to automate for more rapid startups.

Auxiliaries Redesigns and Retrofits are Justifiable

Finally, it is economically relatively easy to justify a closer look at the economics of auxiliary systems improvements because, unlike main process equipment, they are generally less expensive and easier to retrofit, at much lower installed cost and incurring little or no downtime. The relatively modest costs associated with auxiliary redesigns and retrofits, compared to main process equipment, are reflected in their relative new plant contract prices. The following data is for power plants, but applies to most other large process plants as well:

Fans and motors :	2.2% of total contract price
Controls and instruments:	1.5% of total contract price
Electrical equipment (EBoP):	0.9% of total contract price

(IEA CoalOnline, 2007)

In power plants, the cost to build one new MW of coal-fired capacity is approximately $1.3M-$2.2M USD. The capital cost and risks associated with new central plant construction have increased more rapidly than the price since the mid 1980's. Plant licensing and staffing issues can be the largest stumbling blocks for getting to the point of ground-breaking of new plant projects.

Justifying the Focus on Design and Engineering

Energy Management versus Energy Engineering

The scope of this handbook is energy design and engineering in the context of new plant and retrofit projects of modest capital investment. 'Energy management' works through ongoing operational maintenance and monitoring activities and seeks incremental efficiency improvements within the technical constraints of existing plant systems.

Operational Energy Assessment versus Design Audit

An Energy Assessment is a process that evaluates existing plant performance. The customer for an energy assessment is usually a facility operator, who will set the frame of reference for the assessment at the start. If only operational or energy management and budgets are involved, then the assessment will naturally focus on operational improvements. A wider scope and larger budget may lead assessors to investigate design and engineering modifications.

There is continuum between design and operational assessments, depending on the project context and timeframe. The sooner an assessment is performed in the plant's lifecycle, the greater the efficiency improvement potential. There are many good references available on traditional energy assessment procedures, which focus strongly on measurement and prioritization techniques. A design handbook typically focuses on the theory of energy performance so that good practice can be applied even in a conceptual design review, before there are any operational data. This handbook is therefore a complementary reference to design guidelines, to help guide the focus of energy assessments, and energy performance improvement projects.

In large capital engineering projects, the early design phase accounts for just 1 percent of a project's up-front costs, but at that point up to 70 percent of its life-cycle costs may already have been committed (Lovins, 1999). **Energy-inefficient designs are then frozen-in, often for several decades in the case of large process or power plants.** Therefore, it is important for designers and engineers to learn how to quickly review their energy design options and perform relative cost analyses before the final design concept is firmly established; the focus is on 'quickly', because that 1 percent time window is not very long at all. For example, in a three year project, that window will be less than two weeks.

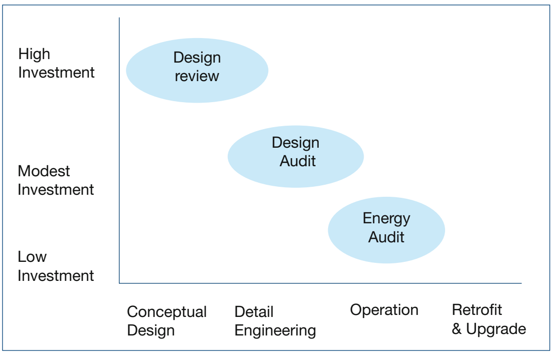


Figure I.2 - Investment return vs. project phase for energy design assessments

Design versus Engineering

Design comes before engineering, and is concerned with overall process flows and capacities. Design determines the mass balances and energy balances, and how the system is controlled. Engineering is concerned with implementation of a design - selection and sizing of process equipment and how it is to be instrumented and controlled. Designers have the most freedom to improve energy efficiency during new projects and large re-development projects. In typical retrofit situations, however, it is the engineering function that has the most freedom. A special word of encouragement, therefore, to engineers starting a retrofit project: You may have more freedom and opportunity than you realize to improve plant energy performance!

Why an Engineering Handbook and Course

Utilities, state or local authorities, and other public entities offer operational efficiency programs to support corporate energy management goals—particularly at the plant level (Hoffmann, 2008), but there are fewer on-the-job learning options for generation or company staff to learn about energy efficiency design and engineering techniques, which can yield much greater improvements.

The market for learning about industrial plant energy efficiency is large and growing. According to a recent survey of corporate energy managers (Johnson Controls, 2008), 70 percent have invested in educating staff and other facility users to increase support for improving internal energy efficiency.

Commodity Product versus Custom Engineering

Many of the technologies that comprise plant auxiliaries are becoming less custom-engineered items and taking on more of a commodity status. This commercialization of technology advances brings benefits to customers such as lower price, shorter delivery times, and increased reliability. On the other hand, more complex technologies, such as variable speed drives, may not be 'plug-and-play' ready for all applications. Operating and engineering staff need to learn to recognize these situations so that commodity solutions can be still be applied successfully without the deep involvement of supplier engineers. The guidelines and information in this handbook provide a bridge between off-the-shelf auxiliary equipment, such as VFDs, motors, and some DCS packages, and the plant applications they are supposed to serve.

Industry versus Academia

Academic training of engineers is important, but there is also a history of technical education for power generation and process industries within the engineering and supplier industries. For example, ABB's Automation University, as well as GE's 'Power Systems Engineering Course' and its accompanying Design Guides, which have been taught to practicing engineers for 60 years. and AspenTech's University are all examples of the industry educating their own.

Who Should Read this Handbook

Anyone who can influence the design, engineering, technical procurement and execution activities should read this handbook.

- Plant electrical and mechanical department engineers
- Operating company energy managers, at all levels
- Plant operators, plant managers, and project managers
- Engineering planners
- Financial officers and procurement managers
- Supplier company technical staff
- Engineering company process, mechanical, and electrical engineers
- Industry regulators' technical staff

The fossil fuel plant version of this handbook assumes that the reader is familiar with the basic design and operation of a fossil-fuel steam boiler. The **Appendix** has a brief overview of sub-critical boiler's main components and their function.

Acknowledgements

This handbook is the result of collaboration between ABB Inc., Power Systems Division, and the Rocky Mountain Institute. Rocky Mountain Institute (RMI) is an independent, entrepreneurial, nonprofit organization. Special thanks to Dr. Amory Lovins, Chief Scientist of RMI for his valuable comments and inspiring work on energy efficiency for industry, and for the opportunity to complete this work at RMI offices in Snowmass, Colorado, USA. The RMI-Competitek DrivePower and Cooling Manuals are an often-cited, valuable source of reference material for this handbook.

Thanks also to all the ABB engineers and scientists without whose contribution of time and material this handbook would not have been possible; for automation: Daniel J. Lee, Pekka Immonen, and Robert Herdman. For motors and VFDs: Moledina M. Varvani, Dennis Kron, and Jiuping Pan. For electrical power systems: Hamid SaharKhiz, Majid Rahimi, Brian D.Scott.

Special thanks to Richard W. Vesel of ABB Power Systems USA for his generous support, technical guidance and encouragement, and to Arash Babaee of ABB Power Systems Canada for his review and comments. The ABB Application Guides were a valuable reference for this handbook, and have been frequently cited, although no special permissions have been yet been sought for internally copyrighted graphics and case examples from this ABB-owned material.

This handbook was written and edited by Robert P. Martinez at RMI, Snowmass, USA while on sabbatical leave generously provided by the ABB Norway, Strategic R&D department, led by John Pretlove. Thanks to Cameron Burns of RMI for copy-editing the first draft and for being a friend during my family's stay at RMI. Final editing, review and publication was carried out by Richard Vesel, with support from program manager Milovan Grbic and marketing director Andy Gavrilos.

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This handbook is published in two versions: one version will be made broadly available to educators and other public consumers as part of Rocky Mountain Institute's public service efforts to increase awareness of energy efficient design though their 10xE program. Another version will be published internally by ABB and may contain confidential portions not intended for wide circulation.

Acronyms and Abbreviations

BoP	Balance of Plant
CCGT	Combined-Cycle Gas Turbine
CFB	Circulating Fluidized Bed
CHP	Combined Heat and Power
DCS	Distributed Control System
DoE	US Department of Energy
EBoP	BoP but same as above, but limited only to electrical equipment
EHV	Extra High Voltage (345000-765000 V)
FOF	Forced Outage Factor
FOR	Forced Outage Rate
GT	Gas Turbine
HV	High Voltage (115000-230000)
IEA	International Energy Agency
IGCC	Integrated Gasification Combined Cycle
LV	Low Voltage (IEEE Std. 666-2007:0 -1000V)
MCR	Maximum Continuous Rating
MPC	Model Predictive Control
MV	Medium Voltage (typically 2400V,4160V,4800V,13,800V)
NEMA	National Electrical Manufacturers Association
NPHR	Net Plant Heat Rate
POF	Planned Outage Factor
SST	Station Service / Startup Transformer
UAT	Unit Auxiliary Transformer
UCF	Unit Capability Factor
USC	Ultra Supercritical
VFD	Variable Frequency Drive
VSD/ASD	Variable Speed Drive, Adjustable Speed Drive
UT	Unit (Step-up) Transformer

MPC	Model Predictive Control
MV	Medium Voltage (typically 2400V,4160V,4800V,13,800V)
NEMA	National Electrical Manufacturers Association
NPHR	Net Plant Heat Rate
POF	Planned Outage Factor
SST	Station Service / Startup Transformer
UAT	Unit Auxiliary Transformer
UCF	Unit Capability Factor
USC	Ultra Supercritical
VFD	Variable Frequency Drive
VSD/ASD	Variable Speed Drive, Adjustable Speed Drive
UT	Unit (Step-up) Transformer

Industry-Specific Terminology

Backpressure power	Higher pressure steam at turbine output; good for CHP
Banked	A unit in reduced load (spinning reserve) operation
Base loading unit	Unit operated at constant load 24 hrs/day, 7 days week
Condensing power	Low pressure steam at turbine output
Day/night loading	Unit operated at constant load during day, then banked or shutdown overnight
Dispatchable/mid-range	A plant which receives dispatch commands to follow load; may be cycled, does not operate much at capacity
Frequency response	Operated at nominal load (one of above) but modulated to compensate for network frequency disturbances
Gross Plant Heat Rate	Fuel heat input per gross power output as measured at generator busbar
Annual Capacity Factor	Actual generated energy divided by rated annual output (accounts for outages and low load operation)
Heat rate	Required input fuel heat to generate a unit of electric power (Btu/kW). The higher the heat rate, the less efficient a plant is.
Shift loading	Unit operated at constant load during each 8-hour shift.
Spinning reserve	A unit operated at low load, in anticipation of rapid ramp-up
Unit	An integrated single boiler system sending steam to a single multi-stage turbine powering a single main generator (typically).

Keywords

Energy Assessment, Energy Efficiency, Energy Management, Generating Station, Power Plant, Variable Frequency Drives, Transformers, Power Factor

Module 1A
The Need for Efficient Power Generation

Module Summary

This module makes the business case for energy efficient plant auxiliary systems and discusses some trends in electricity markets and power generation technologies.

The information in this module section is specific to power generation industries and/or process plants with large on-site power and/or steam heat generation.

Trends in Power Demand and Supply

Currently growing 2.6 percent per year, world electricity demand is projected to double by 2030. The share of coal-fired generation in total generation will likely increase from 40 percent in 2006 to 44 percent in 2030. The share of coal in the global energy consumption mix is shown in the figure below. This share is now increasing because of relatively high natural gas prices and strong electricity demand in Asia, where coal is abundant. Coal has been the least expensive fossil fuel on an energy-per-Btu basis since 1976.

China expanded coal use by 11 percent in 2005 and surpasses U.S. as the number one coal user in 2009. Coal is the most abundant fossil fuel, with proven global reserves at the end of 2005 of 909 billion metric tons, equivalent to 164 years of production at current rates (International Energy Agency, 2006).

In the U.S., coal-fired plants currently provide 51 percent of total generating capacity (Woodruff, 2005), or about 400 GW , from about 600 power plants . Total electrical generation capacity additions are estimated to be 750 GW by 2030 (International Energy Agency, 2006). Of that new capacity, 156 GW is projected to be provided by coal plants (Ferrer, Green Strategies for Aging Coal Plants: Alternatives, Risks & Benefits, 2008). Other estimates put capacity addition to 2030 at 280 coal-fired 500MW plants (Takahashi, 2007).

Higher natural gas prices are reversing a trend toward more energy efficient and lower-emission plant designs. The generating costs of combined-cycle gas turbine (CCGT) plants, which use natural gas, are expected to be between 5–7 cents per kWh, while coal-fired plants are in the range 4–6 cents/kWh (International Energy

Agency, 2006). Integrated gasification combined cycle (IGCC) plants are not yet competitive as of 2008 (which is why government is subsidizing many such projects). Their low relative costs make coal-fired plants competitive in the U.S. with other large central generating plants.

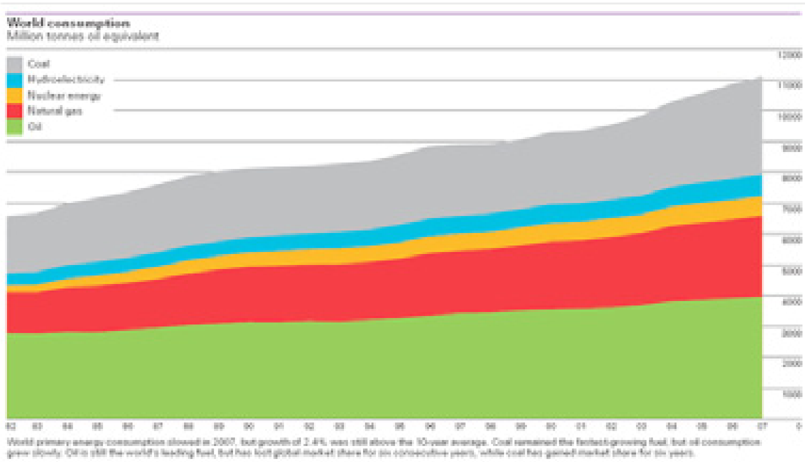


Figure 1A.1 –Trends in energy consumption, (2007 BP Statistical Review of World Energy)

Many new coal plants were being planned or constructed as of 2008, but with some uncertainty regarding the future trend due to carbon footprint and other environmental concerns over current coal-fired plant technology. Regulations imposing carbon dioxide emissions charges will eventually change the economics in favor of CCGT and other more efficient fossil plant types. Even without emissions taxes, the licensing of new plants is threatened by growing grass-roots opposition at local and state levels. According to the US Department. of Energy (DoE), 59 of 151 planned new coal plants were either refused licenses or abandoned in 2007, and 50 plants are being challenged in court. Environmental groups have successfully challenged these new plants by arguing that the additional capacity could be gained through energy efficiency and renewable sources of power. With the industry facing a possible moratorium on new plants, it is more important than ever to make existing plants as energy efficient as possible.

Whether limited by emissions or supplies, the fossil-fuel power generation industry must sooner or later reduce the carbon per unit energy produced. The prominence of coal means that it will play an important role in the transition to a low-carbon future. Dr. Amory Lovins, a leading US energy analyst, anticipated the need for such a transition many years ago when he said; “It is above all the sophisticated use of coal, chiefly at modest scale, that needs development. Technical measures to permit the highly efficient use of this widely available fuel would be the most valuable transitional technologies." (A. Lovins, Energy Strategy: The Road Not Taken 1976)

Trends in Steam Plant Designs and Efficiency

Large fossil-fuel-fired steam plants use a closed steam cycle in which water is converted to steam in a boiler. This steam is then superheated and then expanded through the blades of a turbine whose shaft rotates an electrical generator. The steam exits the turbine and condenses to water, which is pumped back up to boiler pressure. The **Appendix** section of this handbook discusses the steam cycle in greater detail, and describes some variations on this design which improve the 'cycle' efficiency.

Sub-Critical Plant Types

The most common type of plant using this design is alternatively referred to as 'drum boiler' or 'subcritical,' because water is circulated within the boiler between a vessel (the drum) and the furnace water-wall tubing where it absorbs combustion heat, but does not exceed critical pressure. Existing subcritical pulverized coal (PC) boiler steam power plants can theoretically achieve up to 36–40 percent efficiency at full load. Due to major process design changes such as supercritical boilers and **other technology improvements**, the average efficiencies of the newest coal-fired plants are up to 46 percent compared to 42 percent for new plants in the 1990s (IEA CoalOnline, 2008).

Energy efficiency improvements of several percentage points in new plants have resulted from improved designs of the main components and auxiliaries in steam power plants: including auxiliary drivepower:

- Improvements in turbine blade design
- Improvements in fans and flue gas treatment methods
- Reduction of furnace exit gas temperature
- Increase of feed water temperature
- Reduction of condensing pressure
- Use of double reheat on main steam flow
- Optimization and reduction of the consumption of auxiliary drivepower

Super-Critical Coal-Fired Steam Plants

Supercritical plants, also called 'once-through' plants because boiler water does not circulate multiple times as it does in drum-boiler designs, have efficiencies in the mid-40 percent range. New 'ultra critical' designs using pressures of 4,400 psi (30 MPa) and dual stage reheat are capable of reaching about 48 percent efficiency (IEA Coal Online - 2, 2007). Plant availability problems with the first generation of large supercritical boilers led to the conclusion that pulverized coal-fired electricity generation was a mature technology, with an efficiency limited by practical and economic considerations to around 40 percent. However, improvements in construction materials and in computerized control systems led to new designs for supercritical boilers that have overcome the problems of the earlier plants (IEA Coal Online - 2, 2007). Although most new coal-fired plants are expected to use drum steam boilers, the share of supercritical technology is rising gradually (International Energy Agency, 2006).

Combined-Cycle Gas Turbine (CCGT)

A combined-cycle gas turbine (CCGT) power plant uses a gas turbine in conjunction with a heat recovery steam generator (HRSG). It is referred to as a combined-cycle power plant because it combines the Brayton cycle of the gas turbine with the Rankine cycle of the HRSG. The thermal efficiency of these plants has reached a record heat rate of 5690 Btu/kWh, or just under 60 percent.

Some Steam Plants are Lagging

At the beginning of the 21st century, it was believed that a single-cycle coal-fired power station with an efficiency of more than 50 percent would be possible by 2015 (Kjær and Boisen, 1996 in IEA Coal Online - 2, 2007). The efficiency of some new design plants may be high, but almost 75 percent of the existing coal-based fleet of plants in the U.S. is over 35 years old, with an average net plant efficiency of only slightly above 30 percent (Ferrer, ‘Green Strategies for Aging Coal Plants,’ 2008).

In addition to the less efficient design of core equipment, these older plants suffer an additional efficiency handicap due to plant aging; they become less reliable and generally less efficient due to leakage, fouling, and other mechanical factors. Another trend which lowers efficiency is the change in fuel supply systems toward off-design coals for which the boiler has not been optimized (IEA Coal Online - 2, 2007). Fuel supplies may be subject to further tweaking as generating companies seek to reduce their carbon footprint by substituting a portion of the coal they use with biomass.

Another important reason that older plants are lagging in efficiency is that many of them are operating at 30–50 percent below their rated capacities, where efficiencies of all sub-systems are lower. The realities of a more deregulated and competitive marketplace, with renewable and distributed energy sources and new system operating reserve requirements, have led to previously baseloaded plants being operated as dispatchable plants; an unforeseen operating regime (ABB Power Systems, 2008). One view of this latter issue is the global distribution of load factor of nominally baseloaded steam turbine plants less than 500MW for the period 2001–2005. The following figure shows that the median load factor is only 64 percent.

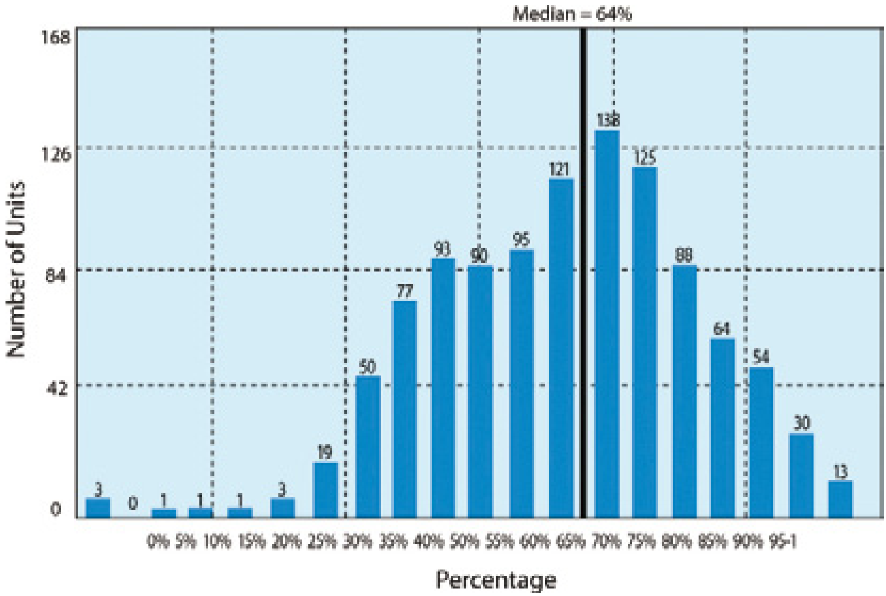


Figure 1A.2 - Distribution of load factor of base-loaded plants, (World Energy Council, 2007)

Plant Auxiliary Power Usage is on the Rise

The share of total plant auxiliary electrical power in the fleet of fossil-fuel steam plants has been increasing due to these main factors:

- Addition of anti-pollution devices such as precipitators and sulfur dioxide scrubbers which restrict stack flow and require in-plant electric drive power. About 40 percent of the cost of building a new coal plant is spent on pollution controls, and they use up about 5 percent of gross power generated (Masters, 2004).
- Additional cooling water pumping demands to satisfy environmental thermal discharge rules.
- A trend away from mechanical (e.g. condensing steam turbine) drives toward electrical motors as the prime mover for in-plant auxiliary pump and fan drives.

For PC power plants, the auxiliary power requirements are now in the range of 7–15 percent of a generating unit's gross power output for PC plants. Older PC plants with mechanical drives and fewer anti-pollution devices had auxiliary power requirements of only 5 to 10 percent (GE Electric Utility Engineering, 1983). These figures are for traditional drum boiler type plants, but the auxiliary power requirements of supercritical boilers are not any lower. The feedwater pump power required to reach the much higher boiler pressure is approximately 50 percent greater than in drum boiler designs. Increased demand for auxiliary power increases a plant's net heat rate and reduces the amount of salable power.

Plant Auxiliary Energy Efficiency Improvements

In-plant electrical power, when taken from the generator bus, may be priced artificially low in some utility companies' auxiliary lifecycle calculations. A process industry customer, however, must always pay high commercial rates (and sometimes penalties), thus providing a strong incentive to improve their auxiliary energy efficiency. Price dis-incentives, regulations permitting cost-pass thru, and other non-technical barriers are discussed in the handbook section on **Barriers to Increased Energy Efficiency**.

These barriers may result in sub-optimal energy designs for power plant auxiliaries, most commonly in oversized motors, fans and pumps. These design decisions have particularly negative consequences when the base-loaded plant then moves to a new operating mode at 50–70 percent capacity (see previous section for a discussion of this trend). Auxiliaries such as pumps and fans that use constant speed motors and some form of flow restriction for control will waste much more power when operating under such partial-load conditions. Other plant systems will also run less effectively below their design points. Boilers at partial loads, for example, run with relatively higher excess air to achieve complete combustion, which lowers efficiency; these topics are discussed in greater detail in the handbook sections on **Drivepower** and **Automation**.

Module 1B
The Potential for Energy Efficiency

Technical Efficiency Improvement Potential

A recent study by the International Energy Agency (IEA) suggests a technical efficiency improvement potential of 18–26 percent for the manufacturing industry worldwide if the best available (proven) technologies were applied. Most of the underlying energy-saving measures would be cost-effective in the long term. Another study, by the U.S. Dept. of Energy, focused on the energy efficiency opportunity provided by automation and electric power systems in process industries. An improvement potential of 10–25 percent was suggested by industry experts, who were asked to consider improvements within the context of operational or retrofit situations. The results of that study are shown in the figure below, and in more detail in the **Automation** module sections of this handbook.

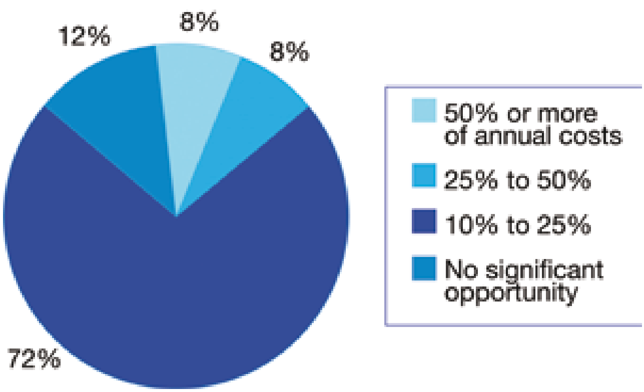


Figure 1B.1 - Process industry survey results on potential of energy efficiency, (US DoE, 2004)

Potential Revealed Through Performance Benchmarking

Access to power generation plant performance data is important for identifying areas for improvement and for showing the results of best practice. Market fragmentation and the increased competitiveness of de-regulated markets in the past have made access to data difficult. There has also been a lack of standards or practices for measuring performance.

The World Energy Council (WEC), through its Performance of Generating Plant (PGP) Committee, is now gathering and normalizing such data so that valid comparisons can be made across countries and markets.

Similar performance benchmarking efforts are done in the U.S., but through industry-funded organizations like EPRI. Standardization efforts are best represented by IEEE Std 762-2006 IEEE Standard for Definitions for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity.

Interestingly, the WEC found that 'new drivers geared toward profitability, cost control, environmental stewardship, and market economics are shifting the focus away from traditional measures of technical excellence such as availability, reliability, forced outage rate, and heat rate' (World Energy Council, 2007). Their PGP database has added individual unit design and performance indices that can be used to compare efficiency and reliability across designs. The published performance data will help industry improve practices, and will put a spotlight on under-performing plants and companies.

Efficiency Potential Revealed by Country Comparisons

The potential for energy efficiency, at least from a U.S. perspective, is also indicated in a recent (2007) comparison of fossil-fuel-based power generation efficiencies between nations that together generate 65 percent of worldwide fossil-fuel-based power. The Nordic countries, Japan, the United Kingdom, and Ireland were found to perform best in terms of fossil-fuel-based generating efficiency and were, respectively, 8 percent, 8 percent and 7 percent above average in 2003. The United States is 2 percent below average. Australia, China, and India perform 7 percent, 9 percent and 13 percent, respectively, below average. The energy savings potential and carbon dioxide emissions reduction potential if all countries produce electricity at the highest efficiencies observed (42 percent for coal, 52 percent for natural gas and 45 percent for oil-fired power generation), corresponds to potential reductions of 10 exajoules of consumed thermal energy and 860 million metric tons of carbon dioxide, respectively (Graus, 2007).

The IEA analysis mentions that more than half of the estimated energy and carbon dioxide savings potential is in whole-system approaches that often extend beyond the process level (Gielen, 2008). 'Integrative Design' is this handbook's approach to the most challenging energy efficiency issues in plant auxiliary design.

Energy Efficiency is Attracting Interest and Investment

The previous sections showed an engineer's view of the importance of energy efficiency. What are the views and plans of corporate energy decision makers and investors?

From Corporate Energy Managers

According to a recent survey on energy efficiency of corporate and plant-level energy managers at more than 1,100 North American companies (Johnson Controls, 2008):

- 57 percent expect to make energy-efficiency improvements during the same time period, devoting an average of 8 percent of capital expenditure budgets on energy-efficiency projects.
- 64 percent anticipate using funds from operating budgets, allocating 6 percent to energy-efficiency improvements.
- 40 percent have replaced inefficient equipment before the end of its useful life in the past year.
- 70 percent have invested in educating staff and other facility users as a way to increase support for increasing internal energy efficiency.

From Industry Investors

When 18 U.S. investment organizations were surveyed about energy efficiency, the results indicated that the technologists should have no trouble funding their projects. According to that study (Martin, 2004), the energy technology attracting the greatest investment interest is energy intelligence (smart instruments, advanced control, and automation). The handbook sections on **Instruments, Controls & Automation** discuss these technologies and how they can be used to improve plant energy efficiency.

Carbon Dioxide Emissions Must be Reduced

According to a 2005 report from the World Wide Fund for Nature (WWF), coal-based power stations are at the top of the list of least 'carbon efficient' power stations in terms of the level of carbon dioxide produced per unit of electricity generated. Based on current developments in Europe and in the U.S., regulations which limit or tax carbon dioxide emissions seem inevitable for all Western economies. A carbon charge of $25 per metric tonne (carbon dioxide) is a conservative estimate used in IEA scenarios. The impact of carbon pricing on fossil-fuel plant generating costs, shown in the figure below, is dramatic compared to most other generation methods. At prices above $20 per metric tonne coal-based plants become the most expensive type to operate at current non-optimized cost levels.

China and India account for four-fifths of the incremental demand for coal, mainly for power generation. For the first time, China's carbon dioxide power emissions in 2008 exceeded the United States' emissions; the lower quality coal used in India and other rapidly expanding economies, decreases plant efficiency and leads to increased carbon dioxide emissions per unit electricity (International Energy Agency, 2006).

Energy Efficiency is Key to CO2 Mitigation

The IEA Energy Technology Perspectives model is a bottom-up, least-cost optimization program. The model was developed to describe the global potential for energy efficiency and carbon dioxide emissions reduction in the period to 2050, particularly in the industrial sector. In the 'accelerated technology scenario' (ACT), the potentials for carbon dioxide reduction on all power consumption are shown in the figure below. This figure illustrates the scenario in which carbon dioxide emissions are stabilized globally in 2050 to 2005 levels, and the world narrowly avoids a costly climate crisis.

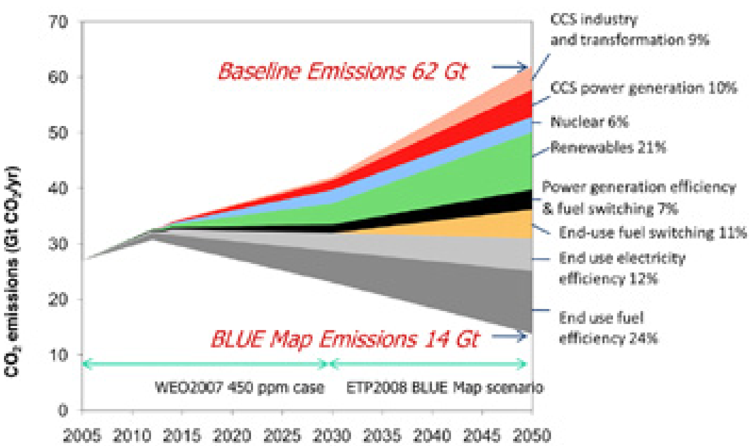


Figure 1B.2 Relative share of CO2 mitigation efforts, all consumption, (International Energy Agency, 2006)

The Role of Power Generation in Reducing Emissions

The IEA's ACT scenario suggests that power generation efficiency can contribute significantly to the overall global effort to stabilize carbon dioxide emissions by 2050 at or near 2005 levels. Surprisingly, the model shows that power generation efficiency alone, which includes improved auxiliaries and other measures, has a larger climate impact than even nuclear power.

When the model is applied to process industries alone, the impact of energy efficiency is proportionately larger. The figure below shows the 'blue' scenario, which uses the same ACT scenario describe above, but with a higher carbon dioxide charge of $50 per (metric) tonne, instead of $25/tonne (Taylor, 2008).

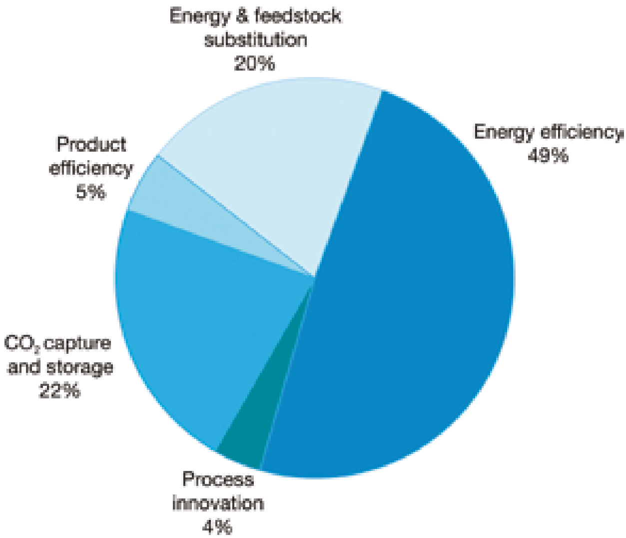


Figure 1B.3 - Relative share of CO2 mitigation efforts in process industries, (Taylor, 2008)

Applying this model to the power generation sector in particular suggests that its carbon dioxide emissions are cut by 36 percent using all of the approaches shown. Half of those savings (18% of total) can be attributed to relatively low-technology energy efficiency measures alone.

Energy efficiency measures are the most important of all the carbon dioxide mitigation approaches for process industries, contributing to almost half of the impact on emissions (Martin, 2004). Although these predictions apply to process industries, the relative potentials are likely to be valid for the steam power generation sub-sector as well.

Multiple Benefits of Energy Efficiency

The primary benefits of a increased plant energy efficiency are reduced emissions and energy or fuel costs.

Power plants which operate partially or wholly at full load will have more salable power. At less than capacity, the fuel savings are significant. In coal-fired steam power plants, fuel costs are 60-70% of operating costs.

The following is a more complete list of benefits accompanying energy efficiency design improvements for plant auxiliaries:

Operational Benefits

- Improved reliability/availability. As has been found with stricter safety design regulations, any extra attention to the process is rewarded with improved uptime.
- Improved controllability: energy is wasted in a swinging, unstable process, partly through inertia in the swings, but mainly because operators in such situations do not dare operate closer to the plant's optimum constraints.
- Reduced noise and vibration, reduced maintenance costs.

Results of Improved Efficiency on Plant Operations and Profitability

- Better allocation: under deregulation, as utilities dispatch plants within a fleet, heat rate improvement can earn plants a better position on the dispatch list (Larsen, 2007).
- Avoiding a plant de-rating due to efficiency losses after anti-pollution retrofits or other plant design changes.
- Improved fuel flexibility—by efficiently using a wider variety of fuels (coal varieties) and, in some cases, increasing the firing of biomass, for example.
- Improved operational flexibility 1) Improved plant-wide integration between units will reduce startup-shutdown times; this benefit applies mainly to de-regulated markets. 2) The heat rate versus capacity curve is made flatter and lower, which allows the plant to operate more efficiently across a wider loading range.

Plant Investment Benefits

- Avoiding forced retirement due to pollution non-compliance: An ambitious retrofit programme may save some older plants from early retirement due to non-compliance with regulations.

- Tax credits—take advantage of newer policies such as EPACT 2005, which may provide tax credits for efficiency efforts. Similar policies are in effect in the EU and China.
- Mainstream industry authority Engineering News–Record's influential Top Lists rankings now include "Top Green Design Firms" and "Top Green Contractors": 'The market for sustainable design has passed the tipping point and is rapidly becoming mainstream' (http://enr.construction.com/).
- Increasingly, shareholders and capital markets are rewarding companies who treat their environmental mitigation costs as investments (Russel, 2005).

Retrofitting may save some older plants from early retirement due to non-compliance with regulations such as the EU's Large Combustion Plant Directive on pollution (nitrous oxides, sulfur dioxide, mercury, and particulates) (International Energy Agency, 2006). In the US, increased compliance may smooth permitting of new units or plants.

All of the 'dirty dozen' in Carbon Monitoring For Action's (CARMA) list of top carbon dioxide emitting sources in the U.S. are coal-fired power plants, emitting an average of about 20 million tonnes of carbon dioxide per year per plant. 'Blacklists' like these, which include rankings by company as well, are increasingly being consulted by large institutional investors and sovereign wealth funds. With tightened credit markets, there is therefore an even greater incentive for top management to watch carbon dioxide emissions. See the section on **Benchmarking** for other global efforts toward increased transparency.

Non-Technical Barriers to Energy Efficient Design

Despite all of the benefits and incentives, and the low-capital-cost improvement potential described in previous sections, the implementation of integrative, energy efficient design and operation is still hindered by several obstacles. Methods for improved design are known and the required technologies are widely available 'off the shelf.' Individual components are generally available in high-efficiency variants. So why are power and industrial process plants energy inefficient in their design as a whole? One clue, is the fragmentation found in engineering disciplines, vendor equipment packages, and even in the way projects are executed.

The current situation with energy efficiency is analogous to the status of safety in process industries a decade or two ago. Operational safety was acknowledged as important and was codified, but there were no standards on how safety could be managed during the design process—on how it could be 'designed-in' from the start. The recent Functional Safety standards IEC-61508 and 61511 point the way forward for energy design and management standards evolution.

Many of the barriers listed below are managerial or procedural rather than technical in nature. These important non-technical aspects are discussed in the final module of this handbook. The discussion is generic for most large power and process facilities, but a specific industry will have additional competitive and regulatory pressures.

Local, State, National and International Regulatory Authorities

Authorities provide the regulatory framework for the activities of all the other stakeholders. The efforts of authorities are closely linked with those of the standards organizations. These factors, however, may contribute to inefficient plant designs:

- Regulations often permit pass-thru of all fuel-related costs directly to the rate base. This financially discourages any economization efforts related to fuel consumption, i.e. efficiency.
- Lack of clarity, unity and commitment to emissions charging makes investors wary of long-term investments in energy efficiency and/or carbon dioxide emissions reduction.
- Deregulation and the ensuing volatility in fuel and energy prices may also discourage the long-term thinking necessary to make some efficiency and carbon dioxide emissions reduction schemes justifiable.

Shareholders & Investors

The observations in this paragraph regarding shareholders and investors apply mainly to new construction or large-scale redevelopment projects. See the following paragraphs for barriers more applicable to facility owner/operators of older plants and retrofit project contexts. Shareholders and investors often influence project schedules, contract clauses, functional specs for new construction and major retrofits of plants. These factors, however, may contribute to plants that are ultimately energy inefficient:

- Project schedules are compressed; front-end design and concept studies are underfunded or curtailed.
- Scope of redevelopment projects is narrow because investors ‘generally want to avoid changes to the long remaining lifespan of the standing capital stock’ (International Energy Agency, 2006).
- Designs are ‘frozen’ early by a pre-established milestone date, even if important data may be missing.
- Cost analysis methods are too crude, or not coupled tightly enough to the conceptual process design, or have wrong initial assumptions regarding risk, return, and lifetime; calculations may ignore significant indirect costs and savings such as substitution costs, maintenance savings, and peak energy prices.

- Operational energy costs may be treated as a fixed cost and therefore receive much less attention than a variable cost.
- Low-bid, fixed-price contracting without strong, well-defined and enforceable energy performance guarantees, at the plant, unit and equipment levels.
- Purchasing managers seek multiple suppliers to reduce cost; this strategy leads to increased design and data fragmentation. Purchasing managers may still prefer individual vendors versus full-service/system integrators.
- Energy-expert consulting companies are usually the last to be hired, and therefore have much less influence over the conceptual design.
- Drawings are issued 'for construction' before even the first vendor drawing is seen, much less approved (Mansfield, 1993), leading to hasty, often energy-inefficient re-design at the interfaces.
- Capital scarcity might favor smaller plants with lower efficiency (Gielen, 2008).

Facility Operators

Facility Operators craft the original specifications, validate the design during commissioning and acceptance trials, determine operational loading and maintenance of facility, and usually initiate and manage retrofit projects. These factors, however, may contribute to plants that are ultimately energy inefficient:

- Retrofit projects to improve energy efficiency are funded from operating budgets, not from larger capital expenditure budgets; payback expectations and discount rates are all generally much higher than in green-field projects.
- Managers focus on optimizing process productivity, in which energy is only one of several other cost functions and may not receive the consideration it deserves; many modern plant-wide optimization systems optimize for productivity, which only indirectly improves energy efficiency.
- There is a war for money between process improvement and energy efficiency camps in a typical plant; process improvement teams and their measures seem to 'get more respect.'
- An increasing number of plants are centralizing purchasing, which means less engineer involvement in purchasing decisions. 'Since purchasing centralization… we've seen companies shift away from using a lifecycle cost model, which seems very short-sighted to us. Some of the decisions customers have been making are committing them to a stream of ongoing expenses that could have been reduced.' (Control Engineering article 8/15/2005).
- Facility operators receiving a new/retrofitted plant/unit are under-pressure to begin operations as soon as possible so they are therefore less critical with respect to energy targets during acceptance tests.
- Facility operators do not or cannot operate plant at design capacities due to changes in market or other factors.

- Plant engineering and maintenance teams are losing experienced older staff; facility operators do not provide adequate training for staff on energy efficiency.
- Power plant/power house energy managers (superintendents or maintenance directors) lack the necessary communication and salesmanship skills to push through good energy efficiency proposals. (a post on J. Cahill's blog, 2007).
- Reluctance to admit non-optimal, energy inefficient, operation to upper management – the perception is that this reflects badly on plant management and their plant operations team.
- Fear of production disruptions from new equipment or new procedures to improve efficiency (International Energy Agency, 2006); doubts about safety, controllability or maintainability
- Expansion projects will simply duplicate an existing unit on the same site, repeating many of the same design mistakes, to reduce the up-front engineering hours; low-labor copy-and-paste projects may also overlook opportunities for rationalization & integration with the existing unit(s).

Design and Engineering Companies

Design and engineering companies determine design specs of facility, select components and execute the design. These factors, however, may contribute to energy inefficient plants:

- A tendency to oversize pumps, fans, and motors by one rating, and oversize them again after handoff to another discipline, and then again by project leaders:
  - Bottom limits in standards already have a safety margin, but these limits are interpreted as a bare minimum (from fear of litigation) and an additional safety margin is added.
  - Overload maximums received from process engineer are interpreted by mechanical and electrical teams as continuous minimums; fat margins are added in lieu of detailed loading study.
  - Additional margins are then added for future, but unplanned, capacity increases.
  - Engineers on auxiliary systems are inordinately fearful of undersizing and risk being singled out as the bottleneck that prevents operation at full design capacity of other, more expensive, hardware
  - Large, commodity motors and fans are commercially available only in discrete sizes. After all the margins, an engineer will choose the next size up if the design point falls between two sizes.
- A tendency to aggressively reduce engineering hours to increase margins on fixed-priced contracts and to avoid selecting premium components for such contracts.

- Trade-offs between floor space and pipe/ductwork efficiency are not life-cycle cost-estimated; civil and architectural concerns are the default winners due to their early head start in most projects.
- Trade-offs between reliability and energy efficiency are not life-cycle cost-estimated. Higher energy costs are seen as insurance against large, but virtual opportunity costs.
- Lack of energy design criteria and efficiency assessment steps in the standard engineering workflow. There is typically a design optimization step for cost, safety, reliability, and other concerns, but not for energy efficiency.
- Shortage of engineers in key industries; junior and outsourced engineers are making higher-impact decisions.
- A reluctant to deviate from their 'standard design' templates, especially on expansion projects where the design has been delivered on previous units. This leads to short cuts and uncritical copying-and-pasting of older, non-optimal designs.
- Engineers work mainly within the confines of their discipline and do not see opportunities for inter-disciplinary optimization of the total design. For example:
  - Mechanical engineers miss out on optimizations from chemical engineering to use waste heat and to optimize plant thermodynamics or create useful by-products.
  - Process engineers do not leverage the full potential of automation, selecting instead familiar equipment like valves to perform control tasks better suited to a variable frequency drive.
  - Electrical engineers do not fully understand the process needs for power, such as duty cycles, and therefore do not fully optimize their designs.
  - None of the engineers mentioned above are typically very quick to leverage advances in materials science, which enable higher operating parameters.

Equipment Vendors and Design Tool Providers

Equipment Vendors and Design Tool Providers determine component energy efficiencies. The vendor's tools directly affect the engineer's workflow, models, and documentation. These factors, however, may contribute to energy inefficient plants:

- Vendors provide black-box components with closed/proprietary/rigid interfaces, which are not easily optimized for the whole system; this is the result of a trend toward 'commoditization.'
- Proliferation of design tools and data formats which are non-integrated and their design model is non-navigable between vendor tools; this hinders integrative design.
- Lack of full-scope energy-optimization functionality in the leading design and modeling tools

– As components become commodities, salesmen are replacing sales engineers, and misapplications are increasing (Plant Services.com, 2008)

Professional and Standards Organizations

Professional and standards organizations provide basic education standards and best practice certifications. These factors, however, may contribute to energy inefficient designs:

– No widely accepted standards specifically for energy efficient designs of entire plants; some operational energy management standards are in development, however.
– No widely accepted certification for energy design for whole plant systems; an energy manager certification is available in the USA, however.
– Lack of mandatory international labeling system for industrial motors, transformers, and other equipment to enable comparison.
– Protectionism and turf wars limit the global adoption of a single set of standards; the divisions between English and SI units are a cause for some confusion, design errors, and incompatibilities.

Educators and Academia

Educators and academia provide basic skills and certification (by diploma) of the next generation of designers and engineers. These factors, however, may contribute to inefficient designs:

– Educators tend to focus on the abstract and theoretical, as opposed to best practice design using state-of-the art commercially available engineering components.
– Systems engineering courses are not mandatory or sometimes not even offered in the average curriculum.
– Electrical engineering curricula increasingly favor more modern topics of electronics and discrete logic at the expense of courses on old-fashioned power engineering; courses on power station design have been dropped.
– Programs or degrees toward industrial or engineering management are too general: the specifics of each discipline cannot be made more abstract.
– Some engineering schools offer no ‘capstone’ design course that encourages synthesis of all the disciplines toward a single design task.

Standards, Best Practice, Incentives, and Regulations

Standards are the designer's and engineer's best design guidelines. Standards also offer customers and authorities an objective measure for applying regulation and incentives. 'Best practices' encompass more than standards, and include case studies, more application details, and some costing information.

Role of Standards in Energy Efficiency

Energy efficiency is an invisible quality and is subject to various interpretations; it is important, therefore, for engineers and managers to be able to have some common definitions and methodologies when assessing efficiency performance. International standards for energy design and management are emerging and some countries, including the U.S., have some standards in these areas. It is likely that these standards will be closely linked to future carbon dioxide compensation schemes, whether at national or international levels (ISO, 2007).

Common benchmarking for performance is good, but at a deeper level, standards can provide the equipment and system inter-operability that can enable a higher performance design. Highly efficient components which are mismatched or poorly integrated make for an inefficient overall system. A joint ISO/IEA technical committee that was recently formed to identify gaps in industrial standards coverage recommended more emphasis on the systemic approach and encouraged a focus on energy efficiency of overall systems and processes as well as retrofitting and refurbishing. This expert committee also recommended that standards should address efficiency improvements through **industrial automation**.

Standards and Best Practice

The standardization efforts relevant to plant auxiliaries' energy performance cover a wide variety of disciplines. The list far below refers to existing standards relevant to the systems in this handbook that specify design, application, labeling and minimum energy performance standards. The list focus is on U.S. standards, but some important international standards are also mentioned, in italicized text. The premier, official sources of unbiased standards are the national standards bodies such as American National Standard Institute (ANSI) for the U.S., CEN/CENELEC (for the EU) and the international bodies such as the IEC and the ISO. A convenient way to search for U.S. and global standards is by using the ANSI NSSN search engine at www.nssn.org. Search by title 'power station design' or 'power plant.'

Other sources of objective standards are the professional societies and industry associations, although the latter may show more bias toward their industry in certain situations:

- Institute of Electrical and Electronic Engineers (IEEE)
- Instrumentation, Systems, and Automation Society (ISA)
- The Hydraulic Institute (HI)
- National Fluid Power Association (NFPA)
- Air Movement and Control Association (AMCA)
- American Society of Mechanical Engineers (ASME)
- National Fire Protection Association (NFPA)

Many standards for steam-water cycle design of cycle equipment can be found in the various ASME and NFPA codes, but these are not within the scope of this handbook. The ASME test codes for determining efficiency, however, are of interest. Energy is a political as well as a technical subject; some 'associations' (not those mentioned above) promoting best practice are actually lobby groups with strong, but not obvious, links to commercial or political entities with various agendas. These sources can be useful if their advice is taken together with the objective sources listed above. Some of these unofficial sources of design guidance are listed in the **Reference** section of this handbook. The following list is not a comprehensive list of all relevant standards; appearing here are only those that have some relevance to plant auxiliaries' energy performance and design.

Power Plant Facilities

- IEEE Std 666-2007 IEEE Design Guide for Electric Power Service Systems for Generating Stations (Revision of IEEE Std 666-1991)
- IEEE Std 762-2006: Standard for Definitions for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity
- ANSI/ISA S77.43.01-1994 (R2002) : Fossil Fuel Power Plant Unit/Plant Demand Development (formerly ANSI/ISA S77.43-1994)
- ANSI/ASME PTC 46-1996: Overall Plant Performance codes
- ASME PTC 47-2006: Integrated Gasification Combined-Cycle Plants
- IEEE 803.1-1992 : Recommended Practice for Unique Identification in Power Plants and Related Facilities - Principles and Definitions
- ISO 13600 series (1997–2002): Technical energy systems. Methods for analysis of technical energy systems, - enabling the full costing and life cycle analysis

Best Practices

- DoE EERE Best Practice guides for Steam, Pumping Systems, Fans **www1.eere.energy.gov/industry/bestpractices**
- EPRI studies and reports – there is a large population of useful reports
- ABB Electrical Transmission and Distribution Reference Book (the 'T&D' manual)

Pump and Fan Systems

- ANSI/HI 1.3-2007 : Rotodynamic (Centrifugal) Pumps for Design and Application
- ANSI /HI Pump Standards : Available through the Hydraulic Institute, a standards partner (www.pumps.org/)

Best Practices for Pump and Fan Systems

- ANSI/HI Optimizing Pumping Systems Guidebook
- US DoE Sourcebook (2006). Improving Pump System Performance, from EERE Industrial Technologies Program:
- US DoE Sourcebook (2006). Improving Fan System Performance. from EERE Industrial Technologies Program
- Air Movement and Control Association (AMCA) International

Motors and Drives

- NEMA MG 1 : Motors and Generators
- NEMA ANSI C50.41:2000 : Polyphase induction motors for power generating stations
- IEEE Std 958-2003 : Guide for Application of AC Adjustable-Speed Drives on 2400 to 13,800 Volt Auxiliary Systems in Electric Power Generating Stations
- IEC 60034-3 Ed. 6.0 b:2007 Revises IEC 60034-3 Ed. 5.0 b:2005 Rotating electrical machines - Part 3: Specific requirements for synchronous generators driven by steam turbines or combustion gas turbines
- IEC 60034-2-1: Motor efficiency testing (September 2007); published as EN 60034-2-1 at CENELEC level.

Best Practices for Motors and Drives

- DoE Motor System Best Practices

The Energy Independence and Security Act of 2007 (EISA) calls for increased efficiency of motors manufactured after December 19, 2010.

Electric Power Systems

- IEEE 493 Design of Reliable Industrial and Commercial Power Systems, also has useful equipment reliability data.
- C57.116-1989 IEEE Guide for Transformers Directly Connected to Generators
- IEEE Std C37.010™, IEEE Standard Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis.64, 65
- IEEE 519-2006 Harmonic voltage and current distortion limits
- IEEE Std 946-2004 IEEE Recommended Practice for the Design of DC Auxiliary Power Systems for Generating Stations
- IEEE Std C37.21-2005 IEEE Standard for Control Switchboards
- 525-1992 IEEE Guide for the Design and Installation of Cable Systems in Substations
- C62.92-1993 IEEE Guide for the Application of Neutral Grounding in Electrical Utility Systems, Part III-Generator Auxiliary Systems
- IEC 60076-1 Power Transformers (VDE 0532 Part 101)
- IEC 62271-1 Ed. 1.0 b:2007 High-voltage switchgear and controlgear
- IEC 61000-2-4 (Worldwide) Harmonic voltage and current distortion limits

Best Practices for Electric Power Systems

- ABB Switchgear Manual, 11th edition, 2006 (available online)
- ABB Transformer Manual, 2007

Energy & Environmental Management

- ISO 14064 and ISO 14065 provide a methodology to help organizations assess carbon footprints and implement emissions trading schemes
- ISO 14001 is an internationally recognized framework for environmental legislation, regulation, management, measurement, evaluation, and auditingassessing.
- ISO 13600 series provides guidelines on technical energy systems

Instrumentation & Control Automation Systems

- ANSI/ISA-77.44.01-2007 - Fossil Fuel Power Plant - Steam Temperature Controls
- ANSI/ISA-RP77.60.05-2001 (R2007) - Fossil Fuel Power Plant Human-Machine Interface: Task Analysis
- ANSI/ISA-77.42.01-1999 (R2006) - Fossil Fuel Power Plant Feedwater Control System – Drum-Type
- ANSI/ISA-77.20-1993 (R2005) - Fossil Fuel Power Plant Simulators - Functional Requirements
- ANSI/ISA-77.41.01-2005 - Fossil Fuel Power Plant Boiler Combustion Controls
- ANSI/ISA-RP77.60.02-2000 (R2005) - Fossil Fuel Power Plant Human-Machine Interface: Alarms

- ANSI/ISA-77.70-1994 (R2005) - Fossil Fuel Power Plant Instrument Piping Installation
- ANSI/ISA-77.43.01-1994 (R2002) - Fossil Fuel Power Plant Unit/ Demand Development-Drum Type
- ANSI/ISA-77.13.01-1999 - Fossil Fuel Power Plant Steam Turbine Bypass System
- 502-1985 IEEE Guide for Protection, Interlocking, and Control of Fossil-Fueled Unit-Connected Steam Stations
- ASME PTC PM-1993 Performance Monitoring Guidelines for Steam Power Plants
- ISO 13380:2002 Condition monitoring and diagnostics of machines - General guidelines on using performance parameters
- ISO/TS 18876-1:2003 Industrial automation systems and integration - Integration of industrial data for exchange, access and sharing

Best I&C Practices

- ISA Instruments and Automation Society, http://isa.org/, both a standards and industry organization with sources on best practice

Power Generation Regulations and Incentives

The regulatory environment for coal-fired plants appears likely to change significantly before 2010. Some US states (2008) are considering a **moratorium on new coal plant construction**, and may slow or stop permitting of plants under construction. A US Supreme Court ruling in 2007 determined that CO2 is an air pollutant; this raises the possibility that CO2 will soon be regulated as such under the Clean Air Act. Some of the most relevant existing regulations are listed below:

- EPACT: Energy Policy Act (1992)
- EPACT: Energy Policy Act (2005)
- CAAA: Clean Air Act (1970, 1990) and National Ambient Air Quality Standards (NAAQS)

EPACT 2005: tax credits for the construction of coal-fired generation projects requisite on meeting efficiency and emissions targets. (International Energy Agency, 2006): According to the IEA, this leads to an increased share of IGCC and 'clean coal' projects, but may also have impact on traditional coal-fired plant designs and operation.

The recent legislation in the Energy Independence and Security Act of 2007 (EISA) will also have an impact on the design and operation of fossil-fuel fired power plants. EISA calls for increased efficiency of motors manufactured after December 19, 2010, for example.

Engineering Basic Standards

- IEEE 280: Standard Letter Symbols for Quantities Used in Electrical Science and Electrical Engineering
- ISO 15926: A meta-structure for information concerning engineering, construction and operation of production facilities.
- ISO 31: Quantities and units, International Organization for Standardization, 1992, now being superseded by the harmonized ISO/IEC 80000 standard.

Efficiency and Lifecycle Cost Calculations

Efficiency Calculations

Efficiency is a measure of how effective a system or component can convert input to output. Efficiency is normally given in units of percentage, or as a value from 0 (0 percent) to 1.0 (100 percent). Energy efficiency can be calculated using either energy (kW/h) or power (kW)

Efficiency percent = (Useful Power Out (kW) / Power In (kW)) x 100

Energy and Power Calculations

Energy must always be defined relative to a given time period or to a given volume, etc. The energy consumed by a system or components during a given time period is determined by multiplying its input power over a time period. The common term 'losses' means wasted energy. Losses can be treated as energy (kWh) in all the calculations in this section. The common term 'loads' means output power. Most energy calculations are based on a year's time, and a year is conventionally assumed to be only 8,000 hours to account for system downtime, when energy consumption is 0. (There are otherwise 8,760 hours in a full year.)

Annual energy consumption (kWhr) = 8,000 (hrs/year) x Power (kW)

Load Profile

In practice, power levels (or 'loads') are not constant, as assumed in the formula above. Loads vary over a given period due to changes in the process or ambient conditions. This variation is described by the component's 'load profile,' which describes the percentage of time (in hours per year) at each loading level (as a percentage of full load) as shown in the sample load profile below:

%	Hours	% of Full Load
5%	400	100
10%	800	90
15%	1200	80
20%	1600	70
20%	1600	60
15%	1200	50
10%	800	40
5%	400	30
0%	0	20
100%	**8,000 hrs**	**Weighted Avg 65**

A more accurate view of annual energy consumption for the above component's profile is the sum of the energies at each load level:

> Annual Energy (kWhr) = Σ (hrs) at load level(i) x (%) full load at load level(i) x full load (kW)

Duty cycle is similar to load profile, but is used to refer to shorter time periods (days or hours) and for cycling (on-off) loads, rather than more continuously variable loads.

Energy and Power Units

Energy has many forms and can be described using many units. The most common units and their conversion factors are given in the Appendix.

> 1 horsepower (hp) = 0.7457 kW = 2546 Btu/hr

Savings Calculations

Savings calculations are used to determine the difference in energy and cost between two components or systems.

By combining the formulas above, one can compare the annual savings of energy for two components or systems of varying efficiency E1(%) and E2(%). The result is an energy saving (Se) in kW per year (assume 8,000 hrs in absence of data):

> Annual Energy Savings (kWhr) = 0.746(kW/hp) x P(hp) x 8,000 x 100(%) x (1/E2 – 1/E1)

One can then multiply by the cost of energy (in $/Kwh) to determine the financial (or capitalized) cost of the annual energy savings calculated above, in $:

Annual Dollar Savings ($) = Se (kWh) x Q ($/kWh), where Q is the price per kWh of electricity

In these calculations the price (Q) of energy is assumed to be constant. In fact, energy prices may change as often as every 15 minutes in a de-regulated market, with much higher prices during peak periods. The average annual price of electricity shows a rising trend. See the section on present value for methods to account for this change.

Lifecycle Costing Methods

Life-cycle costing (LCC) is a method of calculating the cost of a system over its entire lifespan. LCC is calculated in the same way as 'total cost of ownership' (TCO). A technical accounting of systems costs includes initial costs, installation and commissioning costs, energy, operation, maintenance and repair costs as well as down time, environmental, decommissioning and disposal costs. These technical costs, for an example transformer, are listed below.

$$LCC = C_A + C_E + C_I + \sum_{0}^{n} (CP_M + CC_M + CO_P + CO_0 + CR) + C_D$$

where C_A = cost of apparatus
C_E = cost of erection
C_I = cost of infrastructure
CP_M = cost of planned maintenance
CC_M = cost of corrective maintenance
CO_P = cost of operation (load and no-load losses)
CR = cost of refurbishment or replacement
C_D = cost of disposal
n = years of operational life span

Additional, non-technical costs that should be accounted for in budgetary estimates include insurance premiums, taxes, and depreciation.

All costs in an LCC calculation should be discounted to present value (PV) dollars using the present value formulas in the following section. A very simplified LCC calculation with fewer terms considers only the cost of apparatus and the cost of operation, and does not consider inflation or variation in price of energy per kWh. The operational cost term in an LCC formula is typically the annual energy costs calculated using the formulas above, discounted to PV dollars. See the section **Motor System Calculations** for a numerical example.

For systems that directly emit carbon dioxide or other pollutants, the cost of operation should include remediation costs, and the taxes which authorities charge (or may charge) per unit of emissions. For electrical loads powered from a fossil-fuel-based source, the carbon dioxide amounts (in tons) are still relevant, but the carbon dioxide tax (in $) should not be added to that component's operational costs if the tax has already been factored into the price of the consumed electricity.

Carbon dioxide cost calculations

For coal-fired power plants, 1.3 tons of carbon dioxide is emitted per MW hour (C.P. Robie, P.A. Ireland, for EPRI, 1991). A conservative estimate for a future carbon dioxide tax is $25 per metric ton, globally and in the U.S. The tax may take many forms, ether as a direct tax or a traded quota, etc. A metric ton (1,000kg = 2240 lbs) is also written 'tonne.'

The energy and dollar savings calculations can now be applied, using the above data, to give a carbon dioxide (tons) saving and a carbon dioxide dollar savings ($) for reducing power from a fossil-fuel-based source:

> Annual carbon dioxide savings (tonnes) = 0.746(kW/hp) x P(hp) x 8,000 x 100(%) x (1/E2 – 1/E1) x 1,300
>
> Annual carbon dioxide tax savings ($) = $25/tonne x annual carbon dioxide savings (tonnes)

A rule of thumb for coal-fired plants: a 2 percent steam cycle efficiency improvement can reduce carbon dioxide emissions by up to 5 percent (Ferrer, 'Small-Buck Change Yields Big-Bang Gain,' 2007).

Limitations of LCC Methods

LCC analyses often count only single benefits, such as the electricity directly saved by a new motor's higher nameplate efficiency. In fact, there are numerous other benefits to reduce electricity consumption on the size and wear of upstream, power system components. Other benefits that are hard to quantify in LCC analysis include reduced maintenance via the elimination of the control valve, for example. In a detailed LCC calculation it is important to consider substitution cost.

Present Value Formulas

Most of the costs shown in the LCC calculation accrue in the future. These payments must be translated into present values using the time-value of money formulas given here.

Present value (PV) of a future amount (FV) at period ‘n’ in the future at ‘i’ interest rate is:

$PV = FV_n \times 1/(1 + i)^n$

Present value of a uniform series of payments, each of size US (for Uniform Series):

$PV_{us} = US \times ((1 + i)^n - 1)/i(1 + i)^n$

Where ‘i’ is the interest rate from 0-1 (for a 6% rate, i = 0.06)

The formula for PV of a uniform series can be used to determine the value of annual energy savings, where the annual cost is calculated as shown at the start of this section.

If the average annual price of electricity rises at p% per year, then the flat rate Q must be multiplied by the following rising price factor ‘f’:

$f = (q^n– 1) / (q – 1)$

Where: $q = 1 + p/100$
And p is the price increase in %

Using the formula for a 1 kW loss after 20 years shows an accumulated cost which is 41 times the cost of the first year if the average annual increase in the energy price is 7 percent (ABB Ltd,Transformers, 2007).

Payback Calculations

If the PV of the energy savings over ‘n’ periods (years) exceeds that of the investment cost (X), then the investment should be made. The number of periods required for PV to equal X is the ‘payback’ period. For a given value of X, therefore, the payback period ‘n’ can be calculated.

The monetary value of energy losses, called the capitalized loss value, is defined as the maximum amount of money the user is willing to invest to invest to reduce losses by 1 kW.

Levelized Cost Calculations

For non-uniform payments, use the levelized cost (LC) method to determine the levelized amount. This method simply uses the PV formula on each amount to determine the total PV of the stream, then applies the inverse of the PVus formula to determine a levelized amount for each period. To evaluate projects, one can use either the total PV or the LC method. Both will reach the same conclusion, except that the LC shows a comparison by period. In evaluating energy efficiency project alternatives, it may be useful to calculate the ‘capital equivalent cost’ (CEC). The

CEC is found by adding the capital cost to the PV of all the operating costs over the unit's lifetime. This calculation provides a sound basis for comparing bids.

Limitations of PV Methods

Present value methods make assumptions regarding lifetime (number of periods 'n') and discount (interest) rate 'i' which have a large impact on the calculated value. In evaluating energy efficiency projects or components, the conventional assumptions tend to undervalue the savings. High-quality, high efficiency motors, for example, may have a longer lifespan ('n') than standard motors. Also, the lower risk of energy efficiency projects should be reflected in a lower discount rate, especially in common comparisons with new capacity. This comparison is between 'negawatts' (energy efficiency) and Megawatts (new capacity).

Plant Heat Rate Calculations

In power plants, efficiency is often expressed as 'heat rate,' which is the amount of energy generated (kWh) per unit of fuel heating value (Btu = British Thermal Units).

Energy Value: 1kWh= 3414.4 Btu = 3.6 MJ

For a plant with Net Plant Heat Rate of 10,000 Btu/kWh (10.54 MJ/kWh), then the thermal efficiency = 34.14 percent.

Note that heat rate is the inverse of efficiency; a reduction in heat rate is an improvement in efficiency. Sub-critical steam plants use the fuel's higher heating value (HHV) as basis for heat rate and efficiency calculations, whether the fuel is coal, oil, or gas. Combined-cycle gas turbine plants are usually evaluated on the basis of the lower heating value (LHV) of their fuel. This can lead to the differences in apparent efficiency being somewhat greater than they actually are (Eng-tips.com, Fowler, 2006).

Coals vary considerably in their composition, which determines their heating value and carbon dioxide emissions during combustion. A typical coal has a heating value of about 8,000 Btu/pound, a carbon content of about 48 percent by weight and a moisture content of about 20 percent by weight and is combusted with up to 10 percent excess combustion air.

The ASME performance test codes 6 and 6A for steam turbines describe the method to determine steam turbine efficiency in existing plants. Whole plant international test codes are ASME PTC 46 and ISO 2314.

Energy Accounting for Reliability

Reliability Concepts

The methods and terminology in this section are common to the field of quantitative reliability analysis. Reliability (R) is the probability that a unit is still operational after one year, based on the unit's mean time between failure (MTBF) specification. Reliability is expressed as failure rate on per year basis.

$R = e^{(-8760hr/MTBF)}$

Availability (A) of a unit can be calculated as:

A = MTBF / (MTBF + MTTR)

Where:

MTTR = mean time to repair

Energy Cost of Plant Trips

The total cost of a plant trip is composed of many parts, including opportunity cost of lost power sales, cost of substitute purchased power, ISO fines, trip-induced repairs, and energy.

The energy wasted per year due to trip events is therefore R multiplied by energy wasted during startup/shutdown procedures (R x Ess). The wasted energy due to a complete shutdown and cold restart (Ess) is composed of two parts:

E(shutdown energy) + E(startup energy) =Ess

Where:

E(startup energy) = hours duration of startup x energy input/hr
E(shutdown energy) = rotational energy in all machinery + chemical energy in process lines

E for shutdown is more difficult to measure and calculate. As a rough estimation, therefore, E shutdown is assumed to be ¾ of the E startup. So ultimately, the annual energy costs of plant trips :

R x Ess = R x 1.75 x hours duration of startup x energy input (MMBtu)/hr x Energy price ($/MMBtu)

Module 2
Drive Power Systems

To the optimist, the glass is half full.
To the pessimist, the glass is half empty.
To the efficiency engineer, the glass is twice as big as it needs to be.

Module Summary

This module describes the impact of design and engineering on the energy-efficiency performance of auxiliary drive power systems; motors, fans & pump systems, and variable speed drives.

The information in this module may be generally applied to process industries; industry-specific text is indented with a rule above and below as shown here.

This section examines drive power systems from an energy efficiency perspective only and does not provide guidance on critical aspects of drive power engineering such as safety interlocking or fault-tolerant design. See the **References** and **Standards** sections for more complete guidance on all other aspects of drive power design & engineering.

Introduction to Drive Power

Drive power is the combination of a prime mover, such as an electric motor, a coupling, and a speed controller that drives the shaft load of the final element, such as a pump, which puts power into an industrial process. Pump, fan and compressor systems are so-called ‘cube-law’ applications because their power requirements increase as the third power of their speed. A pump or fan running at half speed consumes only one-eighth of the energy compared to one running at full speed. These ‘cube-law’ systems represent more than half of all industrial motor applications and electrical consumption. The focus in this handbook is on large drive power requirements (200 hp (150 kW) or greater) involving pumps and fans. The prime mover for the vast majority of drive power systems are electric motors, so these will also be examined in detail.

This handbook takes an integrative design approach that considers the entire drive power system from energy input to its end-use on the fluid or gas of the process, as shown in the figure below:

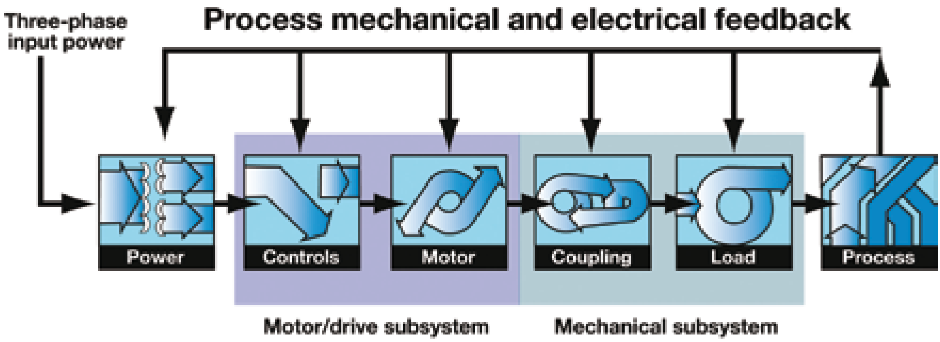


Figure 2.1 – Schematic of an entire drivepower system (Plant Engineering 10/1/2000)

Role of Drive Power in Energy Efficiency

Pumping represents the world's largest use of electric motors, and fans are in second place. Taken together, these two applications account for half of all motors in use. Pumping systems alone account for nearly 20% of all energy used by electric motors (US DoE, 2008).

A large motor, running constantly, uses its capital cost in electricity every few weeks; this explains why more than 90% of the total cost of pump ownership (TCO) is energy consumption. Every one percent improvement in a continuous-duty induction motor system has a present value of $70/kW, assuming a 5%/yr real discount rate for 20 yrs, $0.05/Kwh, no reactive losses, heating or demand charges (Lovins, 2008).

Potential for Energy Efficiency

Two leading energy research institutions, RMI (1989) and EPRI (1990), found that half of all typical industrial motor-system energy could be saved by retrofits, paying back their initial investment in about 16 months, and in much less time at today's higher energy prices. In other studies, ABB (2005) found that pump energy consumption could typically be reduced by up to 20% using well-proven technologies.

Where is the wasted energy in industrial fan & pumping systems that allows such large savings?

- Oversized and under-loaded motors.
- Inefficient motors and couplings.
- Inefficient applications, especially those which use throttling for flow control.
- Equipment running unnecessarily, or for unnecessarily long hours, such as stirrers on empty tanks, deadheading pumps, and ventilation fans running continuously.

This handbook module offers design and engineering guidelines that may help prevent some of this energy waste in new and retrofitted power plants and industrial process applications.

Auxiliary drive power is used in a variety of applications in a steam generating plant, from coal conveyors, grinders and pulverizers to furnace draft fans, condensate and feed water pumps (when electrically driven), circulating water pumps, and various emission control equipment. The table below shows estimates of some major auxiliary drive power loads as % of gross generation:

Electrically driven boiler feed pump	2.5% (Goodall, 1981)
Draft fans and pulverizers	2.0% (Juniper and Pohl, 1996)
Flue gas desulphurization (FGD)	1.5% (IEA Coal Online - 2, 2007)
Remaining auxiliaries	1.5% (IEA Coal Online - 2, 2007)

A more complete list of drive power consumers found in fossil-fuel steam power plants:

Boiler feed water pumping:
- feed water pumps
- feed water booster pumps
- boiler recirculating pumps

Condensate and coolant pumps and fans
- condensate or hot well pumps
- condensate booster pumps
- circulating water pumps
- cooling tower pumps and fans

Furnace draft and combustion air fans
- primary air (PA) fans
- forced draft (FD) fans
- induced draft (ID) fans

Fuel handling drive power
- drive power for conveyors, coal mills & pulverizers
- ash handling pumps
- fuel gas booster compressors (for GT plants)

Emissions control drive power (for flue gas desulphurization, catalytic reduction etc.)
- flue gas ID booster fans

- limestone slurry-feed and absorbent circulation pumps
- oxidation air compressors

Gas turbine (GT) power plants-specific drive power
- GT starter motors
- boiler (HRSG) feed-water pumps

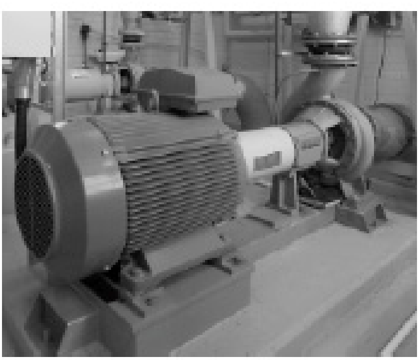
Utility systems drive power
- soot blower pumps, air compressors
- service water pumps
- compressors for instrument & service air
- Oil lubrication pumps for large rotating machinery
- HVAC fans and air heating/cooling loads

Pump Systems

An entire pumping system is a network of fluid handling components such as pumps, valves, pipes and tanks. The purpose of the pumping system is to provide a certain flow and pressure to the fluid needed by the process unit.

Pump Types and Concepts

There are many different pump types, but two basic categories are 1) kinetic and 2) positive displacement. Positive displacement pumps are more suitable for constant flow applications. Where there is flow variation, then kinetic pumps like the centrifugal (also known as rotodynamic) and axial flow (also known as turbine type) pumps discussed in this section, are more suitable. See the **References** section for sources of information on other pump types, applications and standards.



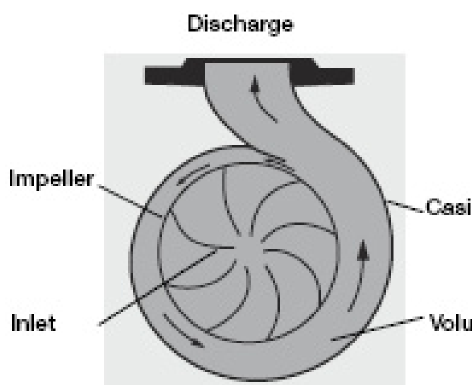


Figure 2.2 - Centrifugal pump system and internal design, ABB Drives, 2005

In a centrifugal pump, the fluid enters the pump at the impeller eye, the center of the pump. This is the 'suction' part of the pump. The rotating impeller imparts velocity (kinetic energy) to the fluid as it is accelerated along the impeller blades and squeezed through the narrow volute, at right angle to its line of entry. As the volute cross-section area increases, the fluid velocity decreases and a higher pressure (head) develops towards the discharge end of the pump.

In an axial pump, the fluid is accelerated by the action of a propeller and moves parallel to the axis or shaft of the pump. In mixed flow pumps, the impeller uses both radial and axial motion to accelerate the fluid along a path that exits the pump at an angle with the pump axis or shaft.

Pump Characteristics

The performance of the pump is given by pump curves, which show how much pressure (Head) can be developed at various flow rates (capacities) at a given speed. Note that Head (H) has units of length (ft.) but is actually a measure of a fluid's energy per unit weight. The distance refers to the height that a column of the fluid could support under gravity. A useful approximate conversion formula between Head and psi is:

$H\ (ft) = (\ H\ (psi) \times 2.31\ )\ /\ Sp$ Sp =1 (for water, approximately)

$H\ (m) = (H\ (kp) \times 9.8)\ /\ Sp$

The head of a fluid has four components:

- Static head, which is independent of flow, increases with vertical height above the pump centerline and is negative for heights below the pump.
- Pressure head, which is due to other forces such as backpressure in a closed tank, and is also independent of flow.
- Friction head, which is due to resistance in elements such as pipes, valves & fittings, and increases with flow.
- Dynamic head, which is a function of the velocity of the fluid, and is given by :

$$H_v = V^2 / 2g.$$

Where:

H_v = velocity head (ft or m)

V = fluid velocity (ft/s or m/s)

g = acceleration due to gravity (32.2 ft/s^2 or 9.8 m/s^2)

Note that the dynamic head is usually rather small and may be ignored in most pumping applications.

Axial-flow pump performance curves are steep, meaning that they can deliver nearly constant flow over a wide range of pressure. Centrifugal pump curves are much flatter, meaning that they can provide a range of flows over a relatively narrow pressure range.

Power Plant Pump Applications:
In a power plant, the circulating pump supplies cooling water at large flow rate and low head to the condenser for heat exchange. Condensate (also known as hotwell) pumps are medium flow, medium head pumps which move the condensed steam from the condenser, through feedwater heat exchangers, to the de-aerator tank. The boiler feedwater booster pump moves water from the de-aerator to the man boiler feedwater pump, which supplies water at high pressure to the steam generator (boiler).

Circulating water pumps:
Circulating pumps are usually mixed flow pumps, with axial designs being used for very low head applications. Note that although dynamic (velocity) head is typically ignored in most pump applications, it is a significant factor in low head, high capacity systems such as the plant cooling water-circulating system. Typical flow rates for circulating water pumps are between 0.35gpm and 0.75gpm per generated kW. (GE Utility Division 1983)

Condensate pumps:
Condensate pumps are usually 2-stage pumps that operate with a high vacuum on the inlet. The discharge pressure must be sufficient to overcome the friction in the piping and low-pressure feed-water heaters, and any static lift required to pump the condensate to the level of the low-pressure feed-water heaters. (Homer M. Rustebakke, GE Utility Division, 1983).Typical power required by condensate pumps is on the order of 3hp per MW of generating capacity

Boiler feedwater (BFW) pumps:
Boiler feedwater (BFW) pumps are usually multi-stage, volute type centrifugal pumps. Typical boiler feed pump power requirements are about 10,000hp (7500kW) for a 300MW plant, then increase by 3300hp (2500kW) for every 100MW (Homer M. Rustebakke, GE Utility Division, 1983). The head of boiler feed pump depends upon the boiler load and thus steam pressure, which varies with plant loading. On large units, there is still usually a feed water control valve for filling and very low load, with pump speed taking over as load rises past some threshold (ISA 2005). Feed-water pumps are characterized by high reliability requirements and fairly high dynamics during plant load changes.

They normally make the biggest contribution to the plant's in-house energy consumption. Another estimate for boiler-feedwater pump consumption is around 15 MWe on a 600 MWe plant, or around 2.5% of gross power (Goodall, 1981).

Total Developed Head

From the perspective of the pump, the process unit is a load that is a combination of pressure, static and friction heads. These latter two exist on the inlet and discharge sides of the pump. On the suction (inlet) side, the pump must 'lift' the fluid if it is coming from a lower elevation and overcome any friction pressure drops through the inlet, together called the Total Suction Head. On the discharge side, the pump must 'push' the fluid against system's static head, pressure and friction pressure drops, together called the Total Discharge Head. The pump(s) must develop enough pressure (head) to meet the combined effect of these energies when delivering the required flow. An important design criterion for any pump is therefore the Total Developed Head (TDH):

TDH = Total Discharge Head – Total Suction Head

Pump Net Positive Suction Head

On the suction side, the system must also provide sufficient suction head so that the pump does not cavitate. Cavitation is a low-pressure phenomenon that reduces performance and may lead to pump damage. Sufficient suction head is called NPSHA (Net Positive Suction Head Available) and designers must compare this with the pumps characteristic curve for NPSHR (Net Positive Suction Head Required) provided by the supplier.

In power plants, the typical margins over this published NPSHR values may run from 50% to100% for a complex boiler feedwater (BFW) system with transient suction condition operations. Particular attention to NPSH margin should be given to boiler feedwater system where load rejection and system transients are expected, (Black & Veatch, 1996)

The suction requirements of BFW pumps are sometimes met by specifying a lower-head booster pump upstream of the main BFW pump.

Pump System Load Curves

The typical load curve shows a system with fixed static and pressure head as well as friction that increases exponentially with flow. Systems without any static or pressure head have curves starting at the zero point. Systems with high friction have steeper curves. Systems with low friction but high flow requirement will have flatter curves. The figure below shows the pump curve for a typical centrifugal pump as well as the system load curve for the head and flow it must deliver. The pump will operate at the values of head and flow where the two curves intersect, known as the operating point, where supply meets demand.

- If two pumps operate in parallel, their pump curves are added horizontally, giving a single equivalent pump curve with higher capacity, but with heads the same as one of the pumps operating singly.
- If two pumps operate in series, then their characteristic curves are summed vertically, to give a single equivalent pump curve with higher heads, but capacities the same as one of the pumps operating singly.

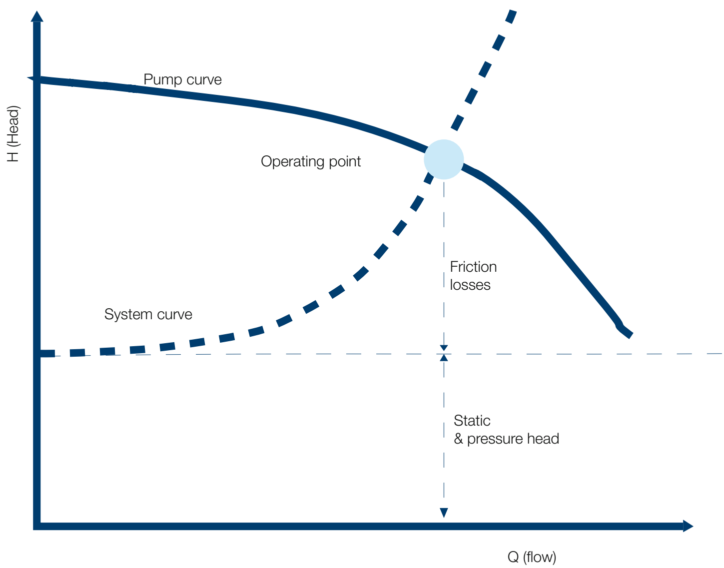


Figure 2.3 – Pump head vs. flow performance and system curves

Pump Power and Energy Efficiency

Pump output power (water horsepower: WHP) to the fluid is given by:

WHP = (Q x H x Sp) / 3960 kW = (Q x H x Sp) / 6128

Where:

Q	= capacity: in GPM (Gallons Per Minute)	(l/min)
H	= total developed head (ft)	(m)

Sp = specific gravity (density) of the pumped fluid (water = 1)

Pump input power required (also known as Brake Horsepower: (BHP) is the water horsepower divided by the pump efficiency: Eff

BHP = WHP / Eff   Motor Power = kW/η (η = EFF)

For estimation of efficiency (using SI units) in centrifugal pumps with developed head (H) between 15 to 100m water and flowrate (Q) between 20 and 300 cu.m/hr one can use the following pump model (Rajan 2003) which has a standard error of about 1%:

$$\text{Eff }(\%) = 65.08 \times H^{-0.12446} \times Q^{0.094734}$$

Affinity Laws

Pumps of similar design but different impeller sizes can be compared by using the pump affinity laws. These affinity laws (see below) below describe the relation between the rotational speeds of the pump (n), flow rate (Q), head generated (H) and power absorbed (P) by the fluid:

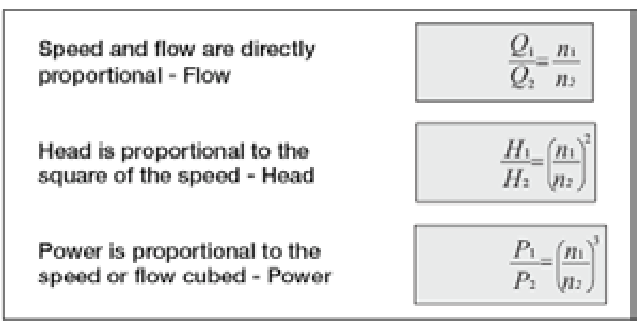


Figure 2.4 – Pump affinity laws, (ABB Oy. Drives, 2006)

For a given speed, a pump curve has an operating point where efficiency is maximum, referred to as the Best Efficiency Point (BEP). The region of high efficiency close to the BEP is called the 'bullseye'. Designers strive to make this the actual operating range for the system, as this will reduce both energy and maintenance costs. When the operating point moves away from the BEP , then relatively more brake horsepower (input power) is required per unit water horsepower output.

Losses and Efficiency

The main losses within a centrifugal pump are due to: circulation within the casing (decreases with flow), shock losses, and friction loss (Rajan 2003). The friction loss varies with the square of flowrate and is the largest loss component when the pump is operating at higher loads. The effect of these losses is revealed in the efficiency vs. flow curve supplied by the pump manufacturer. Older pumps may suffer from impeller wear, **internal leakage** and bearing losses as well, and should be continuously monitored for performance degradation.

The difference between input and output power is mostly lost as heat energy to the fluid. In the minority of applications which call for heating of the fluid anyway, engineers should resist the temptation to include this effect to justify less efficient pumps or designs. Pumps operating far from their BEP will experience greater bearing and other mechanical stresses which lead to increased maintenance costs and downtime. In such applications, it is better to let heat exchangers do the job for which they were designed.

The affinity laws explain the shape and distribution of the family of pump curves which show pump head vs. flow at different pump speeds, where each curve shows pump performance at a given speed. These curves are shown in the figure below, together with the lines of constant efficiency, also determined by the Affinity Laws for pumps.

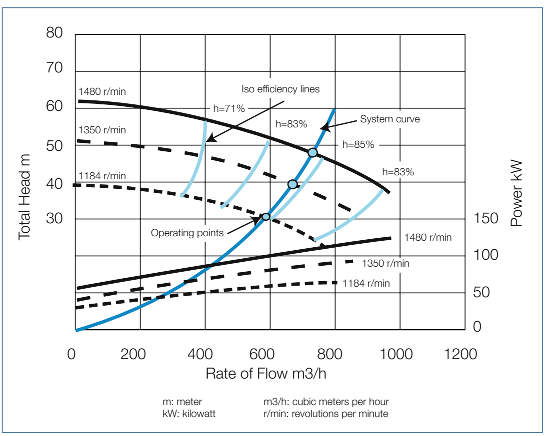


Figure 2.5 – Variable speed pump performance curves, (US DoE Sourcebook, 2006)

Due to the similarity of the efficiency and system curves, there is little loss of efficiency when a pump operates at lower rotational speed. The new operating point is still in the pump efficiency bullseye, its ideal operating region for that speed. Pump efficiency curves at the BEP do not change significantly with pump speed within the family of pump performance curves. When speed is reduced by half of the rated speed, pump efficiency at the new speed's BEP may only be reduced by 3%, for example. Pump efficiency is relatively unchanged, but the decrease in power consumption at the lower pump speed is substantial.

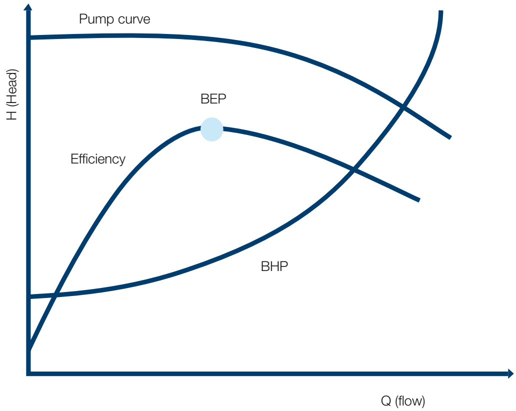


Figure 2.6 – Pump power and efficiency curves

Recall that pumps and fans are 'cube-law' applications because their power consumption varies with the cube of the speed of the pump or fan.

- This relationship yields large power savings even from modest speed reductions, and favors designs that seek to reduce speed, such as using Variable Speed Drives (VSDs). See section on **Pump Flow Control Methods**.
- The cube law also strongly favors selecting the right size of pump for the operating conditions. See section on **Pump System Design & Engineering** for guidelines on correct pump sizing.

Designers can also benefit from selecting high efficiency pumps, which are generally 4% to 7% more efficient and may cost little or no more than standard efficiency pumps. Using a lifecycle approach, super-efficient pumps are even more cost effective. Efficiency varies widely with pump type and flow range; according to the Hydraulic Institute, the pump efficiency of 'large' single-stage end-suction pumps operating at their BEP and at flow rates in the 100 cu.m/h range is 81%.

Pump Flow Control Methods

Some of this section is adapted from the application guide: 'Using Variable Speed Drives in Pump Applications' (ABB Oy. Drives, 2006)

The process system will usually require variable flow rates from the pump. There are four common methods to control the output of a pumping system: Throttling, Bypassing, On-Off, and Variable speed control, as shown in the figure below. Variable speed control may be achieved by motor frequency modulation using a **Variable Frequency Drive**, or by using **gears and hydraulic couplings**.

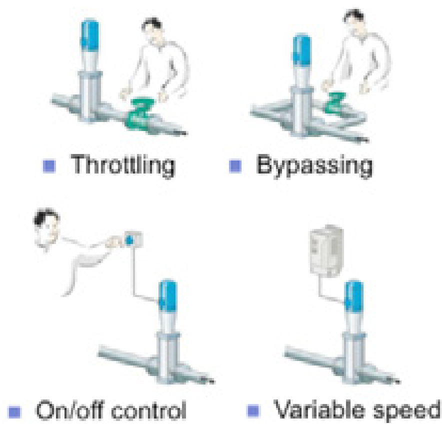


Figure 2.7 - Common flow control methods, (ABB Oy) Drives, 2006)

The relative power consumption of the different control methods can be estimated from the area between the x and y-axes and the operating point on a pressure-flow curve as shown in the figure below. This comparison is based on the formula for pump power (P): flow x head (P=Q x H). In the example shown, the relative power consumption for an average flow rate of 70% (of full flow) is calculated using typical values for the different flow control methods.

Throttling

Flow control can be achieved by modulating a valve immediately downstream from the pump. Throttling effectively changes the process system curve seen by the pump: the valve introduces friction into the system; this makes the system curve steeper so that it intersects the pump curve at the lower, desired flow rate, as shown in the top left chart in the figure below. In this example, the operating point is moved from (Q = 10, H = 10) to (Q = 7, H = 12.7). The relative power consumption can be calculated by P = 7 x 12.7 = 89.

This method has low capital costs, but throttled systems waste energy in two main ways: pressure drop across the valve, and because at reduced capacity the pump performs below its optimum efficiency point.

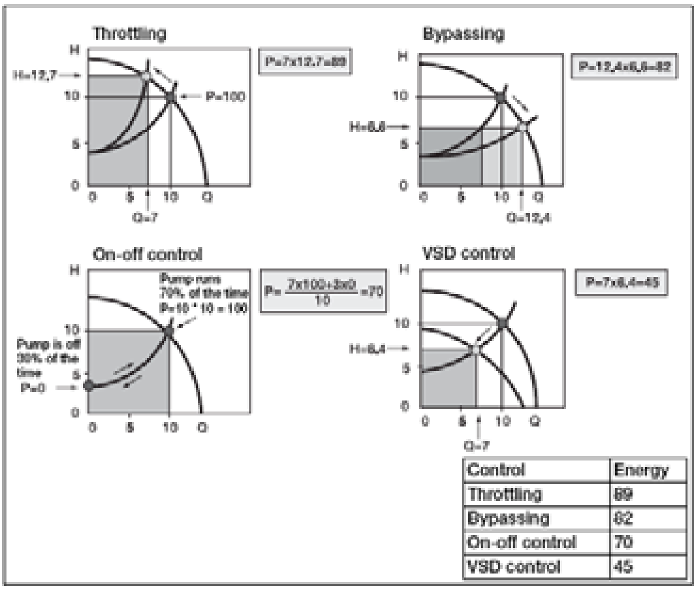


Figure 2.8 - Energy efficiency impact of various flow control methods, (ABB Oy. Drives, 2006)

In power plants, excess pump and throttling energy is not entirely wasted in applications that call for heating of the fluid anyway; as is the case in boiler feedwater regenerative heating. There are three reasons to avoid using such indirect heating to justify continued use of throttling control:

- Higher maintenance costs of the pump operating far from its BEP
- A highly-oversized valve will operate in a nearly closed state, which is not stable. This situation arises in constant speed pumping systems where each layer of engineering bureaucracy adds its own safety margin in calculating pressure drops through pipes, heat exchangers etc. and then, finally, in selecting the pumps. The control valve ends up with all these safety margins, as added pressure drops. (Liptak, 2005)

– Most importantly, for high pressure systems such as power plant boiler feedwater, is the severe wear on valve components from throttling at 2,400 psig (16.5 MPa) (Black & Veatch, 1996)

Bypassing

Although not commonly used for flow control, bypassing (also known as "recirculation") is applied mainly to circulation duty pumps. The flow output to the system is reduced by bypassing part of the pump discharge flow to the pump suction. Flow through the bypass system is controlled by valves. This means that the total flow increases (from 10 to 12.4), but the head decreases (from 10 to 6.6). The relative power consumption is P = 12.4 x 6.6 = 82.

A 'minimum flow' recirculation system is sometimes necessary if the pump operates for extended periods at low flow rates, when the pressure is too low to induce adequate flow into the system. Recirculating flow wastes energy and should therefore be kept to a minimum. Automatic modulating control of the recirculating flow system will ensure that that the recirculation flow control valve only opens when measured pump flow drops below a certain minimum threshold. Recirculating systems are sometimes required on systems equipped with variable speed flow control to guard against low flow conditions. The drive logic of a VFD speed controller may also be programmed to warn operators and to shut off the pump in these cases.

In power plants, this type of pump control may be used in boiler feed and condensate pumping systems to provide flow control and to prevent overheating of the pump at low flow rates. (Black & Veatch, 1996)

Another reason why designers may add a recirculating flow loop is to keep the pump at a higher state of readiness for increased demand. An improved design may make use of any existing, smaller and more responsive startup pump instead of a recirculation loop.

On-Off Control

On-off control is often used where stepless control is not necessary, such as keeping the pressure in a tank between preset limits; in these applications, the pump is either running or stopped. The average flow is the relationship between the 'on' time and the 'total' time, on plus off. The relative power consumption can then be easily calculated by P = 0.7 x 100 = 70.

Variable Speed Control

The Best Efficiency Points (BEPs), when plotted for each pump curve, follow a quadratic shape that is in accordance with the affinity laws; pressure ratios are proportional to the square of flow ratios. In low static head, mostly friction systems, the system curve has approximately the same quadratic shape as the pump's best efficiency curve. By varying the speed, therefore, the operating point can be made to follow the unchanged system curve along a line which is close to the BEP line. If the pump impeller speed is reduced, the pump curve moves downwards. If the speed is increased, then it moves upwards. This relationship ensures that the pumping capacity is exactly matched to the process requirements.

According to the earlier example, both flow rate (from 10 to 7) and head (from 10 to 6.4) are reduced at the new operating point. The relative power consumption can be calculated by P = 7 x 6.4 = 45. This simple example shows that the variable speed control method is the most energy efficient for pumping applications.

The examples were calculated for one flow rate only (70%), but the relative power consumption with different control methods depends on the flow rate. This relationship is shown in the figure below. In these curves, the pump, motor and drive efficiencies are also taken into account and for that reason the results differ somewhat to those in the previous similar figure.

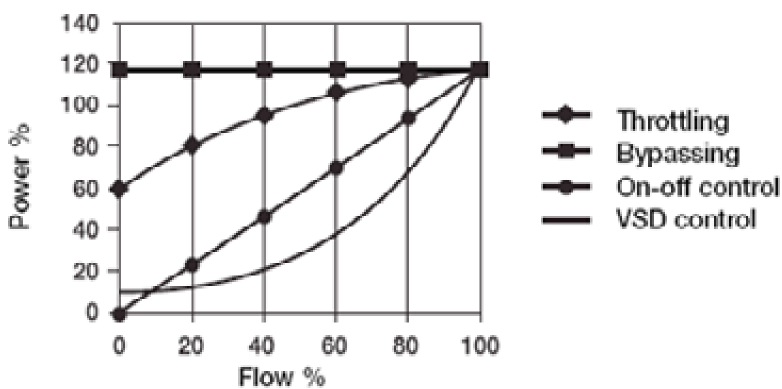


Figure 2.9 - Energy efficiency impact of various flow control methods, (ABB Oy. Drives, 2006)

In power plants, boiler feedwater (BFW) pumps are driven by one or more, or combinations of: squirrel cage induction motor, synchronous motor, mechanical drive steam turbines, or gear drive from main shaft of turbine. Traditionally, pump drivers have been selected focusing on reliability at the expense of efficiency due to their critical role in the steam cycle. Ref ABB Drives. There have been several studies (Black & Veatch 1996, EPRI 1995, ABB 2008) to compare the different options for pump drivers (prime movers) on base-loaded pulverized coal steam power plans, and the effect on net plant heat rate.

In all studies the option with a constant speed motor-driven BFW pump using throttle valve control is the least efficient, wasting significant energy at loads <100% throttle flows. The two basic options involving speed control are slip-type adjustable speed drives and non-slip VFD drives.

In all options except the VFD there is likely a need for mechanical reducing gear if the pump has a design speed greater than the motor rated speed. Reducing gears are efficient, but still lose up to 1.5% of the input shaft power. For an 8MW pump, this loss represents almost 1GWh lost per year.

In all studies, the VFD option to vary motor output speed achieved better net turbine heat rate and better turbine output at all throttle flows when compared with speed control via slip-type hydraulic coupling. (Black & Veatch, 1996)

A third option is the steam turbine-driven feed pump. This pump is driven by a condensing turbine that takes steam extracted from the IP/LP turbine and exhausts to the main condenser. The disadvantages of this type of drive arrangement are the extra valving and piping, plus added complexity in startup, requiring an additional startup electrical motor. The VFD alternative's output does not directly depend on the available steam flows, which vary with loading and season.

In the comparison between the different drivers, a slightly better heat rate is achieved with the turbine driven alternative. At the cost of more valve and piping complexity, the turbine exhaust may be used in feedwater regenerative heating, further enhancing the viability of this alternative.

Still another design option, found in some older plants, is a main turbine shaft drive. These require variable speed coupling for speed control and gears, plus an additional startup electrical motor. (Homer M. Rustebakke, GE Utility Division, 1983). The added complexity and lower reliability has made this design less common on newer plants.

A comparison of the above four BFWP drive alternatives was done for a 500MW unit with 2 x 50% capacity BFPs in parallel (Black & Veatch 1996). The comparison was done at 3 different load rates: 100, 75 and 50% throttle flow and considers net turbine heat rate (NTHR) and electrical output (NTO). In that comparison, the VFD alternative offers better NTHR and NTO than the hydraulic coupling alternative, at all throttle flows. At 50% load, the throttle alternative has bhp=14,459 (10.8 MW) whereas the VFD alternative has bhp= 9,185 (6.9 MW).

This difference is a substantial 36% improvement, representing a net reduction of 3.9 MW continuous power consumption.

High Static Head or High Pressure Systems

In high static head or high pressure systems, the system curve is more horizontal than vertical. Referring to the family of pump speed curves, a lower pump speed intersects the system curve at a point of much lower flow and efficiency, which has these consequences:

- The required speed reductions are smaller, and so are the power savings, in high head systems.
- The efficiencies are lower at lower speeds; this further reduces the power savings from the above speed reduction.
- The lower speed pump curves may not form a well-defined operating point with the flatter system curve, leading to large changes in flow for small changes in speed and hence a more challenging flow control task.

Despite the reduced savings compared to mostly frictional systems, pump speed control in this case is still more economical than throttling the flow with a control valve. The added mechanical stresses on pump, motor and valve also favor speed control even in this case.

A compromise design of high-static head systems combines one constant speed pump and one speed-controlled pump. The constant speed pump overcomes the high static head, and the VSD-equipped pump provides the additional, variable capacity. According to the ISA, the use of only one VSD-equipped pump is the right selection if the static head of the system is between 50% and 67% of the pump's TDH.

Case Example
Helsinki Energy, Finland

Helsinki Energy is one of the leading experts in the world in the field of Combined Heat and Power (CHP) technology and one of the biggest energy companies producing and distributing electricity and district heat in Finland. Helsinki Energy's Hanasaari B power plant is located by the seaside in the city of Helsinki and has a capacity of 220 MW for electricity and 445 MW for district heating. The power plant's efficiency is 85%. In 1990 Helsinki Energy was granted the UN International Environmental Award for its pioneering and determined work in developing CHP technology and the consequent improvement of the city's air quality.

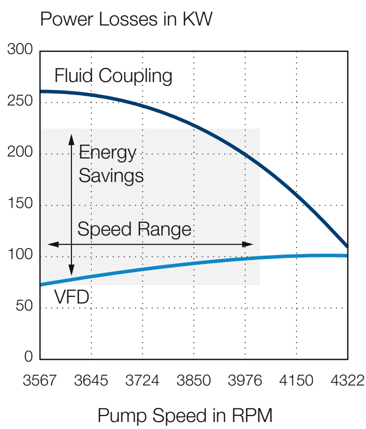

Originally, the Hanasaari power plant's equipment was selected among the best available technologies at the time of construction to fulfill the requirements of high availability and efficiency. However, since the time of construction, variable speed drive technology had taken a big leap forward. Even though the old ASEA and Strömberg wound-rotor motors with slip recovery control systems operated very well, Helsinki Energy decided to upgrade them in order to reduce maintenance work and to further improve the plant's efficiency. Given the efficiency problem of boiler feedwater pumps driven by fixed speed motors at partial loads, the most economic control is achieved with a variable speed drive system. The boiler feed-water pump is rated at 4500 kW (6050 hp).

In the spring of 1999, Helsinki Energy ordered from ABB four water-cooled ACS 1000 drive systems with AMB 560 motors and oil-immersed 3-winding supply transformers. The Hanasaari B power plant's automation upgrade project was executed together with Helsinki Energy's Helen Engineering that specializes in the design of energy production and distribution equipment as well as in the related project management. The aim of these design and construction services is to support the profitability of business operations throughout the life cycle of the equipment.

Boiler feed-water pumps are one of the biggest energy consumers in a power plant. Operating feedwater pumps with variable speed drives can significantly increase the efficiency of a power plant. Outside the boiler feed-water pump's nominal range, the capacity needs to be sufficient to handle rare but possible abnormal situations in a boiler that operates under very high pressure. Depending on the local authorities' requirements, the pump, and the supplying drive, must be capable of delivering 10-25 % over pressure or overflow. As a consequence, the drive operates practically all the time under partial load, a situation where a variable speed drive offers the best available efficiency.

Using ACS1000 variable speed drives as level control devices for feedwater drums can reduce maintenance of the feedwater throttling valves. These haven't necessarily been designed for the full pressure differential resulting from throttling the flow with fixed speed motors. Further savings can be achieved by designing a new generating unit's electricity distribution network for feedwater pumps operated by Variable Frequency Drives. As main loads, their across-the-line starting behavior typically impacts on - depending on impedance of the plant transformer- capital cost, either through a more expensive transformer, through higher fault currents, or a more expensive switchboard. Variable speed drives as such act as soft starters and cause no starting current peaks. The ACS1000 can be connected via the most common fieldbuses to become an integral part of the plant's control system. Original case text from ABB Switzerland , MV Drives, 2008.

Case Example



A European power plant was comparing fluid coupling with AC drive for its feed pump (1,450 kW) control. The comparison shows that within the speed range needed, the AC drive consumed about 150 kW less than the fluid drive.

- Energy saving: about 1,200,000 kWh/year
- Reduction in CO2 emissions: 600,000 kg/year (660 tons)
- Reduced reactive power
- Reduced stress to the supply
- Reduced need for maintenance

Case text provided by: (ABB Oy. Drives, 2006)

Pump System Pipes, Valves and Fittings

Pipes, valves and fittings serve to direct and control the flow, but all of these components can introduce extra friction that requires more input power. Many references exist on how to reduce friction in pump systems. In this section, only the energy efficiency impact of piping elements are discussed.

Valves

There are many types of valves, and these have varying degrees of resistance to flow. Wide-open friction is 25 to 35% larger for globe valves (which are common in throttling applications) when compared to ball or gate type valves. Further reductions in friction can also be achieved by optimizing pipe layout such that redundant and 3-way valves may be eliminated. The case for eliminating control valves for flow control is made in the **Flow Control** section in this module. A close look at all fittings and valves to eliminate unnecessary flow restrictions is worthwhile from a lifecycle energy perspective.

Pipes & Fittings

Friction in pipes is related to:

- Pipe diameter and length
- Internal smoothness of the pipe
- Pipe layout with regard to bends, elbows and size changes.

Friction is proportional to almost the fifth power of the diameter. Lifecycle costing may reveal that very large pipes are the most economical choice, even when the high price of steel is considered. It is important to include the capital cost of pumping power in such a calculation, as smaller pumps and motors are the reward for reducing downstream friction.

Pipe wall roughness also increases friction. If application standards and materials allow, then a ‘smooth pipe’ design should be lifecycle cost estimated and then compared to the standard design. Pipe layout, which is typically done after equipment layout, may have sharp bends and elbows that increase the friction in the system. Short, straight, fat pipes not only reduce friction and upstream pumping costs, but have lower capital cost. The potential for energy efficiency through improved piping engineering is often limited by project phase considerations and even by the design tools that engineers use. Popular pipe layout design software packages may not even be capable of optimizing layout according to the criteria discussed here; such computer aided engineering (CAE) tools are indispensable on all but the smallest projects. RMI found that manual review of one automatic layout reduced the number of elbows from 28 to only 3 (Lovins,A, 17/72008)

Taken together, all the above effects make the efficiency of an average length industrial, rough-walled, average diameter pipe typically about 69% (deAlmeida, 2006). Using low friction piping techniques can increase the efficiency of piping to 90%.

In power plants, steam temperature is controlled by attemperation, which involves spraying feedwater into the superheated steam. In designs that take the water from the economizer inlet, throttling of the main feedwater flow path may be required to ensure adequate pressure drop & flow thru the attemperation line.

Around 2–5% of the main flow may be diverted for attemperation of the superheated and reheated steam, so the pumping power wasted across this throttle valve is significant.

Pump System Design & Engineering

The pump (or fan) sizing and selection process generally follows this sequence:

- Gather data on the system flow configuration : from PFDs
  - Flow paths (i.e.: single, parallel or serial configurations)
  - Liquid specification with density, temperature etc.

- Gather data on the general piping layout; from rough P&IDs
  - Pipe run lengths
  - Vertical head changes
  - Valves and other fittings

- Determine the basic output hydraulic requirements
  - Required flow (capacity) with variation ranges for average AND peak flows. Flows are determined by process requirements and flow paths from step 1)
  - Calculate or measure the pressure drops across components from step 2), using standard formulae; sum these pressure drops to determine system head and flow characteristic.
  - Based on the above, calculate average and maximum pump power

- Determine the input basic hydraulic requirements
  - Required suction & discharge pressure ,with variation ranges

- Specify pump material and casing
  - Depends on fluid composition, temperature

  - Maximum differential pressure for the pump casing

- Ambient and mounting specifications
  - Working conditions
  - Any special conditions in the mounting space

The sizing and selection process then moves to the electrical engineering domain and is discussed in the **Motors** and **VFD** sections of this module:

- Specify pump prime mover and drive train
  - Electric motor vs. other types
  - Exceptional starting, stopping and other running conditions
  - Shaft coupling method

- Specify sequencing and/or pump flow control method
  - VFD or other methods of speed control (VSD)
  - Additional components for power system compatibility

Pump Sizing and Selection
The following simplified small pump example reveals some basic steps in the sizing process.

Required flow = 300 l/s (79.2 gps)
Required discharge pressure head = 30m (98.4 ft)

Using the pump curves from the manufacturer's catalog shown in the figure below:
- Find the required flow, 300 l/s
- Move upwards to match the required head, 30 m
- Required performance is achieved with pump of 1400 rpm speed
- For needed power, move down to the lower curve set along with 300l/s line
- When crossing the 1400 rpm curve move to left to read the power needed at the operating point (110 kW)

Margins and Oversizing
The selected pump is the smallest one capable for the operating point required. If we know that there is no need for higher capacity, either now or in the future, there is no need to choose a larger pump, as it would lead to both higher initial and operating costs.

It is estimated that 75% of pump systems are oversized, many by more than 20%. Uncertainty about static head and/or load flow variation leads designers to specify a large pump with consequently larger efficiency bullseye to handle this variation.

Engineers may also tend to oversize pumps so that the ratio between minimum and maximum energy loss is not large. This means that the gain will not change much with load (Liptak, 2005), making their control task easier, but at the expense of wasted energy. Pumping system authorities provide these additional sizing guidelines for selecting a centrifugal pump in combination with a VFD:

‘For a system with some static head, a pump should be chosen such that the maximum flow rate is slightly to the right-hand side of the best efficiency point (BEP). The exception is for a constant flow regulated system, in which case the recommendation is to select a pump that operates to the left of BEP at maximum pressure. This approach optimizes pump operating efficiency’ (US DoE, 2008).

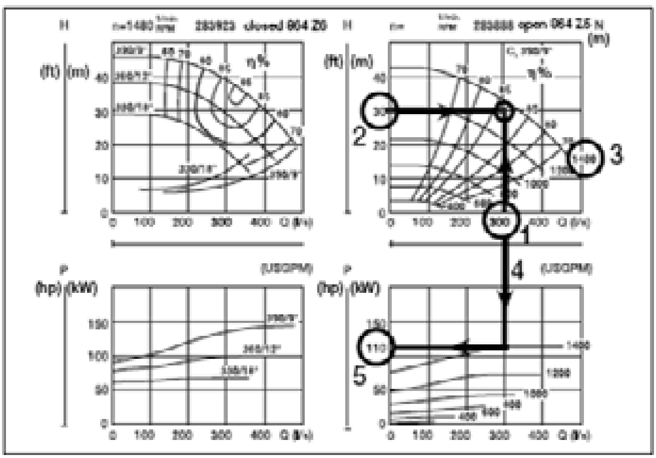


Figure 2.10 - Pump sizing example, (ABB Oy. Drives, 2006)

Power Plant Pump Design Requirements:

In power plants, the design criteria for boiler feedwater (BFW) pumps, condensate pumps and other plant components are typically for the valves-wide-open (VWO) and a 5% overpressure full load condition. However, new market situations may require plants initially intended for base-load operation near their full load design point to now operate in a low to medium load range, and to do so efficiently.

Flow Requirements:

The main flow requirements come from the cycle mass and energy balances at the VWO load condition. Some flows, such as attemperation, soot blowing and boiler blow down, do not contribute to power generation but require pumping power nevertheless. These flows should be minimized wherever possible. A 5% margin is commonly added to the final maximum flow value.

For steam temperature control, the careful control of combustion, possibly with the aid of tilting burners, will reduce the need for steam attemperation flows. Attemperation flows (and their cycle efficiency impact) can be eliminated on supercritical boilers by controlling the firing rate to match the feedwater flow (IEA Coal Online - 2, 2007).

Attemperation is from 2 to 5% of the main steam flow. Soot blowing uses up to 0.5% of the main steam flow and, like attemperation, is taken only intermittently. Boiler blow down on drum boilers to control the water quality will also result in some loss of heat from the cycle and additional pumping power. Once-through (supercritical) boilers do not have blowdown, because they have no drum to store a supply of blowdown water (IEA Coal Online - 2, 2007).

Head Requirements:
The BFW pump(s) must have a combined total developed head (TDH), plus a design margin of 5 to 10%, to meet the following pressure requirements: throttle pressure at turbine valve, pressure drop due to friction through superheater, reheater, economizer, and high-pressure feedwater heaters, plus the static heads due to height difference between pump outlet and drum water level. (Black & Veatch 1996)

Under infrequent circumstances, perhaps to satisfy peak demand in a hot summer day, the BFW pump may be required to operate for a short time 10-15% above its nominal range. The pump and motor must be capable of supplying this added power, so they are specified accordingly. Speed control (using a VFD for example) will provide efficient power modulation at partial loads, where the BFW pump operates for most of the time.

Multiple Pump Systems

It is worthwhile to consider specifying multiple pumps, each optimized for a piece of the load curve; this design is efficient when VFDs are not used. Another energy-efficiency strategy is to consider two or more smaller pumps instead of one larger pump so that excess pump capacity can be turned off. If VFDs are available to the designer, then one or more of the pumps in the system can have a VFD for top-end speed control. The section on VFD **Multi-Drive** describes an efficient and flexible architecture for driving and controlling multiple motors.

Recall that the combined performance characteristic of a multiple pump system can be determined as follows:

- Pumps operating in series have a combined performance curve which is calculated by adding the individual curves vertically, providing increased total head.
- Pumps operating in parallel have a combined performance curve which is calculated by adding the individual curves horizontally, providing increased total flow.

The advantages (right-sizing, reliability) of using multiple pumps must be weighed against some additional costs; the extra equipment requires additional cabling, piping and space. Isolation or check valves between multiple pumps in parallel may be necessary to avoid fluid flow through inactive pumps. The LCC analysis of this configuration should also consider the generally lower efficiency of smaller motors compared to larger ones. The direct on-line (DOL) motors will also incur a power factor penalty, compared to using a VFD for speed control on a single larger motor.

The reliability advantage of parallel pumps, each controlled with a VSD, is that if one pump fails, the remaining pumps can continue uninterrupted.

In power plant applications that require high availability and redundancy, additional BFW pumps are specified. If the main BFW pump trips then a back-up auxiliary feed pump is started and the boiler's firing rate is rapidly reduced in order to prevent the furnace-tubing temperature from rising excessively (Kirmse and others, 2000). Another common pump configuration for increased reliability consists of 2 x 50% capacity BFW pumps operating in parallel.

The high-flow, low-head requirements of circulating condenser cooling water also leads to multiple pump configurations. Pump automation can cycle these pumps to provide a range of flows without the need for excessive throttling. A 4-pump configuration would be more efficient than a system with fewer, larger pumps, and the greater efficiency would offset the higher capital costs of the extra pumps; this rule is still recommended in some design guidelines: (Black & Veatch 1996) The evolution of reliable and lower cost VFDs, however, favor parallelism mainly for reliability reasons only, because the flow can be continuously controlled through varying the pump speed.

Pump Automation

Proper control of multiple pump arrangements is essential to realizing their full energy saving potential. Pump priority control balances the operating time of all the pumps in the system over the long term. This can boost energy efficiency by operating pumps closer to their best efficiency point according to the required flow (duration curve or actual signal) and pump capacities.

Pump automation is important to take advantage of the speed control provided by VFD-equipped pumps. The applications are varied, but one common design uses signals from flow or pressure transmitters as input to a feedback loop, which then modulates the output to the VFD. The desired flow or head setpoint is provided by a unit-level control system. In head-controlled systems, differential pressure transmitters (PDTs) are commonly used to provide the pressure drop across unit loads. For proper head control, the placement of PDTs must span the target load plus the additional loads incurred by piping and valves. If the unit has a common supply 'header' to supply multiple loads, then the ISA recommends that pressure transmitters for this header should not be located near any major load junctions.

In some multiple pump systems, a VFD-driven pump is combined with a constant-speed pump. In these cases, automation can be used to provide additional flow control on either (or both) sides of the constant speed pump's BEP. For low-flow control when the VFD pump approaches its maximum speed, then a switch or signal will auto-start the constant speed pump. According to the ISA guidelines (ISA 2005), extra increments of pumping capacity are started by pressure (when demand is increasing), but stopped by flow (when demand is decreasing).

See the section in Automation module on **Feedwater Control systems** for a description of typical pump automation applications in power plants.

Pump System Design Guidelines - Summary

Sources for this section are RMI (Lovins A. 2007), the US DoE EERE (US DoE Best Practices, 2008) Pumping Tip Sheet, Hydraulic Institute and Europump.

Reduce Static & Pressure Head and Flow Requirements

Gather data to understand the actual loading requirements, especially the duty cycle and load profile of the pump.

Consider process design or operational control alternatives that reduce the maximum and average flows and static or pressure head required.

In power plant auxiliaries, a good example of this rule is adopting a sliding pressure control strategy, which reduces the boiler pressure head and hence pump power requirements, assuming that pump speed control is used instead of flow throttling; see the section on **sliding pressure control** in the Automation module of this handbook.

Right-Size the Components

- Do not oversize for ‘flexibility’: do not choose a larger pump than what is necessary; the larger size leads to both higher initial and operating costs.
- If conditions change, it may be cheaper to trim the impeller or retrofit the entire pump than running an oversized pump over the entire period; specify pad and geometry to accommodate other sizes.
- Employ a control strategy that optimizes **multiple pump systems**.
- Where possible, use pumps operating as turbines to recover pressure energy that would otherwise be wasted, as described in the section on **VFD Regenerative Braking**

Reduce Friction in Pumping Systems

- Select gate or ball valves instead of globe valves where appropriate; strive to use larger pipes and smaller pumps instead of vice versa.
- For above efforts, start downstream so that sizing calculations of upstream components can benefit from efforts at reducing friction downstream.

Use Variable Speed for Flow Control

- Use **variable frequency drives** to control flow, rather than throttling, bypassing or sequencing.
- The benefits of VFDs are larger on low static head, high friction systems & systems with varying flow

Select Energy Efficient Components

- Select an energy-efficient centrifugal pump design.
- Select an **energy-efficient motor** to drive the pump.

Install Components Correctly

- If using **control valves**, ensure that they are properly linearized for good control response.
- For pump hookups, allow at least > 5 clear pipe diameters on inlet and > 3 pipe diameters on outlet.
- Ensure that there is **sufficient suction head or suction lift**.

Pump Drive Train

Speed and Slip

The inevitable slip of induction motors means that actual RPMs will be slightly less, approximately 1% to 5%, than the motor’s nameplate speed rating. The amount of slip is generally lower if high-efficiency motors are used; the extra rotational speed from a motor efficiency retrofit must be accounted for in the new application design.

Startup Conditions

The inertia of centrifugal pumps is normally small enough to be ignored where the prime mover is an induction motor. However, this inertia should be considered together with motor pull-in torque requirements if a synchronous motor is used.

Torque developed by an induction motor varies roughly with the square of the applied voltage. Voltage drops during startup of large motors may lead to insufficient startup torque. On most true centrifugal pumps, closing the discharge valve will reduce the power requirement during early startup. On axial pumps the opposite is true, so the discharge valve should remain open during startup. On mixed design pumps, the discharge valve is opened at some point during startup, when axial behavior begins to dominate (IEEE, 2007).

The reduced torque demand will make it less likely for the electrical engineer to trade away optimum running efficiency for a **design with high starting torque capability**. Pump startup against very high static head or system pressures will increase the starting torque requirements of the prime mover, which is most often an electric motor. If the process allows it, then any method should be used to reduce a high startup torque requirement.

In power plants, the check valve on the boiler feedwater pump discharge line isolates the pump from boiler drum pressure during startup to at least 70% full speed. When the check valve opens, torque and speed demand increases rapidly, the 10% margin of motor over load torque may disappear and startup may not succeed (IEEE, 2007). The concern over long startups and overheating may prompt the electrical engineer to trade away optimum running efficiency for a design with high starting torque capability. The inrush of power late in the startup may lead the engineer to oversize other power system components, such as a unit auxiliary transformer, at the expense of lower continuous operating efficiency.

In some plant designs a motor-driven startup boiler feedwater pump is specified. This is a requirement for steam-turbine driven main BFW pumps, but has advantages even when the prime mover is an electric motor. Depending on its design, this pump may also be used outside of its startup role to provide additional capacity and response. (Black & Veatch 1996). Turbine driven pumps have lower efficiency at low loads compared to motor-driven pumps. A unit's efficiency could be increased by using the motor-driven startup pumps at low loads.

See the Power Systems, **Transformer** section for details on transformer sizing for startup and the **Motor Startup** section for details on motor sizing for reduced voltage startup.

Power Factor

The chosen speed control method also has a significant impact on **power factor** (PF). Lower PF leads to oversized power supply equipment and reduced efficiency. The following figure shows how PF suffers when a motor operates much below its rated speed, as is the case in throttling flow with a control valve.

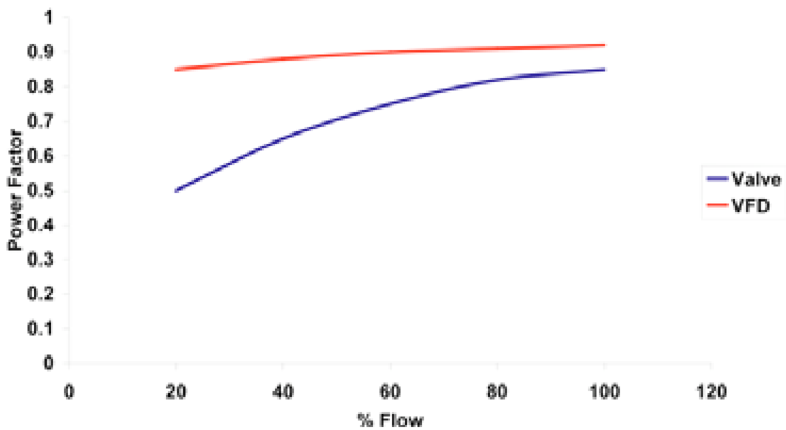


Figure 2.11 - Effect on PF of different flow control methods, (ABB Motors & Drives, 2004 S. Weingarth)

Pump System Maintenance

Impeller wear will lead to increased agitation and the resulting heating of the fluid can be revealed by monitoring the temperature differential across the pump. Close running tolerances should be maintained between stationary and rotating wear rings; the losses from a C% change in this clearance (Rajan 2003) can be estimated by the following model:

$$BHP\ \% = 141.49 \times C^{0.85836} \times Ns^{-1.10219}$$

Where:

C%Wr = percent change in clearance from design ("C" is 1 for a 1% change, 2 for 2%, etc.)

Ns = suction specific speed

Pump electrical horsepower can be compared to water horsepower calculated from real-time measurements of flow and head. Any protracted deviation from the expected pump efficiency at given flowrates is a likely indicator of pump degradation and signals the need for maintenance.

Another, more precise method of monitoring pump efficiency uses a thermodynamic measuring method (according to the British Standard EN ISO 51983). This method requires the installation of extremely sensitive temperature sensors – precisely calibrated –measure the pump's suction and delivery water temperature a shown in the figure below. One vendor (ABB) has patented a highly accuracy delta-T transmitter (HADTT) device. The HADTT enables extremely accurate (in the milli-Kelvin range) temperature differences. High-accuracy water pressure measurements are also required for the unit to calculate the enthalpy gain and water horsepower. These measurements are provided by intelligent pressure transducers with typical accuracies of 0.075 percent. Continuous monitoring of pump efficiency and flow measurements will inevitably lead to saved energy and reduced operating costs.

A Pump Efficiency Monitoring System (PEMS) can perform continual analysis of the pump historical data and propose specific maintenance activity. Additionally, it can enable the operator to choose the most efficient pump or combinations of pumps to use in a complex system (ABB Review 2/2008).

Other elements of the pump drive train can be monitored by the methods described in the section on Condition Monitoring of **Rotating Machinery**.

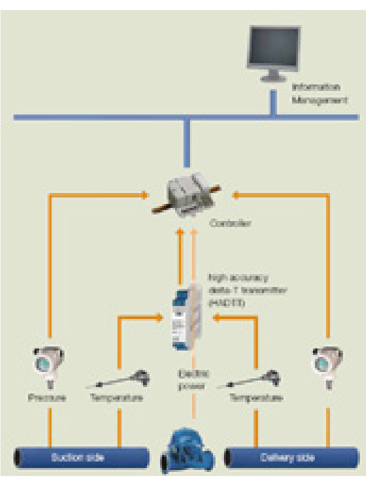


Figure 2.12 – Pump Efficiency Monitoring System, (ABB Review 2/2008)

Pump System Cost Calculations

For pumping systems, the three main lifecycle costs (LCC) are energy, initial investment and maintenance. The initial investment cost is composed of hardware, engineering and installation costs (including civil costs). **Energy consumption is the dominating element of the LCC, especially if a pump runs more than 2,000 hours per year.** To perform a lifecycle cost valuation one needs the following data parameters, shown with sample units:

- Pump type and Impeller type
- Nominal flow (l/s or gpm)
- Liquid density (lb/cu.ft, kg/l)
- Efficiency (%)
- Static head (ft or m)
- Nominal head (ft or m)
- Max head (ft or m)
- Flow control method
- Transmission nominal efficiency (%)
- Motor efficiency (%)
- Motor supply voltage (V)
- Annual running time (hrs)
- Operating profile (% hrs for % nominal flow)
- Energy price ($/kWh or €/kWh)
- Investment cost ($ or €)
- Interest rate (%/yr)
- Service life (yrs)

The output of system cost calculations are usually the following parameters:

- Specific pump power (kW/(l/s)) (kW/(cf/s) or kW/gpm)
- Required input motor power (hp or kW)
- Annual energy consumption (kWh)
- Annual energy saving (kWh)
- Annual money saving ($ or €)
- Payback period
- Net Present Value ($ or €)

See the **Case Studies** section for fully worked-out examples lifecycle cost calculations with benefits.

Pump Power Calculation Tools

There are several freely available software tools for calculating fan power consumption and savings from certain optimization upgrades. A comprehensive list of tools is available from the US DoE web site.

- The 'Pumping System Assessment Tool' (PSAT), from the US DoE , EERE program.

– The ABB's 'PumpSave' calculation tool estimates the energy and cost savings when using variable speed AC drives compared to other flow control methods (throttling, ON/OFF, and adjustable speed using hydraulic or other slipping type drives).
– Many pump manufacturers support their products with power and efficiency calculation tools.

Fan Systems

Industrial fan systems in the US annually consume 78.7 billion kWh of electricity, representing 15 percent of the electricity used by motors (US DoE Sourcebook, 2006). An entire fan system is a network of fans, dampers and/or inlet guide vanes, and ductwork. The purpose of the fan system may be to provide a certain flowrate of air, or to maintain a partial vacuum. Fans can supply large volumes of air, up to 1 million cubic feet per minute, but typically only at low pressures.

In power plant combustion processes, the largest demands for auxiliary drive power come from the ID and FD fans. Typically, FD and ID fan motors consume enormous amounts of energy in a plant, with motor sizes approaching 14 MW to 18 MW in many larger plants. When a boiler is operating at non-peak loads and the traditional fan-motor-damper system is in use, a good deal of energy is wasted in the fan/motor combination. If a 15 MW motor is wasting 20 percent of its energy due to inefficient flow control, that waste amounts to 3 MWh during each hour of operation. At current prices, that equates to roughly $100 an hour. At 5,000 hours a year of operation, it represents a half-million dollar loss.

Figure 2.13 - Centrifugal fan and motor

Fan Types and Concepts

In a centrifugal fan, air moves perpendicular to the shaft. Centrifugal fans accelerate air as it moves along an impeller blade toward the outer rim. This extra kinetic energy is converted to static pressure as it slows in the fan discharge. Centrifugal fans can generate high pressures and can host blade designs suitable for applications with high particulate count and high moisture.

In axial fans, air moves parallel to the shaft, where it is pressurized by fan blades with an airfoil shape. Axial fans have less rotation mass (inertia) than equivalent centrifugal fans, and higher rotational speeds (US DoE Sourcebook, 2006). Axial fans can maintain higher efficiencies over a wider load range than can constant speed centrifugal fans controlled with inlet dampers or vanes. Axial fans have a higher capital cost than centrifugal fans, and because of more numerous parts and complexity, they also require more maintenance (Black & Veatch, 1996)

Fans must develop enough static pressure (SP, usually measured in inches of water) to overcome the resistance if the system of ducts and elbows and deliver the required volumetric flow (usually measured in aCFM (actual cubic feet per minute). Unlike pumps, centrifugal fan output pressure drops to zero at maximum flow, a phenomenon that is called fan ‘runout’.

Fan Characteristics

The pressure and flow characteristics of fans are dependent on the orientation and shape of the fan blades. Backward-curved blades have the highest efficiency, up to 90%, higher than straighter ‘radial’ designs that achieve up to 75% efficiency. Backward-curved blade fans also have the advantage of a non-overloading horsepower characteristic (Black & Veatch, 1996). Fans whose blade design has overloading characteristics have a sharply increasing power demand as flow increases past the fan’s best efficiency point (BEP). The lower air velocities along backward-curved blades, however, promote more build-up of contaminants and may preclude their use in ‘dirty applications’.

An additional blade design factor is the cross-sectional shape of the blade, which may be flat, curved or airfoil shapes. Airfoil shapes are the most energy efficient. The airfoil shape, however, creates regions of unstable operation leading to stalling. To avoid operation in these stall regions may require installation of energy-wasting devices such as recirculation or bleed valves (US DoE Sourcebook, 2006).

In power plants, fans used to supply combustion air are termed forced draft (FD) fans, and fans used to exhaust combustion flue gases are termed induced draft (ID) fans. Primary air (PA) fans supply air to carry an air+fuel mixture through ducts to the burner nozzle (or fuel bed) and on into the steam generator. Together, all the fans electric drive power may add up to 2-3% of the plant's rated output.

Single stage (one rotor/blade set) axial fans are typically used in FD service on balanced draft steam generators. FD fans are sometimes referred to as 'blowers'. If a centrifugal fan is used, then it is likely to have backward curved blades for improved efficiency.

Axial fans in ID service have higher pressure needs that require a 2-stage fan. Axial fans with variable pitch blades are expected to be used more often in ID service, due to more stringent emission control requirements. A lowered particulate count can reduce some concerns associated with axial fan blade fouling (Black & Veatch, 1996). If a centrifugal fan is used instead of an axial fan, then it is likely to have forward-curved blades. The higher stack pressure drop due to emissions control equipment has led to increased horsepower requirements of ID fans and booster fans. The ID hp is typically doubled by the addition of a wet limestone scrubber, with some units requiring up to 4 times more horsepower (GE Utility Division, 1983).

On larger plants, all these fans are typically configured in pairs working in parallel, mainly for reasons of redundancy. See section on **Multiple Fan Systems** for more details.

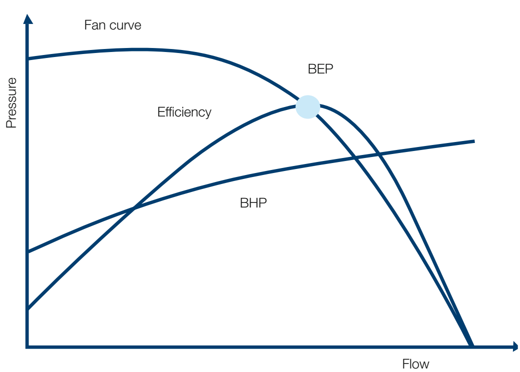


Figure 2.14 -Typical fan performance curve, showing efficiency and power relationships

Fan Power and Energy Efficiency

The input shaft brake horsepower (BHP) required by a fan is proportional to the product of pressure rise and flow, and is given by:

BHP = (k)(P)(FLOW) / (EFFm)(6354) (kW = kPF/EFFm)

Where:

EFFm	= mechanical efficiency, %	
FLOW	= airflow, cubic feet per minute	(m^3/sec)
P	= total pressure rise across the fan, inches of water	(millibar)
k	= compressibility factor, dimensionless	
BHP	= brake horsepower	(kW)

Stated another way, efficiency is given by:

EFFm = (k)(P)(FLOW)/ (BHP x 6354)

Values for k depend on the absolute inlet and outlet pressures. Using a range of typical k factors, the mechanical efficiency of different fan types and designs can be calculated:

Centrifugal fan; forward-curved blade	45-60%
Centrifugal fan; radial-tipped blade	60-70%
Centrifugal fan; backward-curved blade	75-85%
Centrifugal fan; airfoil blade	80-90%
Axial flow fan	85-90%

Ref : (Babcock & Wilcox, 2005)

Static pressure (SP) is often used instead of total pressure in discussing fan performance. Fans are rated by either their total efficiency or their static efficiency. For large fans at design speed, most of the fan total pressure is in the form of static pressure, so the difference between the two efficiency measures is small.

The **Affinity Laws** for fans are the same as for pumps, but with an additional factor to account for change in air or gas density. Fans, like pumps, are cube-law applications whose power consumption increases with the cube of fan rotational speed.

Fan System Load Curves

The system of ducts, elbows, dampers etc. create a resistance load that is proportional to the square of the volumetric flow. When plotted as Pressure vs. Flow, the system load curve has a parabolic (quadratic) shape. In reality, the pressure drops are slightly greater, and the curve slightly steeper, due to losses in flow irregularities such as vortices and swirls (US DoE Sourcebook, 2006).

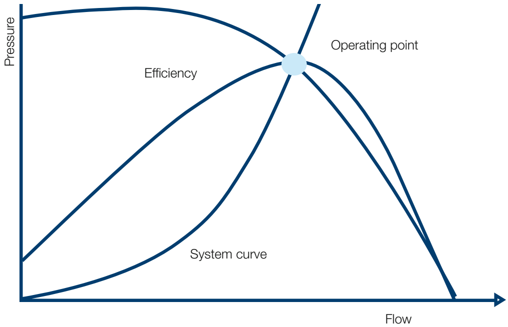


Figure 2.15- Typical system load curve, showing efficiency and power

Supply fans generally work against a system back pressure, while return fans exhaust to low-pressure i.e.: the atmosphere. The system curve for supply fans is therefore typically shifted higher up the vertical axis than that of return fans. In high constant pressure systems, the system curve is shifted vertically up the pressure axis and is flatter at operating flows.

In power plants terminology, the supply fans are the Primary Air (PA), Forced Draft (FD) and the Gas Recirculation (GR) fans which supply air to the furnace chamber. The return fans are the Induced Draft (ID) and FGD booster fans.

Designs with both FD and ID fans are termed 'balanced draft' plants, and the balance point of zero gauge pressure is the furnace.

FD fans must develop pressure to overcome system resistance in ductwork, air heater, burner or fuel bed and the furnace itself. FD fans must supply enough flow to serve needs of fuel combustion plus flow lost due to air leaks in the heater and other areas. FD fans draw fresh air and therefore are more vulnerable to density changes due to outside air temperature change than ID fans. Colder, denser air increases the mass flow and power requirements.

Fan Stability

At low flow, there may be no clear intersection of the fan and system curves, and thus no clear stable operating point,. This causes unstable operation in which the fan pulsates as it 'hunts' back and forth for an operating point, reducing the energy efficiency and increasing the wear on fan components. On most fans, this unstable region occurs to the left of the maximum pressure point, so fans should always operate to the right of that point. Pulsation is more likely in fans whose pressure rise exceeds 10 in. of water. (ISA, 2005)

These unstable modes are more likely to occur in variable speed operation at very low speeds, or when outlet dampers are throttling the flow to create high backpressure conditions, or in multiple parallel fan systems operating at low flow rates. If a VFD is used for flow control, then it can be easily programmed to avoid these areas of operation.

Pipes, Ducts and Elbows

Resistance pressure drops vary generally with the square of the flow rate. Some additional useful rules of thumb for energy-conscious designers of ductwork:

- Pressure drops along ducts vary roughly with the fourth power of the duct diameter and are responsible for much of the total system resistance. Even small increases in diameter will have a large impact on energy efficiency of the system.
- Energy is wasted in irregular flows such as swirls and vortices. Elbows, especially near fan inlet or outlet, cause especially high losses, decreasing the flow by up to 30% (US DoE Sourcebook, 2006). These resistances are also known as ‘system effects’.
- Round ducts have less surface area per unit of cross-section, and smoother flow compared to ducts with square cross-sections.

Fan Flow Control Methods

When centrifugal fans are required to operate at variable loads, the pressure and flow may be controlled by one of the following methods:

- Inlet dampers
- Inlet guide vanes
- Outlet dampers
- Two-speed motor control
- Variable speed control by VFD or hydraulic coupling methods

When inlet dampers and guide vanes are partially closed they create a pre-swirl in the direction of rotation of the fan. This motion reduces the relative velocity of the air with respect to the fan blades and therefore reduces the fan capacity and pressure. (Black & Veatch, 1996)

Inlet guide vane control is more efficient than inlet dampers due to reduced friction in creating the pre-swirl movement.

Outlet dampers are least efficient of all methods; they throttle the airflow to remove power supplied by the fan. As outlet dampers close, the system curve becomes steeper, intersecting the fan curve at the required lower flow rate, and at a point below the fan's BEP.

Vane or damper control is highly non-linear, and little control is possible near the full-open position

Inlet guide vanes are more effective on forward-curved than backward-curved fans; an important consideration in some retrofit situations (Competitek, 1995). The struts and actuators needed for inlet guide vanes obstruct flow and will slightly reduce efficiency.

In power plants, VFDs are an increasingly popular solution for variable speed control, but ID fan speed control in may also be achieved by other means, such as single-speed motors with variable speed fluid couplings. The relative performance and merits of these alternatives in are explored in the **Pump Flow Control** section, but the conclusions apply generally to most fan applications as well.

Axial fan control is provided by variable pitch fan blades whose angle can be changed in real-time to adjust the load on the fan. The effect of variable pitch fan blade has a similar effect as inlet guide vanes on the flow. In large applications, the blade pitch is changed using hydraulic actuators. If speed changes are infrequent, then manually adjustable pitch blades or belt-drive systems with different diameters may be used, but these methods require the fan to be at standstill for some time.

The efficiency of variable pitch fan control is similar to that of VFD speed control, but the increased number of moving parts and decreased motor efficiency at off-capacity loading make a VSD an attractive alternative, even on axial fans. In large two-speed induction motors, typically, the low speed is selected for the most common operating point and the higher speed for all the higher loads. Switching between speeds in large motors, however, is neither trivial nor smooth and may lead to process transients and upsets.

Some power generating plants that have experienced problems with speed changes simply keep the fan at high constant speed with consequently higher energy loss. (Black & Veatch, 1996), due to the sensitivity of furnace conditions to fan pressure fluctuations. Also, if the 2-speed fan has been oversized, a very common engineering practice, then it is likely that the top speed will never be used.

VFD Speed Control

In applications requiring variable flow and pressure, VFDs are the most efficient method of control. Varying the speed of the fan adjusts the flowrate to the system requirements without the need of additional mechanical devices, and at high efficiency. The benefits of VFDs are diminished in applications with higher system (back) pressures, where the system curve is flatter. The relative power requirements for the different control methods are shown in the graph below:

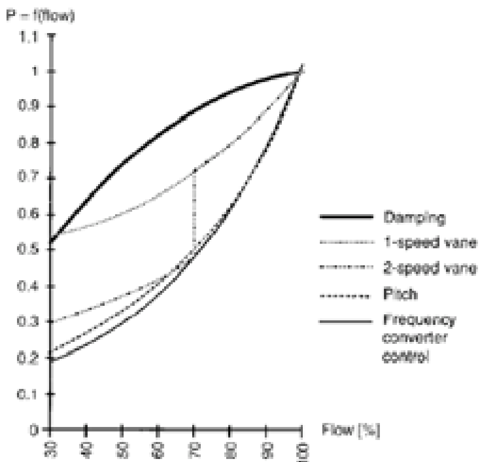
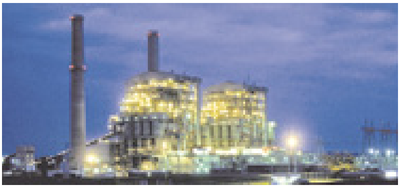


Figure 2.16 - Input power for different centrifugal fan control methods, (ABB Drives, 2005)

In power plants, ID fans are ideal candidates for VFD control, as the following short case histories illustrate. Axial ID fans in particular, with their inherently low turndown capability and steep pressure vs. flow curves compared to centrifugal fans, are also well suited for VSD control. Good control can be achieved either by VFD motor speed control or by variable pitch blades, which have a good, nearly linear response.

In PC plants, the relatively high and constant system pressures (mostly due to the windbox and burner pressures) to be overcome by PA fans over a large range of flow, may make them less attractive for VSD speed control. PA fans are typically matched and packaged together with the burner assembly and may therefore not lend themselves to retrofit engineering.

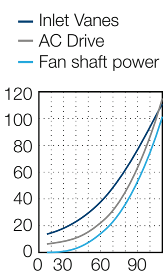
Case Example #1
Power Plant, UK

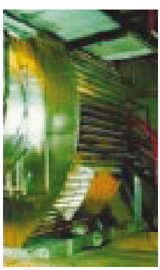


The ID fans at a UK power plant (200 kW + 150 kW) were running at full speed with flow control by dampers, but as the boiler ran at low loads for long periods, management believed that energy could be saved with variable speed control. When variable speed AC drives were installed for flow control, and dampers locked in open position, these benefits were noted:

- Energy saving: 1,000,000 kWh/year
- Reduction in CO2 emissions: 500,000 kg/year
- Faster response to load changes (Immonen, 2003)
- Noise level reduced from 89 dBA to 77 dBA
- Payback period of just 16 months

Case Example #2
Industrial Power Plant

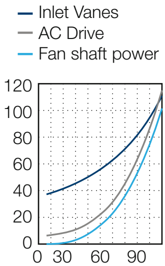




A Finnish pulp mill's industrial power plant compared hydraulic coupling to AC drive (1,370 kW) for its power plant ID (Induced Draft) fan. The power plant is running continuously and the flue gas flow varies from 50% to 90% of the maximum capacity. With AC drive:

- Energy saving: 376,000 kWh/year
- Reduction in CO2 emissions: 188,000 kg/year
- Better pressure control
- Less maintenance by soft starting
- Fan critical speeds can be avoided

Case Example #3
Industrial Power Plant



An industrial power plant compared inlet guide vanes to AC drives (110 kW each) for its FD (Forced Draft) fan. The power plant is running continuously and the fresh air flow varies from 50% to 90% of the maximum capacity. With AC drives: Power plant FD fan - AC drive instead of inlet guide vanes, Power plant booster fan - AC drive instead of inlet guide vanes

- Energy saving: 482,000 kWh/year
- Reduction in CO2 emissions: 241,000 kg/year
- Better pressure control with varying loads
- Less maintenance by soft starting
- Efficient combustion

Case Example #4
Abbott Power Plant, UI, USA

In a drive to reduce the plant's operational costs, Abbott Power Plant engineers selected ABB's ACS1000 standard medium-voltage (MV) drive to control a 1000 hp fixed speed scrubber booster fan that was previously regulated by inlet vanes, and thereby improved the overall efficiency with reduced maintenance effort.

- Energy savings of USD $63,000 per year, an improvement by 25% on inlet vanes
- Reduced maintenance and hardware savings : USD $10,000 per year
- Payback on investment period was 24 months
- Additional benefits of the variable speed drives include:
  - no motor start-up problems
  - total process controllability

Fan System Design and Engineering

Fan selection and sizing is based on many factors. The most important criteria are the system's pressure and flow requirements and how these vary under operating conditions.

Margins and Oversizing

As with other turbo-machinery, most industrial fans are oversized or under loaded, for a variety of reasons. First, there is uncertainty in the flow requirement due to changes in demand, changes in temperature and air density, and system leakage increases due to deteriorating seals. Second, there is uncertainty in the pressure requirements due to system resistance. The common practice of freezing the equipment layout before the connections between equipment creates sub-optimal designs; from higher losses due to convoluted ductwork and/or from gross oversizing of the fan drive system.

The latter point is a common problem, as the ductwork contractor may decide late in the detail engineering phase to add additional turns to avoid interference with certain equipment; the number of 90-degree elbow turns is not known for certain until later in the project. The uncertainty surrounding these and other criteria is behind the unfortunate practice of high design margins and oversizing. A 15% design margin on flow is accepted in industrial applications. Given that power is proportional to the cube of flow, this margin will mean a 50% increase in power consumption at capacity unless counteracted by VFD speed control or, far less efficiently, by guide vanes or dampers.

Oversizing of the fan usually also entails oversizing of the motor plus drive train and the power supply equipment. The **Fan Drive Train** section discusses the futility of oversizing motors on non-overloading type of fans. All this equipment is less efficient when operated much below their rated loads; the Motors and Power System sections list other negative consequences of oversizing. In existing fans, an indicator of gross oversizing is that vanes or dampers are almost always in a nearly closed position.

For axial fans, there is an additional penalty for operating an oversized machine. The lower flow brings the operating point closer to the fan's stall line, increasing the risk of stall during transient downstream pressure conditions (Black & Veatch, 1996). A fan can operate in stalled condition, but is much less efficient and at the cost of increased vibration stress on fan components.

In power plants, fans in furnace draft service may be oversized by engineers to be quite certain that the fans will not be a bottleneck for (the much more expensive) boiler capacity. Chief among these concerns is uncertainty in the flow requirement due to changes in fuel quality and granularity. Power plant engineering texts advise a 20-30% margin on fan head capacity and a 15-20% margin on flow. (Babcock & Wilcox, 2005). In some plants, boiler fan capacity does in fact limit plant capacity during peak power production on very hot days. Energy efficiency efforts, including radial leakage reduction in air heaters, could be sufficient to remove such a capacity restriction in these plants

ID fan capacity may, however, be a real bottleneck for some plants potential to burn waste fuels. VFD overspeed may provide the additional short-duration capacity needed to burn a small inventory of waste fuel. For longer term firing with waste fuel, a fan retrofit or booster fan may be required. **Generally, use of VFDs is the only way to get additional capacity from a fan system if the overall combustion process is "fan limited" when running full out at nominal frequency. Running a VFD at 5-10% overfrequency is possible, as long as the overall design of the fan/motor/drive system is appropriate for overspeed operation.**

Fan Selection and Sizing

Calculating or measuring the system resistance curve is essential to proper sizing and selection of the fans that will supply it. The design analysis steps are:

1. Gather data: Plant capacity and estimated or historical performance data, Process flow diagrams, P&ID drawings to determine system configuration.
2. Determine the system flow requirements at maximum continuous rating (MCR) conditions, taking air density, moisture content and leakage flows into account, plus only a small margin (<10%).The flow requirement is based on process needs.
3. Calculate the pressure drop across all the individual components using the governing equation and coefficient for that component (duct, damper, elbow etc.), and include the boiler furnace pressure. The resulting curve is called the 'boiler resistance line'.
4. Add the above pressure drops to determine overall system pressure required at the MCR flow condition.
5. Estimate or measure the load profile and duty cycle of the fan in operation: % of time at % of loading, including vane and damper positions.
6. Estimate or measure the particulate levels, air temperature ranges, floor space which influences the selection of fan and blade types.
7. From previous step's requirements, narrow down selection to fan type (axial vs. centrifugal), blade orientation, and shape. Gather data from fan supplier, especially pressure and power curves showing efficiencies, stall line. A fan selection diagram may also be provided.
8. Using data from previous step, apply the system curve to an appropriate fan's performance curve (specific speed and specific size) to verify that the fan's BEP is at 100% system rated capacity.

The load factor determination of existing fan systems should also include the position of any mechanical flow control devices (inlet vanes, dampers etc.), as this may reveal an energy-saving retrofit opportunity for variable frequency control.

In power plants, the basic flow requirement for FD fans is the stoichiometric amount of air given by the chemical oxidation reaction equation, plus a certain amount of excess air to compensate for imperfect mixing during combustion, less the flows to the PA fans. The stoichiometric amount varies with the coal or fuel type. Values for these are available from ASME standards and test codes. For ID fans, the basic flow requirement is given by the stoichiometric (chemical equation) products of combustion, plus leakage flows.

On balanced draft boilers, where the furnace is under slight negative pressure, air tends to leak in, especially as boilers age. Leakage in air heaters is a source of 1) reduced cycle efficiency and 2) increased auxiliary power. Air heaters are used to recycle heat from the flue gas back into the boiler, by pre-heating the fresh air for prior to combustion. Air heaters increase the boiler efficiency by 10% to 15% (Babcock & Wilcox 2005) and are typically located immediately downstream of the economizer. Air heater leakage reduction will improve heat transfer in the air heater and therefore will also improve overall cycle efficiency.

Regenerative air heaters transfer heat from hot to cold sides by warming up metal tubing set into a slowly rotating rotor. The efficiency of the air heater itself is typically 85% to 90% (Rajan 2003). Typical leakage values for regenerative air heaters range from 6-15%, and values increase with age and consequent wear of seals, and air leakage rates of 20% are not uncommon (Guffre 2007). Tubular and heat-pipe (recuperative) air heaters have no mechanical seals and therefore have low leakage rates, typically under 3%.

Process design attention to reducing air leakages will reduce the loading on the ID fans. At typical rates, air seal leakage accounts for up to 25% of fan horsepower (Guffre 2007), which represents between 0.5MW to 2.0MW of fan auxiliary power, depending on plant design. Radial leakage in regenerative air heaters is unwanted flow from cold to hot sides of the heater. Radial leakage adds to the fan load and, because it is not pre-heated, does not aid combustion either. Leakage also disturbs the balance between primary and secondary flow and has been observed to cause poor flame stability and increased desuperheating (attemperation) spray flows (McIlvaine, 2008). The leakage of fresh air into the flue gas stream decreases the efficiency of downstream emissions control equipment such as the electrostatic precipitator.

The fan pressure requirements at unit MCR conditions can be estimated using component pressure drop equations, but the industry sources named above have typical, empirically determined values. For FD fans, the largest pressure drops are across the burner/windboxes and across the air heater. For ID fans, the largest pressure drops are across the scrubber, air heater, and economizer outlet. Special attention to the design of these components, especially the regenerative air heater, will have a beneficial effect on auxiliary system and thermal energy efficiency. The rotary design of regenerative air heaters still used in new plants dates back to 1923. Reducing gaps and installing modern seals can lead to a 50% reduction in radial leakage on existing regenerative air heaters (McIlvaine, 2008).

See power generation industry texts (Black & Veatch, 1996) and (Babcock & Wilcox, 2005) for details on the individual leakage flows and pressure drops for FD, ID and PA fans.

Multiple Fan Systems

In applications with very wide range of flow, it is worthwhile to consider specifying multiple fans, each optimized for a piece of the system load curve, where they can operate close to their BEP. With two or more smaller fans instead of one larger fan, excess fan capacity can be turned off. One or more of the fans in the system can have a VFD for some finer degree of flow control. Redundancy is the more likely reason to favor pairs of fans in large industrial applications, however.

The combined performance curve of fans operating in series (typically no more than 2 fans operate in series) is calculated by adding the individual curves vertically. Fans operating in parallel have their curves added horizontally. One or more of the fans in the system can have a VFD for top-end speed control. When operating fans in parallel, it is most energy efficient to split the load equally between the fans (Babcock & Wilcox, 2005). The **References** section contains references to fan system guidelines on how to determine rating of fans in parallel and series.

Supply and exhaust fans operating on opposite ends of a system decrease the pressure build-up in a duct or space compared to a single fan. It is usually easier to control a zero point location or maintain low pressures, such as the draft in a boiler, if supply and exhaust fans are used (Greenheck, 2008). Another advantage of forced/induced fan combination is that the lower pressures will help to reduce leaks (US DoE Sourcebook, 2006).

Fan Automation

Proper control of multiple fan arrangements is essential to realizing their full energy saving potential and to avoid unstable or stall operation due to interactions between multiple fans at low flows, especially for fans in parallel. Isolation dampers between multiple fans in parallel may also be necessary to avoid air flow through inactive fans. In fans with damper control, a flow cascade loop is typical, with the master comparing actual to demanded airflow. The setpoint is sent to the cascade slave loop for comparison with a sum of the damper position signals. The ISA Control & Optimization handbook contains details on this loop and additional control loops for optimizing cycling fans with dampers (ISA, 2005). Good fan flow control is very important if the downstream process is combustion, in which air supply will determine the intensity and the safety of the process.

In power plants, stable FD fan pressure is essential to the stability and efficiency of the combustion process downstream in the furnace. Smooth variation of pressure with flow is necessary, and this can be achieved through either adjustable pitch blades on axial fans or with VFD speed control. Multiple fans pose a special challenge for smooth control; to ensure smooth performance design requires the combined effort of both the controls and mechanical engineering disciplines.

Fan flow control is important to several critical boiler & turbine control systems: Combustion control (firing rate, fuel/air) control , involving FD fans, - Excess air (O_2) control involving ID fans, Furnace draft (pressure) control, involving ID fans, Gas flow distribution (recirculation) control, involving GR fans.

Correct instrumentation and actuation is also important to the overall controllability of these loops. Flow transmitters are typically not calibrated or not capable at low flow rates (<25%). Louver-damper fan systems pose a particular control challenge, due to the non-linearity, hysteresis and leakage (up to 10%) of dampers (ISA, 2005). Dampers with smart positioners will increase the controllability of these actuators.

Automation also plays an important energy efficiency role in reducing power requirements during large fan startup; see the **Fan Drive Train** section for details.

Fan System Design Guidelines - Summary

Sources for this summary section are: (Lovins A. 2007) and the DoE EERE (US DoE Best Practices, 2008) Fan SourceBook.

Reduce Static & Pressure Head and Flow Requirements

– Consider process design or operational control alternatives that reduce the maximum and average static or pressure head required. Consider these aspects also **under startup conditions**.

Right-Size the Components

- Gather data, take time to understand and document the real loading requirements; the actual duty cycle and load profile of the fan.
- If implementing a **multiple-fan system**, use a control strategy which optimizes parallel fans

Reduce Friction in Fan Systems

- Be aware of trade-off in floor space vs. fan system pressure drops caused by elbows and ductwork.
- Reduce system effects by using flow straighteners and other passive fittings that eliminate energy-sapping vortices and swirls.
- Reduce system duct friction by specifying larger diameter ducts, and shorter runs.
- For the above efforts, start downstream so that sizing calculations of upstream components can benefit from efforts at reducing friction downstream.

Use Variable Speed Drives for Flow Control

- Use variable **speed drives to control flow**, rather than outlet or inlet dampers or even guide vanes.
- The benefits of VSDs are larger on lower static head, high friction systems, and on systems with varying flow rates.

Select Energy Efficient Components

- Select an energy-efficient fan type and blade design where the application allows
- Select an energy-efficient motor to drive the fan, as described in **Motor Power and Efficiency**

Install Equipment Correctly

- If using **dampers for flow control**, ensure that they have minimal hysteresis and their control function has been linearized for good control response.
- Ensure that there is sufficient distance from an elbow on the fan inlet and outlet.

Fan Drive Trains

Motor and Coupling

Axial fans with direct drive expose the motor to potential damage from particulates and/or high temperatures. Belt drives are sometimes specified in axial fans for this reason, as the motor can then be located outside of the air stream. Motors for centrifugal fans can more easily be located for direct drive outside of the enclosure (US DoE Sourcebook, 2006).

In power plants, Gas Recirculation (GR) fans operate in high temperature and particulate airflows, making them unsuitable for axial fans with directly exposed motors.

Fans with non-overloading blade design, common in power plant draft service, have absolutely no benefit from an oversized motor, because horsepower drops with increasing flow beyond the BEP.

Speed and Slip

The inevitable slip of induction motors means that actual RPMs will be slightly less (approx 1- 5%) less than nameplate speed. Synchronous motors do not exhibit slip.

Startup Conditions

Fans, especially centrifugal fans more so than axial fans, have a large rotating mass and hence high inertia, given approximately by mR^2 (where m is the mass and R is the fan radius). According to Newton's law, Torque = (mR^2) x A, where A is the angular acceleration. The larger the inertia, the greater the torque required to accelerate the fan to its normal operating speed. Air mass within the fan adds to the starting torque requirements (US DoE Sourcebook, 2006). An example of applying Newton's formula to determine acceleration time for a fan is described in the Motor section on **Torque ,Inertia and Acceleration**

The **Motor Selection and Sizing section** discusses the trade-offs between high startup torque and good running efficiency in motors. Large centrifugal fans typically exceed the NEMA normal inertia limits and require special designs. (IEEE, 2007). For smaller fans the NEMA high-slip design 'D' offers high torque starting capability, but reduced running efficiency.

- Soft-starters and VFDs are useful in fan applications to reduce the high startup current and resulting stress on the power system and the motor.
- The motor windings receive an amount of thermal energy equivalent to the kinetic energy of the rotating mass of the fan at operating speed. Higher winding temperatures may lead to maintenance problems and reduced motor efficiency.

Given the high inertia of fans, it is good design practice to use any means to reduce the inertia and/or load on the motor during startup. For centrifugal fan types, the power requirement can be reduced by closing inlet vanes or dampers during start-up. Axial fans with certain blade profiles may require a different strategy, depending on the power vs. flow curve for that particular fan. Axial fans with variable pitch control typically should be started with reduced blade pitch. Starting multiple vane axial fans should be done with both at the same reduced pitch. When both fans are up to speed and aerodynamically balanced, increase the blade pitch of both fans to the desired operating condition (Greenheck, 2008).

In older designs, piggyback or 'pony' motors were used to allow engineers to specify a right-sized, high–efficiency main motor. If the application allows some method to keep the fan rotating at low speed, then a VFD with 'flying start' capability can then use that rotational energy in the startup sequence, thus reducing the heat load on the motor. The **Motor Startup** section has some guidelines for reduced voltage startup.

In power plants, a 1500-hp ID fan motor may use its full rated starting torque with a safety margin of only 10%, but then drop to 30 to 50% of full load once it has settled to run at normal speed. This motor will typically lose, at 50% load, about 1.8% points in efficiency and over 2% points in power factor. At 30% load the motor does much worse, perhaps a 4% efficiency loss (Competitek, 1996).

ID fans have a high duty factor, and each % point of efficiency loss in such large motors is worth tens of thousands of dollars per year. The savings will justify many efforts to provide some form of starting assistance to these motors.

Fan System Maintenance

Continuous and pro-active maintenance is essential to preserving energy efficiency of the system during operation. Fans used in air streams with high levels of particulates may become fouled or eroded, with consequent reduction in energy efficiency and performance. Backward-curved blade designs are more prone to build-up of such contaminants than straighter, radial designs.

Vibration monitoring and analysis equipment will usually reveal build-up of contaminants on the fan blades, in addition to other imbalance problems. This equipment can be installed to run continuously and provide real-time data to plant maintenance staff and alarms to plant operators. See the section on **Condition Monitoring Systems**.

Another condition that deserves real-time monitoring is the stalling potential of axial fans. Stall operation is very energy inefficient and is accompanied by damaging vibrations. Instrumenting the fan with upstream flow and pressure sensors will provide detection of pre-stall conditions and warning to operators. (Black & Veatch, 1996)

Fan System Cost Calculations

For fan systems, the three main lifecycle costs (LCC) are energy, initial investment and maintenance. The initial investment cost is composed of hardware, engineering and installation costs (including civil costs). Energy consumption is by far the dominant element of the LCC, especially if the fan runs more than 2,000 hours per year. To perform a lifecycle cost valuation, one needs the following data, shown with sample units:

- Fan type (centrifugal vs. axial flow)
- Air or gas temperature or density (lb.cu ft, kg/cu m.)
- Impeller type (Forward curved, backward curved, radial blades)
- Nominal volume flow (cfm, cms)
- Total pressure increase (inches of water, psi, or millibar)
- Nominal Efficiency (%)
- Flow control method
- Transmission nominal efficiency (%)
- Motor efficiency (%)
- Motor supply voltage (V)
- Annual running time (hrs)
- Operating profile (% hrs for % nominal flow)
- Energy price ($/kWh or €/kWh)
- Investment cost ($ or €)
- Interest rate (%/yr)
- Service life (yrs)
- Drive data: Nominal efficiency 95%

The output of system cost calculations are usually:

- Specific fan power (kW/(cu.m/s) or kW/(cf/m))
- Required input motor power (hp or kW)
- Annual energy consumption (kWh)
- Annual energy saving (kWh)
- Annual money saving ($ or €)
- Payback period
- Net Present Value ($ or €)

The **Case Studies** section has a fully worked-out example of retrofit cost calculations.

Fan Power Calculation Tools

There are several freely available software tools for calculating fan power consumption and savings from certain optimization upgrades:

- The ‘Fan System Assessment Tool’ (FSAT) from US DoE. The FSAT calculates power consumption and efficiency of upgraded fan systems.
- ABB’s ‘FanSave’ calculation tool compares AC VFD drive control against traditional flow control methods for fans (outlet damper, inlet vane or pitch control methods). The tool provides financial and environmental estimates for each control method retrofit project and recommends a suitable VFD drive type.

Note that some fan calculation tools assume a parabolic fan curve and a system curve with zero constant pressure. This latter assumption may invalidate some of the results for high constant-pressure applications.

Other Drive Power Loads

Conveying & Grinding Systems

Material handling systems involving conveying and grinding are typically constant torque applications. These are linear-law applications; the required power varies with the square of the motor speed. The design guidelines in the **motor sizing & selection** section still apply to these applications. These types of applications vary greatly, but they share a common need for control of torque as well as speed. The use of Variable Frequency Drives (VFDs) for **Variable Torque Control** of conveyors can save energy through improved controllability and a more direct drive train with fewer losses.

Large conveying systems with up and downhill sections may benefit from **energy recovery through 4-quadrant VFD speed control**. The braking power generated by downhill conveyors is transferred to the common DC busbar by means of an energy recovery unit, significantly reducing the energy consumption of the complete system.

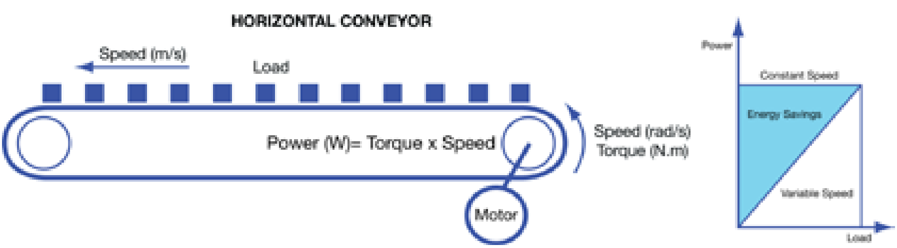


Figure 2.17 – Conveyor systems and VSD energy savings diagrams (De Almeida, 2006)

In many conveyor systems, the conveyors are running at maximum speed and the feeder controls the flow of material. Energy can be saved by using some form of variable speed control via a VFD on the motor; the speed of the conveyor can then be varied with the amount of material flow. When there is no flow, the conveyor runs at minimum speed; material sensors can be used to detect if the conveyor is empty or not.

HVAC Systems

The large fans at the heart of HVAC systems are cube-law applications whose power requirement increases as the cube of the motor speed. Commercial and residential buildings offer the highest energy saving potential, but even industrial facilities' HVAC systems can yield energy efficiency gains through careful redesign of their air handling components. Most of the design guidelines from the **section on Fan Systems** also apply to HVAC air handling systems, but are re-stated here only in summary form.

The most efficient HVAC fans (70-85 % total efficiency) are axial design or backward-curved centrifugal fans. Large, round ducts with a minimum of sharp elbows will reduce pressure requirements. A right-sized and energy-efficient electric motor will save from 5-15% over a standard, oversized one. VFD speed control can save a further 20-40% for fans operating at lower loads and dramatically reduce noise. Even when compared to axial fans with variable pitch blades, VFDs are still a slightly more efficient method of air flow control.

Compressed Air Systems

Reciprocating pumps and rotary screw pumps which are used in compressed air systems are a linear law load, whose power requirements vary linearly with motor speed, as shown in the figure below. Air compressors account for 10% of industrial consumption of electricity, yet they have poor energy efficiency. Estimates of the potential energy savings are in the range from 5% to 50% (De Almeida, 2006), and average savings are estimated to be 25%. These estimated are based on the following assumptions: Power-110 kW, Equipment life span-15 years, Operating hours-4000 h/year, Electricity price- 5 c€/kWh.

In linear-law systems, it is the running time of the motor at various speeds which will determine the energy demand and the potential for savings. (Competitek 1996). Some systems have their compressors running continuously just to maintain the minimum required pressure; a smaller helper motor could be used to handle such situations more efficiently. An even better option is to use a **variable frequency drive (VFD)** to control the speed of the compressor. The figure below shows energy saved by using a VFD for speed control on a rotary screw air compressor:

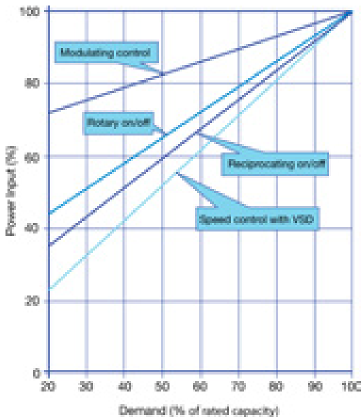


Figure 2.18 – Compressed air power required by control method, (De Almeida, 2006)

Motors and Drive Trains

The purpose of a motor is to provide torque greater than or equal to the load torque of the machine being driven, such as a pump or fan. The driven machine's shaft will then rotate and perform useful work within a process unit. Electric motors use two-thirds of industry's electricity, and this consumption is reflected in the high operating costs; for a large motor in continuous duty the operating costs represent more than 95% of the total cost of ownership.

Industry surveys show that there is room for improvement in the engineering of energy efficient motor systems. Data from the US electric power utility PG&E showed that one-half of industrial motors are operating at less than 60% of their rated load, and one-third are operating at less than half their rated load (cited in (Competitek 1996) Ch.9). These underloaded motors suffer an efficiency penalty from 0.5 to 4.0 percentage points.

Many **References** already exist on the subject of electric motors and drive trains. This handbook section provides information to help engineers and designers understand the energy impact of their choices and guidelines to help improve the efficiency of the motor drive train from power supply to motor shaft. The Pump and Fan sections discuss energy efficiency of the application.

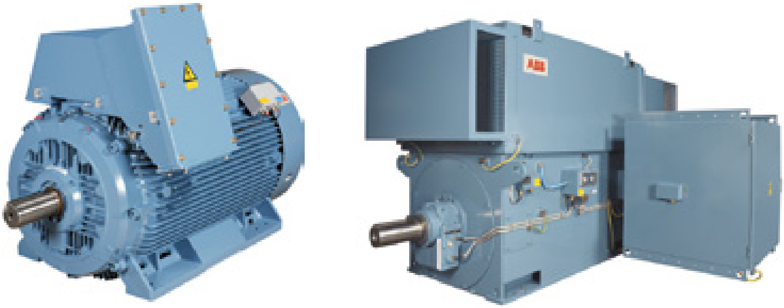


Figure 2.19 - Small LV (left) and large (right) MV induction motors, (ABB Drives, 2008)

Motor Types and Concepts

By far the most common large motor types used in power and process industries are AC synchronous and AC induction motors. In both these motor types a magnetic field, rotating in a physically fixed outer stator, exerts a force on another magnetic field within the inner rotor, whose rotating shaft provides power needed by the industrial process. Unless otherwise specified, the common motor type assumed in this handbook is assumed to be an induction motor.

Induction Motor Types

In an AC induction motor, the rotating stator magnetic field induces a current in the rotor conductors. The two magnetic fields interact to produce a torque on the rotating rotor shaft. This torque continues as long as there is relative motion of the two magnetic fields, which is why the rotor lags the stator rotation by an amount known as ‘slip’. Slip is defined at the motor’s nominal point, which occurs when the motor is powered at the nameplate voltage, frequency and current. Due to slip, the nominal (nameplate) speed (n_n) will be less than the synchronous speed (n_s) at that frequency, which is why motors of this type are also known as ‘asynchronous; motors. Slip is defined according to this difference, as shown by the following formula:

$$s_n\ (\%) = 100 \times (\ n_s - n_n\ )\ /\ n_s$$

From the above, it can be seen that slip is equal to zero at synchronous speed. The synchronous speed, (n_s in RPM) of a synchronous motor is proportional to the nominal frequency of the power supply (f_n in Hz) and inversely proportional to the number of pairs of poles in the winding, according to the formula:

$$n_s\ (\mathrm{RPM}) = (\ 2 \times f_n \times 60\ )\ /\ \text{pole number}$$

For example, a 60Hz , 4-pole motor with 1.5 % slip has a synchronous speed n_s = (2 x 60 x 60) / 4 = 1,800 RPM, and a nominal speed n_n = (100 – 1.5)/100 x 1800 = of 1,773 RPM.

The motor's maximum torque (also called breakdown torque and pull-out torque) occurs at about 80% of nominal speed. A standard induction motor's maximum torque is typically 2 to 3 times the nominal torque. The maximum torque T_{max} occurs at slip s_{max}, which is greater than nominal slip.

The slip at which maximum torque occurs is proportional to rotor resistance. In order to use an induction motor efficiently the motor slip should be in the range 0 to s_{max}. This can be achieved through right-sizing of the motor to its application, or by controlling voltage and frequency by using a **variable frequency drive (VFD).**

In a 'squirrel cage' type of induction motor, shown in the figure below, the rotor conductors are placed longitudinally. The cross-section of these bars determines the torque and speed characteristics of the motor. Their simple operation and construction make squirrel cage induction motors the workhorses of industry. These motors exhibit versatility, reliability, and are available in all sizes up to 18MW. Other basic types of induction motors are **wound rotor** motors and some variations on these two designs, such as **multispeed** motors.

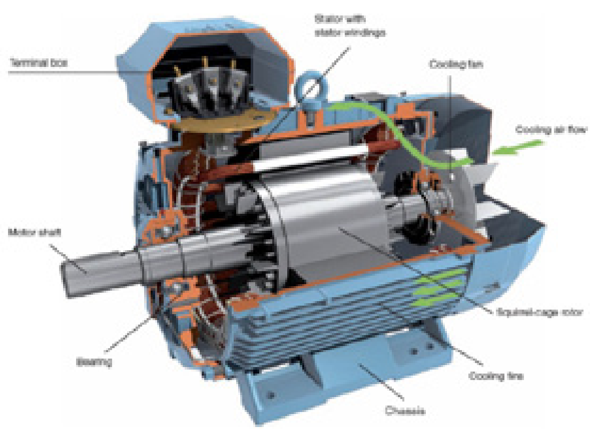


Figure 2.20 - Induction motor cutaway view, ABB Motors & Drives, 2007

Synchronous Motor Type

In a synchronous motor the rotor moves in lockstep with the rotating field in the stator, whereas in asynchronous (induction) motors there is slip between rotor and stator fields. Since there is no slip, the rotor magnetic field must be created through a separate DC excitation system. For the same reason, starting of a synchronous motor requires temporary use of the induction principle; a small number of conducting bars in the rotor are used to develop startup torque until the rotor has sufficient speed to 'pull-in' to the stator speed, at about 85% full speed, and thereafter operate fully synchronously. The standard horsepower, speed, and voltage ratings of synchronous motors are listed in Sections 21.10 and 21.12 of NEMA standard MG1

Synchronous Motor vs. Gas Turbine

The following section is based on information from ABB and IEEE Std.666-2005, paragraph 11.3.1.1:

For very high-power applications, four-pole synchronous motors are a cost-effective alternative to powerful mechanical drives such as turbines; this may be the reason behind a trend toward ever larger synchronous motors. Compared to steam or gas turbine drive, synchronous motors are more energy efficient and require less maintenance. A gas turbine averages only 25 to 38% efficiency and less than 25% at off-peak loads. The efficiency of a large synchronous motor is between 97 and 99%. Gas turbines require frequent costly attention and have other drawbacks compared to electric drive, as shown in the table below. One facility (Statoil Snøhvit plant) reported an additional 10 normalized on-stream days per year for their LNG liquefaction compression application after converting to a motorized drive system.

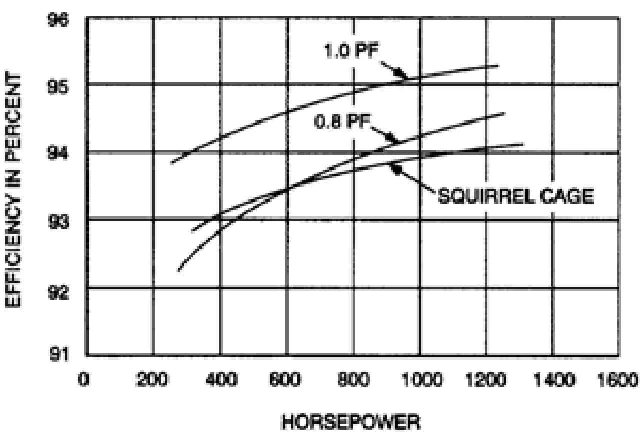
Characteristic	Gas Turbine	Synchronous Motor
Weight and space	Light unit, but large & heavy auxiliaries	Similar to that for gas turbines
Efficiency	Narrow peak range	High over wide range
Average operational efficiency	25-38%	97% Drive (+ 95% HVDC Transmission + 60-80% generation)
Major maintenance cycle	20,000 hrs	100,000 hrs
Minor maintenance cycle	2,500 - 4,000 hours	25,000 hours
Minor maintenance duration	6-10 days	1-2 days
In operation system MTBF	4,000 hours	> 25,000 hours
Control Response	Slow	Medium to quick
Logistics Delivery time	3-4 years	1-2 years

Synchronous Motor Power and Efficiency

Electrical drives have more than 10 times faster response and excellent dynamic performance. This improved controllability has an energy efficiency benefit for the application as well. In the case of compression, the improved controllability allows better balance between compressor stages and consequently less energy-wasting recirculation flow. An electrically-driven compressor can operate with a lower surge margin which improves the thermodynamic performance range. Higher efficiency and reliability in the drive means that larger trains are possible; and large compressors are more efficient, too. The cumulative effect of these benefits yields an average of between 3.5% to 5.0% efficiency improvement in large (e.g. LNG) compressor applications (ABB Inc, Oil & Gas Norway, 2008). The payback compared to a conventional gas turbine drive is less than half a year.

Synchronous motors are generally more efficient than induction motors at higher power ratings, as shown in the following figure (data up to1600 hp). At even higher power ratings (above 9000 hp) this improved efficiency favors synchronous motors in lifecycle costs when compared to induction motors. Synchronous motors are typically used at lower speeds relative to induction motor applications, but are more expensive, more complicated, and have higher maintenance costs compared to squirrel-cage induction motors.

In the past, synchronous motors were favored due to their speed control capability by simple frequency variation, and also for their ability be used for **plant-wide power factor correction** . Variable Frequency Drives (VFDs), however, can now provide the precise speed control of induction motors that was previously only possible through frequency control on synchronous motors. Some drive types equipped with active front-end power electronics may also be used in plant-wide PF correction as well. One area where synchronism has the advantage; the inherent slip of induction motors, which increases with load, may lead to slower speed response to load changes. Fast response is necessary to reduce the risk of pressure fluctuations in some dynamic pumping applications, for example.



1000 hp = 746 kW

Figure 2.21 - Typical Full Load Efficiencies for synchronous vs. induction motors, (IEEE, 2007)

The pulling-in requirement of synchronous motors makes them generally unsuitable for large fan applications as found in power generating stations forced and induced draft drive power.

Switched Reluctance Motors

Switched reluctance motors offer very high efficiency, but are still limited to relatively low-power applications, typically up to only 75 kW. This motor technology is in rapid development and may lead to higher power ratings in the near future.

Permanent Magnet Motors

In PM motors a magnet is used in the stator for generating a magnetic field. The position of the rotor is determined by motor control electronics, which then adjust the modulated stator field accordingly. By eliminating one set of windings and the associated ohmic losses, this motor design is more efficient than induction motor types. High cost of the magnet material has restricted this motor type to relatively low power (< 2kW) applications. Changes in the relative prices of magnets and copper, coupled with lower prices of motor electronics, may eventually make this motor feasible for higher power situations.

Motor Nameplate Terminology

Standards bodies such as the NEC and NEMA have agreed on definitions for the following induction motor parameters which must be prominently displayed on the motor nameplate and provided with the vendor's documentation.

- **Rated voltage or voltages:** This value has a 10% tolerance covering common voltage variation in some industrial networks
- **Rated full-load amps for each voltage level:** The nameplate FLA is used to select the correct wire size, motor starter, and overload protection devices necessary to serve and protect the motor.
- **Frequency:** This value is either 60 Hz in North America, and 50 or 60 Hz elsewhere.
- **Phase:** Either single or 3-phase
- **Rated full-load speed (rpm):** The motor speed under full load conditions.
- **Insulation class and rated ambient temperature:** A measure of motor's ability to dissipate heat.
- **Rated horsepower:** The work available from motor at full load torque and speed
- **Time rating:** Standard motors can operate continuously at their full-load torque and speed. For intermittent duty applications, a time rated motor can be selected to reduce weight, size and costs.

- **Locked-rotor code letter:** A code letter that defines an inrush current a motor requires when starting it.
- **Manufacturer's name and address**

In addition to this required information, motor nameplates may also include data such as frame size, NEMA design letter, service factor, full-load efficiency, and power factor.

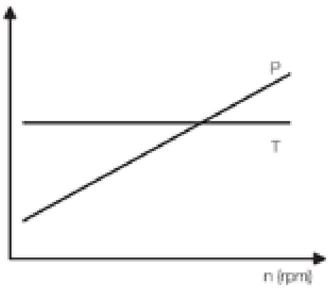
Motor System Loads

A motor application is fundamentally defined by the load's torque-speed requirement, the duty cycle, and the load profile.

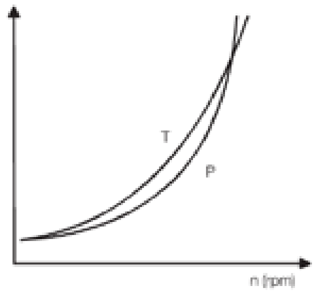
Load Torque vs. Speed Requirement

According to these definitions from ABB's Technical Guide (ABB Drives 2002) and the Competitek Drive Power manual (Competitek 1996), the applications can be categorized by how the power varies with motor speed.

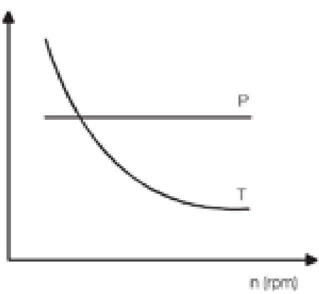
- Linear-law loads require constant torque across the entire speed range, and power consumption varies linearly with speed. Examples of this type of load are: **reciprocating compressors** , positive displacement pumps, drilling machines, **conveyors** and grinding systems (curve (a) on page 112).
- **Cube law loads require a torque which varies with the square of speed, and power consumption varies with the cube of that speed. Examples of this type of load are: pumps and fans and winders. The prevalence and high power consumption of these loads is why they deserve special attention in designs for improved energy efficiency** (curve (b)).
- Constant power loads; A constant power load is normal in steelmaking when material is being rolled and the diameter changes during rolling. The power is constant and the torque is inversely proportional to the speed (curve (c)).
- Constant torque, then constant power loads. This load type is common in the paper industry. It is a combination of constant power and constant torque load types. This load type is often a consequence of dimensioning the system according to the need for certain power at high speed (curve (d)).
- Square law loads require a torque which is directly proportional to speed, and power consumption varies with the square of that speed. Examples of this type of load are hoists and winches.
- Constant speed loads are applications which require constant speed but varying torque. Examples of such applications are grinding and milling machines, sawmill blade cutters and escalators (Competitek 1996), and extruders, all of which must run at the same speed regardless of loading.



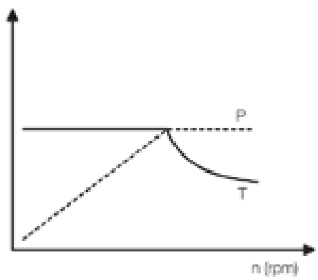
(a) Constant torque



(b) Cube-law loads



(c) Constant power



(d) Constant torque, then constant power

Figure 2.22 – Load types by torque vs. speed performance, (ABB Drives 2002)

Load Duty Cycle and Load Profile

The term ‘duty’ describes how the load is used over a fixed time period. Loads which are frequently turned off and on are known as ‘cycling loads’. A repeating pattern of load activation over a time period is known as the duty cycle.

Near-continuous loads are known as ‘heavy-duty’ loads. These loads are best characterized by their loading profile over a fixed period of time. This profile is the % of time spent at various discrete % of load levels, as shown in the figure below.

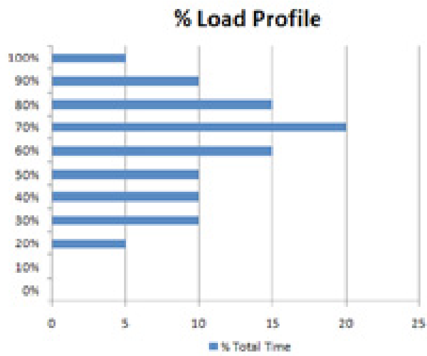


Figure 2.23 – Load profile showing %-load versus %-total time (annual)

Load Startup Requirement

Startup torque requirements vary widely, from a fraction of the full-load torque to applications that require several times the full-load torque for starting. The load curve for a high starting torque type of application is shown in the figure below. Typical applications for this load type are centrifugal fans, extruders and screw pumps/ compressors.

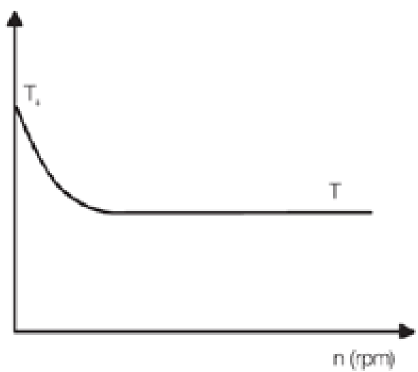


Figure 2.24 – Load type curve where high starting torque is needed, (ABB Drives 2002)

Motor **soft-starting** is needed in applications which are sensitive to shock or high motor torque during startup. For example, NEMA Design B motors produce a starting torque which is about twice its full load torque (Competitek 1996). Other drive-train components can also benefit from the smooth acceleration provided by soft-starting.

Dynamic Torque and Acceleration

The load characteristic curves shown above reflect the steady-state torque required at different speeds. Accelerating (or decelerating) between different speeds requires a positive (or negative, braking) 'dynamic' torque to be supplied by the motor drive system in addition to the load torque which the application (pump or fan, for example) requires.

The driving torque of a motor during startup is the 'run-up' torque and the acceleration time to achieve nominal speed is known as 'run-up' time. The driving torque must exceed the load torque by a margin in order for satisfactory acceleration to occur.

Torque T [Nm] is related to speed through Newton's Law for rotating bodies of inertia J [kgm^2]. Torque is proportional to the rate of change of this speed n [rpm], when expressed as [$radians/s^2$]. The change of rotational speed within a given time period is its acceleration (or deceleration) and is as follows:

$$T = T_m - T_{load} = J \times (\Delta n / \Delta t) \times 2\pi/60$$

Moment of inertia J is the sum of the load and motor moments of inertia, as supplied by the machine builders. If the rotating components are circular, with radius r and a relatively homogenous mass m, then J can be found by:

$$J = ½ \times m \times r^2$$

The above formula can be applied to large fans, for example. If there is a mechanical gearbox between motor shaft (1) and load shaft (2), then all load-side inertias must be reduced by the square of the inverse of the gear ratio (the ratio of the number of teeth) as follows:

$$J = J_2 \times (n_2/n_1)^2$$

These formulas are useful for determining acceleration times of large inertia loads, as shown in the following example from an ABB Technical Guide (ABB Drives 2002);

For example: accelerating a fan to nominal speed is done with nominal torque. At nominal speed, torque is 87%. The fan's moment of inertia is 1200 kgm^2 and the motor's moment of inertia is 11 kgm^2. The load characteristic of the fan T^{load} is quadratic as shown in the figure below, relative to nominal. Motor nominal power is 200 kW and nominal speed is 991 rpm. Calculate the approximate starting time from zero speed to nominal speed.

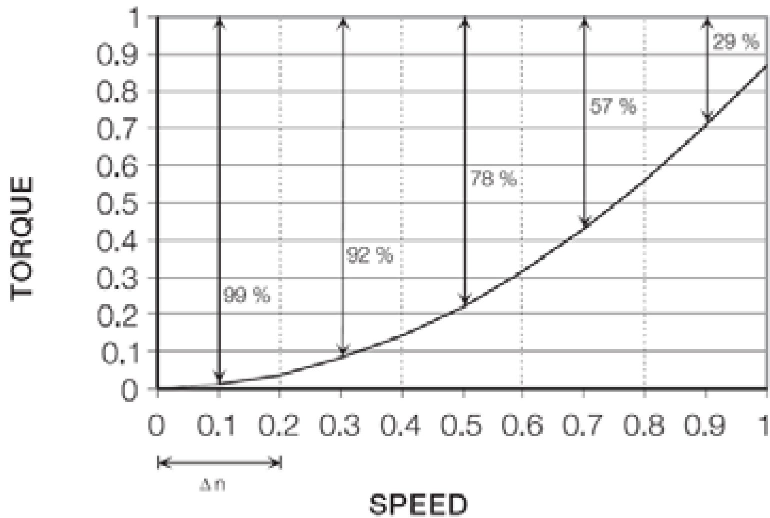


Figure 2.25 – Fan torque vs. speed, with relative values at five equidistant speed points, (ABB Drives 2002)

Motor nominal torque is:

T_n = 9550 x 200 / 991 =1927 Nm

The starting time is calculated by dividing the speed range into five sectors. In each sector (198 rpm wide) the torque is assumed to be constant. Torque for each sector is taken from the middle point of the sector. This is acceptable because the quadratic behavior is reasonably approximated to be linear in each sector. The time to accelerate the motor (fan) with nominal torque can found by re-arranging Newton's formula as follows:

$\Delta t = J \times \Delta n /(T_m - T_{load}) \times 2\pi/60$

Acceleration times for each of the five different speed sections are:

0 to 198.2 rpm	$\Delta t = 1211 \times 198.2 /(0.99 \times 1927) \times 2\pi/60 = 13.2$ s
198.2 to 396.4rpm	$\Delta t = 1211 \times 198.2 /(0.92 \times 1927) \times 2\pi/60 = 14.3$ s
396.4 to 594.6rpm	$\Delta t = 1211 \times 198.2 /(0.78 \times 1927) \times 2\pi/60 = 16.7$ s
594.6 to 792.8 rpm	$\Delta t = 1211 \times 198.2 /(0.57 \times 1927) \times 2\pi/60 = 22.9$ s
792.8 to 991 rpm	$\Delta t = 1211 \times 198.2 /(0.29 \times 1927) \times 2\pi/60 = 45.0$ s

The total starting time from 0 to 991 rpm is approximately 112 seconds.

The above formula in English units is:

$$\Delta t = WK^2 \times \Delta RPM / (308 \times (T_m - T_{load}))$$

Where:

T	= Torques in lb-ft
WK^2	= Total inertia (motor and load) in lb-ft^2
ΔRPM	= Change in motor speed in rpm,

Motor Characteristics

This section is based on information in the standards NEMA MG-1, IEEE Design Guide 666.

Since the majority of motors in process and power plants are of the squirrel-cage induction type, this is the type which will be the main focus of the following sections.

Torque vs. Speed Performance

The fundamental characteristic of any induction motor is its torque vs. speed performance. The points of interest on a torque-speed curve are shown on the figure below.

- Locked-rotor torque point (a) occurs at zero speed,
- Pull-up torque point (b) occurs during acceleration,
- Maximum motor torque point (c)
- Operating point (d) on the figure is the nominal, full-load operating point of the motor. This point is the source of the nameplate parameters on the motor. The full-load speed is typically 96% to 99% of the synchronous (‘no-load’) speed.

Note that when the machine operates with negative slip, it is in generator mode (region G on the figure) and the torque versus speed performance is inverted.

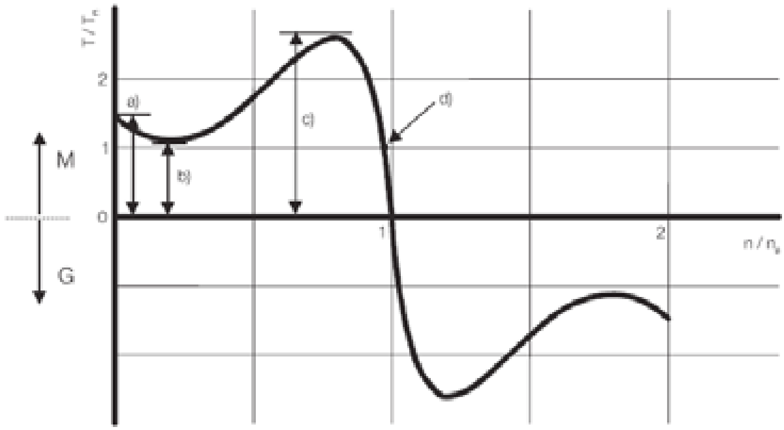


Figure 2.26 - Torque vs. speed for squirrel cage induction motor, (ABB Drives 2002)

Small to medium-sized motors are a commodity item. For these standardized, polyphase induction motors NEMA has developed a rating designation (A,B,C,D,E) for different application requirements. Large motors, however, are typically custom engineered to a specific set of loading and service conditions, and are therefore not subject to easy rating or classification. Large motors still share some characteristics with the NEMA motor classes described below.

Normal Starting Torque Motors

- Normal starting torque, normal starting current, low-slip and high efficiency.
- Centrifugal pumps and motor generator sets, infrequent starting duty; used where high efficiency and high full-load speed are required. Modification of the motor design can provide variations in torque characteristics and increased thermal capability required for drives such as high inertia fans.

High Starting Torque Motors

- High starting torque, normal starting current Centrifugal pumps, fans, unloaded conveyor, vacuum pumps. This is the general-purpose motor suitable for pump and fan drives.
- High torque, high slip motor; has relatively high starting torque and normal efficiency at full load. Positive displacement pumps, compressors, loaded conveyors, crushers without flywheels, pulverizers. This motor has the high starting torque motor with almost constant torque throughout the entire speed range

– High torque, high starting torque, but with lower starting current. Car puller, crusher with flywheel, pulverizers, and high inertia drives that do not require high efficiency. Design D has higher starting torque than C, but motor efficiency is lower.

Motor Service Factor

Motors will have a service factor (SF), typically 1.0, or 1.1, or 1.15. As an example; a 1000hp motor with an SF of 1.15 means that the motor could be run at 1150 hp indefinitely without risk of overheating, but only at the rated voltage and frequency conditions. The standards specify that the motor can operate at a nameplate temperature rise of 90°C at service factor horsepower. SF offers a means to avoid oversizing a motor to handle temporary modest increases in load and uncertainty about loading.

Designers must be aware that higher temperatures will reduce a motor's ability to withstand some of the other effects, such as increased harmonics, which stress the insulation. The IEEE offers some further warning; the efficiency and power factor at service factor load can be different from the respective values at rated nameplate levels. It may not be energy-efficient to run for long periods at SF horsepower. Another consideration for designers wishing to actually use the SF margin is that the motor's starting and breakdown torque capability is based on rated horsepower only. If the starting torque requirement was high to begin with, and was then significantly increased under the new SF operating conditions, then there is no guarantee that the motor will be able to start within an acceptable time limit.

With careful design of the power system, as described in the **Power Systems section**, a well understood loading condition, and with robust real-time monitoring of the motor, it is worthwhile and defensible to exploit allowable SF margins of a high-quality motor. The motor will be more correctly sized to its application and will offer improved efficiency at normal operating conditions.

In some applications, extra drive power is required for short durations; for example to maintain condenser performance during peak supply on a hot summer day. In these cases, a VFD will be able to increase speed to within the SF limits, while the VFD drive diagnostics continually monitors motor temperature.

A NEMA committee warned a long time ago (in the 1960's) against use of SF on large motors as an alternative to a higher standard horsepower rating. Their advice on this issue is reproduced below:

– ‘Standard horsepower increments in the larger ratings are usually within a 1.15 range, so that the next larger standard horsepower can be reasonably selected in lieu of the service factor.
– ‘Use of a larger horsepower when overload is required avoids exceeding the nominal temperature rating for the class of insulation system used and avoids any encroachments upon the thermal life of these larger, vital motors.’
– ‘Use of a larger horsepower when overload is required eliminates any reduction in torque margin.’

Advances in motor technology over the last half-century, however, may eventually lead NEMA to a revision of their old guidelines and allow designers the room to improve energy efficiency without any fear of compromising reliability.

Motor Power and Efficiency

The power and speed requirements are set by the application’s load profile. For example, in pump and fan applications, the load torque decreases with the square of the speed; this is a direct result of the **Affinity Laws** discussed in the Pump and Fan systems sections. The power rating of a motor indicates its output mechanical power, often stated in horsepower or kW. Motor electrical (input) power is usually stated in kVA.

Motor Mechanical Power

The motor’s mechanical output power is simply the output torque multiplied by motor speed. In SI units:

$$P_m = T \times N$$

Where:

T = torque, (Nm)
P_m = mechanical power at the shaft (watts)
N = speed, (rad/s)

The same formula with power in kW and speed N in rpm (where 1 rpm = 2 x π / 60) is:

$$P_m = T \times N / 9550$$

Where:

T = torque, (Nm)
P_m = mechanical power at the shaft (kW)
N = speed, (rpm)

The same formula again, in all English units is:

$$P_m = T \times N / 5252$$

Where:

T = torque, (lb.ft)
P_m = mechanical power at the shaft (rated hp)
N = speed, (rpm)

For example: a motor has nominal power of 250 hp and nominal speed is 1480 rpm. What is the nominal torque of the motor (in lb.ft)? Using the last of the above formulas:

$$T_n = P_m \times 5252 / N = 250 \times 5252 / 1480 = 887 \text{ lb-ft.}$$

Motor Input Power and Current

The nominal electrical motor input power (in kW) can be calculated based on the mechanical output power, as was calculated in the above formulas, and the nameplate efficiency:

$$P_{in} = P_m / \eta$$

Where:

P_{in} = input power (kW)
P_m = mechanical output power (kW)
η = per-unit efficiency of the motor (0 to 1)

If the output power is given in horsepower (hp), then use the conversion factor 1 hp = 0.746 kW. The total input power in kVA can be expressed as:

$$S = (P_m \times 0.746) / (\eta * FP)$$

Where:

S = total input power (kVA)
P_m = mechanical output power (hp)
η = per-unit efficiency of the motor (0 to 1)
PF_P = per-unit power factor

The active power (kW) at the motor terminals can also be calculated from electrical parameters $P_{in} = 3^{½} \times V_{L\text{-}L} \times I_L \times PF_P$

Where:

P_{in} = power (kW)
V_{L-L} = three phase line-to-line voltage (kV)
PF_P = per-unit power factor ($\cos(\phi_n)$)

For example: What is the nominal efficiency of a 400 kW (V= 4.16kV, 71A and PF_P = 0.85) motor?

The above formulas can be used to calculate the nominal efficiency of the motor as follows

$$\eta_n = P_m / P_{in} = 400 / (3^{½} \times 4.16 \times 71 \times 0.85) = 0.92 \text{ (approx)}$$

To calculate the input electrical energy cost for R running hours, given input voltage and current and a Price:

$$\text{Cost} = 3^{1/2} \times V_{L-L} \times I_L \times PF_P \times R \times \text{Price\$/kWh} / 1000$$

The VFD section contains additional formulas for **estimating motor current**, and additional **electric power formulas** are in the Electric Power System part of this handbook.

Motor Efficiency

Motor efficiency refers to the amount of input electrical power required to achieve a particular output from the motor. Using the power formula from above, a 100 hp rated motor with 93% efficiency at rated load will draw 89.1 kVA from the supply when running at full load and 0.9 power factor. The motor current at this operating point is shown as the FLA (full load amp) rating on the motor nameplate.

Most motors will the show nominal full load efficiency value on their nameplate as determined by a highly-accurate dynamometer and a procedure described by IEEE Standard 112, Method B. These measurements provide average values from a large test sample of motors. The motor efficiency of an individual motor in the field can only be determined by field testing methods, such as measurements with a watt-meter. Statistics on the manufacturer’s test sample provide a minimum efficiency value which also appears as the ‘guaranteed minimum efficiency’ on the nameplate; this value assumes that the worst motor in the sample could have losses as much as 20% higher than the average. These minimum values are in Table 12-8 in NEMA MG-1 (Cowern, Baldor Electric, 2004).

Standard motors tend to operate most efficiently at between 75–110% of full load speed. Smaller motors are less efficient than larger motors. Standard motors below

200 hp have efficiency between 80 to 90%, while the efficiency for motors in the range of 250 to 5000 hp varies between 90 to 96%. Larger motors with higher peak efficiencies tend to have flatter efficiency curves above 50% load, as shown by curves (1) and (2) in the figure below. For these larger motors, maximum efficiency is still at about 95%, but with only a small (0.3 to 1.0%) decrease to full load.

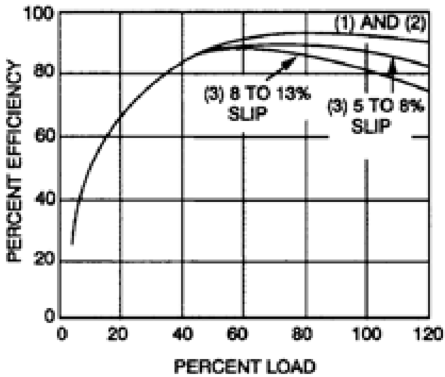


Figure 2.27- Efficiency vs. Load for squirrel cage induction motors, (IEEE, 2007)

As the curve shows, efficiency drops sharply below 50% load for all motors. An average 100 hp standard- efficiency motor loses 15% in efficiency as load decreases from 50% to 25% of full load (Competitek 1996). As a general rule, smaller motors lose more efficiency than larger motors at lower loads.

Motor Losses and Efficiency

The greatest losses in a motor are the iron losses that occur in the rotor and stator, accounting for 50 percent of the total loss. This can be improved by using low loss steel and thinner laminations. Copper losses account for 20 percent. Using an optimum slot fill design and larger conductors can reduce these losses. Bearing friction and windage losses total 23 percent and can be reduced by using a smaller cooling fan. Stray losses, which account for 7 percent of the total, can be reduced by improving the slot geometry. The main sources of motor losses and corresponding design improvements are shown in the figure below from the ABB Review Special Report on Motors & Drives, 2005. By virtue of these design changes, motors have improved in efficiency by an average of 3 percent in the last decade (from 1995 to 2005).

There are important design trade-offs between losses and torque performance; low rotor resistance results in high full load speed (low slip), high efficiency (low rotor losses), and slightly higher starting current. High rotor resistance results in high starting torque for line current drawn and slightly lower current during starting, but results in lower full load speed and lower efficiency (high rotor losses).

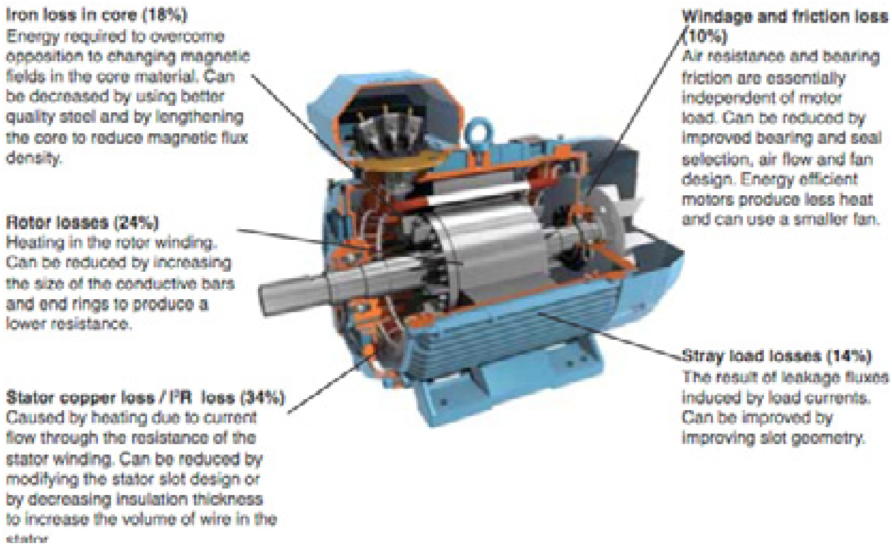


Figure 2.28 – Cutaway view showing sources of motor losses, (ABB Drives, 2006)

Rotor ohmic (I^2R) losses are proportional to slip and are in the rotor winding of a squirrel cage motor. Higher-efficiency motors tend to have lower slip and will therefore rotate faster under the same loading conditions: one percent increase in efficiency is equal to about a 1/3 of a percentage point decrease in induction motor slip. Voltage at the motor terminals also has an effect on efficiency, as discussed in the section on **Power Quality - Voltage and Frequency Variation**

Power Factor

Power factor (PF) is a measure of the amount of reactive power which the motor draws from the power source. A PF less than 1.0 means that some reactive power, which is induced by the motor coils, must be generated and carried by the power supply system. Industrial end-users pay a demand charge based on maximum reactive power usage within a certain time period. This charge is in addition to the regular cost of energy, charged per kWh, and covers the provider's cost for the increased size of their power delivery equipment. An oversized electric motor will typically decrease (i.e. worsen) the PF by 10% compared to a right-sized motor.

PF in induction motors generally follows the same shape as the efficiency curves with respect to % loading.

PF is a minimum at no load and reaches a maximum near full-load condition. This relationship between PF and motor speed is shown in the figure below, from IEEE

Std 666. The average 100 hp standard-efficiency motor loses about 10% points in PF from full load to 50% load, and almost 20 more points moving down to 25% load. The PF as listed on the nameplate applies to the full load operating condition.

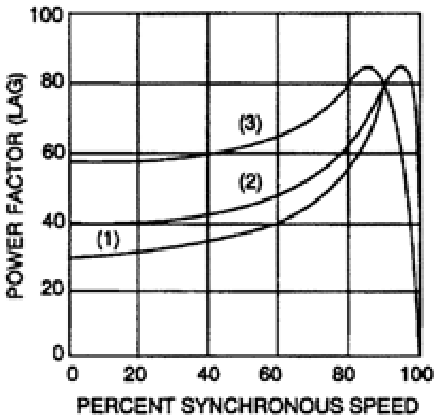


Figure 2.29 - PF vs. Load for squirrel cage induction motors, (IEEE, 2007)

The capacity of the power system to deliver real power (the only kind which can do real work) can be increased by applying **various reactive power compensation methods**, either at the motor, or centrally in the electrical power supply system.

High-Efficiency Motors

With the Energy Policy Act (the EPAct) of 1992, the USA and Canada imposed new, minimum efficiency standards, effective from October 1997, for general-purpose induction motors of NEMA designs A and B. These motors are typically 3–8 percentage points higher in efficiency than standard motors. The EPAct specifically targets motors from 1 to 110 hp (0.75 to 150 kW) as prime candidates for improvement, with a published list of high-efficiency motors and reduced electricity tariffs for users of these motors..

A similar program by the Danish Energy Authority published a list of high efficiency motors and offers subsidies for motors purchased from this list: US$ 10 per kilowatt for both new plant and for replacements. In the EU there are three class levels of efficiency, known as Eff1, Eff2 and Eff3, applying to low voltage two- and four-pole motors with ratings between 1.1 and 90 kW. Both the US DoE and the EU require that a motor's efficiency rating be prominently displayed on the motor's nameplate.

A higher-efficiency, 'premium' NEMA class of motors is also available, known as class E. The price of these premium, higher efficiency motors ranges from 10 to 20 percent higher than standard motors in continuous duty applications (US DoE

Sourcebook, 2006). A high efficiency motor has lower energy losses (described in the figure below), hence lower running temperature and improved reliability; all desirable characteristics in critical and high-duty applications. These NEMA premium efficiency 3-phase motors have efficiencies ranging from 86.5% at 1 hp (750 W) to 95.8% at 300 hp (220 kW).

The recent legislation in the Energy Independence and Security Act of 2007 (EISA) calls for increased efficiency of motors manufactured after December 19, 2010. EISA regulation re-classifies EPACT minimum efficiency motors as Subtype I, so these motors will be required to have nominal full-load efficiencies that meet the levels defined as 'premium' by NEMA MG-1 (2006). The EISA law also creates a completely new category (Subtype 2) of motors which regulates efficiency for motor designs that were not covered under previous legislation, such as polyphase motors rated at less than 600 volts.

Motor Slip and Energy Efficiency

High efficiency motors tend to have less slip at a given load compared to standard efficiency motors. The reduced slip may provide improved torque vs. speed characteristics, but the increased speed at operating point may incur power losses greater than the gains of increased motor efficiency. The increased speed is an important factor to consider when facing a **motor retrofit situation**. A general rule of thumb is that every 1% increase in efficiency is equivalent to about a 1/3% decrease in slip (Competitek, 1996). The losses due to increased speed occur only in constant speed applications, and are largest in cube-law applications such as fan and pump systems. The gains from using high-efficiency motors can be preserved by 1) specifying a variable speed drive to reduce speed, 2) specifying a smaller rated motor (if peak loads allow) or 3) compensate by trimming the pump impeller or fan blades (Competitek, 1996) 4) specifying a high-slip, but still relatively more efficient replacement motor.

Motor Couplings, Speed Control & Variable Frequency Drives

Motor Shaft Couplings

A motor's shaft can be either directly coupled to the drive shaft of a pump or fan, or indirectly coupled by using chains, belts or gears. Indirect coupling is necessary when physical space or layout restrictions prevent the motor from being in-line with the drive shaft, or to allow for mechanical speed adjustment.

Speed 'adjustment' is not the same as speed control, in which speed can be varied continuously by a signal from an operator or an automatic controller. The pros and cons of the various coupling methods are discussed below, but direct shaft-to-shaft coupling is the only method with zero drive-train losses.

Chain Drives

Chain drives have no slip and are suitable for low speed, high torque applications. They are high-maintenance couplings, but can achieve efficiency up to 98%. The desired speed adjustment is achieved by changing the diameters of teeth of the chain wheels.

Belt Drives

Belts have the lowest efficiency of all the common coupling methods, V-belts are the least efficient belt type due to inherent slip, followed by cogged V-belts flat belts, and synchronous belts. Synchronous belts are the most efficient belt type (up to 97%), but are intolerant of abrupt changes in loading (Competitek, 1996). The desired speed adjustment is achieved by changing the diameters of the belt pulleys. In standard belts, wear leads to increased slippage and reduced efficiency. Synchronous belt pulleys are available only in discrete sizes; and adjusting belt drives to achieve the optimum speed may be impossible.

Gear Drives

Gear reducer efficiencies depend on the type of gear and reach 98% for helical and conic gears. Screw and worm type gear drives have efficiencies from 66 to 96%. (Competitek, 1996) Due to higher cost, however, gear drives are less common than other coupling methods. Gear drives are more suitable for low speed, high torque loads. The desired speed adjustment is achieved by changing the number of teeth of the gear wheels.

Coupling Alignment

Torque is reduced by about 1% per degree of misalignment up to 5 degrees, after which failure is likely. (Competitek, 1996) Flexible couplings compensate for minor alignment errors and reduce the risk of bearing failure, but at the cost of reduced efficiency. Rigid couplings with laser-aided alignment are recommended practice on high-performance machinery.

Multiple Speed Motors

A form of speed control is possible with multiple speed motors, constructed to be able to operate at one of several discrete speed settings. There are two basic designs: motors with multiple poles or motors with multiple windings. Selective energizing allows these motors to achieve different multiples of speed. The former design (also known as a consequent pole motor) has only two speeds, but the motor with multiple windings and poles can have 2, 3 or 4 speeds. For example, a 2-speed, 2-winding motor can provide ratios of 2:1, 3:2, or 4:3 (Competitek 1996). In two-speed induction motors, the low speed is typically selected for the most common operating point and the higher speed for all the higher loads, including ‘test block’ load (Black & Veatch 1996).

Multiple speed motor systems have some inherent disadvantages; 1) for large motors, switching between speeds is neither trivial nor smooth and may lead to process transients and upsets. The sequence of power breaker and pole switching must be closely coordinated with motor speed 2) Multiple speed motors tend to be slightly less efficient than single speed motors, due to compromises in their design to allow for multiple sets of windings. Although they deliver savings in cube-law applications, they are still less efficient than the VFD plus single-speed motor combination.

Wound Rotor Motors

Wound rotor motors are induction motors with a slip-ring and brush assembly which connects the rotor to an external variable resistor. Varying this resistance will change the rotor resistance and slip, hence speed of the motor. The disadvantage of this motor type is that significant slip energy is dissipated in the resistor (Competitek 1996). Slip-recovery variations (Kramer and Scherbius drives) on wound rotor designs increase the efficiency to VFD plus motor levels (Competitek 1996). The brush assembly is similar to that found on DC motors and is a source for the same maintenance and reliability issues associated with DC motors.

Variable Speed Control Technologies

There are a number of different coupling technologies specifically for continuous speed control which are commercially available and feasible for large industrial machinery: hydrodynamic, hydro-viscous, magnetic, and DC or AC variable speed drives (known as a **Variable Frequency Drive (VFD**) for AC systems). All of these technologies provide the necessary speed control and achieve energy savings over the less efficient flow control methods such as control valve or damper throttling.

- In hydrodynamic type couplings, the shaft drives an impeller which imparts energy to oil which then transfers it to blades of a runner fixed to another shaft. Control is achieved by varying the amount of oil via a scoop tube. The hydrodynamic coupling will always have slip losses, even at rated speed, typically 2%-3%. The hydraulic coupling offers a form of soft-start capability, but this comes at the expense of controllability at low speeds (Competitek 1996). This type of variable speed arrangement is still common in many existing plants (Black & Veatch, 1996).
- In the hydro-viscous type of variable speed control, a thin film of oil between a series of discs transfers energy from the driving shaft to the output shaft through shear forces. Speed control is achieved by varying the pressure on the discs. The hydro-viscous coupling can be locked at rated speed, incurring no losses, which make this type of drive useful as a clutch for starting.

- In a magnetic variable speed coupling, torque is transmitted from the motor to the load across an air gap. The torque is created by the interaction of powerful rare-earth magnets on one side of the drive with induced magnetic fields on the other side. By varying the air gap spacing, the amount of torque transmitted can be controlled, thus permitting speed control. In magnetic coupling torque at full rated motor speed, the slip is between 1% and 3% (Magnadrive, 2008). However, demagnetization occurs at about 300ºF for some of these drives, which may be a problem in some application environments.
- Permanent magnet eddy current couplings allow for vibration isolation between the load and the motor, but are large, have poor turndown characteristics and poor efficiency at lower speeds.

For a technical description of a typical Variable Frequency Drive, see section on **VFD Concepts** in this handbook. For more details on the other variable speed technologies, see references such as RMI-Competitek's Drivepower Manual. When compared to the other variable speed methods, VFDs are generally more efficient, have better power factor and offer more precise speed control (Competitek 1996). The fast and direct action of a VFD on the prime mover also means it is better able to mitigate common problems created by resonant frequencies at certain speeds. A great advantage of VFDs over most other methods is the ease with which they can be retrofitted; they make no extra demands on the physical space and layout of the process area. This area is typically highly engineered, compact, and often difficult to re-arrange. Even greenfield designs benefit from the layout flexibility that VFDs provide compared to the bulky in-line equipment required by other forms of variable speed control

Motor System Design & Engineering

The common motor system design & engineering steps are summarized below.

Step 1: Gather data on load and power system requirements:
- Gather data on the application peak and continuous power & speed requirements; inputs are the pump or fan system ratings
- Gather data on motor duty cycle; its cycling pattern (# of start, stop per period) and its load profile (% time at % loading)
- Gather data on any special needs for braking or regeneration of power.
- Gather data on the power supply system; voltage levels, frequency, power capacity
- Gather data to determine other requirements for physical and environmental factors; such as required IP class, mounting type etc. see (IEEE, 2007)11.6.1 for complete list of motor selection factors

Step 2: Determine motor ratings

- Calculate maximum running torque and input power, using **average or peak-load sizing methods**
- For VFD speed control, follow the **design guidelines** in that section to determine motor loadability.
- Determine starting conditions based on process requirements & power supply; inertia, starting time requirements, load torques during startup, **voltage drop on bus** due to high starting current, resonance vibration frequencies during startup.
- Use the minimum voltage if starting with reduced voltage as basis for calculating motor speed vs. Torque, and ensure at least 10% margin over the pump torque vs. speed during startup

Step 3: Select motor type and rating based on the above work; the minimum motor specifications needed are listed below.
- Design type: Induction vs. Synchronous
- Power rating
- Efficiency Rating and efficiency vs. speed
- Speed, Frequency and Slip (vs. speed)
- Voltage Level : LV or MV
- Service Factor
- Frame size : NEMA frames or IEC frames
- Required IP class enclosure, mounting type (vertical vs. horizontal)
- Synchronous speed and number of poles

Problem of Motor Oversizing

Oversizing of motors is a very common, but hidden cause of energy inefficiency. Oversizing does not lead to any highly visible failure events, but it is a continuous, low-level problem as energy costs and total emissions accumulate. Oversized motors, those operating an average of less than 60% of rated load, will incur three operational penalties:

- Reduced motor efficiency
- Reduced slip (hence higher speed); important for cube-law load applications
- Reduced (worsened) Power Factor (PF)

Data from the US electric power utility PG&E showed that one-half of industrial motors are operating at less than 60% of their rated load, and one-third are operating at less than half their rated load (cited in Competitek, 1996, Ch.9). According to the same source, motors operating below 60% load incur an efficiency penalty of 0.5 to 1.5 percentage points. Motors operating at half their rated load are 2.0 to 4.0% less efficient than at rated load.

Starting a Direct-On-Line (DOL) over-sized motor means the motor starter and other power system components will need to be oversized, as the majority of starting current is reactive and dependent on the motor size; larger motors take more starting current. For this reason, VFDs and Soft Starters should be evaluated for suitability during the motor specification process. As the section on **Variable Frequency Drives** explains, these devices can correct for all accumulated design margins and also provide the required soft-start capability.

Engineers may wish to believe that the widespread problem of oversizing is actually due to under-loading; in other words, that the plant is operating at much less than its target rated capacity due to prevailing market conditions beyond their control. An analysis of the large motors in a US pulp and paper mill, however, revealed an average load times capacity factor of 43% at a time when the mills where operating at nearly full rated capacity (cited in Drive Power manual Competitek, 1996). Data such as these suggest that the problem of oversizing is real, and that it must be solved by engineers and technical managers.

Causes of Motor Oversizing

The causes of technical oversizing are investigated in detail throughout this handbook, but the story of how margins 'creep' in a typical project is told below, in the case of a large industrial motor:

The process designer, following the guidelines in the Pump and Fan Systems sections of this handbook, will provide the electrical engineer with the maximum required pump or fan torque at the required operating speed. This process specification is often misinterpreted, by the electrical engineer, to mean the minimum acceptable continuous torque for the motor even if the requirement is actually a peak load which must be sustained only for a small fraction of the motor's duty (Competitek, 1996).

The electrical engineer may further oversize the motor in the face of uncertain, high-starting torque requirements and other power system uncertainties, just as the process designer may have overstated the torque and speed requirements to account for later changes in piping design or capacity demands. Customer or company guidelines may force the electrical engineer to specify a high service factor (1.15) machine and class 'F' insulation, all of which add even more unnecessary margin.

The project lead engineer may add further layers of margin fat by applying an across-the board-design 'margin of error or safety', as well as a generous 'future capacity increase' margin. Finally, if the resulting specification is only slightly higher than a standard commercial rating, then the next and higher rating is usually selected. The gap between standard ratings is larger as motor power increases, which makes this common practice costly in the long run. Most of the above margins are compounded (margin as a percentage of the margin below), the end-result is a motor which is often twice as large as it needs to be.

Motor Sizing and Selection

The **motor design and engineering procedure** described previously will help to establish whether the maximum torque specification is a normal maximum or a short-duration peak maximum. If the value represents a transient peak torque, then other methods, such as a **motor service factor** margin should be investigated before this value is used as the baseline for sizing. The design procedure then calculates, from the maximum required torque at the required operating speed, the motor's power rating according to the **motor power formulas** and will establish the system (bus) voltages. (See ANSI C50.41-1982 for list of preferred motor rated voltages.) The nominal system voltages are slightly higher than the rated motor voltage due to anticipated steady state voltage regulation in the power supply system. Special attention to **motor starting conditions** is important for energy efficient design. As with peak running loads, transient conditions should be carefully vetted before they are allowed to form a minimum requirement. Other transient conditions such as high ambient temperature should receive the same critical profiling analysis as duty cycle. Worst-case estimation of ambient temperature may lead to extra thermal margins and larger than necessary machines.

Average Load Sizing

Maximum load sizing is the default method for sizing, but the alternative 'Andreas' method uses average-load power. This average load sizing is only for applications that do not require high inertia load starting or frequent starting, and which operate at varying loads. Since motor heating is a limiting factor in sizing a motor, this method uses the RMS (root-mean-square) losses, approximated by RMS horsepower over the load cycle, to determine the thermal suitability of a motor. The RMS horsepower is defined as 'that equivalent steady-state hp which would result in the same motor temperature rise as that of a defined load cycle' (See reference Competitek, 1996, for an example calculation.) The calculated RMS hp will indicate the required motor rating from thermal considerations, but the maximum peak load must still be within the range of that motor's service factor.

Motor Starting Conditions - Acceleration

The NEMA MG1 and ANSI C50.41 standards provide sizing rules based on the torque required for accelerating the inertia of a rotating mass. Induction motors built according to these standards develop at least 70% of their full load torque during startup, which should be sufficient for most load applications.

Motors serving high inertia loads such as fans, however, exceed the NEMA normal inertia limits. These special motors required for those applications tend to be oversized with additional thermal capacity to account for load torque and possible low voltage conditions, factors which slow the acceleration time period and thus allow the motor to accumulate more heat. See the **example for determining acceleration time** of an industrial fan in the **Fan Systems** section.

Motor Starting Conditions - Voltage

Low voltage conditions during startup are a particular challenge for large motor applications. The effect of low voltage starting conditions on developed torque is magnified, because torque drops with the square of the applied voltage. Very long acceleration times and increased heating or even the inability to reach full operating speed are some of the consequences of inadequate design for startup.

For motors running in island mode networks, such as oil platforms, even smaller motors might require starting methods other than DOL due to the lower short circuit capacity of such networks (ABB Review, Ahlinder, 2001).

The three most common designs for motor startup are: 1) Direct-On-Line (DOL), 2) Star-Delta 3) Soft-starters, which also include VFDs. Direct-on-line simply connects the motor terminals directly to the supply network. DOL is the lowest capital cost and most used system to start small squirrel-cage asynchronous motors. As shown on the figure (left) below, starting is carried out at full voltage, high current and with constant frequency; this develops a high starting torque with much reduced acceleration times. This method is useful for full-load starting applications. High inrush currents, first of 10-12 times rated current, then holding at up to 6-8 times well into startup, will stress both the power system and motor.

Star-delta and soft-starters or VFDs are collectively referred to as reduced voltage methods, with star-delta being the most common. In star-delta, inrush currents are reduced by using first a star circuit, then switching over to a delta circuit during later startup.

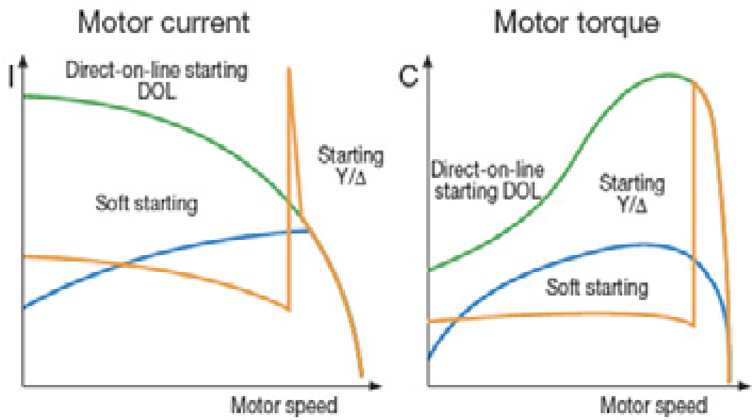


Figure 2.30 - Relative startup characteristics for different starting methods Ref (ABB Motors & Drives, 2007)

Carefully designed special lubrication and cooling systems will provide some extra thermal support margin needed by the motor for high transient load conditions. Existing motors can avoid being de-rated if extra cooling is available for such situations. Learning more about the process load and duty cycle, then careful calculation and proper mitigation efforts will help in right-sizing a motor under all conditions.

A high-starting torque design motor has lower operating efficiency at full load. For some applications with many starts & stops and short running times, however, a high-starting torque motor may be the overall most energy efficient selection.

Motors in Retrofit Situations

Downsize an Underloaded Motor

An underloaded motor has poorer efficiency and power factor. These motors can be identified in an energy assessment process. The replacement motor can be sized based on the actual load factor; a 100 hp (75 kW) motor at 50% loading can be replaced by a 50 hp (37 kW) motor. This replacement motor should be chosen to have higher efficiency, but careful attention to slip is important.

In an economic analysis of motor downsizing performed by RMI in their Competitek Drivepower Manual, an average 100 hp (75 kW) standard motor at less than 50% loading can be downsized (to a much smaller, but slightly more efficient model) for a payback in under 3 years, in a cube-law application. Additional benefits of a downsized replacement motor are a smaller motor starter and smaller, less expensive conductors (Competitek 1996).

Motor Upgrade to Higher Efficiency Model

In a fixed speed application, a motor upgrade to a higher-efficiency model with the same rating may inadvertently lead to increased power consumption if the new motor runs faster than the previous one, due to lower slip. The section on **Motor Energy Efficiency** offers guidelines on how to avoid this situation. See the section on **Lifecycle Costing** (LCC) for methods to calculate the energy and money savings related to motor efficiency improvements; a numerical LCC case example is provided at the end of this module.

Motor Rewinding

Another pitfall in retrofits is the loss of efficiency due to successive rewinds of an old motor. Typical rewinding practice degrades motor efficiency by between 0.5% to 2.5% for each rewind (Competitek, 1996)

A study by Ontario Hydro found an average efficiency reduction of 1.1% in small (< 15kW) rewound motors, concluding that an upgrade to a higher efficiency model was more worthwhile on motor failure.

Efficiency is lost in rewinds for several reasons: core losses increase due to the high temperatures experienced during failure; stripping the motor for repair also damages the laminations; copper losses increase because of the practice of using smaller conductors, increasing I^2R losses. Finally, fitting of universal cooling fans, which may not be designed for the particular motor, leads to an increase in windage losses (ABB Review, Special Report Motors & Drives, 2003).

Older, standard motors which have been rewound several times will be more than 10% less efficient than a high-efficiency motor. Rewound motors are also at risk of increased phase unbalance within the motor. The negative effects of phase unbalance are described in the section on **Power Quality - Phase Voltage Unbalance**.

Upgrade from DC to AC

A common retrofit opportunity involves upgrading older DC drives and motors to new AC ones. This upgrade is an opportunity to improve harmonics, power factor, uptime, spare part savings and other maintenance costs. In the past, DC drives and motors were the only solution for high starting torque and accurate speed control but this is not the case today. DC drives generate a high level of harmonic distortion and are high maintenance due to brush and collector wearing. Both of these factors reduce energy efficiency. The upgrade potential to AC is larger in certain industries which have a population of older, energy-inefficient DC motor controls; typically in the steel, cement and paper industries.

A DC motor upgrade may be an opportunity to use a **VFD with variable torque technology**. This drive can provide high starting torque and accurate speed control, along with the side benefits of reduced maintenance, improved PF, and reduced harmonics.

Motor Sizing and Selection Tools

A software package, MotorMaster+ 3.0 is available from the US DoE's 'Best Practices Program' to assist with motor selection. The software includes a built-in database of more than 27,000 U.S. motors and has the capability to compare different motors and compute relative costs (including initial, annual energy, and life cycle costs) and savings for the motors being considered.

Another package, DriveSize, is available from ABB Drives to help select a motor and a drive, and then calculate combined motor & drive efficiency.

Motor System Guidelines – Summary

The following design guidelines will generally improve the energy efficiency of the design or re-design of a motor system, at relatively low capital cost, with a short payback period:

- Downsize underloaded motors
- Upgrade to higher efficiency motors
- Upgrade old DC motors and controls to AC
- Use VFDs for speed control
- Avoid margin creep; follow **proper sizing procedures**

Many more tips for energy efficient motor systems can be found in the DoE EERE (US DoE Best Practices, 2008) Motor Tip Sheet.

Motor System Maintenance

The large number of motors in a plant requires a comprehensive motor management program to ensure they are managed cost-effectively. Such a policy helps bring together capital, maintenance and revenue budgets, showing the effect they have on each other when different types of motors are selected. Industrial users benefit from such a policy through reduced energy costs, by upgrading to high-efficiency motors at the most cost-effective time. The forward planning inherent in the practice helps reduce downtime. Inventory can also be reduced through a fast track delivery agreement. (ABB Review, Special report, Motors & Drives, 2005). Many technical tips for motor systems maintenance can be found in the DoE EERE (US DoE Best Practices, 2008) Motor Tip Sheet.

Motor System Cost Calculations

The investment costs for a motor are mainly hardware, engineering and installation costs. Combined, these costs are referred to as the total installed cost (TIC) of the motor. The hardware cost per hp generally decreases with the size of the motor, but varies greatly with motor type and other factors. As a first approximation, a large (>500 hp) standard induction motor has a hardware cost of about $100 per hp. The total installed cost can be approximated by adding 60% of the hardware cost, so the TIC in this case will be $160 per hp. A motor rewind can cost between $25 to $40 per hp.

Value Calculation Case

Sample comparison of two 2000 hp (1.5 MW) motors at 85 and 97 % efficiency over 1 year:

Energy Savings = 2000 hp x 0.746 kW/hp x 8,000 hrs/yr x 100(1/85 – 1/97) = 1,737,198 kWh
Dollar Savings = 1,737,198 kWh x $0.07/kWh = $121,603

Now applying LCC methods to determine the present value of the savings over 20 years at 6% RoR:

PV = 121,600 x ((1 + 0.06)20 - 1) / 0.06(1 + 0.06)20
PV = $1,394,742

The **Case Studies** section has a fully worked-out example of retrofit cost calculations with payback.

Variable Frequency Drives

VFD Concepts

Electric AC motors are the most common source of process industry drivepower due to their reliability and low cost. An additional feature of electric motors is that shaft speed or torque can be controlled by varying the electrical supply at the motor terminals. This feature is exploited by a separate piece of power electronic hardware known as the Variable Frequency Drive (VFD), some of which are pictured in the figure below.

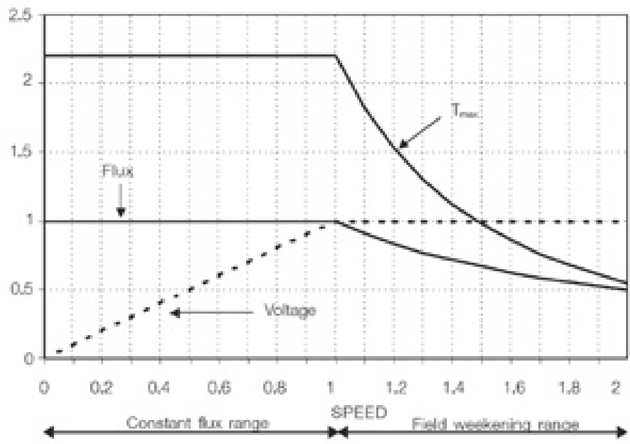


Figure 2.31 - Torque-speed curves for idealized VFD, (ABB Drives 2002)

VFD Energy Efficiency Potential

The main benefits of applying VFDs come from matching the input power to the needs of the process. These benefits are magnified in cube-law applications such as pumps and fan systems, where power requirements increase with the cube of speed, and the savings are typically between 30 and 50%. The following sections introduce the technical features of VFDs with the greatest potential for energy efficiency.

Speed Control instead of Throttling

Of the estimated 65 percent of industrial energy used by electric motors, some 20 percent is lost by wasteful flow throttling mechanisms. The mechanics of flow throttling is described in the **fan** and **pump** sections of this handbook. Additional energy is wasted in inefficient **variable speed coupling methods**. VFDs allow application speed to be controlled without energy-wasting flow throttling or inefficient belts and hydraulic couplings.

VFD controlled pumps and fans can respond faster and more reliably than flow throttling valves or dampers, especially at flow extremes when **control valves become highly non-linear**. VFDs avoid the problem of poorly-sized control valves which may be unstable for control at less than 10% opening. In fan systems, the use of a VFD for speed control avoids the deadband and hysteresis found in mechanical dampers or inlet guide vanes control methods. Damper leakage is also avoided when using VFDs for flow control. Compared to throttling control methods, VFDs have lower inspection & maintenance costs. Any reduction in speed achieved by using a VFD has major benefits in reducing pump wear, particularly in impellers, bearings and seals.

There are some additional side-benefits for VFD-flow control in pumping systems. With a VFD receiving a signal from a pressure transmitter, it is possible to monitor the pressure of the incoming pipeline and configure the converter to take steps if the risk of **cavitation** is high; i.e. if pressure falls below NPSHR plus a margin. Water hammer is caused by rapid changes in flow. These flow changes are followed by rapid pressure transients that cause pipes, pipe supports and valves to be damaged causing leakage. VFDs allow the user to gradually ramp pump acceleration at a safe rate to avoid hammering.

Despite the potential for 60% savings in many cube-law applications, only 5% of all industrial motors are controlled by VFDs, and it is estimated that 30% of existing motors can be cost-effectively retrofitted with VFDs (ABB Drives, 2006). The potential is larger in smaller applications (under 2.2 kW) where 97 percent of all motors have no form of speed control at all, equating to some 37 million industrial motors sold annually worldwide (ABB Review, Special Report Motors & Drives, 2003). 40 percent of the value (and 90 percent in units) of all drives shipped are rated at less than 40 kW.

Improved Motor Efficiency

Another benefit of VFDs is the improved energy performance of the motor itself. The VFD control allows the motor to operate closer to its best efficiency point. The drive can generate a family of characteristic curves for the motor, in the same way that a speed-controlled motor generates a family of characteristic pump curves. In both cases, the intersection with the load characteristic curve gives an operating point which is near to the area of optimum efficiency for the equipment.

VFDs can correct for oversized motors by running them at reduced speed. The operational benefits of such correction can justify a VFD even in applications which do not call for speed control.

Compared to most other speed control methods described in the **Motors and DriveTrains** section, with a VFD there is no loss due to mechanical slip between motor and load.

Two and Four Quadrant Operation

Quadrant operation is the term used to describe a drive's ability to provide braking, reversing (2-quadrant) and regenerative (4-quadrant) power. The 'quadrant' refers to the space these modes occupy on a torque-speed axis shown in the figure below.

For loads which generate power for only a short time, then it is typical to offer only a braking resistor where the power generated is dissipated as heat losses.

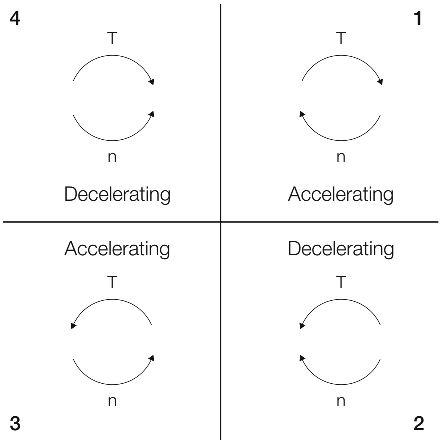


Figure 2.32 – Four quadrants of VFD operation

Active rectifiers will allow these losses to be regenerated into electrical power for the network. The type of rectifier will determine if power can flow in both directions. A conventional passive diode rectifier only supports motor loads where the power flow is only in one direction.

Motor Soft-Starting

VFDs provide the same functionality as a dedicated **soft-starter** - a power-electronics device installed in-line with the motor that slowly ramps up the voltage for a smoother startup. Soft starting is mainly used to limit large motor starting currents and to better manage power factor during startup so that the electric power system is not unduly stressed. Soft-starting therefore improves voltage bus stability, reduces currents and allows reduction in transformer size, and other power system hardware. There is also reduced risk of process disturbance due to voltage drops; and fewer trips of other electrical devices connected to the same bus. Most motors experience startup in-rush currents that are 5 to 6 times higher than normal operating currents, which is reduced to 1.5 with VFDs, thus reducing wear on the motor. Soft starting reduces heat load and allows a greater number of starts within a given time period, increasing the flexibility of the control system to optimize the process. (Motors not equipped with a VFD or other form of soft startup power electronics are referred to as 'Direct-On-Line' (DOL) motors.) Note that the load itself may also benefit from a smooth ramping up of torque and speed. The sections on **Motor Starting Conditions** and **VFD Starting Torque Conditions** discuss design criteria for startup conditions.

Power Factor Correction

The internal design of a VFD helps to improve a motor's power factor (PF). When a VFD is installed, the reactive power that is the source of low PF circulates mainly between the DC link and the motor, and therefore it cannot affect the input AC electric power supply system. Higher **power factor** will reduce I^2R losses in the power network transformers and cables. A VFD-equipped motor system will typically have high PF of 0.98 compared to 0.83 for a typical DOL motor. The PF when using a VFD does not degrade with decreased speed, as is the case with DOL motors.

The VFD's rectifier unit can optionally be of the 'active' type that performs leading and lagging PF correction, which is to the benefit of the entire input side of the electric power system. The potential for such an Active Rectifier Unit (ARU), also known as 'active front end' is discussed in the handbook section on **reactive power compensation**.

Slip Compensation

Without a VFD, when the motor load torque is increased, the speed of the motor will decrease as shown in the figure below. To compensate for this slip, the torque vs. speed curve is modified with use of a VFD so that the torque increase can be accomplished while maintaining a constant speed (ABB Oy. Drives, 2002). This slip-compensation is a standard function on most VFD drives and is especially useful in applications which require **constant speed but varying torque**.

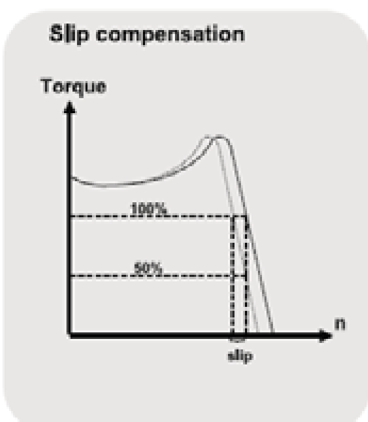


Figure 2.33 – Slip compensation of a VFD shown on motor torque vs. speed curve, (ABB Oy. Drives, 2002)

Speed Setpoint Control

The VFD drive is more than just a speed control actuator - most VFDs are also equipped with programmable **PID loop control** functionality to maintain a desired motor speed or torque setpoint. Having the PID controller onboard the drive reduces loop latency to a minimum and allows faster response to process changes when compared to central speed control. The extra responsiveness is useful in a few applications with highly varying load torques, where precise speed control is a requirement. VFD control can **hold the process at a steady set point**, instead of exhibiting cycling that may occur with other means of speed control.

VFD programming tools are equipped with libraries of application-specific control functions for pumps, fans, cranes etc. The control blocks in these libraries have pre-defined Input-Output characteristics and are optimized for these applications

Regenerative Braking

Some VFDs are able to 'harvest' wasted energy through motors acting as generators. This is also known as 4-quadrant operation. The LCI and VSI drive types (described below) can be ordered with inverter-equipped front-ends that are capable of such 4-quadrant operation. In conveyor systems with uphill and downhill conveying, some VFD drives can manage energy sources and sinks using a common bus principle, with optimum efficiency and energy flow between motors of motoring and generating mode (ABB Switzerland, MV Drives, 2002 p.16, Fact Pack #2).

Inherent Motor Monitoring and Protection

VFDs have built-in power functionality needed to protect a motor from abnormal conditions in the power supply or within the motor itself. Most critically, VFDs have acceleration and deceleration ramp limiting functions and motor current limiters to prevent driving torques which cannot be sustained by the motor. VFDs isolate motors from the electrical supply line, which can reduce motor stress and inefficiency caused by varying line voltages, phase imbalance and poor input waveform.

Many of these vital protective functions would otherwise require the installation of separate devices. The most common protective functions are: short-circuit, over current, unbalanced phase, ground fault, motor temperature, and motor stall. VFDs also monitor for underloaded situations, as in the activation of safety release mechanisms in the driven equipment, and will also detect phase loss on the incoming side. If a problem is detected, the VFD will send a warning or an alarm to operators, and initiate a drive trip.

Built-in monitoring of motor current and temperature, plus many other parameters allows the VFD to detect, warn and even take action to mitigate the effects of certain drive system problems. For example, if the motor current is oscillating, this may indicate a problem at the couplings. No extra current transducer is required for this monitoring. VFDs may also be programmed to take action when a faulty gearbox or bearing sends a high-temperature signal when operating at full load, but no such warning at lower loads. In this situation, the VFD can decrease the load until an appropriate time for maintenance on the faulty equipment. These monitoring functions can improve the uptime of a plant, with benefits as described in the section on **Lifecycle Costing Calculations - Energy cost of a trip**

Overspeed Capability

By controlling the frequency and voltage, VFDs can achieve higher motor speeds than otherwise possible from only a fixed electric power supply. This overspeed capability may be sufficient to handle modest production capacity increases without the investment needed to replace the motor or actuator. Speed increases of 5-20 percent are not a problem for VFDs on most motors. This extra capacity is within the ratings of most installed motors, which are specified with generous margins plus a service factor. Margins and more details on over-speeding can be found in the NEMA MG-1 standard.

Variable torque applications, such as pumps and fans, require increasing torque with speed. If the intention is to run above the motor's nominal speed, then it may be necessary to oversize the motor due to the reduced torque in the field weakening region.

Voltage Fluctuation Ride-Through

This feature is especially useful on weaker networks (for example, in industrial boiler applications) with transient voltage dips; VFDs allow the motor to ride through such dips thus avoiding a trip. Dips may last from a few cycles to a few hundred milliseconds. See the section on **Lifecycle Costing Calculations - Energy cost of a trip**

Voltage Boost and IR Compensation

At low speeds during startup (<20 Hz), a VFD can provide a temporary increase in voltage to help motors achieve a higher breakaway torque, without the high currents associated with DOL starting. One pitfall with voltage boost is the risk of overheating of very lightly loaded motors at speeds under 10 Hz (Bezesky 2001). Voltage boost applies a fixed extra voltage, but with IR compensation the extra voltage is proportional to the motor current, as shown in the figure below. IR compensation will therefore only provide extra voltage for motors under load and drawing current, reducing the risk of saturation and overheating.

Both of these features apply only to voltage/frequency (scalar) drives, or **vector drives** operating in scalar mode. Vector drives by design can generate higher starting torques and do not need a voltage boost feature; these drives can provide several hundred percent higher than nominal torque for motor starting. The ability of drives to boost starting torque allows engineers in some cases to avoid oversizing or selecting less-efficient high-torque motor designs.

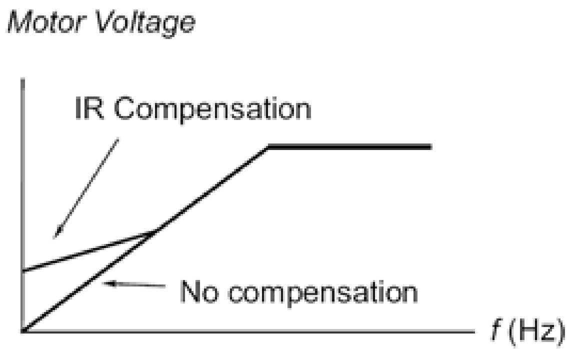


Figure 2.34 – Voltage boost at low speed, ABB VFD Programmable Features

Figure 2.35 - Small (LV) and large (MV) VFD hardware (ABB Drives, 2008)

VFD Types and Applications

Industrial VFDs cover a wide power range, from 100 hp (75 kW) to more than 30,000 hp (22 MW). Most large industrial plant VFD applications require a medium voltage AC drive, which are normally in the power range from 500 hp (380 kW) to 7000 hp (5 MW) and operate at bus voltages from 2.3 to 6.9 kV.

There are several different drive types, and the choice of drive type depends on many factors, starting with the basic motor type: Induction motors are typically controlled by Voltage Source Inverter (VSI) or Current Source Inverter (CSI) system topologies. Synchronous motors are typically controlled by Load Commuted Inverters or Cycloconverters, all described in the following sections.

The internal converter control method also varies between topologies, and there may even be more than one control method to choose from for any given topology. See the ABB Guide to Standard MV VFDs ('Fact Packs #1 and #2)

VFD Internal Design

VFDs are **power electronics** devices that convert a constant input frequency and voltage into variable frequency and voltage output for the motor. A complete VFD system may consist of all these elements: cabling, an input isolation transformer, power factor correction equipment, harmonic filters, the frequency converter itself, output filter, and an electric motor. The combination of all the above elements is the physical 'topology' of the AC drive system. The converter element's power switching function is the 'motor control platform', which should not be confused with a low-voltage Motor Control Center described elsewhere in this handbook.

The physical topology provides the electrical 'hardware' and the motor control is the 'software' which performs the power switching routine.

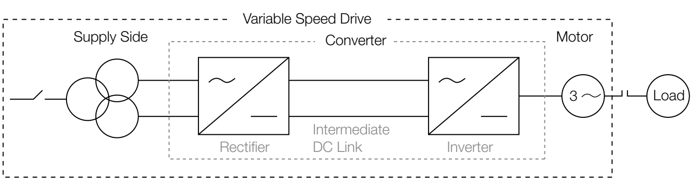


Figure 2.36 – Diagram showing VFD nomenclature, (ABB Switzerland, MV Drives, 2002)

The most common converter topology is composed of three main equipment stages:

- A 'front-end' rectifier unit on the 3-phase supply side to convert AC to DC power and to ensure that harmonics drawn from the network are kept within tolerance.
- A DC link composed of one or more capacitors and inductors which filter and smooth the DC voltage
- An inverter unit, using one of the power electronics technologies described in the sections below, performs the inversion and modulation of the voltage which is applied to the motor windings.

The effect of these stages on the sinusoidal input AC supply is shown in the figure below:

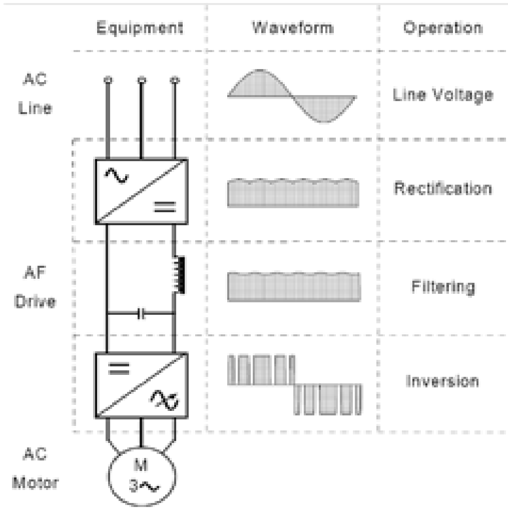


Figure 2.37 - VFD waveform at different stages, using PWM-type drive as an example (ABB Inc. 1998)

VFD Power Electronics

The switching elements at the heart of much power electronics are thyristors, also known as Silicon Controlled Rectifiers (SCRs). These are turned on (conduct power) by a control signal and will continue conducting until current drops near zero, a feature known as ‘self-commutation’ (Competitek 1996). The number of switching elements (or ‘pulses’) in the converter is a measure of the ‘resolution’ of the drive in supplying output to the motor. The number of pulses will roughly determine the amount of **VFD harmonics** induced in the motor and drawn from the power supply. The power electronics switching technologies that are in use today are:

- IGCTs (Integrated Gate Commutated Thyristor) offer fast switching (like a transistor) and inherently low losses (conducts like a thyristor); in other words, it combines the best of both technologies above. IGCT technology is the most common switch in MV drives sold today.
- IGBTs (Insulated Gate Bipolar Transistor) are fast switching and low cost, but losses are high at medium to high voltage levels. Used in LV applications.
- GTOs (Gate Turn-Off Thyristor) are thyristors with a controllable ‘off’ switch, additional circuitry that lowers overall reliability, slows the switching and increases expense. GTOs are used in high-current, high-power applications, but have relatively high MV losses.

From an energy efficiency perspective, a semiconductor drive technology that has low losses means greater energy efficiency, less cooling equipment, and greater reliability of the VFD device.

VFD Topologies

The main drive topologies which are in wide usage today are listed below, based on descriptions from the ABB Drives Fact Pack #1, 2005.

Voltage Source Inverter (VSI)

This section is based on information in (Competitek 1996), (IEEE, 2007), and (ABB MV Drives, 2002)

The VSI drive is sometimes referred to as a Variable Voltage Inverter (VVI) because it achieves speed control by varying the voltage fed to the motor. In its simplest and earliest form, the VSI inverter's switching elements produced a 6 (or 12 or higher) step voltage waveform output for the motor. The design of the VSI topology is shown in the figure below. A common topology and control combination for low to medium horsepower AC machines today is VSI hardware using PWM inverter control. The high-speed PWM switching converter provides fast response, precise speed control and maintains high PF over the entire speed range.

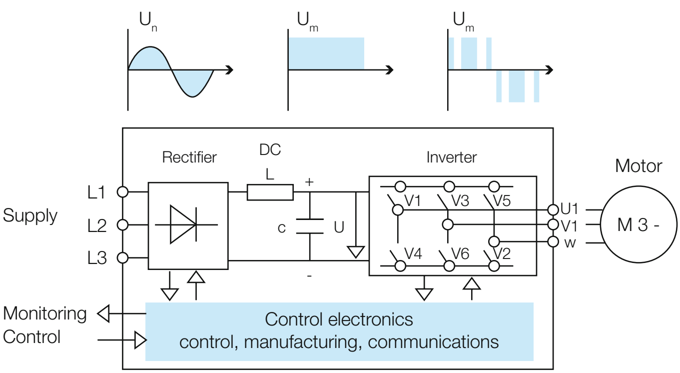


Figure 2.38 - VSI design schematic ABB (ABB Switzerland, MV Drives, 2002)

The main characteristics of a VSI drive with PWM are summarized below.

- power range : up to 8,000 kW (for 3-level inverters)
- motor voltage levels : 2.3 to 6.9 kV
- speed range : 0 – 100%
- has low starting current
- does not contribute short-circuit current
- not capable of regenerative operation,
- high ac input power factor, near unity for entire speed range
- converter efficiency >= 98%
- PF is high and constant over entire speed range
- low network harmonics, voltage reflections & voltage stress

– full torque even at standstill & very low speed
– standard drives for pumps, fans, compressors, conveyors

Although PWM is the most common converter control method, other methods such as **Flux Vector** can also be used together with the underlying VSI topology.

Current Source Inverter (CSI)

This section was adapted from these sources: (IEEE, 2007) and (ABB Switzerland, MV Drives, 2002)

The CSI drive system controls current output to the motor using a gate-turn-off-thyristor current source inverter on the load side. The inverter is operated in a self-commutating mode over the full speed range of the drive; they turn off by themselves every time current passes through zero. The amplitude of the motor current is adjusted by the supply-side rectifier, whereas the frequency and thus motor speed is controlled by the load-side inverter. Most modern CSI drives are configured with a 12-pulse output (Competitek 1996). A simpler, but less efficient design makes these drives suitable for larger induction motors operating at higher speeds. The main characteristics of a CSI drive type are summarized below.

– Suitable for larger induction motors
– Horsepower range typically 500-10 000 hp (380 kW–7.5 MW) (but is rated up to 80 MW)
– Often applied as a retrofit adjustable speed drive system for existing motors.
– Output voltage 2.3 to 6.9 kV
– Typical applications are pumps, blowers and fans
– Capable of regenerative operation
– High efficiency at speeds above 50%
– Continuous operation at very low speeds is not always possible.
– PF is not constant over entire speed range, and is poor at low speed
– The large filter capacitor (DC–link) introduces additional losses and larger size.
– Converter efficiency: 97%
– Speed control range 2-100%

Load Commutated Inverter (LCI)

For conventional synchronous motors, the most common power electronics drive technology is Load Commutated inverter (LCI). Permanent magnet synchronous motors also use the PWM drive technology.

The following section is based on information from (IEEE, 2007) and (ABB Switzerland, MV Drives, 2002).

In the LCI design the DC current is switched directly to the synchronous machine's windings, which behave like a DC machine. LCI drives have a simple and robust design because no special switching circuit is needed; the thyristors are switched by the action of the current waveform of the load itself (Competitek 1996). A control function using a feedback sensor in the motor prevents the rotor from falling out of step. The LCI drive system can be furnished with regenerative braking capability, which is discussed in the section on **VFD Regenerative Braking**. The main characteristics of this drive type are:

- Unmodified, it is suitable only for synchronous motors, with brushless or slip ring excitation
- Wide speed and power range 1- 80 MW
- Speed control range (0)-10-100%
- More expensive than other drives
- Poor power factor at low speed
- Suitable for continuous operation
- Fans & pumps, compressors
- Converter efficiency > 99%

A modified LCI drive with a large DC-link capacitor can use CSI technology to drive either synchronous or induction motors. The capacitor also servers to shape the waveform so that harmonic heating in the motor is reduced (Competitek 1996).

Cycloconverter

The Cycloconverter design does not use any intermediate DC circuit, which limits the load frequency to a maximum of 83% of the line frequency (for cross-current type of drive). Cycloconverters are used for high power, low speed synchronous motor drives such as rolling mill drives, and ship propulsion. The main characteristics of this drive type are:

- Power range 1.5 – 30MW
- Excellent performance and speed control at low speeds
- Non-constant PF
- High harmonic distortion
- Capable of regenerative operation
- Maximum speed limitation 600/720 for 50/60 Hz supply

VFD Control Methods

Also referred to as Motor Control Platform, the drive control method is the logic which switches the power electronics elements to produce a certain output waveform.

Pulse Width Modulation (PWM)

In small to medium-sizes, the voltage amplitude is held constant and the PWM controls average (RMS) voltage by varying the pulse duration and frequency (Competitek 1996) as shown in the figure below. In larger drives the voltage amplitude is also modulated. PWM outputs current to the motor as a nearly sinusoidal waveform. PWM control is also sometimes referred to as 'scalar' or voltage/frequency (V/F) control because a certain voltage is generated for a given frequency.

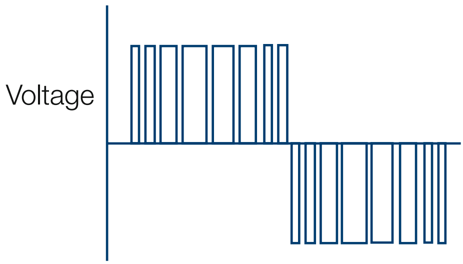


Figure 2.39 – Modulated width voltage pulses from a PWM drive

Scalar vs. Vector Drives

The V/F control method is 'open-loop' because it does not receive any feedback from the motor itself. In these drives, a fixed volts/Hz pattern is applied to the motor, and the actual torque is then determined by the motor and its load. Precise torque control is not possible with these drives, and speed control is not possible below 10Hz; limitations also commonly associated with DC motors.

'Vector' drive control emulates the operating characteristics of a DC motor by tracking the spatial position of the rotor magnetic flux in an AC induction motor. Some common limitations of vector drives: 1) they cannot be used in multi-drive configurations of the type described in the next section 2) they cannot be used if there is a transformer between the drive and the motor. However, vector drives can produce much higher torques at lower speeds (3 to 5 Hz) than PWM drives, and have torque response and speed accuracy which is several orders of magnitude greater than PWM (ABB Oy. Drives 2002). Pump, fan and other cube-law applications, however, do not normally require the enhanced torque and low-speed control provided by vector drives. In these applications, lower-cost scalar drives are sufficient.

[The following descriptions of these drive technologies was adapted from the ABB Technical Guide (ABB Switzerland, MV Drives, 2002).]

Flux Vector Control

Flux vector control (often simply called 'vector' control) can produce full torque at much lower speeds than V/F drive types. By closing the loop with motor state feedback, vector drives provide a torque response and speed accuracy that are several orders of magnitude greater than with open-loop scalar drives. Flux vector control, however, requires an extra speed feedback device (encoder) between motor and the drive control system to sense the speed and position of the shaft.

Sensor-less Vector Control

The 'sensor-less' flux vector technology uses a motor model to eliminate the need for feedback from a tachometer or encoder. The model uses internal measurements of motor current within the drive to determine torque and flux. An algorithm estimates motor slip, speed and shaft position. The drive can then calculate the necessary voltage and frequency to produce the desired torque and speed.

When a vector drive operates in torque control mode the speed is then determined by the load. In screw pumps a drive using torque control technology will be able to adjust itself for sufficient starting torque for a guaranteed start. In conveyor systems, torque control may be used to control feed rates where one section is allowed to run faster than another.

Vector drives can be selected to operate in either torque-control (vector) or speed-control (scalar) modes. Note that at very low speeds (< 5Hz), sensor-less vector drives cannot easily determine magnetic parameters, and motor slip estimates then become inaccurate. This inaccuracy makes sensor-less drives generally unsuitable for crane and hoist operations; other vector drive designs avoid this limitation.

Direct Torque Control

ABB's proprietary variant of sensor-less vector drive, Direct Torque Control (DTC) allows the motor's torque and flux to be used as primary control variables, without the need for an additional modulation processing step. Torque response time is an order of magnitude faster than with other vector drive designs. Using the DTC technique, the torque accuracy is 2% within a speed range of 2-100% and a load range of 10-100%. A DTC drive can work with any type of induction motor of asynchronous, squirrel cage design.

A feature of DTC that contributes to energy efficiency is a development called motor flux optimization. With this feature, the efficiency of the total drive (that is controller and motor) is greatly improved in fan, pump, and other variable speed applications. The efficiency gains are greatest at lower speeds, as shown in the figure below. For example, with 25% load there is up to 10% total energy efficiency improvement. At 50% load there can be 2% total efficiency improvement.

Unlike traditional AC drives, where up to 30% of all of the modulator's power electronic switchings are wasted, a drive using DTC technology knows precisely where the shaft is and so does not waste any of its switchings (ABB Drives 2002).

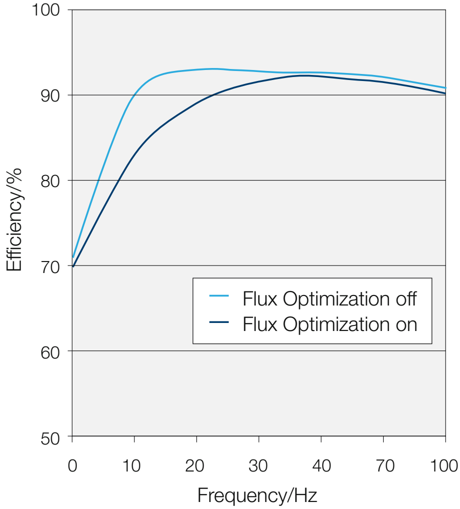


Figure 2.40 – Efficiency improvement with DTC flux optimization, (ABB DTC Presentation, 2008)

Multi-Drive

In the multi-drive architecture, multiple inverters are fed from a common DC-link bus and central rectifier unit. The individual inverters do not all have to have the same power rating: a multi-drive package can consist of drives of very different sizes. A higher overall VFD efficiency is achieved by eliminating the separate rectifier and DC-link for each drive. In a plant with many drives, the total lifecycle savings can be significant.

A multi-drive architecture also allows a cost-effective way to reduce energy-wasting harmonics by installing a single active front-end supply unit or at least a 12-pulse line supply. Another advantage of this technology is to be able to supply energy from **VFD Regenerative Braking** from one motor to another motor in the group, without the need for any additional power inter-connection equipment.

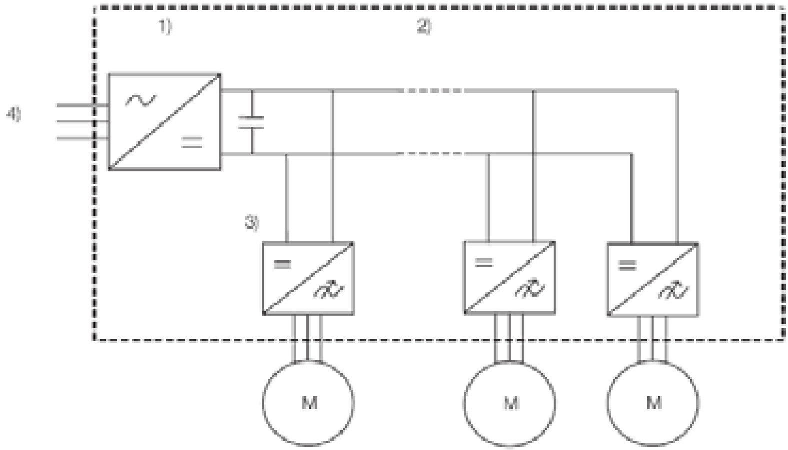


Figure 2.41 - Multi-drive system1) rectifier section 2) common DC-link 3) drive sections 4) power supply (ABB Drives 2002)

Multi-drive systems are cost-effective in applications where there are several motors installed close together, such as sets of conveyors, fan banks, pump banks or in master-slave applications which require motor synchronization, such as paper machines. Compared to set of single drives, these systems save cabling on the power input side and allow faster replacement of faulty units. The cost of multi-drives are decreasing, but these systems still require some engineering when compared to single drive applications; this may explain why multi-drives are generally under-utilized in industry. A lifecycle cost (LCC) analysis, however, may reveal energy savings large enough to overcome a preference for standard, non-engineered single drive products.

AC Motor Control Terminology

Discussions on motor speed or torque control require clarification of a few basic terms in common usage. The Variable Speed Drive (VSD) term, as used in the Pump and Fan sections of this handbook, refers to any means of modulating the output shaft speed given a constant input shaft speed from the source of drive power. Another common and equivalent term to VSD is ASD: Adjustable Speed Drive. A variety of methods to vary shaft speed are discussed in the **Motors and Drive Trains** section. In some industry texts the broader term VSD is used even when VFD control is meant. Sometimes, only the word ‘drive’ or ‘converter’ is used to refer to a VFD, and some technical sources may incorrectly refer to the entire VFD as only ‘the inverter’. The naming situation is further complicated when AC torque control drives, also known as vector drives, are included. The preferred, and least ambiguous, term for all these AC drive technologies is Variable Frequency Drive, abbreviated as VFD.

The discussion in this section is limited to the application of VFDs within an industrial process, and the drive's interaction with the motor and the load. For a discussion on how VFDs may impact power quality of the electric power system, see the section on **Electric Power Systems.**

Speed and Torque Performance

If a motor is driven without a VFD, then its performance characteristics cannot be modified; the motor will produce only the torque at a certain speed given by its **torque vs. speed curve** and specified values for starting, breakdown and full-load torque as shown in the figure below (left side). When started direct-on-line (DOL), the motor accelerates continuously, passing through these points until it reaches its nominal operating torque and speed.

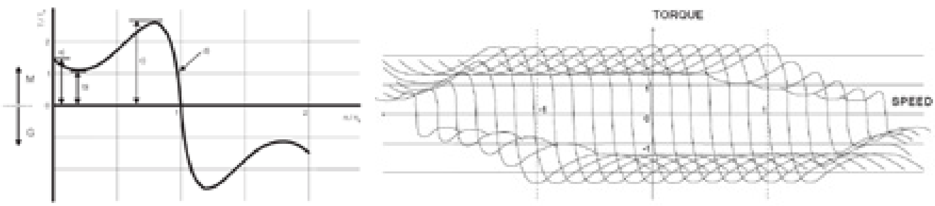


Figure 2.42 – Torque-speed curve for a motor (left) and a VFD-equipped motor (right), (ABB Drives 2002)

With a VFD, however, the input voltage and frequency can be continuously modulated so that a family of characteristic torque-speed curves is available over the nominal speed range, as shown on the figure's right side. The actual operating point of the drive system is the intersection between the active torque-speed curve of the drive-motor combination with the **torque-speed characteristic curve of the load**.

A VFD is commonly used in speed-control mode, in which the torque is determined by the load. Some VFD designs allow a torque control mode, in which the speed is then determined by the load.

A VFD can drive and hold the motor at any point along any of these characteristic motor curves, limited only by the thermal capability of the motor and the load on the motor. The VFD can hold the motor at Tmax for short-term overloads. In practice, VFDs typically will limit the maximum available torque to 70% of Tmax.

Newer VFD designs, however, can achieve high breakaway torques, typically 2 times nominal torque.

VFD Operating Regions

For speeds below the nominal speed, the magnetic flux in the motor is constant. At speeds above the nominal frequency/speed the motor operates in the 'field-weakening' range, in which magnetic flux density is sacrificed for higher speed. The maximum torque of an induction motor is proportional to the square of the magnetic flux. Below Ns the Tmax is constant; above Ns the Tmax decrease is inversely proportional to the square of the frequency.

For example, a 100 hp, 460 V, 60 Hz, 1775 RPM (4 pole) motor supplied with 460 V, 75 Hz (6.134 V/Hz), would be limited to (60/75)2 = 64% torque at 125% speed (2218.75 RPM) = 100% power.

In most applications a VFD approach is chosen to provide different torque vs. speed performance than would be possible for the motor by itself. This performance is usually matched to the load's **torque–speed performance** curve. For example, constant torque over a wide range of speed is a common requirement for many applications. The figure below shows how voltage and speed control can achieve theoretical constant Tmax over the range of speed from zero to synchronous speed (n/ns =1.). At higher speeds, the weakening magnetic field causes torque to drop in quadratic fashion, known as the constant power region of operation.

VFD Performance & Efficiencies

Motors are developed and optimized to run at constant voltage and frequency and at full load. Adding another device, a VFD, cannot improve the combined efficiency of the system operating at full load. In fact, the non-sinusoidal electrical output plus the internal losses created by the VFD actually lower the combined efficiency at full load by several percentage points, compared to the motor acting alone. (Competitek 1996).

A VFD saves energy when it can modulate the motor power to match loads which are less than 100% full load. Variable flow applications are obvious candidates, but constant speed applications would benefit as their loads are seldom perfectly and forever matched to the rating of the motor. Many well-matched, constant-speed applications could still profit from VFD soft start, power-factor correction and other **VFD Features**.

Motor Current Estimation

Estimating motor current is important for dimensioning a VFD, and can be done once the motor torque characteristic is known. The total current in a motor (I_m) has active (I_q) and reactive (I_d) including magnetizing current components, as described in the section on the **power triangle**. Only the active current component can produce torque; when torque is zero, so is the active current. The active current can always be calculated by multiplying the total current by the power factor, also shown as $\cos(\phi_n)$.

In the constant flux region (below field weakening point):

In the constant flux region the motor currents do not depend on speed. The active current can be approximated as follows:

$$I_a = I_n \times (T_{load}/T_n) \times \cos(\phi_n)$$

Where:

I_n = nominal (nameplate) current

At higher torque values motor current becomes nearly proportional to the torque. A good approximation for total motor current at a given load is as follows:

$I_m = I_n \times (T_{load}/T_n)$ when T_{load} is between $0.8 \times T_n$ and $0.7 \times T_{max}$

For example: a 150 kW motor's nominal current is 320 A at power factor 0.85. What are the approximate active and total currents at 120% torque, below the field weakening point? Using the approximation formulas from above:

$$I_a = 320 \times 1.2 \times 0.85 = 326 \text{ A}$$

$$I_m = 320 \times 1.2 = 384 \text{ A}$$

In the decreasing flux region (above field weakening point), the motor currents depend on speed. The active current can be approximated as follows:

$$I_a = I_n \times (T_{load}/T_n) \times (n/n_n) \times \cos(\phi_n) = I_n \times (P_{load}/P_n) \times \cos(\phi_n)$$

Where:

P_n = nominal (nameplate) power

Within a certain operating region the total motor current becomes proportional to the relative power.

$I_m = I_n \times (T_{load}/T_n) \times (n/n_n) = = I_n \times (P_{load}/P_n)$ when T_{load} is between $0.8 \times (n_n/n)$ and $0.7 \times (n_n/n)2 \times T_{max}$

For example: a 150 kW motor's nominal current is 320 A. How much current is needed to maintain the 100% torque level at 1.3 times nominal speed (assume Tmax =3 x Tn)? Using the approximation formula above:

$I_m = 320 \times 1.3 = 416$ A

For additional motor power and torque formulas see the **Motor and Drive Train section**.

Drive Efficiency

Efficiency levels of MV AC drives vary from 95 to 99%, including the supply transformer, power factor correction equipment and any harmonic filters. A typical VFD efficiency curve stays relatively high (above 90%) and constant until about 20% of full load. At loads below 20% full load, the VFD efficiency drops to between 75% and 90%. This drop is partly because the losses in the drive electronics account for an increasing proportion of the input power. The extra protective circuits which are often built-into modern VFDs, such as suppressors and line reactors, improve reliability but they come at a slight cost in drive efficiency (Liptak, 2005). Vendors of VFDs may promote small drive efficiency margins over other vendors, but these are tiny compared to the efficiency gains of the entire drive power system, VFD, drive train and pump or fan. Engineering support, programmability and other factors will likely play a more important role in total drivepower system efficiency, which is the only valid basis for comparisons and design decisions.

VFD Harmonics

A harmonic is a sinusoidal component of a periodic wave or quantity having a frequency that is an integral multiple of the fundamental frequency. Harmonics are caused by the non-linear switching action of VFD inverter electronics. The rapid step changes in voltage levels found in most drive outputs, and especially in PWM drives, create flux harmonics and heating within the motor. Rotor heating from PWM drives can range from 30% to over 300% more than with only 60Hz input power, depending on the type of modulation control used (Competitek 1996).

High harmonic content coming from early frequency converters led to heating of motor windings and the practice of de-rating the motor 5-10% for use with VFDs. Modern VFD drives now output low levels of harmonic content and perform according to the detailed standards in IEEE 519 and NEMA MG1 Part 31 specifications (or G5/3 n the UK); it is usually no longer necessary to de-rate a motor for use with a VFD (US DoE, 2008).

Harmonics tend to be drawn from the supply network and may affect other electrical equipment. For a discussion of the energy impact of these supply-side harmonics, and of ways to mitigate their effects, see the Electric Power Systems section **Harmonics Mitigation**.

VFD Application Design and Engineering

After two decades on industrial service, VFDs have evolved to high levels of reliability and functionality. Early VFD pitfalls have been eliminated in modern VFD designs. On the motor side, early pitfalls encountered with VFD applications were related to harmonics and voltage spikes, which induced heating and led to motor damage. On the power side, early pitfalls with VFDs were line interference, power system harmonics and poor power factor at low speeds.

VFD Trends

Advancements in power electronics and usability are moving drives toward the status of a commodity item. In the past, all drives were considered 'engineered' items which suppliers (such as ABB) would configure based on detailed application specifications that the customer would put out to tender. Engineered drives with custom capabilities may still be required for applications with special loading profiles, special environmental conditions, or where plant power supply issues such as harmonics and phase unbalance pose a particular challenge. Most drives have features that handle these issues 'out of the box' for approximately 85% of all applications (ABB Drives, 2006). All drives are available as separate devices, but often 'component' drives are embedded in small-scale OEM equipment solutions requiring speed control.

Although VFDs are becoming more of a commodity item, careful engineering following the guidelines below will help to address most of the problem areas and to achieve the expected efficiency improvements.

VFD Selection and Sizing

The following sections provide an overview of the steps involved in dimensioning a drive system. This overview focuses on energy efficiency aspects; for more complete guidelines see the full ABB Technical Guide No.7 for Dimensioning a Drive (ABB Drives 2002) upon which this section is based, or the NEMA Application Guide for AC Adjustable Speed Drive Systems 2001, IEEE Paper No. PCIC-2001-7.

Select Drive Size & Rating

Standard drives can be selected from the catalog and with some vendor assistance, based on inputs from the process, mechanical and electrical application engineers. The requirements for each of the four main elements in the drivetrain system are shown in the figure below.

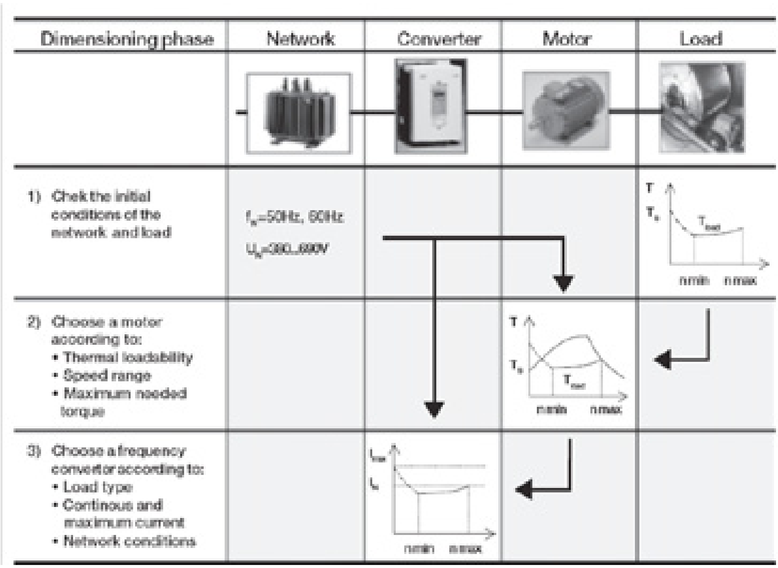


Figure 2.43 – Drive dimensioning procedure, (ABB Drives 2002)

The typical dimensioning steps for a drive and motor system are listed below. These steps apply mainly for variable torque applications, such as a pump or fan application. Details and example calculations for each step are given in the ABB Technical Guide for Dimensioning of a Drive System, 2002.

Step 1: Check initial requirements and conditions of network and the load

- 1.1 Required voltage level (LV or MV)
- 1.2 Required quadrant control (reversing, regeneration)
- 1.3 Required power system capability (voltage/frequency/harmonics tolerance)
- 1.4 Required maximum application load (for example, fan or pump) power and speed

Step 2: Choose the (or evaluate an existing) motor

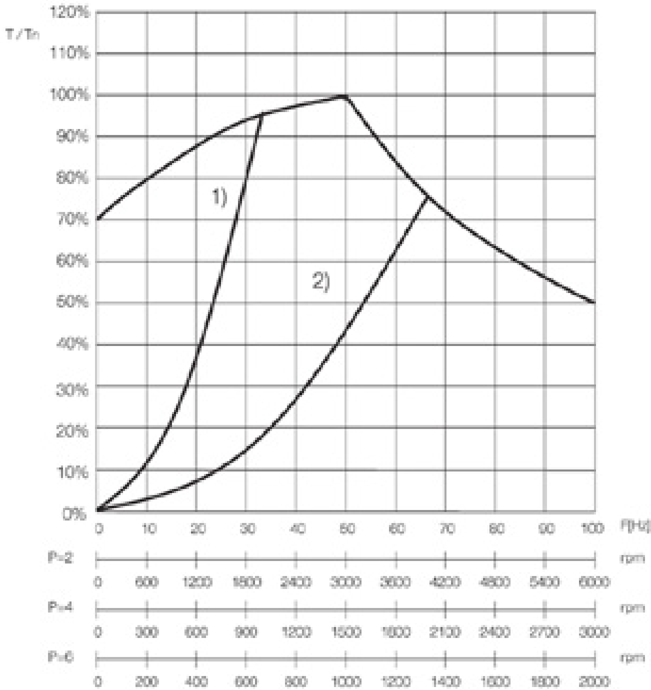


Figure 2.44 – Motor loadability curves comparing 1) 2-pole and 2) 4-pole motors

- 2.1 Determine the required maximum load torque at full speed - narrow selection of motors
- 2.2 Check motor loadability. using torque profile curve, at the nominal speed and then over the required speed (rpm) operating range
- 2.3 Check for high application load torque starting conditions
- 2.4 Determine motor nominal torque and power, based on number of motor poles
- 2.5 Select a new (or approve an existing) motor; add a margin (from 10 to 30%, depending on loading information certainty) so that power is available at maximum speed.

Step 3: Choose a VFD and associated equipment

- 3.1 Determine type of load (cube law, constant power, constant torque, quadrant operation)
- 3.2 Determine total motor continuous current (Amps) at full speed
- 3.3 Specify any special operating conditions and required IP (enclosure) class

- 3.4 Select a drive based on current estimation and vendor tables
- 3.5 Specify drive cooling requirement based on drive selection, ambient conditions
- 3.6 Specify input transformer power rating
- 3.7 Specify length and type of cabling between drive and motor

In Step 1, the application load (for example, the pump or fan) power rating at maximum speed can be used to determine the necessary application torque requirement using the power – torque formulas. The power supply network must be capable of providing nominal voltage (step 1.1). If the supply voltage is lower than nominal, the field weakening point shifts to a lower frequency and the available maximum torque of the motor is also reduced in the field weakening range (ABB Drives 2002).

In Step 2, the motor nominal values for power and torque are determined, based on the application requirement (from step 2.1) and the motor model loadability data. Then a motor selection can be made, or an existing motor is approved for a drive retrofit.

In Step 3, the motor total current is determined based on the nominal motor values in Step 2 and load torque in Step 1, and then a drive selection is made. A drive should be dimensioned according to the continuous full load current requirement, and not the horsepower requirement. The mechanical or process unit needs are usually supplied in terms of a motor load torque characteristic, from which motor current is derived according to the **motor current approximation formulas**. These values are then compared to the converter's limits to select the correct size and model. The motor's nominal current may also be used as a first approximation for converter dimensioning. Note that when a high-efficiency motor is specified in Step 2, then a smaller drive might suffice due to the lower current requirements.

A common temptation in VFD sizing is to add a design margin to the VFD size. This is not usually necessary because in common practice the motor has already received a **very high margin**. The VFD is merely a conduit for motor power and therefore adding a margin only for 'process flexibility' serves no purpose. An exception to this rule is if there is possibility for the motor to exceed its full load amp rating (beyond service factor margin). This situation may arise due to unforeseen changes in process flow densities, for example. In such cases, a higher drive rating is necessary to avoid drive trips. Another exception is if the drive is to be located in warm ambient conditions, as may be the case in small industrial boiler applications (Plantsystems.com, 11/2008).

In practice, the manual selection & sizing process outlined above is complemented by engineering software tools as discussed in the section on **VFD Sizing and Selection Tools.** Vendors normally have certain selection tables where typical motor powers for each converter size are given; these tables are also incorporated into the software tools.

For example: a pump has a 300 hp (224 kW) load at a speed of 2000 rpm; there is no special starting torque requirement.

Step 1: First find the necessary load torque:
T = 300 x 5252 / 2000 = 788 lb.ft (SI: T = 9550 x 224/2000 = 1070 Nm)

Step 2: Check the loadability for a few candidate motors:

For a 2-pole motor at 2000 rpm, loadability is 95%, which means that the nominal torque must be at least:

T_n = 788 / 0.95 = 830 lb.ft (1125 Nm)

For which the nominal power must be at least:

P_n = 830 * 2000 / 5252 = 316 hp, so a 350 hp motor (1975 rpm , 460V, 500 A, PF 0.87) is chosen.

The nominal torque of that motor is:

T_n = 350 x 5252 / 1975 = 913 lb.ft (262 Nm)

The motor current at 2000 rpm (in the constant flux range) is approximately:

$I_M = P_{load} \times I_n / P_n = T_{load} \times I_n / T_n = 788 \times 500 / 830 = 474$ A

The continuous current used to select a VFD is then 474 A.

For a 4-pole motor, loadability at 2000 rpm is 75%

The same series of calculations reveal that the motor current is less than that for the 2-pole motor at the operating speed, so the 4-pole motor is chosen as the most energy efficient.

Voltage Level: Low-Voltage (LV) vs. Medium Voltage (MV)

The selection process begins with selection of the voltage level. Low voltage AC drives may be technically possible for certain power levels and their generally lower price may seem attractive. However, LV drives draw higher current for a given motor power than for MV drives. For long cable lengths between motor and inverter, the larger required cable diameter and cost will favor an MV drive option. **Power system control and protection devices** like contactors may be a limiting factor in high-power LV designs.

Converter voltage output ranges up to 4kV, which is sufficient for most standard LV and MV motors. For HV motors, however, a specially designed step-up output transformer is required. A standard transformer cannot be used due to variation in frequency, the harmonic distortion and the DC component existing during transients in the output voltage of the frequency converter.

The selection of VFD voltage level is closely related to the selection of bus voltage levels as described in the section on **Power System Design and Engineering**. For a retrofit, the availability of MV or LV busses is a decisive factor.

Quadrant Control, Converter Basic Type

The converter technology largely determines the drive losses, and hence the requirement for cooling, the drive's physical size, and reliability. The converter selection also determines many aspects of the drive-plus-motor's torque-speed performance. Application requirements should be carefully considered in this step of the selection process. Special requirements for 4-quadrant control will also strongly affect the drive technology selection; see the **VFD Types and Applications** section for the common application areas for various drive technologies.

Motor Capability – Harmonics

Although it is usually no longer necessary to derate a motor for use with a modern VFD, it is still good practice to check with the drive or motor suppliers as to whether a specific motor can tolerate the drive's harmonic levels. Older and/or rewound motors may have reduced tolerance for the effects of harmonics.

A class of motors called 'inverter duty' (NEMA MG1 Part 31) offers a higher performance standard to ensure compatibility with VFDs. Modern VFDs ,however, are designed to work within the tolerances of the 'general purpose' class of motors; this was not generally the case for older 6-step drive inverters.

Motor Capability – Retrofit Situations

Modern VFD drives can be applied to many existing induction & synchronous motors as part of a retrofit without de-rating 5-10% as was done previously. In addition to improved controllability, a VFD allows a previously oversized motor to be run at lower speeds, consuming much less power while preserving power factor and efficiency. However, in retrofit situations there are several additional unknowns that should be investigated as they may lower tolerance to some of the effects discussed in the 'Issues' sections below:

- Condition of the insulation of the existing motor.
- Impedance of the motor cabling and motor, which in some cases may amplify voltage reflections. This may be a concern in retrofit situations with very long cable runs between motor and converter. See the Cabling and Conduit issues in the following section for more details..
- For fan applications: look for possible regions of instability at low speed/flow conditions, especially with axial fans. Careful review of the performance curves should precede the selection of a VFD (US DoE Sourcebook, 2006). In retrofit situations, the VFD can be programmed to avoid these speeds.

In addition to harmonics-induced heating, there are other important issues regarding VFD compatibility with induction type motors. The following section is based on information from ABB and (US DoE, 2008):

- Voltage stress: Motor insulation systems may deteriorate more rapidly due to the rapid step changes in voltage output of a drive. Filters on the inverter output can eliminate this problem by providing a purer sine wave output.
- Common mode voltages are induced by the electromagnetic disturbance from a drive's modulation technique. These cause current flow in the shafts of larger motors and may harm motor bearings. Industry sources and the US DoE recommend the following corrective measures:
  - Insulated non-drive-end bearings are recommended on all motors rated over 100 kilowatt (kW)
  - Common mode filters may additionally be required for higher powers and voltages. These eliminate common mode voltages and voltage reflection effects as well.
  - The choice of drive technology also affects the strength of common mode voltages. For example, a 3-level VSI with an output filter arrangement can avoid common mode voltages by grounding the star point of the output filter (ABB Switzerland, MV Drives, 2002).

Motor Capability – Cabling and Conduit Issues

A drive's modulation technique creates electromagnetic disturbances, requiring adequate electrical screening such as screened output cables (US DoE, 2008). These EM disturbances can cause 'transmission line' (also known as voltage reflection or 'standing waves') effects in long cable runs and cause raised voltages at the motor terminals, as shown in the figure below. Voltage reflections can also damage motor insulation, and are a particular concern in MV retrofit situations (ABB Switzerland, MV Drives, 2002). Some preventive design tips for inverter-fed motors are 1) use input and output reactive filters and 2) ensure that the grounding system is well designed. According to one source, (Competitek 1996), PWM drives cannot tolerate long cable lengths (longer than 500 m due to standing wave effects. It is important to consult with drive vendors and their expertise before specifying VFDs with long cabling to motors.

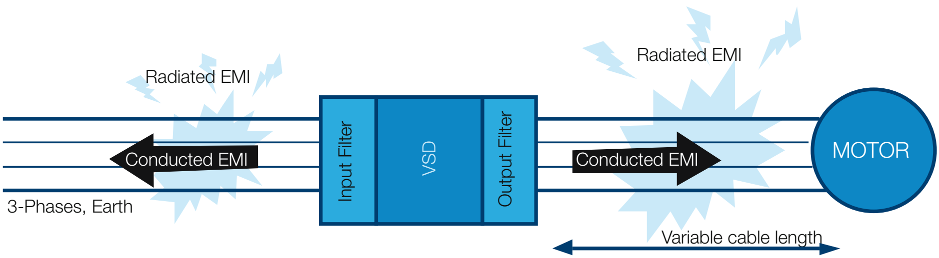


Figure 2.44 – EMI disturbance from VFD (shown as VSD above) cabling, (DeAlmeida, 2006)

Circulating currents can also be induced in the walls of metal conduits, even when it contains balanced phases. A preventive design tip is to use non-metallic conduit material, such as PVC (Competitek 1996).

Motor Capability - Resonance Issues

The following issues may arise due to complex, dynamic interactions between the VFD drive-electric motor and pump (or fan) system. These unwanted dynamics are usually eliminated for maintenance or reliability reasons, but they also degrade system energy efficiency if allowed to continue at a level judged 'tolerable' for the equipment. This phenomenon is also called 'torque pulsation' in some technical sources.

- Structural Resonance. Resonance is a mechanical vibration phenomenon that occurs when the VFD output frequency matches the one of the natural frequencies of the entire pump, piping, and mounting system. The strong vibrations at these particular frequencies are harmful to the motor and pump equipment couplings, bearings and support structure.
- These resonances are usually designed-out of pumps and motor combinations operating at known constant speeds. In variable speed applications however, the wide variation in motor frequency may uncover new resonances, especially those resulting from fluid pressure pulsations. Pumping system authorities (US Doe, Hydraulic Institute, Europump) recommend the following techniques to predict and avoid resonance situations (US DoE, 2008):
  - Simple hydraulic resonance calculations

– Passing frequency analysis
– Using Finite Element Analysis to reveal structural resonance
– Modal testing on the actual machines, via a vibration test

Modal testing involves using an electromagnetic shaker or impulse hammer to apply a force that is measured by an accelerometer (Plantservices.com, 2008). In retrofit situations, where motor hardware cannot be easily re-designed, the VFD can be programmed to avoid troublesome resonant frequencies, once they have been identified using the methods described above.

Starting Load Torque and Speed Issues

A VFD provides many different loading options compared to the motor acting alone. As shown previously, a VFD can provide **nearly constant torque** over a wide range of speed, as shown in Curve1 in the figure below (for a 50Hz nominal input frequency). For applications with high but temporary starting torque requirements, then the VFD can produce torque following Curve 3 in the figure below. Vector drives are particularly suitable for supplying high torque at low speeds.

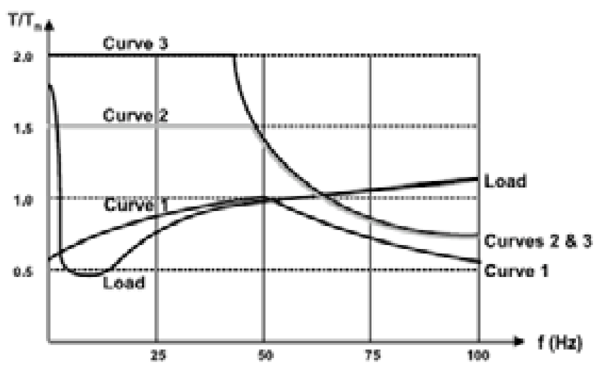


Figure 2.45 - Motor torque performance curves possible with VFD control, (ABB Oy. Drives, 2002)

A heavier-duty VFD may be required for applications with high starting torque requirements, or where there are high torque pulsations (Competitek 1996). The NEMA Application Guide for AC Drives (2001) cautions that applications with static torques above 140% of full load torque may require an oversized drive and a motor with **higher torque capacity**. Vector drives are an alternative solution to this application requirement.

Variable torque loads such as most pumps (and some fans) have low torques at low starting speeds. Constant torque applications typically have higher starting torque requirements than variable torque loads. High-inertia rotating machinery, such as very large fan, however, may require special attention to achieve startup, as discussed in the **Fan Drivetrain** section. One possible solution is to bypass the VFD during startup, allowing the motor to develop to its full breakaway torque to get the load moving. See NEMA-MG1 and the NEMA Application Guide for AC Drives (Bezesky 2001) for some special precautions regarding this approach.

Constant torque applications typically have higher starting torque requirements than variable torque loads, and stricter requirements for acceleration and torque repeatability. Although VFDs, properly sized, can satisfy these applications, they are also good candidates for vector control drives. A vector control drive can provide more precise torque control and much higher low-speed torque than scalar drives.

Soft Starting Torque

A common torque vs. speed curve for a VFD-equipped motor is a gentle ramp up to maximum continuous torque at about 30% of rated speed, then a horizontal line meaning constant torque all the way up to 100% of rated speed. Compared to a simple soft-starter, VFDs have the advantage of being able to adjust the ramp time for the voltages and frequencies at the motor terminals, as shown in the following figure.

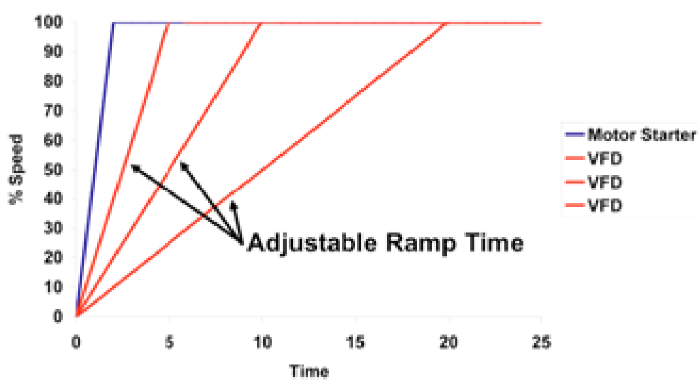


Figure 2.46 - VFD adjustable startup- speed vs. startup time, (ABB Oy. Drives, 2002)

The figure below shows how VFD driving torque adjustment can be engineered to follow the load torque for optimal energy and acceleration time performance during startup.

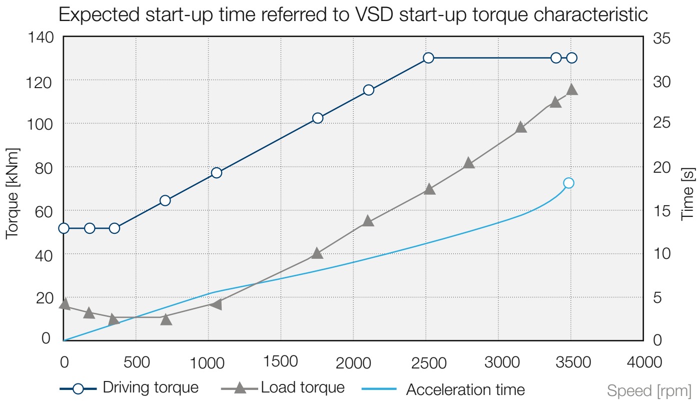


Figure 2.47 - Load torque, run-up torque and time as function of speed, (ABB Switzerland, MV Drives, Ormen Lange case, 2008)

A potential energy-efficiency feature of VFDs is known as 'flying start'. The flying start feature is useful when a motor is connected to a flywheel or a high inertia load, and allows a startup even when the load is rotating, and without a speed feedback. The inverter is first started with a reduced voltage and then synchronized to the rotating rotor. Once synchronized, the voltage and the speed are increased to the corresponding levels (ABB Motors & Drives, 2004 S. Weingarth).

In power plants, flying start capability can prevent a unit shut-down in the case of a temporary trip of the ID or FD fan. These large fans normally take a long time to decelerate, necessitating a boiler shut-down and a long re-start of the unit. A flying start allows the drive to re-accelerate the rotating fan shaft and avoid a boiler shutdown.

Motor Loadability and Cooling

Through frequency and voltage control, VFDs can make a motor run faster than its normal full speed rating and at maximum torque over a wider speed range. This capability greatly extends the useful operating range of a pump or fan drive system, for example. The limiting factor in this operation is the capability of the motor to remove excess heat, known as motor 'thermal loadability'.

Standard induction motors are commonly totally enclosed fan-cooled (TEFC) motors. These motors use a shaft-mounted fan to draw ambient air over cooling fins to self-cool the motor. The added heat removal capability of motors with a separate cooling system allows those motors to sustain higher, constant torques at lower speeds when equipped with a VFD. The effect of extra cooling is shown on the following figure. The following figure shows how an actual VFD can provide near-constant torque from zero to nominal speed, if sufficient cooling is available to maintain a constant nominal operation temperature for the motor; values with subscript ‘n’ are nominal values. Note that torque is limited in the field weakening range of operation regardless of cooling method.

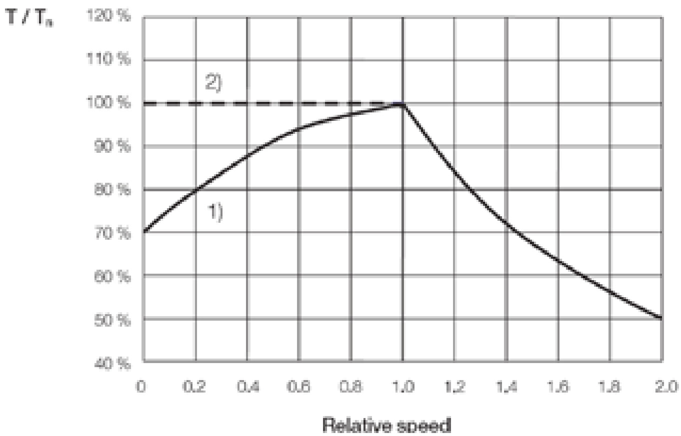


Figure 2.48 – Standard induction motor loadability 1) without and 2) with separate cooling, (ABB Drives 2002)

With VFD speed and torque ‘overdrive’, a motor may be dimensioned according to its normal use, not for transient peak conditions, thus reducing motor size and investment cost. Where loading peaks are expected, however, it is important that the load, the VFD and the motor are compatible, otherwise the motor or the converter may overheat and increase the risk of damage.

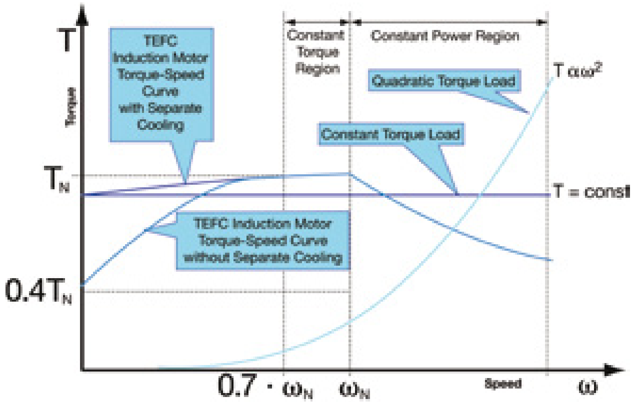


Figure 2.49 - Torque-speed curves with VSI-PWM VFD and 2 types of load, (based on deAlmeida, 2006)

This figure shows torque and power for a totally-enclosed fan-cooled (TEFC) induction motor fed by a VSI-PWM type VFD, assuming. Two typical load curves are shown; constant and quadratic (i.e. cube-law power load) torque. These loads can be served by a normally-sized VFD. Loads with high starting or breakdown torque requirements require more careful **sizing and selection of the VFD**.

Drive Loadability and Cooling Issues

Energy losses in the VFD cubicle are a measure of the drive efficiency. For drives averaging 98% efficiency, therefore, the heat energy is 2% of the input power. This heat must be removed from the VFD, usually through forced cooling. It is important to ensure sufficient drive module cooling and to include the drive fans and cooling system in a regular maintenance program.

Generally speaking, a frequency converter's short term loadability is often more critical than the motor's. The motor thermal rise times are typically from 15 minutes (small motors) to several hours (big motors) depending on the motor size. The frequency converter's thermal rise times (typically a few minutes) are given in the product manuals (ABB Drives 2002).

Proper application design and **regular maintenance** are the key to realizing drive suppliers claims of mean-time-between-failure (MTBF) specification somewhere between 20 and 100 years. Advances in technology however, are likely to prompt a facility to upgrade a drive within a shorter time frame. The life expectancy of the VFD converter is generally directly related to the temperature of the internal components, especially the capacitors (US DoE, 2008).

Power System Capability

A VFD and motor running at much lower than full speed have a lowered power factor. Drives with sufficient power factor correction capability are desirable in applications which require long periods of low speed operation. Harmonics induced by the VFD on the power supply network are one of the issues discussed in the **Power Systems** section.

Input Transformers

VFDs in the MV range require input transformers to manage the connection to the power system. These transformers perform several functions:

- They adjust power supply voltage to the levels required by the converter; most suppliers have drives that can be connected to 3.3 – 6.9 kV today, but many plants have voltages that lie outside this range.
- They protect the motor and/or network from common mode voltages.
- They provide isolation in case of faults; there is no physical (metallic) contact between primary and secondary windings.

Modern VFDs have small ‘footprints’ and a flexible input transformer configuration. This configuration allows the large input transformer (See picture below) to be placed outside the electrical room. The choice of VFD power electronics affects the flexibility of the layout. For example, a 3-level VSI topology reduces the number of cables between the input transformer and the converter (ABB Switzerland, MV Drives, 2002). An input transformer that can be located outside the electrical room reduces the size and cooling requirements for that room (ABB Switzerland, MV Drives, 2002).

Figure 2.50 – Photo of a large input isolation transformer, (ABB Drives, 2008)

Operating Environment

Due to the sensitivity of drive electronics, in retrofit situations the VFD hardware cannot usually be placed in the same location as previous mechanical speed reduction equipment (US DoE, 2008). VFDs electronics are housed in an enclosure called a ‘cubicle’. Like most electronics, the VFD cannot normally tolerate corrosive, very humid or very hot ambient conditions. For this and other reasons related to cooling (see the section on Drive Cooling), the VFD cubicles are usually placed in a separate ‘electrical’ room, usually together with low-voltage switchgear & motor control centers. Typical dimensions for a large VFD cubicle are 9–16 ft long, 3 ft deep and 6 ft high. VFD drives and switchgear can be housed in modular pre-fabricated units for easy site installation and limited civil engineering costs.

Figure 2.51 – Photo of a typical MV drive cubicle ABB Drives, 2008 (ACS-5000 Medium Voltage drive)

VFD Maintenance

Availability (the inverse of failure rate) of a modern VFD is typically in the high 99+% range. VFDs provide online diagnostic information of the status of the drive and motor. This information is accessible via open process industry communication protocols and can be used by pro-active maintenance programs to increase the reliability and the energy efficiency of the drive system. Basic values such as VFD inverter and motor temperatures, voltage, frequency, currents, operating hours and even total number of motor revolutions are recorded and stored at high resolution. Derived values such as energy, torque and horsepower are also calculated and stored for performance improvement efforts such as plant energy efficiency programs. The VFD itself also continually performs automatic diagnostics using this information, for early fault detection. The average MTBF in months, in a typical industrial application such as pump flow control, is 32 months (ABB, Weingarth, Automation World, 2004). This compares well with the MTBF of a control valve, which is 18 months. (ABB MV drives have an available optional DriveMonitor™ package, for use in modern asset management programs.)

VFD Cost and Technical Calculations

In the early days of VFDs a small drive cost in the region of US$500 per kW. Technology advances and economies of scale have brought the price down in the region of $150 per kW, and the average hardware cost per hp decreases with the size of the drive. Small to medium drives (100 to 500 hp) range from $200 to $150 per hp, while larger drives (500 to 10,000 hp) will range from $100 to $75 per hp.

The total investment cost of a VFD are mainly hardware, engineering and installation costs. The 'total installed cost' of a drive is typically more than double the hardware cost for small to medium drives, and about 40% more for larger drives. A typical cost of a 1,000 hp drive is $100 per hp (ABB Power Systems, 2009). The base cost of such a large system, not including engineering, is about $100kUSD. The total cost is therefore around $185-200kUSD.

The installed cost of a VFD is small when compared to the application's energy savings from speed control. An analysis of VSD economics by RMI in the Competitek Drivepower Manual showed payback periods ranging from 4 years down to 1 year for initial costs ranging from $750 to $175 per hp, in an industrial pumping application. The handbook's **Case Studies** section has a fully worked-out example of a flow-control retrofit showing payback and present value cost calculations.

Many of the VFD side benefits are not quantified in lifecycle cost (LCC) calculations. VFDs have many built-in **motor protection** and power quality functions that replace costly dedicated equipment in new plant designs; these foregone costs should be considered in LCC analyses. Some indirect benefits also reduce the investment cost; for example, the reduced current in VFD applications means that smaller-sized electric power system elements (breakers and cables) may be specified.

VFD Calculation Tools

There are a number of sizing and selection tools that allow application engineers to evaluate the economics of several VFD options before calling in vendor engineers. The common input data to these tools are: Required speed range and mechanical load (power and torque) with overloads, duty cycle, ambient conditions, supply network characteristics, and the required IP class (enclosure) of the motor.

The common output data of these tools are: optimal motor, frequency converter and transformer, calculated network harmonics, and drive efficiency values.

- ASDMaster, an adjustable speed drive evaluation and applications software package, is available from the Electric Power Research Institute, www.epri.com .
- ABBs free DriveSize (shown in the figure below) is a PC program to help select an optimal motor, frequency converter and transformer. DriveSize can also be used to compute network harmonics and to create documents about the dimensioning. The tool has current versions of the ABB motor and frequency converter catalogues.
- ABB's free FanSave and PumpSave tools calculate saved energy and money when using VFDs instead of other means of flow control.
- DriveMag's DASH software tool, whose evaluation of different speed-control methods also includes installation costs and energy cost fluctuations.
- ABB's DrivePump, which is similar to PumpSave, but achieves greater accuracy by using actual pump curve data as input, or specific speed and internal tables based on pump handbook data. The tool can also compute motor currents and network harmonics and energy efficiency. This tool requires more data input than PumpSave, but its output can be used in contractual documents.

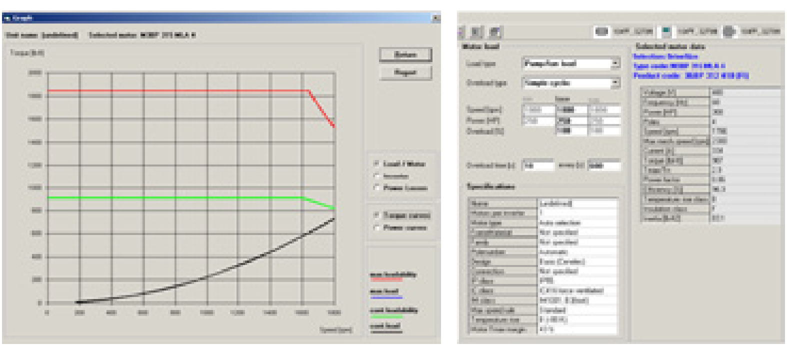


Figure 2.52 - Screenshots of DriveSize motor sizing and selection tool, showing loadability of motor in a pump or fan application, with quadratic torque load, (ABB Motors & Drives, 2007)

Module 3
Electric Power Systems for Auxilaries

Module Summary

This module provides general design & energy impact of the most common components of in-plant electrical power system, also known as ‘Electrical Balance of Plant’ (EBoP). Most of the material in this section is applicable to all industrial electrical power systems. The purpose of this section is to help identify areas of controllable losses in medium and low-voltage (MV and LV) plant power systems and to provide some guidelines to mitigate those losses.

The information in this module may be generally applied to all industrial facilities industries with large internal power distribution networks; industry-specific text is shown in alternate text, such as follows:

For power plants, the scope for this module begins at the generator busbar’s connection to the auxiliary transformer(s), but also includes the power path leading through the main step-up transformer. The relationships between electric power system ‘balance of plant’ (EBoP) items are shown in the figure below.

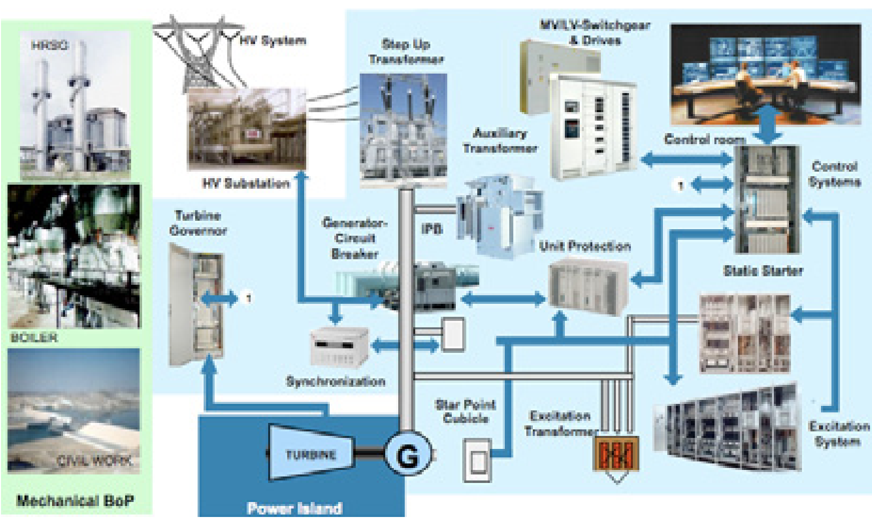


Figure 3.1– Electrical balance of plant equipment in a fossil-fuel power station, ABB Power Systems, 2008

This section examines power systems from an energy efficiency perspective and does not provide guidance on other, critical aspects of power system engineering such as protection & control, safety, or installation. For more complete guidance on all other aspects of power system design, see both the standards and references sections of this handbook.

Role of Power Systems in Energy Efficiency

The energy impact of power services is growing due to increased proportion of auxiliary electrical loads as well as the increased variability of plant loading; see the section on **Plant Efficiency Trends**.

Poor design of in-plant power factor and power quality increases electrical losses, which reduces efficiency and also leads to increased maintenance costs – another good reason to look at power and its application.

The electrical power system has an impact on the reliability of almost all equipment in the plant. Instability in the power system has a multiplier effect that can incur energy penalties due to unstable production and reduced reliability in many other parts of the plant.

Need for an Integrative Design Approach

An integrative systems approach to power systems design is needed due to the interrelated nature of auxiliary loads and the power system; drive power to pumps and fans, energy efficiency, soft-starters, PF correctors, VFDs, harmonic mitigation and phase unbalance are all interrelated technologies and issues.

An electrical upgrade to improve energy efficiency, such as increased use of VFDs, premium efficiency and downsized motors, new transformers etc. should prompt a re-evaluation of the plant power system to ensure that overall efficiency and reliability is not compromised.

An integrative approach requires the engineer to learn as much as possible about the plant's loading or load mode, to work closely with the mechanical and process teams towards a prediction, up to 10 years, of how that process load will vary.

Power System – Overview

The purpose of the in-plant power services is to supply electrical power to plant auxiliary process loads, instruments and control systems. The criteria for delivery of this power are:

- **Power quality:** allow only tolerable small amounts of harmonics, spikes, sags and swells or phase voltage unbalance.
- **Power factor:** control the power factor at all levels of the plant to reduce the losses associated with carrying reactive power.
- **Power level and capacity:** supply power to required capacity, at the voltage levels needed, through efficient, right-sized transformers.
- **Power protection & control:** allow full automatic or manual control of power distribution to serve the needs of the loads, while protecting those loads and the power system itself from harm.
- **Power distribution & layout:** carry power from the source to its destination at the load with minimal losses.
- **Power reliability:** supply all the above with high reliability

All of the above design criteria have a direct impact on plant energy efficiency, which is the focus of this module.

In a power plant, most of the auxiliary power demand, up to 80% of total auxiliary load, is used by large MV electric motors that are typically connected to the medium voltage switchgears/switchyards supplied through unit auxiliary transformers.

Between 6 to 15% of gross electrical output can go to auxiliary power, depending on the type of prime mover for large pumps and fans, the type of fossil fuel, and the required environmental control systems.

Power System Concepts

Electrical Power

There are three basic forms of electrical power:

Active power is the real power consumed by the electrical load, in which the electric energy is transformed into other types like heat, light, mechanical, or chemical. Active power is the power that can do useful work

Reactive power is the power required to bring electrical components to the status of operation when magnetization or induction is involved, as with generators, transformers, and motors. Though necessary for operation, reactive power does no useful work and simply circulates within the network.

Apparent power is the angular sum of Active and Reactive powers derived from the following formula:

$S = (P^2 + Q^2)^{1/2}$

Where:

S = Apparent power (volt-amps)
P = Active power (watts)
Q = Reactive power (volt-amps reactive)

Power factor is the angular relationship between the Apparent power and the Active power; this ‘phase’ angle is represented by the Greek letter ϕ, and the power factor is defined as the ratio P/S or $\cos(\phi)$

The following formulas describe power in 3-phase systems:

Apparent power	$S = U \times I$
Active power	$P = U \times I \times \cos(\phi)$
Reactive power	$Q = U \times I \times \sin(\phi)$
Power factor (PF)	$\cos(\phi) = P/S$

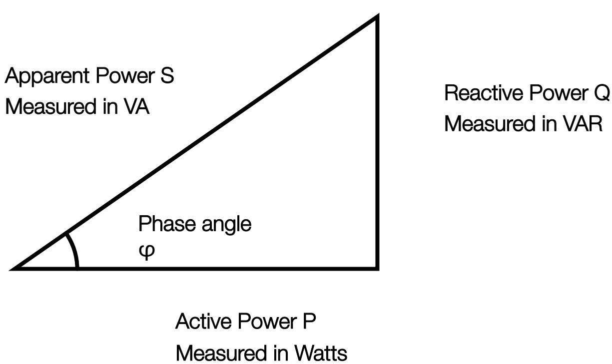


Figure 3.2 – The power triangle diagram

For a symmetrical 3-phase system, these same formulas can also be expressed as follows:

$S = 3 \times U_1 \times I_1 \qquad = 3^{1/2} \times U \times I_1$

$P = 3 \times U_1 \times I_1 \times \cos(\phi) \qquad = 3^{1/2} \times U \times I_1 \cos(\phi)$

$Q = 3 \times U_1 \times I_1 \times \sin(\phi) \qquad = 3^{1/2} \times U \times I_1 \sin(\phi)$

Where:

U = rms value of the phase to phase voltage

U_1 = rms value of the phase to neutral voltage

I_1 = rms value of the phase current

The unit for all forms of power is the watt (W). The unit watt is also called 'volt-ampere' (VA) when stating electric apparent power and 'volt-ampere-reactive' or simply Var (VAR) when stating reactive power.

Harmonic Power, not shown in the power triangle figure, is power which is dissipated at higher harmonic frequencies.

A harmonic is a sinusoidal component of a periodic wave having a frequency that is an integral multiple of the fundamental frequency (i.e. 50 or 60 Hz). Harmonic Distortion factor (DF) is defined as the ratio of the root-mean-square (RMS) of the harmonic content to the RMS value of the fundamental wave, expressed as a percent of the fundamental.

The distortion factor (DF) is applicable to the definition of the total harmonic distortion (THD) for voltage harmonics and the total demand distortion (TDD) for current harmonics.

$$DF = \sqrt{\frac{\text{sum of squares of amplitudes of all harmonics}}{\text{square of amplitude of fundamental}}} * 100\%$$

The distortion factor (DF) is applicable to the definition of the total harmonic distortion (THD) for voltage harmonics and the total demand distortion (TDD) for current harmonics.

Electrical Power Losses

There are two basic kinds of losses in electric power systems:

- Variable losses, also referred to as copper losses, occur mainly in lines and cables, but also in the copper parts of all electrical devices, especially transformers and vary in proportion to the amount of current that is transmitted through the equipment.

- Fixed losses, also referred to as iron or 'core' losses, occur mainly in the generators/motors/transformer cores and do not vary according to current load, beyond the threshold required for energizing. (Leonardo Energy, 2008).

If harmonics are present, then iron losses in transformers will vary with the current, as discussed in the Transformer losses section, Effect of Harmonics.

It has to be noted that, not only do copper losses in electrical devices increase direct power consumption, but they also produce heat. To keep the device within the tolerable heat range, equipment shall be cooled either individually (e.g. fan or pump in transformers) or centrally by introducing HVAC (Heating, Ventilation and Air Conditioning) to the electrical enclosure or room. These additional cooling systems will further decrease the overall net produced energy. Generated heat will affect the aging of the electric components as well.

Power Factor

Lagging PF is due mainly to the reactive power demands of large inductive loads such as induction motors. Reactive power does no useful work, but all plant power system elements must nevertheless be sized to accommodate it. A 'high' PF system is considered to have values between 0.9 to 1.0, and 'low' PF systems have values less than 0.8 for in-plant power supply. The disadvantages of low power factor are:

- Increased losses: the current that carries reactive power leads to losses in electrical devices such as transmissions, distributions and in transformers. These I^2R losses are real power and reduce the overall efficiency of the system.
- Reduced capacity: generators, transformers and other power system equipment carrying reactive power have a consequently reduced capacity for carrying real power.
- Increased maintenance: The heat, which accompanies these losses, often leads to reliability and maintenance issues and decreased component lifetimes.
- Reduced voltage regulation: low PF worsens systems voltage regulation of a transformer (RMI-Competitek,1996)

Most industrial customers, with the possible exception of utilities themselves, are penalized by the electric utility for low plant PF. Industrial process plant PF typically ranges from 0.87 to 0.95, but best practice calls for a 0.95 total PF (including harmonics) and a fundamental PF greater than 0.97. Another design goal is to maintain high PF over the entire normal operating range of the equipment.

For coal-fired steam power plants the power factor of aggregated plant auxiliary loads, at the auxiliary transformer, is typically around 0.80~0.85 (ABB EBoP 2008). Note that this PF is lower than the industry averages described above.

The power factor at the unit step-up transformer is a bit higher, typically at 0.85 to 0.90, but may vary considerably depending on the type of customer loads served.

Reactive Power Compensation Concepts

The first approach to PF correction is prevention, beginning with the selection of high-PF, high efficiency motors that are correctly sized and operated. PF correction can be implemented at the inductive source, centrally, or as a mix of these two methods. Central PF correction at a distribution panel or switchboard has been referred to as 'bank compensation' because large rows or 'banks' of capacitors were used.

Reactive Power Compensation Terminology

Devices used to control power parameters (such as voltage and reactive power) in transmission and distribution systems are generally known as Shunt Connected Controllers, of which there are two basic types: Static Synchronous Generators (SSG) and Static VAR Compensators (SVC):

- A Static Synchronous Generator (SSG) is defined by IEEE as a self-commutated switching power converter supplied from an appropriate electric energy source and operated to produce a set of adjustable multiphase voltages, which may be coupled to an ac power system for the purpose of exchanging independently controllable real and reactive power. If capacitors are used instead of an active energy source, then the SSG device is known as a Static Synchronous Compensator (STATCOM). When a STATCOM is used for harmonic filtering it is called **Active Power Filter**. High-power STATCOMs use the same PWM technology as found in a VFD.
- A **Static VAR Compensator (SVC)** is defined by the IEEE as a shunt connected static VAR generator or absorber whose output is adjusted to exchange capacitive or inductive current so as to maintain or control specific parameters of the electrical power system. The term static refers to the lack of moving/rotating equipment. An SVC does provide dynamic VAR compensation/control.

Reactive Power Compensation

PF correction which is matched and installed at the inductive source (a motor, a transformer or other inductive elements) has distinct advantages over central compensation. Correction at the source generally avoids problems with over-compensation, and no special switchgear and sophisticated switching or control devices are required. The PF benefits are enjoyed by all equipment upstream from that point. Other considerations in approaching PF correction are listed below:

- PF control strategy should include power parameter monitoring at strategic, large equipment points in the network. Voltage transducers on all phases should be specified for these points, as these will also provide warning of voltage phase unbalance (See section on **Phase Voltage Unbalance** for details)
- PF control should be considered together with harmonics, unbalance and other power quality issues. Some compensation solutions that employ capacitor/ inductor combinations are susceptible to damaging resonance at certain harmonic frequencies.
- Modern active filtering technology offers solutions, which allow central compensation for these issues from a single package. (See section on **Power Quality-Harmonics**, for details on active filters)

The amount of extra reactive power needed to compensate for inductive loads and their PF can be calculated from the reactive power balance formula:

$$Qk = P\,(\tan\phi n - \tan\phi d)$$

Where:

Qk = reactive power necessary for compensation; (kVAR)
P = the load active power (kW)
$\tan\phi n$ = the non-compensated tangent value
$\tan\phi d$ = the tangent value that should be achieved by the compensation.

Recall that ϕ is the phase angle and that PF = cos ϕ, so therefore ϕ = arcos (PF).

More detailed formulas and sample calculations for sizing of passive central compensation circuit elements are from **www.leonardo-energy.org**, under the subject of 'Centralized Reactive Power Compensation'

Motor Soft-Starting

The power system is stressed by direct on-line (DOL) motor starts; large induction motor DOL startups draw 5 to 8 times the normal operating current for a sustained period and at low power factor. Soft-starters typically reduce individual startup currents to only 1.5 to 2 times the operating current, improving PF during startup, but without speed control capability during normal operation. The reduced inrush current reduces the heat load on the motor, allowing more frequent starts between cool-down periods. Soft-starting also allow the engineer more flexibility in right-sizing the components of electrical power system by reducing the peak loading.

See the section **Motor Starting Conditions** for more requirements on motor starting, and their connections to the power system.

The term 'soft starter' usually refers to a class of power electronics devices capable of ramping up voltage to achieve a smooth motor startup. It is important to note that **VFDs can also provide soft-starting capability**, along with the added benefit of high and constant PF across the operating speed range. When operational speed control is not required, however, soft-starters may be the more economical choice.

Static Synchronous Compensators (STATCOMs, described in the previous section) also provide soft-start capability. Unlike most VFDs, however, compensators can be serviced while the motor is running.

Synchronous Motors for PF Compensation

The IEEE standard Std. 666-2007 suggests that synchronous motors used on continuous loads can be run with a leading power factor and thus compensate for lagging power factors from other, smaller motor loads that are running throughout the day. 'Because of their separate source of excitation, the load of synchronous motors can be increased without requiring any additional reactive power (the unity power factor motor), or the load can be increased and the motors will supply reactive power as well (0.8 power factor or overexcited motor).' This recommendation applies only to continuous, low-speed and high-power applications. Also, the corrective benefits are at the major bus level in the plant; so losses due to poor PF on lower-level busses are not avoided (Competitek, 1996).

VAR Compensators

Network users on the demand side of the step-up transformer pay for both real and reactive power. Real power is billed by actual megawatt-hours consumed, but reactive power is billed as a demand charge based on the maximum required within the period. Statistically aggregated maximum demand will help determine the individual unit's generator capacity and PF excitation level. When more reactive power is demanded, then the excitation may deliver it (within the generator capability curve), but the capacity for productive real power (MW) from the generator will be reduced. Freeing the generator to supply more real power would increase the capacity of the unit and the transmission lines to their maximum, thermal limits.

The amount of reactive power that the network demands from the generator is not constant; these mega-VARS (MVAR) can vary considerably, in both leading and lagging modes, throughout the day. Activation of a large industrial load on the network will change the VAR demand on the network, for example. To manage changing network power factor needs, utilities may install sets of capacitors and reactors which can be mechanically switched in or out of service. These devices are known as mechanically switched capacitance (MSC) and reactance (MSR), and can be operated in under a second.

Some dynamic network events, such as lightning strikes, short circuits, or other faults, require a much faster and more accurate compensation response by the utility. Static VAR Compensators (SVCs) use the same power electronics technologies found in VFDs to switch in (or out) VAR-compensating elements as fast as 2 times per cycle. The term 'static' refers to the solid-state electronics' lack of moving parts in this device when compared to mechanical (MSC or MSR) or rotating devices. SVCs are more expensive than the mechanical compensators, but they are continuously controllable, offer much faster and more precise response, without regard for hysteresis in the load pattern. In practice, these two VAR compensation methods are complementary; mechanical devices can switch in large steps, and the SVC can be used for fast and fine tuning of the compensation.

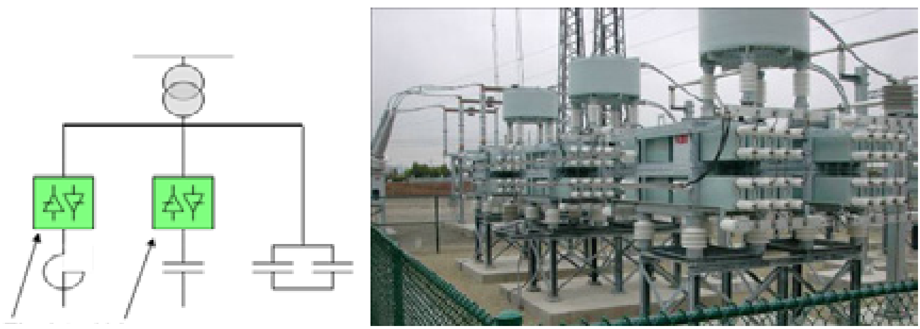


Figure 3.3 – SVC switches for reactance (left) and capacitance (right), (ABB Grid Systems,2009)

VAR compensators can be placed at any point in the electrical power system; near the generator source, in the grid, or near the large consumer loads. VAR compensators can increase the net real power output of the generator, but they are not without small losses. These small losses can be further minimized by specifying more, smaller increments of capacitive and reactive elements, based on an LCC analysis.

The following case material was provided by Brian Scott of ABB Grid Systems.

A generator with rated output of 695MVA is currently producing 625.5 MW. The utility operator wishes to increase the real power output to 693 MW, an increase of 67.5 or almost 11%. The PF requirements are from 0.9 leading to 0.95 lagging.

The generator capability (P-AQ) curves in the figure below show the amount of reactive power required for each of these limits, without (left) and with (right) SVC compensation. Before starting an SVC design, it is recommended that power flow and voltage stability studies be performed. As with other compensation technologies, a harmonics analysis of the entire system is also necessary. And, as with all large equipment in the power system, a detailed understanding of the load pattern is important for engineering an optimal solution and for determining the desired operation points that minimize losses.

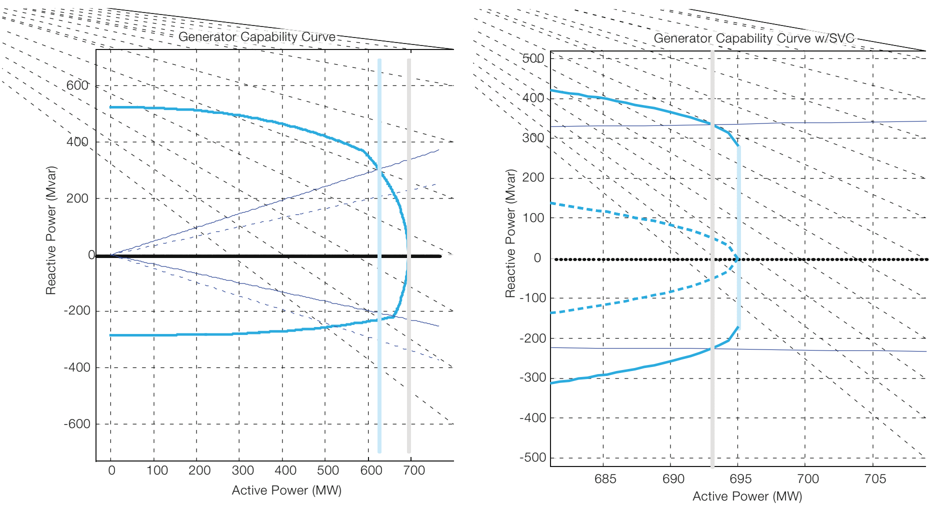


Figure 3.4 – Generator capability curves before (left) and after (right) SVC Var compensation, (ABB Grid Systems, 2009)

In a power plant unit, it is important to determine the combined capability of the turbine-generator system. The target may be to increase MW output by 10% by providing SVC compensation, but this can only be achieved if the turbine can indeed provide the extra power. If the turbine is not the bottleneck, then the extra power can be achieved. This extra power is produced with extra fuel, at the same heatrate as before, but the cost of increasing capacity through SVC compensation is less than one-third of new coal plant capacity.

For example; an SVC system sized to provide +300/-170 MVA compensation would cost over $US20M, not including installation or civil works. If the plant unit happens to be baseloaded, then the extra power freed up by the SVC can be sold at a rate higher than the rate earned by the generator capacity on standby to provide MVARs

In one case where PF was increased from 0.8 to 0.95, the efficiency of the GSU transformer increased by 0.06% due to PF improvement alone. For stable operation and other practical reasons, the PF at the generator cannot be increased much past 0.95.

Active Rectifier Units on Motor Drives

VFDs with an active front end (active rectifier unit - ARUs) can play an important role in improving industrial plant active power generation capability and leading phase operation improvement. A VFD with active front end design gives the possibility to supply reactive power (lead or lag) to the auxiliary power system to compensate the reactive power needs of the remaining constant-speed motors and the reactive power losses of auxiliary transformers.

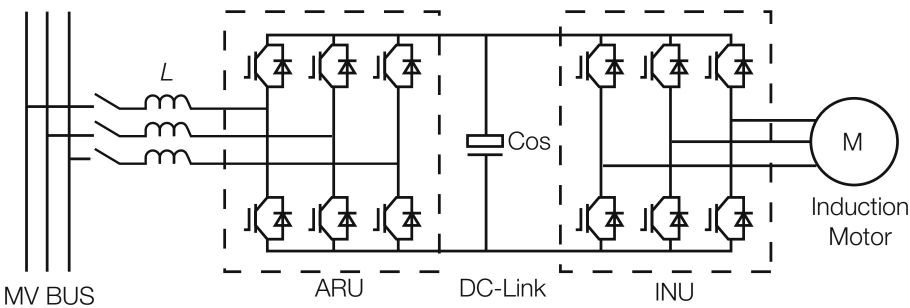


Figure 3.5 – Schematic of VFD with active rectifier unit circuit, (ABB USCRC, 2008)

The reactive power compensation from ARUs is free-of-charge as long as the converter operational point is within its P-Q circle diagram.

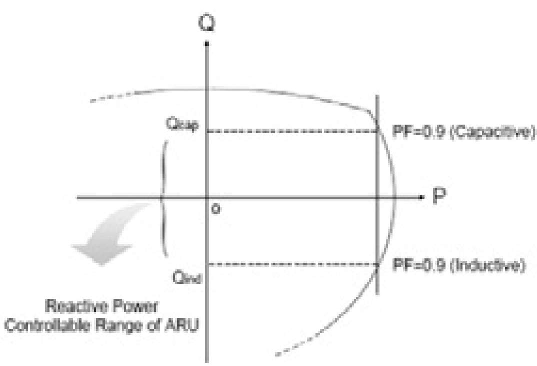


Figure 3.6 – P-Q diagram showing ARU capability, (ABB USCRC, 2008)

The benefits of ARU compensation functions are twofold 1) Full balancing the reactive power demand of all auxiliary loads and thus gives the possibility for the generator to produce more active power, 2~3% of rated capacity while still maintaining the required external reactive power capability 2) Reactive power compensation from ARUs can improve the plant leading phase operation capability and also plant auxiliary system operation performance under various disturbances such as suppressing transient over-voltage or under-voltage caused by generator load rejection.

Power Quality – Harmonics

Harmonics Concepts

Harmonics are voltages and currents at frequencies higher or lower than the nominal frequency (60Hz in the US, 50Hz in Europe). These frequencies are usually integer multiples of the nominal ('fundamental') frequency and are caused by devices that draw current in a non-linear fashion from the power source.

Typical nonlinear loads include rectifiers, Variable Frequency Drives (VFDs), and any other loads based on solid-state conversion. VFDs are a potential source of harmonics due to their fast current switching action at frequencies higher than the fundamental. Transformers and reactors may also become nonlinear elements in a power system during overvoltage/saturation conditions. Chargers for batteries (in the UPS system), for example, may also be a source of harmonics if these do not use the recent switch mode/chopper technology. Harmonics may also be received from other plants nearby, such as an aluminum smelter.

Power at harmonic frequencies does no useful work and causes equipment heating, interference and other undesirable effects. Electronics, including those onboard some VFDs, are particularly sensitive to high levels of harmonics. The presence of harmonics also decreases **Power Factor**, which is why engineers refer to 'true' PF in systems with harmonic distortion.

Figure 3.7- Harmonics-induced damage, (ABB Kurt Schipman ,'Active Filter Savings', 2008)

Harmonic pollution may also cause kWh meters to give faulty readings; these devices are important for monitoring energy consumption.

Harmonics are said to ‘distort’ the pure 60Hz sinusoidal waveform that carries useful power from the source. The summary effect of these waveforms yields the Total Harmonic Distortion (THD) measure.

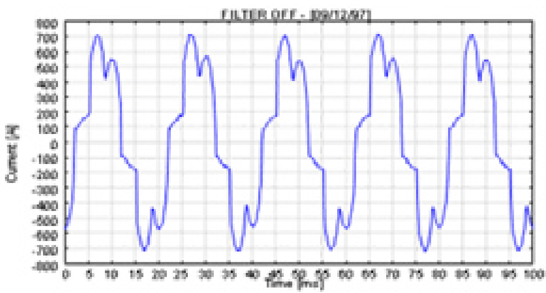


Figure 3.8 – Graph of high harmonic content 50 Hz waveform, (ABB Kurt Schipman)

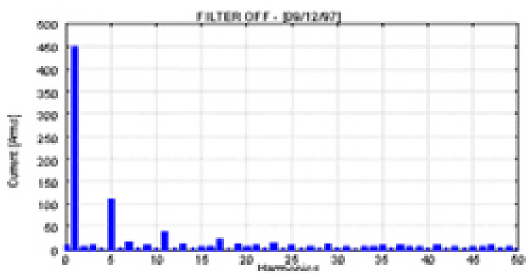


Figure 3.9 – Graph of harmonic current magnitudes of the above waveform, (ABB Kurt Schipman)

Although limits vary in different areas, the IEEE 519-1992 (USA), G5/4 (UK) standards limit THDV ≤ 5% and limit for each harmonic component. The worldwide standard IEC 61000-2-4 also limits THD. This limit is acceptable even for very sensitive loads. These standards also provide detailed harmonics mitigation design guidelines.

VFD-Induced Harmonics Concepts

Under ideal operating conditions, the current harmonics generated by a p-pulse line-commutated converter can be characterized by $I_h=I_1 / h$ and $h=pn\pm 1$ (characteristic harmonics) where n = 1, 2, … and p is an integral multiple of six. In cases of non-ideal conditions (e.g. unbalanced converter input voltage, unequal commutation reactance,..), other harmonics can emerge: even, triple, odd non-characteristic and non-integral (inter-harmonics) harmonics belong to this group.

Harmonics Mitigation

It is considered best practice to reduce harmonics in the system at their point of origin. Installing filters near the harmonic sources, such as with VFDs, can effectively reduce harmonics. By using an individual passive filter for each VFD instead of a large centralized filter, one can also avoid the potential problem of over-correction at low loads. Also, the VFD with filter and motor with may then be moved elsewhere in the plant, to different buses without any re-engineering of a central system. The next best placement of filters is at the nearest switchboard or feeder switchgear.

Harmonics Mitigation Using Passive filters

The following section is adapted from material by ABB Kurt Schipman 'Active Filter Savings', 2008, and Dr. Amory Lovins in Competitek,1997.

For large, easily identifiable sources of harmonics, conventional passive filters designed to meet the demands of the actual application are the most cost efficient means of eliminating harmonics. These filters consist of capacitor banks with suitable tuning reactors and damping resistors. In addition to harmonics mitigation, these filters also perform PF correction because they act as a capacitor at the fundamental power frequency.

Some disadvantages of passive filters are listed below:

- Offer a low impedance path to harmonics
- Tuned below the first harmonic that exists in order to minimize resonance risk
- Filtering efficiency depends on network parameters, hence filtering performance cannot be guaranteed
- Danger for overloading due to load increase or background distortion, difficult to extend
- Multiple branches required for filtering more than one harmonic
- Multiple branches required for filtering multi-pulse arrangements
- Large space requirement and weight
- Always provide capacitive power: but AC drives do not require capacitive power
- Generators may not cope well with leading power factor
- Sizing rules not yet adapted to modern load types
- In LV applications, passive filters are used less and less

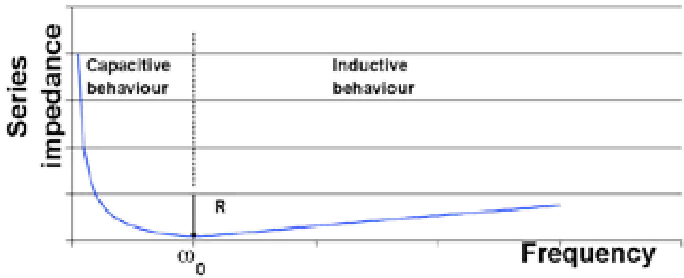


Figure 3.10 – Passive filter performance vs. frequency, (ABB, Schipman ‘Active Filter Savings’, 2008)

Harmonics Mitigation With Active Filters

For small and medium size loads, active filters, based on power electronic converters with high switching frequency, may be a more attractive solution. The basic concept is to put a switching inverter in parallel with the load that is injecting compensation currents at the harmonic frequencies. This approach is also known as a form of Static Synchronous Compensation (STATCOM).

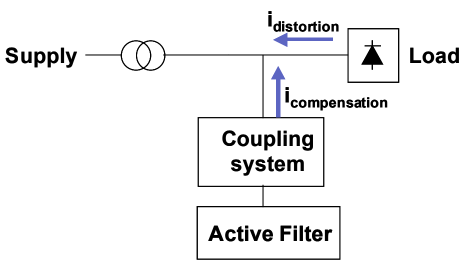


Figure 3.11 – Active filter with load schematic, (ABB, Schipman, 2008)

The advantages of parallel active filter topology are:
- Dimensioned for the compensation current only
- Cannot be overloaded irrespective of the harmonic load increase over time
- Does not directly affect the supply to the load

All commercial active filters on the LV market use parallel topology

Modern active filter technology is able to produce reactive power as well as mitigate, and in some cases, eliminate problems created by power system harmonics. See section on **Power Factor and reactive power compensation** for more details.
Active filters can perform the following Power Quality tasks:
- Harmonic filtration up to high order
- Reactive power compensation

– Load imbalance compensation
– Self-limiting
– Built-in network monitoring

Active filters work by measuring the physical voltage and current signal, analyzing them in real time in a high speed using digital signal processing (DSP), then creating the balancing power inverter control signals. These components are shown on the active filter schematic on the figure below.

The filter is programmable such that various degrees of filtering vs. reactive power compensation can be achieved. The filter's control function may be either open loop or closed loop, but the trend is toward closed loop for these reasons (especially valid at higher frequencies):
– Directly measure and control harmonic current flowing to network
– Correction for system inaccuracies
– Can verify harmonics according to regulation directly
– Can be used for power factor targeting
– Simple CT connection using standard CTs
– Easy for future harmonic load extensions
– Appropriate for local & global compensation

Another trend in filter design is to have dedicated controllers for each harmonic order. This architecture, known as 'frequency domain', allows more precise targeting for each harmonic.

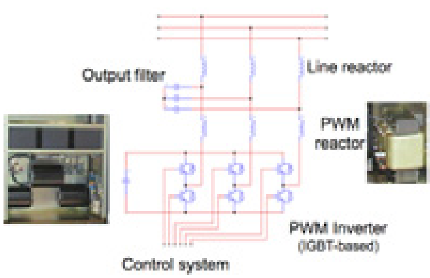


Figure 3.12 – Active filter schematic, (ABB, Schipman, 2008)

The highest amplitude harmonics are usually the 5th and 7th harmonics; these can be removed by using a 12-pulse uncontrolled diode bridge rectifier. A 24-pulse unit can be used for weaker networks or where more stringent THD requirements apply.

VFD-Induced Harmonics Mitigation

There are several approaches to mitigating harmonics induced by VFDs in the power supply system. The main methods are:

– Increasing the ‘resolution’ of the drive inverter by selecting those with a higher pulse count .
– Adding properly tuned filters on the supply line to the VFD.
– Newer technology active front-ends for the drive typically reduce harmonics induced on the supply side.

A comparison of the harmonic content between 6 and 12 pulse rectifiers is shown in the figure below:

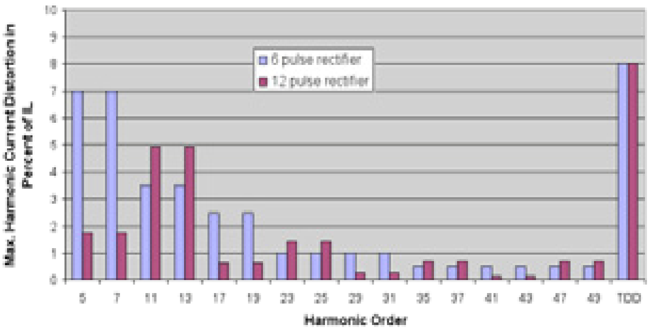


Figure 3.13 – Harmonic distortion for 6 and 12 pulse rectifiers, (ABB Industrie AG, 2006)

Higher power applications (large MV drives) typically will use harmonics-free or high-pulse (18 pulse or higher) inverters to better distribute the load internally. An ideal 18-pulse drive will eliminate the 5/7/11/13th harmonics, but not the 17/19th (harmonics created are ‘pulse number +-1’). A harmonics analysis will reveal if these harmonics are problematic. For very large drive systems, 15MW or larger, a common solution might be a 12 (or 24)-pulse diode supply and passive filters on the line side or alternative a 36-pulse drive without a filter. A third approach is to specify a drive with active front end (Active Rectifier Unit: ARU) to control harmonics on the supply-side.

Case Example
Harmonics in a Pumping Cluster

The figure below shows line voltages & line currents at pumping cluster; the values for harmonic distortion were THDV = 12%, THDI=27%

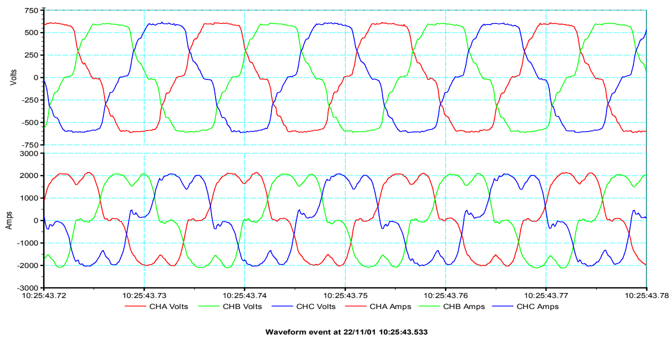


Figure 3.14– Line voltages and currents before filtering, (Schipman, 2008)

The following figure shows line voltage and currents with active filter, which improved the values for harmonic distortion to THDV = 2%, THDI=3%:

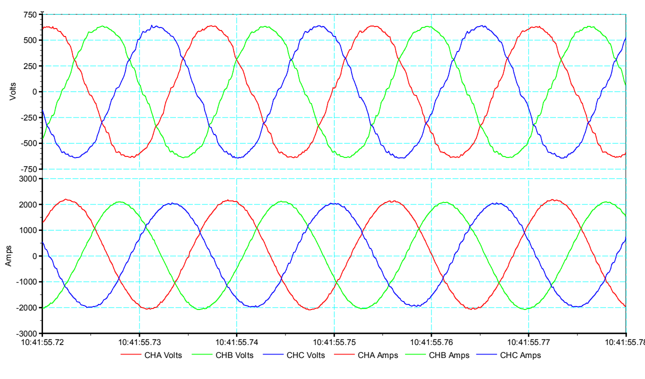


Figure 3.15 – Line voltages and currents after filtering, (Schipman, 2008)

Power Quality - Voltage and Frequency Variation

Transient Effects

Most transient voltage and frequency effects do not have an immediate energy efficiency impact, but may result from some of the PF improvement and harmonics mitigation designs recommended in this handbook. These effects last less than 20 cycles, and may be much shorter in duration.

The list of transient effects includes: voltage sags and swells, under or over-frequency, voltage spikes, and ringing transients: high-frequency damping sinusoids that temporarily boost voltage. The mechanical switching from PF-correcting capacitor banks can cause 'ringing' voltage transients that can trip electronic equipment, even behind isolation transformers. (Competitek, 1996) VFDs themselves may not be immune to such transients as well.

A Voltage Sag or Voltage Dip is a decrease in supply voltage of 10% to 90% that lasts in duration from half a cycle to one minute. A Voltage Swell is an increase in supply voltage of 10% to 80% for the same duration. Voltage sags are one of the most commonly occurring power quality problems. They are usually generated inside a facility but may also be a result of a momentary voltage drop in the distribution supply. Sags can be created by sudden but brief changes in load such as transformer and motor inrush and short circuit-type faults. A voltage sag may also be created by a step change in load followed by a slow response of a voltage regulator. A voltage swell may occur by the reverse of the above events.

An 'Interruption' occurs whenever a supply's voltage drops below 10% of the rated voltage for a period of time no longer than one minute. It differs from a voltage sag in that the sag is not a severe power quality problem. The term 'sag' covers voltage drops down to 10% of nominal voltage whereas an interruption occurs at lower than 10%. A Sustained Interruption occurs when this voltage decrease remains for more than one minute

Sustained Voltage Variations

Sustained, off-design high voltage (110%) increases the magnetizing current in an electric motor. This extra current results in copper and stator core losses, and a decrease in efficiency. At off-design high voltage the power factor is reduced at high loads (IEEE, 2007).

Sustained low voltage operation (90%) leads to higher load currents and therefore increased copper losses, and hence a reduction in efficiency of 2% to 3% at all loads; at near full load the efficiency is relatively constant. Efficiency actually increases when voltage drops below a threshold level for motors at partial load.

VFDs and other power electronics with built-in power factor controllers will therefore act to reduce the applied voltage under these conditions to minimize losses in the motor.

In contrast to voltage variations, small frequency variations have little effect on motor energy efficiencies.

Power Quality - Phase Voltage Unbalance

Sources for this section are: ABB Power Systems, Canada and (Competitek, 1996)

Phase voltage unbalance can cause excessive rotor currents and damaging reversing torques in the motor. The combined effects of phase unbalance lead to increased motor temperature, reduced net output torque, pulsations in speed & torque, increased mechanical stress on motor components and reduced motor efficiency.

Voltage Unbalance – Causes and Effects

NEMA defines voltage unbalance as % of maximum deviation of the line voltage from the average voltage.

For example, a 3-phase system with phase voltages of 466, 458, and 461:

The average voltage is	: (466+458+461)	= 461.7
The phase unbalance is therefore	: (461.7-458)/461.7	= 0.8%

The main causes of sustained phase voltage imbalance are listed below:

- unbalanced transformer windings
- unequal impedances in distribution wiring
- unbalance within the motor itself (rewound motors at higher risk)
- single phase or unbalanced 3-phase loads which are unevenly distributed.
- failures in VFDs or PF correction equipment
- single phase-to-ground faults or disconnection failures

Although rare in industrial process plant networks, just a 3.5% imbalance can increase total motor losses by 20 to 25 percent. In a 90%-efficient motor this is equivalent to an increase in total power loss of 2.0 to 2.5 percentage points. The drop in motor efficiency due to phase voltage unbalance is greater at lower motor loadings, below 75%. At a 5% unbalance, the motor de-rating factor may be as large as 75% of the nameplate horsepower. An unbalanced supply may have a disturbing or even damaging effect on motors, generators, polyphase converters, and other equipment. The foremost concern with unbalanced voltage is overheating in three-phase induction motors. The percent current imbalance drawn by a motor may be

6 to 10 times the voltage imbalance, creating an increase in losses and in turn an increase in motor temperature.

Mitigation through Design

The US DoE recommends that unbalances greater than 1% lead to a de-rating of the motor. Under a condition of 5% voltage unbalance, the motor de-rating factor may be as large as 75% of the nameplate horsepower. An additional effect of voltage unbalance is that the locked rotor and breakdown torques will be decreased, and the motor may no longer be adequate for its intended application. The above applies specifically to induction motors. Situations in which larger unbalanced voltages exist, or in which synchronous motors are supplied by unbalanced voltages, should be stated in the motor specifications (IEEE, 2007).

Downsized motors with correspondingly lower temperature ratings may be more at risk of the overheating that follows sustained phase unbalance than a previously highly oversized motor for the same load. The thermal margin of oversized motors prevents motor failure but unfortunately also masks the cause of the reduced efficiency of the affected motors.

For an existing plant, the best practice is to balance phases as closely as possible and to ensure that power protection devices monitor continuously for phase unbalance exceeding 1% at motor terminals. Regular thermographic and vibration monitoring will also reveal the signature symptoms of phase unbalance. In the design phase, the US DoE advice is to check electrical system single-line diagrams to verify that single phase loads are evenly distributed across the phases. Designs that place all receptacle loads on a single phase also risk phase unbalance, as this capacity varies greatly or is seldom used.

Power System Control and Protection

The function of power system control is to selectively connect power sources with consumers, and to provide facility operators with information on the real-time status of the network. Power also control enables complex, automatic interlocking and energy sequencing logic. As with DCS systems, modern power control has a distributed architecture, with separate units for control (the brains) and actuation (the muscle). The control units execute the logic in a microcontroller unit, then send their output signal to contactors which perform the actual power switching. These contactors send back status and health information to the control unit. Power control is distinct from protection in that the contactors, relays and other ‘switchgear’ in the power control system cannot switch the very high currents during short-circuit; these situations are handled by heavier-duty, fast acting protection devices.

Protection systems safeguard the motors, power system equipment, and human staff from damaging effects of short-circuits and ground faults. The equipment typically in need of protection are: generators, busbars, lines, and transformers. The brains of protection systems are so-called 'numerical relays' which sense a fault condition and then command a circuit breaker to interrupt one or all phases of power; this is known as a **trip**. VFDs have many built-in **protective functions** to protect the motor from abnormal power supply conditions.

Modern, microprocessor-based control and protection systems offer distinct energy-efficiency advantages over older, purely electro-mechanical devices. The ability to execute more complex control logic, in close communication with the process controls running within the DCS, allows a higher degree of energy optimization than possible with electromechanical switching only. Load management schemes can be implemented which balance supply and demand across parallel plant units in a way that that minimizes losses and enhances **power quality. Power control systems also enable complex unit-wide automatic startup and load shedding routines; these can conserve existing capacity and avoid energy-wasting trips, and long or wasteful re-starts.** The self-supervision capabilities of modern control and protection devices further reduces the chances for an energy-wasting trip event.

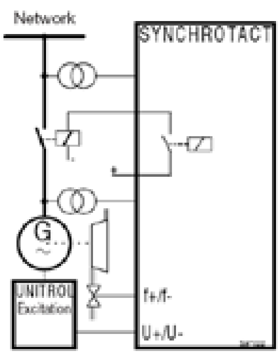


Figure 3.16 – Automatic generator synchronizer device, (ABB Power Products 2006).

In power plants, the power control system can be programmed to ensure that the GSU, the auxiliary and the distribution transformers are not energized when not in use.

Modern power control also enables integrated allocation optimization when there are multiple sources of power, as described in the section on **Multi-Level Real-Time Optimization.**

Much of the design reference information available under the category of substations also applies to large industrial power supply systems.

Generator Control

In power generation, an automatic synchronization device is recommended for parallel switching of generators with the power grid. The synchronizer brings the rotation speed (frequency) and voltage of the generator to within the required tolerance range, using higher and lower commands to the **turbine-generator controller** and the voltage controller (ABB Power Products 2006). Voltage, phase angle and frequency are all dynamic quantities; the synchronizer ensures that the breaker contacts touch at the instant when the phases are matching.

> In power plants, the auxiliary power supply system typically has a high-speed transfer system to ensure a secure supply of power to boiler drivepower; i.e. the BFW pump, circulating pump, and draft fans. In case of an interruption in power, this switchover function provides power from an alternate, standby network. This control function allows the unit to continue operating and avoid the energy waste (and large opportunity cost) associated with a boiler trip.

Transformer Control

This section is adapted from the ABB Switchgear Manual, (ABB Power Products 2006):

Power control devices were once commonly used to operate the taps which change the transformation ratio of a power transformer. This function serves to adapt the voltage in case of load fluctuations, to distribute the load, to adjust active and reactive currents in interconnected systems. Although most modern transformers are equipped with automatic voltage regulation, transformers in parallel operation still require tap change functionality to minimize the reactive current circulating between transformers. Electric furnaces, rectifiers and other devices also rely on tap change control for variation of their input voltage.

Efficient Power System Design and Engineering

Achieving energy efficiency improvements in power system design is challenged by many of the non-technical barriers outlined in the section **Barriers by Stakeholder**. Those barriers most relevant to the plant electrical engineering discipline are:

- In a large power or process plant, electrical engineering (EE) is often the last discipline to be engaged, after process, mechanical and controls. This leaves the EE with little influence to practice efficient integrative design, since most other aspects are now frozen. **This of course, has a deleterious effect on the energy efficiency of a plant, as virtually all of the internally consumed energy passes through the electrical system.**
- The power system is also the first to be commissioned, which further restricts the time that the EE can spend on conceptual studies described below.
- The trend away from turnkey projects and toward multiple suppliers fragments the design and communication, making integrative approaches more difficult.
- The vital role of power systems to all other plant equipment is the reason why customers often stipulate 'liquidated damages' in contracts with their suppliers. This threat of very large opportunity cost from downtime is a subtle deterrent toward newer designs with potentially significantly lower lifecycle costs. (opportunity costs are not as real as wasted energy costs, but often get the same accounting treatment)

In a retrofit situation involving increased electrification or the introduction of VFDs, it is good practice to re-examine the entire power system to ensure it is right-sized and still capable of delivering high quality power at high reliability. For example, with a change in loading previous schemes for Power Factor (PF) compensation may need to be re-evaluated to avoid increased in-plant losses due to low PF or even for over-correction in some cases.

Generating Station Power Systems

The most common design of in-plant power systems is termed 'unit connected', in which each generating unit has a self-contained network supplied by that unit's generator. The plant power system typically has its own step up and auxiliary transformers, plus one or more startup transformers. Large loads are served directly from the MV switchgear, and the largest motors are usually on a separate bus, where the voltage (during motor starts) may be permitted to drop to a much lower level, say 80% (Black & Veatch 1996, p574)

In a typical generating station the nominal voltage ratings of the auxiliary buses are usually 2.4 kV, 4.16 kV, 6.9 kV, or 13.8 kV. All these voltage levels are referred to as medium voltage or MV. Stations in the 10-100MW range may have 2,400V. Most stations in the 75-500MW range use 4,160V as the base auxiliary system voltage. For stations from 500MW to 1,000MW, it is not uncommon to have auxiliary bus voltages of 6,900V. Occasionally, some single dedicated loads such as BFPs in 10,000-15,000 hp (7.5 MW-11 MW) class are supplied by a separate 13,800-V bus (Black & Veatch 1996). Bus design best practice is to separate redundant loads (such as pairs of ID and FD fans), on different buses. This leads to the common 'double bus' design illustrated in the single-line diagram figure below. Another best practice is to distribute the loads equally among buses.

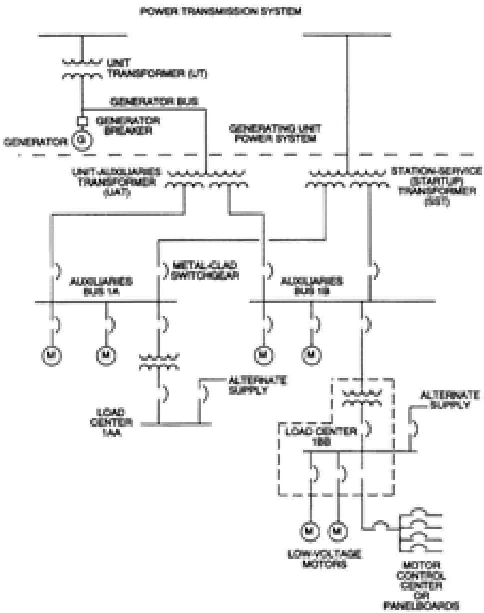


Figure 3.17 – Simplified single-line diagram for unit connected power system IEEE Std.666-2007, Design Guide for Power Stations

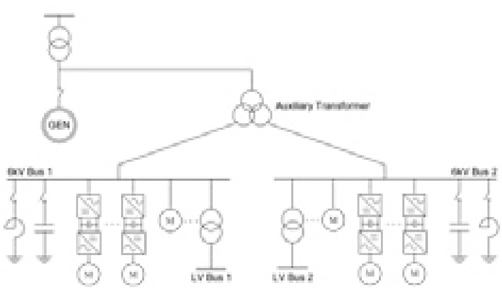


Figure 3.18 – Single-line diagram showing for a unit connected power system, (ABB EBoP/CRC)

Power System Studies

Conceptual studies usually present the greatest opportunities to evaluate the impact of basic efficiency improving design changes, and to seek even greater energy efficiency improvements through rigorous analysis. The power quality conceptual studies most relevant to energy efficiency are:

- Load analysis (especially of auxiliary loads)
- Power flow, voltage selection and voltage drop calculations
- Motor starting analysis
- Harmonic analysis

Other typical power system project studies that have only an indirect impact on energy efficiency are:

- Short-circuit analysis
- Switching studies
- Protection studies
- Reliability analysis

Load List and Analysis

Load analysis is the single most important power engineering step towards increasing energy efficiency. The starting point for design of the power system is to gather data about all the loads that the system will serve. This step includes not just the nameplate data of those loads, but also their criticality, duty cycle, seasonal variations and startup requirements. The sources of much of this data are the mechanical and process design teams. This data is summarized in a 'Load List' which becomes the main document interface between the mechanical/process and electrical disciplines or teams. Due to fragmentation of suppliers, assembling a complete load list is not a simple task. Data from similar past projects can provide a guide, but only a guide, when actual load list information is lacking.

Load Analysis

Analysis of the load list should begin with quantifying the maximum operating load, given the actual loads and load factors. Using only the nameplate values will give a grossly inflated figure and load and lead to oversizing of the supply. A growth factor margin is recommended by the IEEE guidelines, but this may not apply in all cases. The load analysis steps should also quantify the number and loading associated with VFDs. An obvious energy-saving step in load analysis is to reduce auxiliary levels to the lowest possible realistic levels. Large or unusual loads also deserve special attention at this stage. Medium voltage loads tend to be much better understood and documented than low voltage (LV) loads. Attention to LV loading is important, however, as it may comprise up to 40% of the total in a typical industrial plant, with a wide variation between industries.

Electrostatic precipitators (ESP) of the dry type operate by electrically charging flue gas particles for collection on grounded plates. The charging electrodes are energized with 55 to 86 kVDC supplied by a transformer-rectifier (TR) supplied by a 480 VAC bus feeder. An ESP is a capacitive load. The TR is also equipped with controls to vary the voltage depending on current conditions, to achieve maximum voltage without arcing. (Babcock & Wilcox, 2005)

Current loads (kiloamps) can then be calculated from the loads in the load list. The **electric power formulas** at the start of this chapter and may be used to calculate current load in transformers and synchronous generators. For induction motors direct-on-line, see the the handbook's Motors section on **motor power formulas**. For VFD=equipped motors, see that section's formulas for **motor current estimation**.

Power Flow and System Voltages

System voltage selection has an energy efficiency impact. Choosing a higher bus voltage where possible (for example 6,900V vs. 4,160V for auxiliary busses) will reduce ohmic losses due to the lower current levels relative to low voltage busses. Selecting MV rather than LV drives and motors will reduce ohmic losses in drive-power equipment. Motors and transformers rated at the higher voltage levels generally offer higher efficiencies as well. Commercially available circuit breakers are limited to interrupting a maximum of 3000A of short-circuit current. This current limitation may lead designers to split up busses and supply them from multiple, smaller transformers. Smaller transformers have lower efficiency than larger units. Thus, higher bus voltages will allow the designer to specify fewer, larger transformers which will increase the overall efficiency of the system, and enjoy up front cost savings during equipment purchase.

Power flow and short-circuit analyses are required to ensure that voltages are correctly selected during various power flow (both active & reactive) scenarios.

Startup Analysis (Motor Starting)

Motors without **soft starters** draw many times their full load operating current during their startup. High torque demands during startup will also increase the load on the power system and may lead to over-sizing of components for these transient conditions, at the expense of lower continuous running efficiency. The electrical and mechanical/process engineers are encouraged to work together to find creative solutions to make motor startup easier on the power system. For example, a bypass valve could be opened during startup to temporarily relieve pressure, if this is allowed by the process. Startup considerations are discussed in the Fan **Startup**

Conditions, Pump **Startup Conditions** and in the **Motor Starting Conditions sections.**

In power plants, very large motors such as BFW pumps or FGD booster fans may be fed from a separate, higher voltage (13,800V) bus.

Voltage drops at motor terminals during startup may be down to as low as 80% of the normal levels for large motors with long motor leads, far from the main auxiliary bus. (Black & Veatch 1996). Motors which are designed for reduced voltage starting may be specified, but these motors have lower operating energy efficiency. A better strategy is to specify auxiliary power system with a higher capacity supply, at least during plant start-up conditions. This will improve bus voltage regulation, but will increase the short-circuit duty of the switchgear (Black & Veatch 1996).

For power generation stations, a startup analysis should also include a 're-acceleration' study that investigates the consequences of a system trip followed by a quick resumption of power. In such cases several large motors must restart and re-accelerate at the same time.

A similar study is recommended to investigate the amount and consequences of the in-rush power peak that occurs immediately after unit synchronization.

Another opportunity for energy saving is to alter the excitation method during turbine startup. A static frequency converter may allow the elimination of much energy-intensive compressed air during turbine startup.

Harmonic Analysis

A formal harmonic analysis helps to predict the harmonic content, based on the ratio between non-linear loads (like VFDs) and linear loads (like DOL motors) revealed from the Load List. The VFD vendor can help with a first order analysis, but some rules of thumb are provided here, adapted from (CSELive, P.Lynch, 3/1/2008). An industry rule of thumb is that when these loads represent more than 20% of the total loading, then specific power solutions hardware should be considered. This assumes that the drives to be installed have at least 3% ac line reactance or dc link reactance as a part of their standard designs.

If the drives don't include internal reactance, or if many of them are only 6-pulse VFDs, then the system tolerance level drops to about 10%. If these thresholds are exceeded, then a formal harmonic analysis is recommended. If the level of excess harmonic content is high and many drives are involved, installation of an active filter will likely be most appropriate; if only a small number of large drives are involved, then installing drives with active front-ends probably is the best solution. See the section on **Harmonics Mitigation** for more details on passive and active filters.

Equipment Sizing and Bus Design

Correct balancing of loads across buses will improve power quality and thus energy efficiency. In plants with multiple power sources, a correct balancing will also lead to optimal sizing of all power system components and reduced startup power requirements per bus.

A proper analysis will yield the optimum breaker and cable sizing; poor sizing of components here can have consequences for both energy efficiency and protective functions. Undersized cables have higher losses, as discussed in the section on **Cable Selection & Sizing**.

Contactors for Bypassing

Soft-starters are typically bypassed by a contactor (KB) as shown in the figure below when the motor has completed its startup. VFDs, however, are not normally installed with such a bypass contactor for the full load condition. For large motors, specifying a contactor to bypass the VFD, which is not 100% efficient, may be cost effective. The feasibility of this design depends on the motor's duty factor and the duration at continuous maximum load, and several other factors; see NEMA-MG1 and the NEMA Application Guide for AC Drives (2001) for some special precautions regarding this approach.

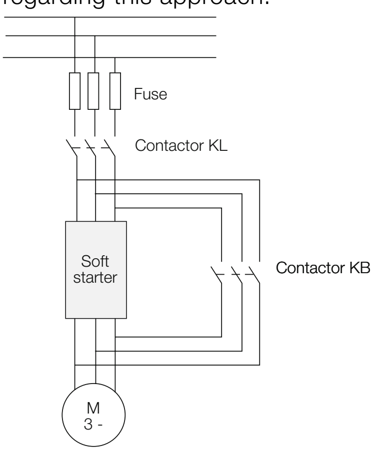


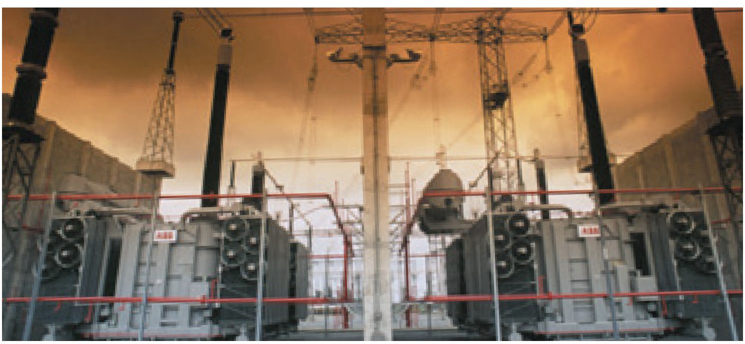
Figure 3.19– Schematic of motor soft-starter on power system, (ABB Motors & Drives, 2007)

Short Circuit Analysis

The main purpose of a short circuit analysis is to ensure that the existing and newly installed breakers will not be over-dutied under short circuit conditions. Breakers must be capable of carrying normal load current and should be able to interrupt fault currents. Hence, breakers have two ratings in ANSI / IEEE; rated current and interrupting ratings. If breakers are called upon to interrupt currents higher than their interrupting ratings then disastrous consequences can follow. In the IEC standard, an additional rating is also addressed, the so-called Making Capacity; if the breaker closes while system is shorted, or the fault is not cleared yet, then the breaker shall be capable of closing on fault without damage and subsequently retrip.

Power Transformers

There are many different types of transformers; the focus of this section is on power transformers, whose main function is to change the voltage levels between a power source and a power consumer, with a minimum of losses. The relevant international standard for power transformers is IEC 60076-1 Power Transformers (VDE 0532 Part 101).



Transformer Concepts

The basic, century-old design of a 3-phase transformer consists of two sets of copper coils wound around the same iron core. The windings form concentric shells of copper around a central core of laminated iron alloy plates, which forms a closed loop for the magnetic field. The primary (input) winding induces a voltage in a secondary (output) winding through the process of electromagnetic induction, transmitted through lines of magnetic flux in the shared core. In principle, however, energy can be transmitted in either direction. The magnitude of the induced voltage on the secondary side (when the terminals are open) is proportional to the ratio of the number of turns of the windings. A transformer tap is a connection point along a transformer winding that allows a certain number of turns to be selected. Transformers that have a set of variable turn ratios enable a rough mechanical form of voltage regulation of their output. The tap selection is made via a 'tap changer' mechanism. Modern **power control** offers other means of controlling transformer voltage, and tap-changing can then become an infrequent operation.

The power capacity (MVA rating) of a transformer depends on the size of the windings and iron core, and also on the method for removing heat, as described in the section on **Transformer Cooling**.

Generator Step Up Transformers - GSU (also known as Unit Transformer – UT)
These transformers take the voltage form the generator busbar MV level (10kV to 21kV) up to a higher (more economic) transmission voltage (HV) level, which may range from 110kV up to 800 kV. Limitations on the insulation design which can be achieved on rotating machinery prohibit the generator from producing HV without need of a step-up transformer (Fassbinder 1997).

The GSU must be matched to the generator so that the transformer can fully utilize the generator's active and reactive power capacities. The standard C57.116-1989 IEEE Guide for Transformers Directly Connected to Generators describes how these characteristics must be matched to the situation:

- Short-circuit impedance
- Secondary (high) voltage rating
- Transformer MVA rating
- Primary (low) voltage rating

Unit Auxiliary Transformers (UAT)
The auxiliary power system can be supplied either from the generator bus or from the switchyard. If supplied from the generator, then one or more 'station service' startup transformers might also be required.

This additional startup hardware may increase the cost and complexity of the power system, but the reliability of the system will increase. Voltage excursions are also lower using power supply from the generator bus, and switchyard disturbances are eliminated. (IEEE, 2007). Typically, two UATs are used for increased reliability and reduce load and fault currents. The IEEE design guide also suggests an alternative configuration which may provide an improved balance between capital costs, reliability and operating costs : a three-winding auxiliary transformer in lieu of two separate auxiliary transformers. (IEEE, 2007)

Station/Startup Transformers (SST)
This transformer is used during unit startup and is fed from the MV switchyard. See the IEEE Std 666-2007 for details on the function and sizing of this transformer.

In power plants with parallel units, the parallel units may share a single SST.

Transformer Losses & Efficiency

The largest power transformers are "probably the most efficient machines devised by man" (Fassbinder 1997). Modern large GSU transformers can achieve efficiencies of up to 99.75% at full load. Despite an impressive efficiency rating, there is still a large incentive for improvement. The throughput of these large transformers can be up to 1000MVA, so even small, fractional percentage gains translate into MW of saved power. Smaller transformers are less efficient (99.0% to 99.5%), but have a smaller throughput. The incentive to seek improvements at this lower scale comes from the fact that most power consumers (at least in distribution networks) receive their power after it has passed through several transformers, which means that savings of reduced loss-transformers are compounded.

Reduced-loss transformers lose energy in their 1) iron cores and 2) copper windings.

- In the core, losses occur mainly through hysteresis effects and I^2R eddy currents circulating within the iron core. Hysteresis refers to the lag between magnetic flux and the magnetizing force and these losses increase with frequency. Eddy currents are small induced currents running perpendicular to the direction of flux. Taken together, these losses are known as no-load losses since they occur when the transformer is energized, and are present even when the secondary terminals are open and under no load. These losses are sometimes referred to as core, magnetization or 'iron' losses.
- In the windings, losses occur due to ohmic resistance (I^2R losses) from the main currents flowing through the windings; these losses vary with the load on the transformer and are therefore known as load losses or 'copper' losses. Some eddy current losses also occur in the windings; so the windings are kept tall and slim to reduce this eddy current circulation. The load loss is officially defined as the active power consumed in a short-circuit test, where rated current of rated frequency is fed into one winding and another winding is short-circuited. This loss is also known as 'impedance' loss.

Loss values are often contractually guaranteed, and are determined at a certain reference temperature in the windings. Some typical penalties for non-compliance with the agreed losses, as revealed during technical testing at the supplier's plant, are $1000 or more per kW of losses (usually iron losses only). This performance guarantee is also sometimes known as a 'loss evaluation' agreement.

Estimating Transformer Losses

Theoretically, a transformer has its highest efficiency at the load in which iron loss and copper losses are equal. Therefore the load at which the efficiency is highest can be found from the following formula:

$$\% \text{ optimum load} = (\text{ iron loss} / \text{copper loss})^{1/2} \times 100$$

This is about 57% of full load, and the curve is fairly flat for realistic core and load loss values. Because transformer designs are conservative with respect to load, the actual highest efficiency point is usually found closer to 80% of the rated load.

Knowing the losses, the efficiency of a transformer can be calculated from the basic formula:

$$\% \text{ efficiency} = [\text{ (input in Watts - total losses in watts) / (input in watts) }] \times 100$$

In practice, the total losses are hard to measure for an existing transformer, so the no-load efficiency of a transformer is usually calculated as shown below. This no-load efficiency is useful for comparing different transformer types.

$$\% \text{ efficiency} = (V \times A_{out}) / (V \times A_{in})$$

Empirical data can be used to estimate the total percentage transformer losses (Pv), using the graph below for typical oil-immersed two-winding distribution transformers up to 40MVA rating, and the following formula:

$$P_v = P_o + A^2 P_k$$

Where:

- A = loading ratio, load kVA/rated kVA (S/S_r)
- I_o = percentage no-load current
- P_o = percentage no-load losses
- P_k = percentage impedance losses

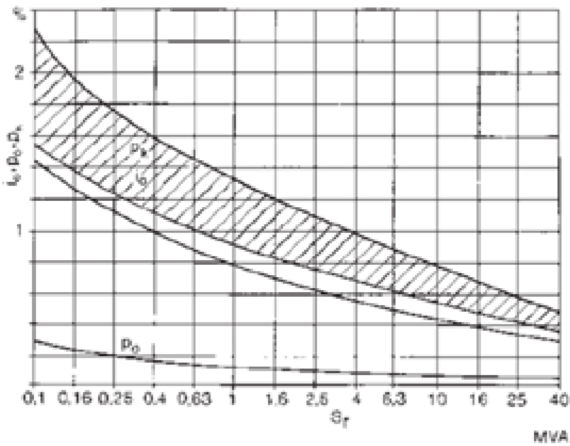


Figure 3.20 – Transformer load-loss estimation curve, (ABB Power Products 2006)

The graph for the load losses P_k has an upper limit for rated high voltage 123kV and a lower limit for rated high voltage 36kV.

For a 2.5 MVA transformer for 20/0.4 kV operating at half load (a= 0.5) and PF=0.8, the percentage no-load losses, as shown in the graph above are P_0 = 0.6%, and the percentage impedance losses P_k =1.0%. The percentage total transformer losses Pv are:

$$P_v = 0.6\% + (0.25)(1) = 0.85\%$$

In terms of real power, the total losses are = P_v x S x PF:

Total losses = 0.85% x 2500 kVA x 0.8 = 1,700 kW

Combining the formula for total % losses with the definition of efficiency leads to the following formula for Transformer Efficiency (Eff %) :

$$Eff = 100\% - 100\% \times (P_o + a^2P_k) / (a \times S_r \times PF + P_o)$$

Transformer losses are stated in MW, MVAR and MVA. The IEEE Std. C57.12.00 and IEEE Std. C57.12.01 [B8] provide the tolerances associated with the transformer losses (IEEE 2007).

According to one power engineering industry guideline (Black & Veatch 1996), step-up transformer MVAR losses can be estimated by applying the following multipliers to the generator MVA rating.

kV (HV)	Multiplier
69	0.09
115	0.10
138	0.11
161	0.12
230	0.13
345	0.14
500	0.17

Figure 3.21 – Multipliers (of MVA) to determine transformer MVAR losses, (Black & Veatch 1996)

The same source cites empirical data behind the following multiplier for transformer MW losses, which suggest that power transformers are on average 99.7% efficient:

MW losses = Generator MVA rating x 0.003

In a power plant, as an example of using these multipliers, one can start with a generator rated at 500MW real power and 0.9 network PF, and a high-voltage side of 138kV.

- Calculate the generator MVA rating : 500/0.9 = 556.0 MVA
- Calculate the transformer MW losses : 556 x 0.003 = 1.7 MW
- Calculate the transformer MVAR losses : 556 x 0.11 = 61.2 MVAR

An underloaded transformer has a relatively larger core cross-section, thus reducing iron losses. If the transformer is too lightly loaded, however, the equivalent secondary resistance will cause the winding and core losses to be unequal and the efficiency will be correspondingly lower (EC&M, 2000, M. Lamendola).

Power consumed by the transformer's auxiliary forced-cooling system (fans and pumps) shall also be considered as the third source of losses for any calculation of Total Loss in the transformer. These losses are harder to calculate, but will increase with the %load and temperature as the cooling system tries to remove excess heat.

Total Transformer Losses = iron losses + core losses + auxiliary (cooling) losses

Skin effect losses, which increase with frequency, are a final, but minor source of losses.

By increasing or decreasing the cross-section of the winding conductors or the core, a wide range of designs with lower losses can be achieved; the quantity of materials will be higher and therefore also the cost of the transformer. See the section on Transformer Lifecycle Costing for more details on the trade-offs between capital and operating costs.

For unit step up transformers, rated in hundreds of MVA, there are design optimizations that introduce beneficial second-order effects, moving the optimum efficiency point upwards into the 70-80% load range, and flatten the efficiency curve even more. Realistically, a modern large step-up transformer can be expected to be at or near peak efficiency over a range of 50-100% of rated load, with that peak efficiency being at or near 99.7%.

Effect of Harmonics

The increased number of non-linear loads such as VFDs and switched power supplies can lead to greater **harmonic content**. Harmonic distortion losses in a transformer, mainly in the windings, are due to deformation of leakage fields. Losses mean higher temperatures and deterioration of transformer insulation and efficiency performance. The magnitude of losses associated with the fundamental and the higher order harmonics are shown in the table below, for MV and HV lines and step-down transformers in a distribution network.

The standard IEC 61378-1 describes a method to calculate losses when the current contains harmonics. The standard ANSI/IEEE C57.110-1991 also provides an estimation method, based on a certain load current spectrum of harmonics, which is used to calculate the transformer's 'K' factor; its ability to withstand increased losses due to harmonic currents on the low-voltage side(Phillips 2009). The K-factor is used mainly for 480V step-down units and provides guidance on derating of the transformer when high levels of harmonics are present.

		Fundamental Frequency Losses, E_{AF} (%of total incoming energy, E_I). [5]	Additional Losses, E_{AH}, due to Harmonics			
			Approximate calculation		Detailed calculation	
			% of E_{AF}	% of E_I	% of E_{AF}	% of E_I
LV lines		1.90%	5.47%	0.1039%	6.00%	0.1140%
MV/LV transformers	Copper	0.55%	5.72%	0.0315%	4.02%	0.0221%
	Core	0.92%	0.10%	0.0009%	0.10%	0.0009%
	Total	1.47%		0.0324%		0.0230%
MV lines		2.70%	1.30%	0.0350%	1.72%	0.0464%
HV/MV transformers	Copper	0.21%	3.72%	0.0078%	4.94%	0.0104%
	Core	0.27%	0.10%	0.0003%	0.10%	0.0003%
	Total	0.48%		0.0081%		0.0106%
TOTAL		6.55%		0.1794%		0.1941%

Figure 3.22 – Transformer losses due to harmonics , Leonardo Energy,'Network Losses' 2008

Harmonics losses can be reduced using the same methods described in the **Harmonics Mitigation** section.

Transformer Cooling

There are 5 basic power transformer classes, based on how they dissipate internal heat from losses;

- "A" for dry-type transformers, in which core and windings are embedded in cast resin. These transformers are used up to 20MVA and a maximum of 36kV.
- "O" for mineral (or other flammable) oil-immersed transformers, which have a maximum temperature below the oil flame point 300 oC.
- "K" for synthetic-oil immersed transformers, which have a higher maximum temperature.
- "G" for gas cooling system with fire point > 300 oC
- "W" for water cooled systems

Note that oil-immersion serves as both insulation and coolant, and is most common on all large (>20MVA) transformers. There are several alternatives for removing the heat generated by losses, and these may be combined at different stages in the transformer. For example, in oil immersed transformers, the cooling circuit collects hot oil at the top of the tank and returns cooled oil lower down on the side. The cooling arrangement consists of two circuits, one inner and one outer. The inner circuit transfers heat from the hot transformer surfaces to the oil, and the outer circuit transfers the heat to a secondary cooling medium. IEC standards provide definitions for the different types of oil immersed transformer cooling arrangements.

Code	Inner circuit	Outer circuit
ONAN	Oil Natural	Air Natural
ONAF	Oil Natural	Air Forced
OFNAN	Oil Forced	Air Natural
OFAF	Oil Forced	Air Forced
OFWF	Oil Forced	Water Forced

The transformer MVA power ratings are usually are stated to reflect different levels of cooling. For example, the rating ONAN/ONAF1/ONAF2 may be 120/160/200. These ratings show the maximum power rating depending on the level of cooling active. At low loads, the ONAN circuits are sufficient; no forced cooling, hence no auxiliary losses, are active.

Cooling has the effect of moving the operational power point lower down on the saturation curve. The cooler the transformer, the more power and energy can be passed through the transformer. On the other hand, power that is consumed by the cooling devices serves to effectively increase the transformer total losses.

Oil-filled transformers with pump circulation cooling systems are common, but these have higher losses and the higher parts count means reduced reliability compared to fan-cooled type units. The only advantage of pump-cooled systems is the reduced size of the unit.

Some dry-type transformers, for example, Resi-block transformers, have a design that can withstand extremely cold temperatures. These transformer types do not need startup heaters, as oil-filled units do in such conditions, to achieve operating temperatures. From an energy perspective, transformers without need for startup heating save energy, provided that full load efficiencies are not reduced.

According to IEEE Std 666-2007 'An economic evaluation that considers the initial cost of the transformer installed plus the evaluated cost of losses is used to determine the type of cooling, e.g., ONAN, ONAN/ONAF, ONAN/OFAF ONAN/ONAF/OFAF. These transformers supply the unit auxiliary loads and are loaded a large portion of the time. Losses will consist mostly of load losses and have a tendency to make an ONAN rating equal to normal load the most economical.

The standards (IEC-3540) define the 'hottest-spot' temperature in the winding as the limiting factor for loading & overloading limits, and provide a method for calculating this temperature based on bottom or top oil temperature measurements and the gradient.

Transformer Configuration

Some facilities specify separate power transformer units for each phase, usually based on the assumption that separate units offer increased reliability over combined 3-phase units. Although this may have been true in the past, the reliability of 3-phase transformers is now so high that it should no longer be the main reason to split phases. Single phase transformers have lower energy efficiency than combined phase units, are more expensive and require more auxiliary equipment which combined units can share between the phases. Additional reliability can be achieved through a bus design which includes a reserve transformer powered from another source, for example.

In power plants, the generator step-up unit (GSU) is 5 to 6 times more prone to failure than network transformers. This higher failure rate is due to the much higher thermal and mechanical stresses experienced by these large transformers. The average age of large power transformers in the US is now 39 years (as of 2008). To maintain a slight edge in efficiency, but mainly to avoid the costs of random failures, this fleet of 130,000 aging transformers should be carefully monitored and screened for potential problems and eventual replacement or refurbishment. ABB, for example, offers transformer monitoring systems (TEC), and has a formal program offering (TRES) for fleetwide assessments of utility transformer condition, providing users with indications where there is substantially increased risk of failure for individual transformers.

Hartford Steam Boiler's insurance division projects that the 2% annual failure rate of the existing installed base will increase to 5% by the year 2013. Most (43%) of these failures will be due to problems with the winding insulation.

Selection & Sizing

Transformer selection and kVA sizing is based on a thorough understanding of the loading that it must endure, and how this loading varies over the unit's operating regime during day, week, month and year; the unit's complete duty cycle. As with electrical motors, knowledge of startup loading demands is required. See sources such as IEEE Design Guide (IEEE, 2007) for details on transformer sizing.

In power plants, the step-up transformer is downstream from the auxiliary transformers, as shown in the simplified single-line diagrams from the previous section. The MVA size of the step-up transformer can be estimated by starting with the generator MVA size and then subtracting the auxiliary system transformers combined MVA ratings and the step-up transformer's own losses, estimated from the multipliers in the section on Transformer Losses & Efficiency. Industry engineering guidelines (Black & Veatch 1996) recommend adding the MVA of one auxiliary transformer for the case when it is out of service. This extra capacity allows a design in which the generator step-up transformer can supply the loads of the out-of-service auxiliary transformer. The operational cost of this extra, but seldom-used capacity may be reduced by designs which can use some of the capacity of startup (SST) or reserve transformers in such situations.

Sizing of the unit auxiliary transformers follows the same procedure as any substation or industrial transformer, and is described in the sections below.

Problem of Over-sizing

In contrast to the design guidelines for motors and drives, an oversized transformer is actually somewhat more efficient than one operating at 100% capacity

Most improper selection and sizing are due to an incomplete **load analysis**. Even if the load analysis is complete and correct, there may still be a tendency to add too many margins for electrical equipment, especially for power transformers and large motors.

These margins may surpass 100% when the actual duty cycle is examined more closely, using historical data. Even if significant future load expansion is anticipated, it is generally more economical to size the transformer with the necessary additional hardware to allow higher capacity cooling to be added later, when it may be required (IEEE 2007).

A certain overload for a limited period of time is permissible. However, overloading which leads to increased winding temperature above 221 °F (105 °C) in oil immersed transformers increases the probability of bubbling in the cooling oil, which may lead to dielectric breakdown in the transformer. Aging of the oil will also be accelerated by stress due to overheating.

According to IEEE-666-2007, some plants require much higher startup power than others. A CCGT plant unit requires a large amount of power to bring the GT to pull-in speed, after which the load requirements drop to a much lower level. Coal-fired plant startup also requires more power during startup, due to high fan load inertias. In all cases, however, the startup for auxiliaries is relatively short and therefore the transformer can be safely loaded beyond its rating, as per the guidelines in IEEE Std. C57.91 [B13] and NEMA TR98, for short periods of time, instead of permanently oversizing the auxiliary transformer.

According to the NEMA TR98 guide, an oil-filled transformer may carry 155% of its full load rating for up to 4 hours with only a small estimated loss of life.

Sizing Procedure for Motor Load

The following simplified procedure assumes that the motor is the only load on the transformer. Start with the rated current on the secondary side of the transformer and make this current equal to the continuous rated current of the motor. The next step is to determine the rated secondary voltage of the transformer. The rated secondary voltage according to standards (IEC 60076-1) is in the no-load condition. The process and mechanical engineers must provide data needed to determine the voltage and current during motor start-up, continuous and intermittent operation, and number of starts per hour. The Power Factor (PF) is also needed for the transformer sizing, both during start-up and in continuous operation.

The short-circuit power of the source feeding the primary side of the transformer is also a relevant parameter, especially when this value is low in relation to the power rating of the motor. This may indicate that there will be a considerable drop in the applied voltage from system to the primary side of the transformer during a motor start. The transformer manufacturer might help with these issues, which are also important in sizing a transformer for a given motor in retrofit situations.

Case Example

In one power plant, the transient high startup power demand led to a grossly oversized unit auxiliary transformer of 10MVA. This plant was also a pumped storage facility in which the generator was used as a motor for the water pump. The transient high load was due to a 12,000hp (9 MW) starting motor, which operated for only 15 minutes each day, during startup rotation of the motor-generator when in pump mode. The transformer was sized to accommodate this very high, but short-lived load, even though the normal auxiliary load was less than 2MVA.

An improved design was `to specify a separate dedicated startup ‘pony’ transformer which has a rating high enough for the temporary high load. After startup was complete, this transformer could then be bypassed in favor of a 2 MVA unit auxiliary transformer. This pony transformer could safely serve the high transient load with a rating much less than 10MVA, since the duration period is so short.

Sizing a power plant unit auxiliary transformer is based on normal and maximum expected auxiliary loads, but with an eye to load profile and duration. According to IEEE Std.666-2007 Design Guide, these auxiliary loads vary for different types of plants such as for combined-cycle and coal-fired plants. For a combined-cycle plant, the starting load (particularly static type) to bring the gas turbine to firing speed is considerable, when compared to normal operating load. Since the start duration is typically less than 30 min and is infrequent for a base load plant, temporary loading beyond nameplate per IEEE Std. C57.91 [B13] in lieu of oversizing the auxiliary transformer would be a consideration for kilovolt ampere selection. It would be advisable to include this type of expected loading duty in the transformer’s specification.

Transformer Retrofits

The benefits of new transformer design can be gained at lower capital cost by selective replacement of certain elements, such as winding, core and cooling system, while retaining the existing tank and mounts. These replacements can increase energy efficiency on old transformers without the need for additional civil and mechanical engineering needed to accommodate a new form factor. A component retrofit may also have shorter lead times compared to a complete unit especially for large power transformers. The decision to replace transformer internals should be addressed in the course of a plant power systems assessment. The greatest energy efficiency is gained by complete replacement of the old transformer, especially if the original transformer is over 50 years old. Advances in transformer core steel technology can substantially reduce core losses.

The following table shows the general benefits of reduced winding losses in new transformers vs. old, and the range of capital costs involved for different transformer capacities.

MVA Size Range	Price Range $/MVA	% Losses(old)	% Losses(new)
Large	$5k-$10k	0.2	0.1
Medium	$6k-$12k	0.5	0.2
Small	$10k-$15k	0.6	0.3

Transformer Cost Calculations

Lifecycle costing and accounting for operational costs is particularly important for transformers due to their exceptionally long service life. The difference between the purchase price of a standard transformer and an energy-efficient one is paid back several times over this lifespan.

This section is based on information from these sources: (ABB Ltd,Transformers, 2007, Loss Capitalization & Optimum Transformer Design).

The manufacturing cost, hence purchase price, of a transformer increases with the transformer mass. However, the cost of transformer losses decreases with the transformer mass. The optimum transformer design or model is one which has lowest lifecycle cost (LCC) for the application.

As a first, very rough, approximation, the hardware cost alone of a new transformer is $10,000 per MVA (based on a medium-sized step-up power transformer). The total installed cost (TIC) of transformers is large, due to the civil and installation costs; these vary widely, but are at least double the cost of the hardware alone in most cases. More specific rules regarding large power transformer costs is difficult due to to the very high degree of customization in their design.

In LCC methods, the no-load loss is assumed to be present at its measured reference value for the whole time the transformer is energized. The evaluation of load loss is more complicated due to the variation of the load. From the section on losses, **Transformer Losses & Efficiency**, the load loss varies with the square of the load (I^2R losses). Using the formulas from the section on **Lifecycle Costing Methods**, the no-load and load losses can be capitalized : the present value of the annual energy costs can then be calculated.

In the case a power plant GSU, it is normal practice to value the load losses higher when the transformer is operating near its rated load, which is expected in baseloaded plants.

Note that these simplified LCC methods do not take into account differences between rated and service voltage, or the effects of any tap-changer settings.

Calculation Case

Sample comparison of two 25MVA-rated unit auxiliary transformers, at 0.85 PF, at 99.3 and 99.7 % efficiency over 1 year:

Energy Savings = 25MVA x 0.85 x 8,000 hrs/yr x (0.997 – 0.993) = 680 MWh
Dollar Savings = 680 MWh x $60/MWh = $40,800/yr

Now applying LCC methods to determine the present value of the **savings** over 20 years at 5% RoR:

PV = $40,800 x ((1 + 0.05)20 - 1) / 0.05(1 + 0.05)20
PV = $508,500

Plant Power System Layout & Cabling

The physical layout of the power system components and the length and diameter of cables can be chosen to minimize losses. This challenge is similar to that of reducing friction in a pumping system, where power is wasted in in friction through pipes, valves and fittings.

Waste heat from transformer and VFD cooling systems may be used in process heating, or to seasonally augment the HVAC system, if the layout allows it and if there is good communication between the process, piping and electrical teams. For very large units, this recycling of heat may show a net lifecycle benefit to justify the added hookup cost. At an early stage in plant (re)design, therefore, the process engineers should be encouraged to include the largest power system equipment in their heat balances.

Cable Selection & Sizing

In an electrical power system, power is wasted as losses in cables, switchgear and other current carrying devices, including control and protective circuits. Some useful design guidelines to reduce such losses, adapted from (IEEE, 2007):

- Centrally locate the load center transformers, switchgears and LV **MCCs** to:
  - Reduce length of cable runs
  - Reduce losses and voltage drops
- Keep buses and taps as short as possible to:
  - Reduce distance between aux unit transformer and generator

- Increase cable diameter of smaller cables to one or max. two gauge higher to achieve multiple benefits:
  - Lower ohmic losses
  - More cable of fewer different cable sizes reduces wastage during installation, gets better terms such as Minimum Order Quantity.
- Use VFDs to reduce average current to motor loads
  - Saves on capital costs and losses in cabling

As with pumping systems, the main equipment is often laid out before the connections between them are determined. Also analogous to pumping systems is the unforunate design choice of smallest allowable diameter cables to reduce initial material costs, at the expense of much larger lifetime operating costs.

Voltage Drop and Power Loss

For cables and lines, the following formulas from ABB Switchgear Manual (2004) may be used to calculate line voltage drop and power loss in 3-phase systems, given the resistance of the line R_L.

voltage drop
$$\Delta U = \sqrt{3} \cdot I \cdot l \, (R'_L \cdot \cos\varphi + X'_L \cdot \sin\varphi)$$

percentage voltage drop
$$\Delta u = \frac{\Delta U}{U_n} 100\,\% = \frac{\sqrt{3} \cdot I \cdot l \, (R'_L \cdot \cos\varphi + X'_L \cdot \sin\varphi)}{U_n} 100\,\%$$

power loss
$$\Delta P = 3 \cdot I^2 R'_L \cdot l$$

percentage power loss
$$\Delta p = \frac{\Delta P}{P_n} 100\,\% = \frac{3\, I^2 \cdot R'_L \cdot l}{P_n} 100\,\%$$

conductor cross-section[1]
$$A = \frac{l \cdot \cos\varphi}{x \left(\frac{\Delta U}{\sqrt{3} \cdot I} - X'_L \cdot l \cdot \sin\varphi \right)}$$
$$= \frac{l \cdot \cos\varphi}{x \left(\frac{\Delta u \cdot U}{\sqrt{3} \cdot I \cdot 100\,\%} - X'_L \cdot l \cdot \sin\varphi \right)}$$

l one-way length of conductor

R'_L Resistance per km

P Active power to be transmitted ($P = P_n$)

U phase-to-phase voltage

X'_L Reactance per km

I phase-to-phase current

In single-phase and three-phase a.c. systems with cables and lines of less than 16 mm² the inductive reactance can usually be disregarded. It is sufficient in such cases to calculate only with the d.c. resistance.

[1] Reactance is slightly dependent on conductor cross section.

Cable Laying Method

The cable laying method is an important aspect of cable layout and design. The standards call for a 'derating factor' to be applied to certain sub-optimal methods, such as vertical (wall) mounting and duct bank designs. See the ABB Switchgear Manual for more detailed guidelines and references on cable laying methods.

Busbar Design & Sizing

Some guidelines for copper busbar sizing: Increasing the cross section reduces energy losses exponentially - doubling the conductor cross section area cuts the resistance in half and reduces the losses by 50%. The first few incremental size increases above the minimum allowable will make a big difference in the loss, but the cost of each increment increases while the return decreases. Selecting multiple bars in lieu of a single bus is another issue a design engineer has to consider for achieving a lower loss system.

In power plants, the currents in bus ducts between generator and step-up transformer are very large and may cause circulating currents in the bus ducts themselves. These currents reduce efficiency and may lead to overheating. Correct design of the termination of the bus duct at the transformer end can reduce these losses and the risk of overheating. (ABB Ltd,Transformers, 2007)

To reduce busbar losses, the step-up and unit auxiliary transformers should be located as close as possible to the generator. (IEEE 2007) . According to (Leonardo Energy , 'Busbar Design', 2008), the following procedure will improve the energy efficiency of busbar designs:

1. Select working and ambient temperatures
2. Assume initial current density of 8 amps/mm2
3. Find appropriate size in standard range
4. Calculate heat generated due to current
5. Calculate heat loss at working temperature
6. If 4>5, increase size and return to 4
7. When 4=<5, this is smallest possible size

Having calculated the size of the bar, there are three further considerations:

- voltage drop
- short circuit current
- skin effect - increases apparent resistance by reducing effective area - important for thick busbars, high frequencies, harmonics generated by non-linear loads

Busbars are especially long-lived plant components, which gives their running energy costs more weight in lifecycle calculations. The figure below shows how these energy costs decrease as cross-section of the busbar increases.

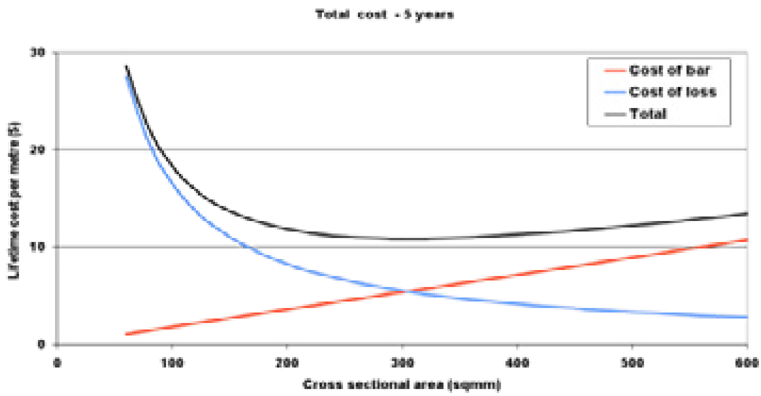


Figure 3.23 – Curves showing lifecycle cost for busbars, (Leonardo Energy , 'Busbar Design', 2008)

Power and Load Management

Power Management Systems continuously monitor the configuration of the network and can respond instantly to preserve capacity and power quality. PMS is typically used in industrial power systems to provide load-shedding, load balancing, synchronization and generator control functions.

In power plants with multiple generators, these industrial functions may also be applied to ensure the most economical allocation of in-house loads to generators; a kind of load dispatch or load sharing.

Even in single generator plants, a PMS can provide automatic non-essential load shedding at very low loads to slightly improve heat rate. An intelligent PMS would also be a useful addition to more radical energy designs requiring optimal use of multiple sources of auxiliary power, including renewable sources.

Suppliers of these systems, which are also referred to as Energy Management Systems or Electrical Control Systems (EMS,ECS) will soon be adding new capabilities as new communication standards for electrical equipment (IEC -61850) are adopted by more equipment manufacturers and industries.

Power System Design and Analysis Tools

There is a general lack of unified toolsets for modeling power systems for energy efficiency performance and calculating energy savings from different design alternatives. Some popular Schematic and design/drawing tools; elProCad,E3, eTAP, Innotec Comos, SmartPlant Electrical, and Auto-CAD Electrical. Some popular System / Network dynamic simulation tools; eTAP, MatLab/SimPower, PSSE, SKM, and EEDSA. Tools specifically for energy efficiency design are few and non-integrated with the big packages listed above.

Power System Maintenance

A large transformer fails on average every 5-6 years, based on statistics for power generating plants (NERC GADS data, GAR Report 2006). The average opportunity cost per outage is 25,4GWh; so at 60kUSD per GWh this means $1.5MUSD per outage. These opportunity costs hide the real loss of energy associated with an outage. These losses are estimated in this handbook's section on **Efficiency & LifeCycle Cost Calculation**.

It is common practice to manually inspect the step-up, startup and auxiliary transformers once every three years (Burns & McDonnell 2007), and even more frequently for older equipment.

Some useful power system preventive maintenance guidelines are in NFPA 70B Recommended Practice for Electrical Equipment Maintenance. For transformers specifically, one can consult the ABB 'Service Handbook for Power Transformers'.

On-Line Condition Monitoring & Control

Transformer electronic control (as in ABB's TEC) for modern transformers can provide advance warning of degradation and eventual failure, and provide optimal cooling control. The enhanced, real-time monitoring capability allows transformers to be overloaded when required, reducing the need to oversize the unit for these transient situations. Overload capability forecasts can be made, in which the estimated thermal aging is also taken into account. The monitoring software will calculate the extent to which the transformer can be overloaded, and provide the financial impact of this overloading due to any extra aging of the insulation.

Modern transformers can be equipped with the monitoring and diagnostic functions covering critical performance parameters shown in the figure below. Older transformers, which are most in need of improved monitoring and control, can be retrofitted with such a package.

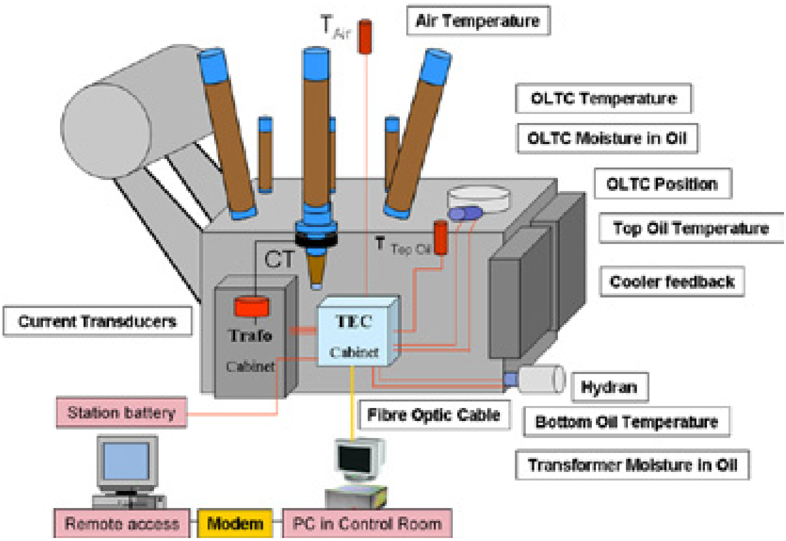


Figure 3.24 – Transformer electronic control (TEC), ABB Transformers USA, 2006

Modern transformers use these data for hotspot calculation and for optimal control of the cooling system. The optimal amount of cooling power will minimize lifecycle costs. In an overloading situation, the controls will start the coolers earlier to avoid premature ageing of the transformer. The controller also provides temperature warning and alarms; when a lower temperature limit is exceeded, then the TEC control will first issue a warning to operators. If temperature continues past the higher limit, then an alarm is generated and a trip command will be sent to the protection relay to isolate the transformer.

The extra data from a well-instrumented transformer can be used to perform an online heat balance which can continuously calculate heat losses from different sources, as shown in the figure below. These losses can be compared to a model of the iron and copper losses at the current load level, providing another indicator of performance.

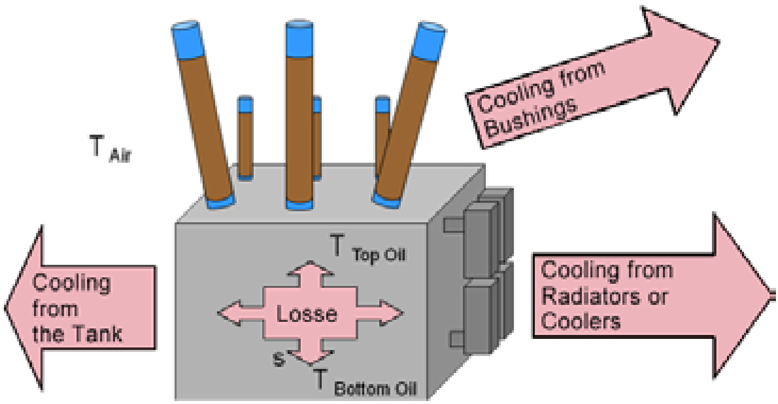


Figure 3.25 – Heat balance monitoring in a transformer, ABB Transformers USA, 2006

Off-Line Condition Monitoring

The following off-line condition monitoring tools are also useful for uncovering wear and damage that could lead to reduced efficiency and failure:

- Transformer condition monitoring tools - oil and gas analysis.
- Infra-red thermographic equipment & analysis.
- Ultrasonic partial discharge (PD) detectors.

For greatest benefit, the data from these tools should form the input to a more comprehensive power system assessment process.

Power System Assessments

An upgrade, revamp and/or replacement are conceptually different than routine maintenance. System reliability, availability and innovative service support analysis requires a systems approach. It starts at the network and ends at the process equipment, and must cover all components in the system. This analysis involves an extensive review study, plant rating evaluation, and a mechanical study including plant layout. A budgetary cost model is developed to support the study of financial viability. The analysis takes into account plant requirements related to regulation, protection, controls, metering and indication. The final step in a power system assessment is a road map which specifies the most attractive improvement targets, and provides some medium and long-term solutions to improve plant efficiency, system reliability and availability.

Power System Efficiency Guidelines – Summary

Design practices worth considering for improved energy efficiency in the power system are listed below:

- Select higher voltage levels for some buses (MV instead of LV).
- Use 3-phase transformers instead multiple single phase.
- Use large transformers instead of multiple, smaller ones; share transformers between units.
- Upgrade old transformers to achieve higher efficiency, improved monitoring
- Use PF correction, near the inductive sources where possible, to approach 0.95 PF.
- Use a generous cable laying method; avoid methods which lead to cable derating.
- Consider a plant arrangement which reduces length of cable runs & voltage drops.
- Ensure that harmonics are well within tolerance.
- Understand motor duty, and size accordingly, following the guidelines in Motor Sizing and Selection
- Ensure phase loads and voltages are balanced.

Module 4
Automation Systems

Module Summary

This module describes the general design and energy impact of the plant instrumentation, controls and optimization systems. While a detailed presentation of all relevant automation concepts is beyond the scope of this handbook, this section examines automation from an energy efficiency perspective and does not provide guidance on other, critical aspects of automation engineering such as interlock logic, emergency shutdown sequencing, or fault-tolerant design. For a more complete guide to all other aspects of automation design, see the standards and references sections of this handbook.

The information in this module may also be generally applied to process industries; industry-specific text is shown between rule lines.

Automation Concepts

A process plant is a hierarchy of equipment & control systems: a combination of hardware, software, people and operating procedures interrelated as shown in the figure below.

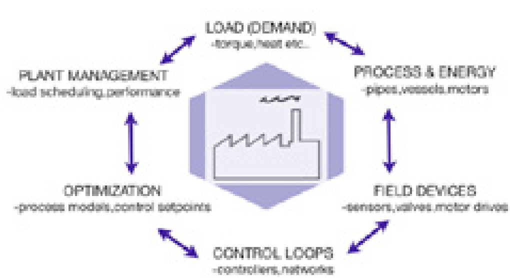


Figure 4.1 – Levels of automation in an industrial plant

Instrumentation, control and optimization, collectively known as ‘automation’, encompass equipment, software and methods, ranging from field devices to plant management. The main function of plant control and automation systems is to regulate various parts of the process, such that they operate at desired setpoints, to initiate shutdown or trip action in case of problems, and to monitor key performance parameters for continuous improvement. The ISA is a leading professional society for this relatively new field of engineering. Automation is one of the youngest disciplines in engineering, and is growing rapidly as more sensors and intelligence are embedded in common plant equipment.

Role of Automation in Energy Efficiency

Automation allows faster and more consistent response to changing load conditions compared to open loop (or human in the loop) control methods. Automation also enables the process to operate in a more stable way, and thus can be safely operated closer to its constraints for optimum energy efficiency. When a survey (US DoE, 2004) asked process plant professionals to identify the operational or process changes that would realize significant energy savings, most of the responses involved one or more automation technologies.

The responses generally fall into these broad categories:

Control and Optimization:

- Improved control of boilers, and other efficiency improvements through optimization, modeling and equipment design.
- Advanced control strategies such as model predictive control, improved measurement devices
- and sensors, multivariate data processing and analysis, better scheduling optimization strategies
- Use of thermal optimization based on process integration technology (e.g., pinch technology): use of waste heat /use of waste heat recovery technologies.

Drive Power:

- Optimized pumping & fan systems based on appropriately sized/specified equipment and often relying on variable speed drives
- Use of variable speed motors rather than throttling valves to control process flow

Management & Decision Support:

- Use of information tools (advisory/monitoring) to improve decision making on thermal energy use
- Improved system-wide decision-support across the whole plant and groups of plants
- Better management of power & electric loads
- Regular and disciplined application of electrical and thermal energy assessment tools

For process & industrial controls, end-users envision potential energy savings ranging from about 2% to 25%. Vendor estimates of the savings from plant-wide automation integration alone were on the order of 5% of the total energy, on average for all process industries (US DoE, 2004).

Instruments and Actuators

Plant automation and performance monitoring & improvement functions are all dependent on reliable plant data measurement and acquisition, and precise controllability of processes.

Figure 4.2– Pressure transmitter (left) and process analyzer (right). (ABB,2006)

Collectively known as ‘field devices’, anything that directly senses or controls a process typically is categorized as an instrument, an analytical sensor, or an actuator. Instruments are sensors that obtain real-time measurements of basic process variables such as temperature, pressure and flow rate. These are sometimes also referred to as transmitters and are typically used as inputs to fast-acting control loops and interlocks. Actuators are output devices such as drives, valves and dampers that can either directly or indirectly modify measured process variables.

Process Instruments

The most common types of measuring devices (instruments) in a process or power plant are; pressure sensors, temperature sensors, level sensors, and flow-meters. Additionally, control may require measurements of speed, current, voltage, chemical composition or various physical properties, such as thickness, opacity, resistivity, etc. Accurate measurement is a requirement for process precision, as well as energy-efficient control. Poorly chosen or located instruments will introduce lag and instability, causing much energy-wasting corrective action or process instability. According to the ISA, instruments should be installed as close as is practical to the source of the measurement, with consideration being given to excessive vibration and ambient temperature. Other common problems with process instruments are drift, bias and lockup freezing. An instrumented that has drifted from its calibration will lead to off-setpoint control. Bias is when an instrument under or over reports a measurement. Lockup, or freezing, is when an instrument continually transmits a single value while the related process actually is varying.

These effects are particularly troubling if the instrument's on-board diagnostics are unable to detect and report them to operators. 'Smart' transmitters have fewer such problems due to their continual diagnostic monitoring. These transmitters tend to be more accurate as well, and the extra signal processing allowing them to be turned down by a factor of 10 and still provide accurate measurement (ISA 2005). Smart transmitters should be specified as part of a broader strategy, which typically includes an upgrade to fieldbus communication. Smart transmitters are currently available in three widely accepted varieties – HART, Profibus and Foundation Fieldbus.

Performance monitoring, condition assessment, diagnostic tools, maintenance management systems and asset lifecycle optimization rely on the data from smart instruments and the automation system to provide in-depth information about the process, as well as the condition of the process equipment itself. This information is provided in real-time, without the need for scheduled downtime or waiting for a plant shutdown to perform equipment inspections.

It is an energy efficiency design oversight to omit instruments altogether in certain critical areas. The lack of accurate process data will hinder efforts at automatic control and energy performance improvement.

In a power plant, steam flow measurements are essential to feedwater control and in a coordinated boiler-turbine control scheme described in **Coordinated Boiler-Turbine Control**. Instead of direct flow measurement, however, the value is inferred from the HP turbine 1st stage pressure, which introduces lag and inaccuracy in the control systems.

In feedwater control, the specification of two additional sensors enabled the 3-element control now common on sub-critical boilers. Lack of turndown in these sensors, however, leads some units to fall back into less-stable and less efficient single-element control at low loads. See **Feedwater Flow Control** for details.

Choice of sensing technology also has an impact on power plant control effectiveness. Level sensors that are undesirably sensitive to density variations will introduce errors unless corrected for with additional controls. Vibration and other effects may disturb some sensors used in condenser and de-aerator level control. Levels in de-aerator are also important energy-saving steam leveling strategies.

Improved measurement coverage allows a more accurate and complete cycle energy balance that can be used with real-time cycle monitoring and optimization techniques discussed in **Real-Time Optimization**

Steam flows are particularly challenging to measure due to their sensitivity to changes in pressure and temperature. Flow sensors with real-time compensation for these effects will provide more accurate data for control and optimization. (Rosemount Instruments, 2008).

Analytical Instruments

Analytical instruments are also sensors, but they are more complex than transmitters and perform chemical composition analysis or other procedures usually resulting in multiple outputs. Analytics may operate at slower data update rates than process transmitters, and are typically used for slower-acting control loops, or overall process quality evaluation and control.

In power plants, analytical instruments are used for measuring CO, NOx, O2, pH and conductivity. In the burner system, flame scanners are used for combustion flame stability monitoring. Other analytics are used for measuring flue gas composition for emissions control and monitoring. A ‘carbon in ash’ analytical instrument is for the on-line measurement of unburned carbon in fly ash.

Modern analytical instruments, like process instruments, are placed in-line in with the process equipment and provide data in real-time, using the same communication bus technologies as simpler instrumentation. Some analytical instruments, however, are mounted only intermittently to perform special studies such as corrosion testing or vibration analysis.

In power plants with fewer instruments, boiler and heat loss efficiency tests cannot be performed continuously in real time. These older plants require the temporary mounting of extra instrumentation, whose type and number are given by the ASME Performance Test Code, such that the desired accuracy may be achieved. The test codes will allow accurate measurement of efficiency, in some cases within a range of 0.05%, such as for steam turbine efficiency.

Process Actuators

Actuators are devices that can directly act on the process through physically directing gas and fluid flows. Some actuators typically found in a process or power plants are; Dampers, Louvers, Inlet Guide Vanes, Servo valve position controllers, Variable Frequency Drives, Solenoid (on-off) valves.

Actuators with significant deadband (hysteresis) will have poor control response, and non-linear actuators will require additional correction (linearization) to behave well across their entire operating range. Also, a reduced range of action, such as low turndown, can severely limit a unit's energy performance at low loads. Another common problem with process actuators is stiction, in which a large force is required to overcome static friction between two surfaces in contact.

Figure 4.3– Part-turn actuator for rotary movement of final control elements, (ABB PME120 brochure)

Control Valves

Control valves (CVs) are valves used for automatic control of fluid flow. Valve opening is controlled by a positioner that may be driven by an electric motor, hydraulic power, or by compressed air in response to a command from the control system.

Control valves that are oversized will operate in a nearly-closed state for most of the time. Oversized valves are hard to control and may cause instability during rapid changes. Control valves are oversized as a result of the oversizing of constant-speed upstream components, pumps and motors, as described in this handbook. When the actual flows are much smaller than these components nominal operating points, then the CV must drop correspondingly more pressure by closing more fully. As described in the section on pump flow **Throttling**, the CV wastes energy that should not have been input to start with. Speed control is the preferred method of flow control, and eliminates the need for energy wasting throttling control valves.

CVs are mechanical devices that often operate under great fluid pressures and are prone to stiction in the valve stem and hysteresis. These effects will cause CV control loops to oscillate and may lead to process instability. There are methods to measure stiction online, and techniques for tuning PID controllers where stiction is observed or suspected. CVs and other actuators are usually powered electrically, or from the plant's **compressed air** system, which requires energy-intensive compression. Specifying only devices with minimal air consumption or leakage, especially when at rest, will have a significant energy efficiency benefit in a plant with hundreds or thousands of such actuators.

In power plants, a special kind of control valve is used to throttle the steam entering various stages within the steam turbine. Known as turbine governors, these devices are responsible for speed and load control, and for starting and synchronization. Turbines retrofitted with modern fast-acting hydraulic actuators provide much improved control response for faster ramp rate and increased energy efficiency, as described in the section on **Turbine-Generator Control**.

Dampers and Louvers

Dampers are used to control the flow of air or flue gases by modifying the cross-sectional area for flow within a duct. Louvers are a type of damper in which a series of parallel blades can be rotated to control the area open for flow. Isolation dampers are designed for on/off shutoff service (Babcock & Wilcox 2005).

In power plants, ID and FD fan control can be made more stable by installing smart transmitters on older systems still using dampers. These final control elements must be accurately and speedily positioned for even basic control schemes to be effective. In some cases, damper movements within 0.25 percent of the device's full range are necessary for precise control and this capability must be maintained over years of operation.

This section is adapted from an article in Power Engineering by Richard Vesel, ABB (Vesel 2007):

Dampers for primary and secondary air control, as well as overfire air control, are typically distributed around the boiler in great quantities (more than 100 in many cases). Advanced combustion control schemes will often require precision control over most air flows, so outfitting each damper and fan with active control elements is essential.

Outdated damper drives—electric, hydraulic or pneumatic—can suffer from a range of problems including insufficient force/torque, slow response time, stiction and inaccurate response due to hysteresis and other causes. Operators can find these problems by looking through relevant operating trends, engaging in specific plant performance assessments or by doing a loop performance analysis where set point, process value and control output from a controller are analyzed over a reasonable period of time (from several shifts, up to one month). Inaccurate or weak damper drives cause poor combustion control response and can cost a plant in terms of poor load following, higher heat rate, slagging, carbon-in-ash, poor emissions control and unacceptable opacity variations.

The goal for improved damper control is to be able to remove process deviations caused by draft-related variables (Furnace Pressure, NOX, excess O2 and so on), enabling operating points to move closer to ideal levels. Modern electric actuators make this possible by positioning the final control element down to within 0.1 percent of the driving control signal. Modern electric actuators also have other operational advantages in addition to improved damper control. Many advanced actuators have diagnostics for ' watchdog ' functions that alert plant personnel before a serious problem develops, avoiding costly downtime. For example, the electric actuator can monitor damper position, frequency of motor reversals, frequency of torque delivered and actuator internal temperature. Monitoring these diagnostics and associated alarms and alerts helps to ensure proactive instead of reactive maintenance, as well as optimum air control and plant performance.

In many cases, accurate damper drives and controls alone will provide significant improvements over legacy systems. See section **Air Flow Control for Combustion** for details on airflow control and alternatives to dampers for air flow control.

Sequential Control

Sequential control (or sequential function chart- SFC) is a series of steps (or tasks) which bring the process through a sequence of well-defined states. This type of control is commonly used during startup and shutdown procedures, or during emergency (trip) action. SFC automates traditional checklists for these procedures and is an important tool for plants with fewer experienced staff. Sequential control has the potential to speed up these procedures within safety limits, thus saving energy and unproductive power generation. The intermediate states in the sequence can be automatically monitored and operators receive alarms if an expected value is not achieved. A sample SFC program, showing states and transitions between them, is shown in the figure below.

SFC programming, combined with the communication capabilities of intelligent **Motor Control Centers (MCCs)** can turn off motors when not required by the process. This may sound trivial, but many motors run uselessly because the motor controls lack the necessary process knowledge that is given by the SFC states. The MCC provides the necessary data to turn off motors even for very short time periods without risk of overheating, when it is economical to do so.

Power plants being repurposed from baseload to intermediate service will be cycled much more often and will be asked to alternate rapidly between a wider variety of loading states. Each change of state requires a complex sequence of events which must be performed in the correct order, and using the correct values. SFC automaton of these tasks can improve unit turnaround and avoid costly, energy-wasting delays due to an aborted startup or other major procedure.

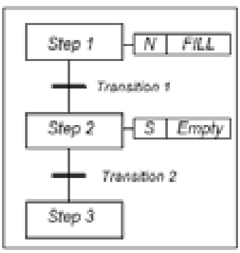


Figure 4.4 – SFC sample program diagram, (ABB Overview of IEC-61131 Standard, 2006)

Feedback Control

Single loop feedback control is a type of modulating control typically used for level, flow or temperature control on a single process line or point. Traditional feedback control typically uses one or more of the following basic regulation methods: Proportional, Derivative, Integral. When typically combined, these are referred to as PID control.

PID feedback control is shown in the form of a simplified block diagram in the figure below:

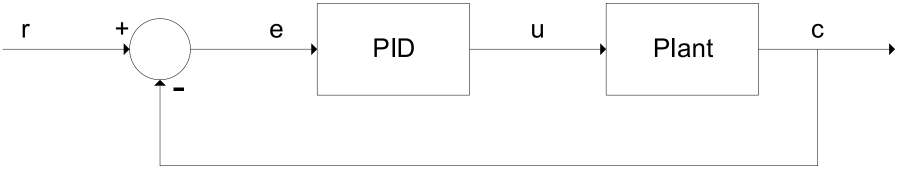


Figure 4.4 – Basic PID controller block diagram with standard symbols

Where, according to ISA terminology:

r = reference signal (also referred to as setpoint)
e = error signal (r-c)
u = PID controller output (also referred to as manipulated variable or control action)
c = controlled output (also referred to as controlled variable)

The PID control loop compares the controlled output of the reference signal to get an error signal ‘e’. This signal is input to the actual controller, shown in the box marked ‘PID’ in the block diagram, which generates a corrective control signal to the actuator in the plant. The action is designed to drive the error signal to approximately zero, such that no further corrective control action is necessary,

A more detailed block diagram of a feedback control loop would show the additional effects introduced by the sensor and final control elements. Such a diagram would also show the ‘disturbances’ which in most cases represent the varying load on the process.

The reference signal is also called the setpoint of the loop. Closed loop control acts to minimize the steady state error so that the output of the process returns to the desired setpoint established by the operators. Unlike open-loop control, feedback control can respond to any disturbance and return the process rapidly to setpoint, but only if the loop is properly tuned. If the underlying process parameters change, due to temperature or other effects, then the loop must be re-tuned.

Untuned loops may waste energy by demanding unnecessary auxiliary drivepower and by allowing (or even causing) greater instability. According to industry research (Matrikon, 2005), up to 75% of regulatory controls in a typical process plant are under-performing. Many loops are incorrectly put into a fixed or “manual” mode, where the PID action has been defeated completely.

Manual mode control and loop instability will generally lead operators to use less efficient process setpoint values to avoid situations when the swinging output variable exceeds a critical limit. Stable automatic operation allows sustained and safe operation closer to optimal process and energy limits.

Process Characteristics

Design and tuning of PID control loops requires an understanding of the physical process under control. From a basic control standpoint, the process is characterized by its gain, time constant, dead-time, and its degrees of freedom.

- Process gain (K) is the amount a process' output changes in response to a change in input. Process gain can be separated into steady-state and dynamic components. (ISA 2005). The product of process gain and controller gain is the 'loop gain'.
- Time constant (TC) describes the rapidity of the above response. After one TC the output variable has reached 63.2% of its final value. More complex processes may have multiple TCs.
- Dead time (DT) is the amount of time it takes for the above response to start after the input has changed. Transportation lag or thermal inertia are common sources of dead time.
- Degrees of Freedom (n) are the number of independent variables in the process, which is also the highest possible number of independently-acting controllers for that process (ISA 2005). The degrees of freedom can be computed by taking the total number of process variables and subtracting the number of relationships (physical, chemical etc.) between them.

All the above process characteristics are important for correct loop design and tuning, hence energy-efficient operation. Oscillations will result if the loop gain > 1. Response will be too slow if loop gain is very low. The controller gain must therefore be chosen to provide a total loop gain of about 0.5 to achieve rapid yet stable performance.

Feedforward Control

Feedback control responds only after a process disturbance has already caused a change in the output; it is blind to the original disturbance. In many cases, this disturbance can be measured and even anticipated, as in the case of a change in process loading. Feedforward control uses this knowledge to compute an appropriate control response, which is then summed with the output of a conventional PID controller as shown in the following block diagram.

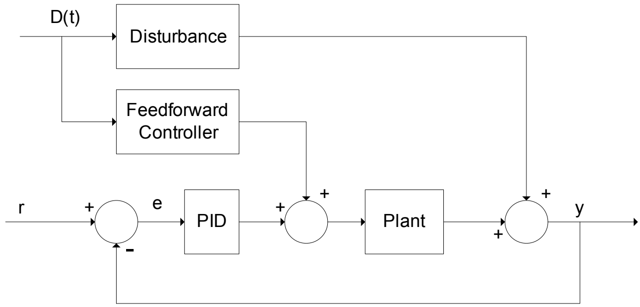


Figure 4.5 – Feedforward controller block diagram

The feedforward response is based on a physical model of how the process responds to the measured disturbance. The success of feedforward is dependent on the accuracy of this model, which is difficult to obtain and maintain. Even with an imperfect model, however, feedforward control combined with PID control usually provides a faster and more stable response than PID method acting alone. The feedforward controller corrects for 90% of the disturbance, while the PID controller can rapidly and smoothly respond for the remaining 10%. (ISA 2005). The feedforward controller model can also provide lead-lag compensation for process dead-times, which would otherwise make a PID loop more difficult to tune.

The improved control response saves process energy and reduces waste, but feedforward control has another energy benefit; reducing the load on the PID controller by an order of magnitude. (ISA 2005), loops which use drivepower for actuation will use significantly less energy.

Cascading Control

In cascading control, one PID is nested within another PID loop as shown in the figure below. The outer (master) loop provides the setpoint for the inner (slave) loop. For cascade control to work, the inner loop must have a shorter time constant than the outer loop. One common example of cascading control is flow control, where the inner loop controls valve position and the outer loop controls for output temperature.

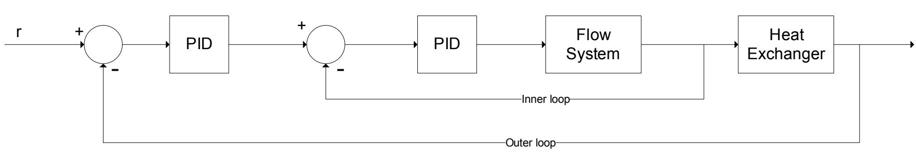


Figure 4.6 – Cascade feedback controller block diagram

Cascade control allows the inner loop to correct quickly for inner loop disturbances, such as valve hysteresis, leaving the outer loop to respond more quickly to changes in the controlled variable.

Adaptive Control

In adaptive control, also known as self-tuning or auto-tuning control, the PID parameters themselves are automatically modified online to respond to the changing sensitivities of the process. In effect, the parameters which are normally fixed in a 'static' PID controller become themselves variables in one or more feedback loops. Some self-tuning controllers operate in static mode most of the time, but will self-tune on request from an operator or after a fixed time interval.

Advanced Control and Optimization

Advanced Control encompasses many methods for controlling and optimizing larger systems with multiple variables and with important constraints. This control level typically operates at slower rates than single loop control, but can still operate in real-time.

Model-Based Control

Model-based control encompasses a variety of techniques using models to generate a control response. These models may be either mechanistic or empirical. Mechanistic models are based on physical principles (sometimes these models are called first principles), whereas empirical models use past data or black-box, mathematical approximations. The most common empirical technique models the process using a collection of step responses, each with its own coefficient(s).

The most widely used model-based technique uses a time-series model of the open loop response of the process. This series is the model's calculated response to a series of predicted control action values and disturbance values. An optimization function then updates the control action value series to achieve minimal deviation from setpoint with limited control action. This sequence of control actions is referred to as a trajectory.

Model Predictive Control, or MPC, has multiple outputs, in contrast to feedback control methods, which output only a single control action in response to a change in the input measurement. MPC uses a form of feedback in which the estimation error is used by the model to improve future estimations, as shown in the simplified block diagram.

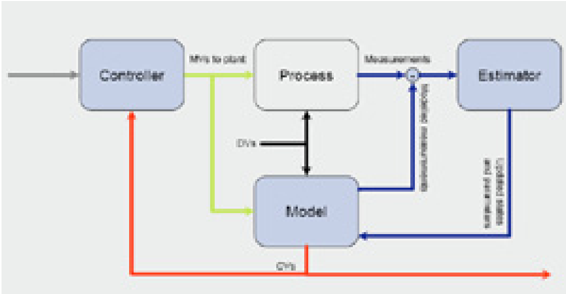


Figure 4.7 – MPC block diagram showing model and correction blocks

MPC is valuable in process situations of multiple variables with non-linear dynamic response, or where several control loops are interacting. The optimization function in MPC is well-suited to handling process constraints without decomposing them into setpoints, as is the case with PID control. MPC is also useful in process situations where direct measurements are not possible, or cannot be made fast enough for conventional PID control to be applied.

MPC is typically used in a hierarchy of control, providing setpoints to the lower, PID level of control as described in the section multi-level real-time optimization. MPC requires more engineering effort, especially during the verification and commissioning phases, compared to conventional control methods. Access to realistic or historical data is important for the model verification phase. Payback time for typical MPC investments is 6-12 months (Cybernetica, NFA Days Norway 2006). Some recent MPC projects, however, have netted impressive results, with paybacks of less than two months.

Inferential Control

Inferential control (IC) is based on techniques such as inference engines or neural networks. Such systems 'learn' from experience and can be used as a guide to operators. A properly designed and maintained IC system can absorb the accumulated energy efficiency knowledge of experienced operators and show the way to younger operators through complex and less frequent tasks, such as startups/shutdowns and complex process transition procedures.

Linear Programming with Mixed Integer Programming (LP/MIP)

The optimization layer uses linear programming technology (LP). LPs are common optimization tools used for planning and scheduling applications in many industries. The LP minimizes an objective function (cost of fuel plus cost of purchased electricity), while adhering to many constraints. Some of the constraints are part of the plant model, representing mass and energy balances. Other constraints represent capacity limits, such as maximum fuel flow rates to boilers, and generator constraints (Pekka Immonen et al, Power Engineering, Nov.2008 'Coordinated Control and Optimization of a Complex Industrial Power Plant').

Multi-Level Real-Time Optimization

This section is adapted from material by Pekka Immonen, which was first published in Power Engineering, Nov.2008 'Coordinated Control and Optimization of a Complex Industrial Power Plant'.

A multi-level approach (see Figure) uses real-time optimization (RTO), connected to advanced process control (APC). At the top level, an optimization program monitors the current situation in the plant and gathers pricing data over the Internet to make timely decisions about loading individual equipment in the plant. The optimization program then dispatches these orders to an advanced control layer, which provides coordinated, decoupled control of pressure and power generation. The base control level modulates the actuators affecting the plant to maintain the measured process quantities at their setpoints.

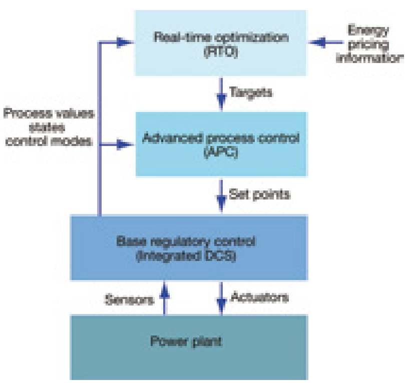


Figure 4.8 – Multi-level real-time optimization, (Immonen, Coordinated Control and Optimization of a Complex Industrial Power Plant, 2008)

In industrial boiler systems, a multi-level approach uses LP to make the selection between the operating modes based on the fuel and power pricing situation and the plant conditions. The selection cannot be made on pricing information alone. The equipment limits are higher priority and they must be honored for safety and equipment protection. The constraint set continually updates as process conditions drift and available equipment varies with maintenance schedules.

The advanced control system uses technology known as model predictive control (MPC). MPC is a multivariable control algorithm. Like the LP, MPC uses a model, but it's dynamic rather than steady-state. MPC runs at a much higher frequency than the LP, less than 10 seconds compared to 15 minutes. Using the model, the controller predicts the effects of moving multiple base control setpoints: high pressure and low pressure boiler fuel setpoints, all three extraction valves on all four turbines, all PRVs and all vent valves (a total of 28 manipulated base control setpoints).

The algorithm is capable of providing smooth transitions, whether opening PRVs, closing vent valves or controlling the steam balance with LP boilers when the HP boilers are maximized. In case of large process upsets, the MPC uses all steam system components to help out, allowing temporary deviations from their optimum targets. As the MPC is a multi-variable algorithm, all the required operating modes are achieved with a single MPC configuration. The overall design is greatly simplified as there is no need for alternative DCS configurations or complex over-ride schemes at the base control layer for boiler-follow, turbine-follow, PRV and other such modes. The most immediate benefit from the implementation of the new strategy was the greatly improved process stability (Immonen, Coordinated Control and Optimization of a Complex Industrial Power Plant, 2008).

Process Model-Based Real-Time Optimization

Process-model-based algorithms and advanced signal processing functions allow operators to quickly identify under-performing equipment and take remedial action on controllable losses. The advantage of model-based methods is their ability to predict plant performance for daily operations or long-term operational investments such as retrofits or process improvements. These tools can be connected directly to the process to run their models in real-time on actual plant data. The calculated (expected) values can then be compared with the actual process values, as shown in the following figure:

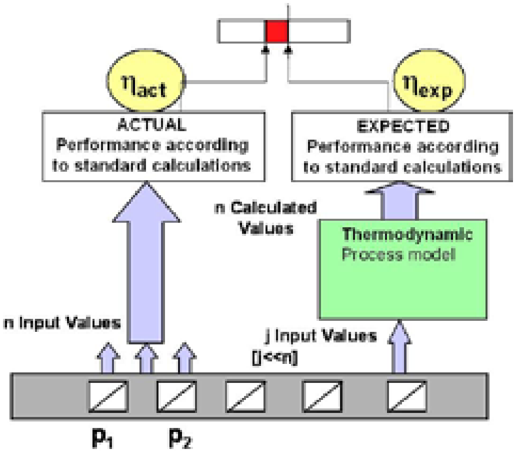


Figure 4.9 – Simulation and monitoring with PowerCycle software, (ABB Switzerland, Power Technology Systems, 2005, PowerCycle brochure)

These comparisons will reveal deviations from optimum energy efficiency, as calculated in the process' thermodynamic model. The resulting deviation data can be used for early detection of equipment degradation of loop tuning problems. The process thermodynamic model use by RTO is developed during the project design phase using the methods described in section **Modeling and Simulation Tools**

Lifecycle Model-Based Real-Time Optimization

The LCC methods described in **Efficiency and Lifecycle Cost Calculations** can be programmed to execute online and then input to one of the plant-wide optimization engines described above.

Supervisory Control

Supervisory Control (SC) is the highest level, providing feedback for such plant management tasks as economic optimization, decision support, performance monitoring and load scheduling. This level of control may have a rate of 15 minutes, hours or even days. SC relies heavily on a Human Machine Interface (HMI) that can calculate and trend plant overall and equipment efficiencies. SC functions also allows plant management to monitor plant performance, identify root causes and correct problems.

> In power plants, load dispatch commands are a semi-automated SC function which is at the center of plant load control and operations.

Performance Monitoring Systems

Performance Measurement Systems do not directly control the process, as the other systems described in this module. Performance Measurement Systems use humans as the actuators by providing them with analysis functions and large amount of historical data. If performance measurement is used regularly and in a pro-active manner by plant operators, then it becomes a very effective nearly-closed-loop system to optimize energy efficiency.

Performance Monitoring Concepts

The plant unit historical data is collected from the plant's instruments and stored in an integrated plant information management system (PIMS). Process data from all sources throughout the plant are collected and securely stored in the data server, where they can be analyzed further. The PIMS data repository, possibly covering the entire operating history of a plant in its archive, is an invaluable source of information for efficient plant operation and maintenance. PIMS can offer a wide range of analysis and presentation tools. Among the basic tools are trend curves from historical data on the operator station to monitor process behavior over time and detect patterns.

In power plants the Performance Monitoring Systems (PM) will also calculate efficiency metrics of individual components such as air heater, condenser, turbine, combustion, and emissions control equipment.

Convective Heat Exchanger Performance

In power plant, it is important to monitor the performance of superheater, reheater and economizer for convective heat exchange. The actual performance value for each section is calculated by measuring water/steam-side heat absorption, and performing an iterative gas-side heat balance for each individual section. Radiation heat transfer is taken into account for the upper heat transfer sections. The clean surface performance is calculated for each section using design information and an iterative gas-side heat balance for each section. The ratio of the actual operating heat transfer rate to the predicted clean heat transfer rate determines the conditions of each section. (ABB Switzerland, Power Technology Systems, Optimax Operations Products, 2005)

Furnace Heat Transfer Performance

An iterative heat balance calculation can also be applied to determine the performance of furnace heat transfer areas. This calculation allows for heat absorption in the roof and walls of the upper furnace, and the radiation heat from the lower furnace. These heat transfer performance calculations lead to a ‘cleanliness value’ that can guide soot-blowing operations (See section on soot-blowing systems).

Air Heater Performance
Similar methods are used to calculate the air heater performance and cleanliness. The gas inlet temperatures at the air heater and other surfaces can also be calculated. Significant deviations can be indicative of large energy losses due to fouling or leakage.

Energy Efficiency Potential of Performance Monitoring
If the plant is properly instrumented, a PM system can be the key to a heat rate awareness and improvement program. Such a program uses benchmarks and key performance indicators calculated and displayed on-line in trend charts by the PM system. The success of a heat rate improvement program depends on an adequate assessment up-front, and management commitment throughout, to ensure that the recommendations are actually implemented. According to one example from EPRI, a PM system, together with a well-supported heat rate program, improved heat rate by 1.5 percent and the net capacity factor by 5.2 percent. Costs at that plant were also reduced by 2.3 percent. (Power Engineering January, 2002, Douglas Smith)

A PM system is a very useful tool in plant heat rate improvement programs, but the historical data in the system must be reliable; this means that primary process information is acquired by properly installed, calibrated and maintained instrumentation, as described in the section on **Instruments and Actuators**.

Condition Monitoring Systems

Field devices, and process actuators in particular, will degrade in performance with accumulated operating hours, number of cycles, or due to fouling and corrosion effects. Catastrophic failures attract attention due to the large single opportunity cost of a trip. The slower, less-visible accumulation of wasted energy due to degraded performance may rival these costs over the lifetime of the unit. The energy cost of a reliability related trip is described in the section on **Energy Cost of a Trip** for a discussion on the energy cost of poor reliability.

Rotating Machinery

Degradation or poor installation of the motor-coupling and bearings will reduce drivepower energy efficiency and lead to maintenance problems. Periodic inspection and measurement helps, but online condition monitoring of rotating machinery will provide earlier warning of impending efficiency problems. A Condition Monitoring

(CM) system monitors bearing vibration, eccentricity and axial rotor position on any type of rotating machinery. These data are integrated into the DCS to leverage the CS logging, trending and operator alarms functionality. The types of rotating machinery deserving this form of condition monitoring are: turbines, feedpumps, fans, pumps, motors, gearboxes and compressors.

Condition Monitoring is distinguished from process monitoring through the use of models or other calculations to interpret the raw data and report on the actual condition of the equipment. The large number of rotating machinery in a power plant would make it difficult for operators to examine trends of each item. This type of automatic analysis is especially important for vibration data, which is a distribution of frequencies (a spectrum), which are both difficult and tedious for operators to interpret. A CM system for vibration monitoring compares baseline spectral data to current spectral data; any changes in the data are matched to a rules based algorithm, which in turn determines the cause of the change. The result is actionable information in the form of specific fault diagnosis, fault severity and maintenance recommendation.

In power plants: for large journal bearing machines like Main Turbines and Boiler Feed Pumps, these CM systems use Full Spectrum, Angle of the Major Ellipse Axis and Aspect Ratio of the Ellipse for Orbit analysis plus Shaft Centerline Position and Bearing Eccentricity. All these tools, along with comparisons to user configured Threshold Values, combine to determine the condition of the machine train, bearing by bearing.

Heat Exchanger Monitoring

The status of heat exchanger performance can be monitored in real-time using measurements of flowrate and temperatures (in and out) of each stream. These data are used to calculate the overall heat transfer co-efficient (U), using the thermodynamic formula for heat transfer shown below.

$$Q = U \times A \times \Delta T$$

Where:

Q = heat transferred (kcal/hr)
A = area of heat exchanger (m^2)
ΔT = temperature difference between hot & cold sides (log C)

All of these values are stored in a 'process historian' database and then continuously analyzed using a fouling factor model. This model is simply an energy balance between the hot and cold streams within the exchanger. If the current overall co-efficient is 5% or more less than the model's prediction (Rajan 2003), then a maintenance alert is triggered calling for proactive cleaning or problem investigation.

Control Systems

Evolution of Control Systems

Control systems have evolved from analog pneumatic controls to modern microprocessor-based systems. There are two main branches in this evolution; programmable logic controllers (PLCs) and Distributed Control Systems (DCS). PLCs are the simpler of the two, and are most suitable for machinery control and other areas of discrete manufacturing. A DCS is most suitable for processing the large number of analog input/output (I/O) in a large power or process plant, and are therefore often referred to as 'process control systems' The term 'distributed' in DCS is meant to distinguish these from an earlier, more centralized control system architecture centered around a process control computer. Another distinguishing feature of DCS is their use of function blocks rather individual I/O 'tags' for easier programmability.

Distributed Control Systems (DCS)

- A DCS provides all of the background services needed for control, operation and monitoring:
- Connections to various communication busses and networks
- Controller CPUs and their associated I/O sub-systems
- Human Machine Interface (HMI) for operator control, alarm and status indication
- Historian services to log & store large volumes of real-time data

These DCS services can have a significant impact on plant energy efficiency. A DCS is the only equipment type that spans all the diverse plant units. The reach of a modern DCS allows improved coordination and plant optimization strategies. Another source of DCS-related energy efficiency improvement comes with the inherent tighter control of modern digital control systems, especially when compared with legacy analog (e.g. pneumatic) control systems which may still live in the parts of some plants. ARC Advisory Group (Dedham, Mass) estimates there is $65 billion worth of control systems that are nearing the end of their useful life; at least a third of these systems are installed in North America, and most of them are more than 20 years old.

Perhaps the most important benefit a DCS can provide to a plant's energy efficiency improvement program comes from this: it is the only plant system which has such a wide and rich interface to the operators and engineers. Thus, the DCS can leverage the process knowledge in experienced plant personnel.

In power plants with antiquated analog control systems, a DCS upgrade can improve unit controls to provide 2-4% greater output and heat rate improvements (ABB Power Systems, USA, 2007).

The improved perfomance monitoring and HMI capabilities of a modern DCS are an enabler for heat rate improvement programs which have been shown to deliver 1.5% improvement. See **Energy Efficiency Potential of Performance Measurement.**

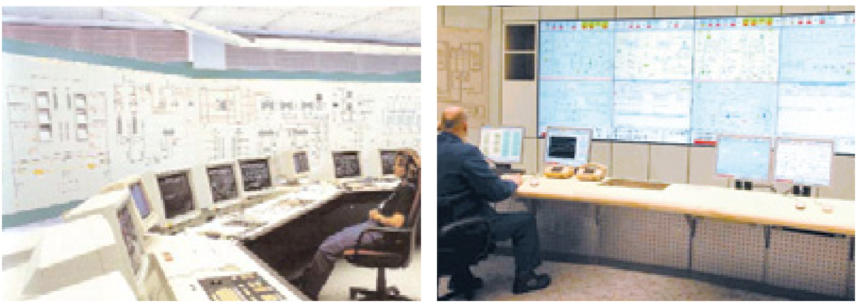


Figure 4.10 – Control room of 'Jänschwalde 6x500 MW' plant : Before (left) and after (right) a DCS modernization. Source: ABB Industrial IT for Power Plants.

Motor Control Centers

Motor Control Centers, or MCCs, allow more intelligent, automatic control of the LV motors and other LV loads. An MCC provides the centralized intelligence to control the contactors providing power to these loads. In many plants, motors may run longer than necessary because they have only manual control in the field. MCCs also enable improved monitoring of motor health, which leads to improved energy efficiency of the motors through predictive maintenance. Most important of all, the modern MCCs communication technology allows rich motor operation, performance and diagnostics data to be shared with the process control and load scheduling systems running in the DCS. Good communications and integration lowers the threshold for real-time energy management and optimization schemes:

- Intelligent load-shedding based on plant state, season, time of day
- Feeder power allocation to most efficient or lowest CO_2 power generating source

– Optimization of duty cycle within all temperature constraints to eliminate or reduce parallel operation

Off-line energy efficiency improvement programs can also benefit from the increased amount and variety of data available from MCCs and integrated with process data. .

In power plant engineering, MCCs are also referred to as Combination Starter Panels. MCC data can reveal hidden relationships between auxiliary power consumption and fuel supply composition.

Recent advances in MCC technology allow for increased communication between MCC and the process control systems. This integration can allows a plant to startup and recover more quickly from a trip condition by coordinating the many LV motors with the needs of the process control system; many startups are aborted because of an LV motor which did not start, a condition which is more easy to anticipate and avoid with MCCs.

Figure 4.11 – Motor Control Center cabinet, and close-up of motor starter ‘drawer’ (ABB Oy, 2007)

Automation System Design and Engineering

The full energy efficiency potential of automation will not be reached unless a systems approach is taken, which includes the entire hierarchy of control; from the sensor to plant operating and maintenance procedures. Automation design and engineering must go through all the familiar project phases as the other, older disciplines. Just as PFDs form the design basis for a process concept, so does the Control and Alarm Philosophy document guide the engineering of a process automation system. (Shutdown strategy is also an important for of the conceptual automation design). One of the outputs of a reevaluation of existing plant automation systems should be a revised control strategy/philosophy document. High-level control can be diagrammed even without the detail of P&ID drawings, using established norms such as System Control Diagrams. In the simplest of terms, the automation design and engineering steps are:

- Develop control and alarms philosophy
- Develop unit control strategy drawings
- Develop P&IDs drawings
- Perform instrument sizing from process requirements
- Create I/O (tag) List
- Develop DCS programming
- Perform Factory acceptance tests (FAT), preferably using process simulators
- Installation, commissioning and Site Acceptance Tests (SAT)

One of the challenges of retrofitting legacy automation systems is the lack of documentation of the original control logic. Also, the logic source itself may be written in a form not comprehensible to current plant staff. Understanding and documenting the current logic may require more effort than simply starting from scratch on a new automation platform.

Automation System Design Guidelines – Summary

Coordinated design with other engineering disciplines is a necessity for a successful automation design. In simple terms, automation is about controlling for disturbances. In the case of pumps and fans, the first step is to investigate the demand for flow and to visit the process designers to see if it can be reduced. In automation, such a process design discussion is also recommended to see if the sources of disturbance can be reduced at relatively low cost. Most of these principles are simply good automation design, but will lead to improved energy performance as well. Material for this section is from ISA 77 standards, ABB and Emerson process experts.

Some general principles to guide and inspire the automation engineer who seeks the most out of energy efficient designs:

Understand the process, then build and use models

- Understand the process dynamics: degrees of freedom, gain, time constant and especially its dead time.
- Model the process to gain further understanding of its behavior and to tune your designs, to get optimal setpoints, and to eventually train operators

Use a broad repertoire of control techniques to improve response

- Use closed loop feedback instead of open loop control to keep the process at setpoint and to correct for disturbances
- Understand how the process is disturbed using data and models, then use feedforward control to improve response to that disturbance
- Use cascade control, with feedforward, to further improve control response to rapidly changing loads, and to reduce effects of actuator non-linearity
- Use model-based control to optimize multiple variable processes, especially those processes with much non-linearity and dead-times.

Use smart, sensitive sensors to reduce dead-time, improve measurement

- Use digital, smart transmitters to improve accuracy, eliminate drift and benefit from onboard diagnostics.
- Use multiple transmitters instead of only one, to increase the accuracy & reliability of measurements.
- Specify additional sensors required for the feedforward signals in your control system strategy.
- Locate sensors to decrease measurement lag, while still avoiding regions of unstable measurement.
- Specify controllers and IO systems with fast scan times to further reduce lags & latencies

– Specify fast, on-line analyzers rather than off-line, sample-based instruments, to reduce loop dead-time

Use smart devices to control power input

– Manage and control energy input; use VFDs for motor speed control instead of control valves (for fluids) or dampers and vanes (for air/gas)
– If control valves must be used instead of VFDs, specify CVs with low friction packing to minimize 'stiction', and use a digital positioner. (ISA recommendation)
– Equip dampers and louvers with smart positioners to obtain better resolution
– Use signal characterization to improve linearity and response of actuators

Other guidelines:

– Wait until commissioning to fine tune controllers under real operating conditions
– Specify equipment with open,programmable interfaces to allow optimization across vendors. monitor energy usage in real-time and use this data to trend & manage energy KPIs.
– Direct operations to use automation as intended without defeating it in whole or in part by placing controls in 'manual' mode.

Module 5
Power Plant Automation Systems

Module Summary

This module describes the energy efficiency aspect of the plant instrumentation, controls and optimization systems. A detailed presentation of all automation aspects is beyond the scope of this handbook.

Gross Heat Rate and Capacity

Heat rate is the thermal energy required to produce 1kw-hour of electrical power. Gross hear rate is the rating for gross power output from the generator terminals. Since some of the power is used to run internal plant processes, and is thus routed back into the plant via the unit auxiliary transformer, then the remainder is delivered as salable power to the network. The thermal energy used to create those deliverable kw-hours is termed net heat rate. The focus of previous handbook sections has been on reducing in-house auxiliary loads through more efficient electrical and mechanical design. These approaches increased net plant capacity, and had their most direct effect on the net heat rate of the unit.

The focus of this module is on how automation can directly improve unit gross heat rate though control action on steam cycle parameters. These gains come from reducing controllable losses, which result from operation of the cycle equipment away from the best efficiency points for given loads. Mitigating these 'controllable losses' is the main contribution of automation to improving energy efficiency. Controllable losses tend to be higher than the cycle designers originally intended because the plant seldom operates in steady state at its design point. Losses are correspondingly higher at lower loads and during periods of load disturbances. Controllable losses worsen under conditions of equipment age, and poor implementation or tuning of boiler controls.

This section examines automation from an energy efficiency perspective and does not provide guidance on other, critical aspects of automation engineering such as safety interlock logic, emergency shutdown sequencing, human factors engineering, or fault-tolerant design. For a more complete guide to all other aspects of automation design see the **standards** and **references** sections of this handbook.

The information in this module section is specific to power generation industries or process plants with on-site power plants. Many sections, however, are also broadly applicable to all industrial steam generation processes.

Power Plant Efficiency Concepts

An understanding of the **basic thermodynamic principles of the steam cycle** and the basic principles of fossil-fuel combustion is essential to appreciate the actions of plant automation systems. There are a number of ways to obtain the initial thermal energy for the generation of steam, including the firing of oil, gas, waste & biomass. The styles of boiler can vary, but typically there are only three main methods of firing: pulverized fuel with multilevel wall or corner burners, fluidized bed, or stoker-fed. The primary focus of the following discussion is the pulverized fuel boiler, as it currently represents the single largest component of the global generation fleet.

Pulverized Coal Combustion Concepts

Pulverized fuel is mixed with preheated primary air and carried through multiple burners, where it is injected and ignited in the lower interior of the furnace. Draft and convection force the ignited fuel up through the active combustion zone, which resembles a large fireball, where the vast majority of the available energy in the fuel is released. Ultimately, the desired combustion product is CO_2 and some H_2O, indicating complete fuel component combustion. Undesired products include CO from incomplete combustion, and NOX resulting from air-related and fuel-related nitrogen sources combining with available O_2 at high temperatures. Rapid and hot combustion reduces CO to virtually nothing, but if it is too rapid and too hot, then thermal NOX is produced to great excess. Other undesired combustion by-products require some form of handling or mitigation, and include SOx (SO_2, SO_3, etc.), ash, carbon in ash, mercury and other heavy metal contaminants, radon, and unburned hydrocarbons.

The rates and temperatures of combustion within the vertical combustion zone determine the production of both desired and undesired combustion products, but they are not constant throughout the boiler. The combustion zones inside modern utility boilers occupy thousands of cubic yards. The size and firing rates of such large boilers mean that fuel and air must enter the combustion zone from many locations and at several levels within the boiler. Flows at each level need to be controlled to both follow the load and optimally manage combustion.

Review of Steam Generation Concepts

The figure below from IEA's Coal Online reference shows the main components in a drum-type subcritical boiler. The boiler feedwater pump supplies water to the drum through the economizer, which heats the feedwater to just under evaporation temperature. The water circulates through tubes in the furnace walls, absorbing radiant heat and evaporating to steam, which is separated from water in the drum. The steam flows through the hanging tubes of the primary and secondary superheaters before entering the high pressure (HP) turbine stage. The steam exiting the HP turbine is reheated to much the same temperature before entering the low pressure (LP) turbine stage and finally the condenser. Boiler efficiencies can be relatively high, at up to 90-94% (LHV basis).

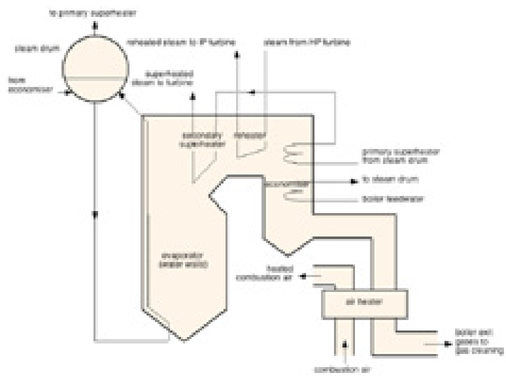


Figure 5.1 – Simplified drum boiler diagram (IEA Coal Online - 2, 2007)

The furnace heat is transferred in these proportions, for a single-reheat subcritical PC power-plant unit: 8% in the economizer, 35–45% in the evaporator, 30–40% in the superheater elements, 15% in the reheater elements (IEA Coal Online - 2, 2007). The air heater also recycles substantial remaining energy of the flue gas heat to warm the intake air prior to combustion.

Parameters for Increased Thermal Efficiency

Cycle thermodynamics shows how the following basic system parameters can be controlled to give greater thermodynamic efficiency in all power plants. Many of these performance parameter values, including efficiency, are guaranteed by the boiler manufacturer when the unit is fired with a specific type and quality of fuel.

- Increase the average boiler steam outlet temperature and pressure up to safe operation limit.
- Decrease the average flue gas O2 of the boilers down to a level compatible with opacity limits

- Minimize the turbine extraction and exhaust steam pressures
- Reduce flue gas exit temperature (FGET) down to a level which still prevents condensation

The rules of thumb relating these parameters to thermal efficiency are given below, with an assumption of linearity within typical operating ranges:

- Boiler efficiency improves 1% for every 40 ºF (22 ºC) reduction in flue gas exit temperature., whose heat is recycled by the economizer and air heater. Ref (Babcock & Wilcox 2005)
- For a supercritical unit: each 50 ºF (28 ºC) increase in main steam temperature increases cycle efficiency by 1% (Babcock & Wilcox 2005)
- For a sub-critical unit: each 50 ºF (28 ºC) increase in main steam temperature decreases heatrate by 70 Btu (74 kJ) per kWh at full load, which corresponds to an increase in cycle efficiency of approximately 0.7% (EPRI report CS4554)

For a sub-critical unit: each 100 psi (690 kPa) increase in main steam pressure decreases heatrate by 35 Btu (37 kJ) per kWh (i.e. about 1/3 of a percent) at full load (EPRI report CS-4554).

For a sub-critical unit: each 50º F (28 ºC) increase in reheat steam temperature decreases heatrate by 65 Btu (68 kJ) per kWh at full load (about 2/3 of a percent). (EPRI report CS-4554)

- For a sub-critical unit: each 50 klb/hr (23 tonne/hr) reduction on reheat spray flow decreases heatrate by 108 Btu (114 kJ) per kWh (about 1%) at full load. (EPRI report CS-4554)

In industrial power generation situations and/or CHP plants, these additional system parameters can be controlled for improved energy efficiency and lower operating costs:

- Minimize the use of pressure reducing valves by-passing turbine generators
- Optimize (minimize) the use of the steam vent valves
- Optimize the mix between purchased power and own condensing
- Increase the use of low cost fuels, decrease the use of expensive fuels

Energy Efficiency Potential of Power Plant Automation

The energy efficiency potential of automation is summarized below, based on data from ABB, IEA CoalOnline and the US DoE:

- Faster plant start-up and shutdown by programming the plant-control sequences

- Higher availability by detecting and indicating the causes of impending malfunctions
- Greater thermal efficiency by reducing process variability and moving variable set points closer to the safe operating limits
- Reduced emissions by controlling the combustion process and downstream emission-control technologies
- Lower maintenance costs by replacing pneumatic, electromechanical or electronic/analogue devices
- A decrease in operational costs by reducing staff requirement: today's designers are even striving for single-operator control of coal-fired power plants (Swanekamp, 1995)

Automation allows tighter integration between generator, turbine and boiler units, which can give significant energy benefits. Integrated (real-time) control between plant cycle equipment and between plant units is a particularly valuable technique to achieve energy savings in co-generation power plants or process plants that produce some of their own power and heat on-site (US DoE, 2004) p13. Retrofits that include biomass co-firing can also be made more economic by means of tighter integration with the energy consuming units.

The average life of a modern automation system varies from 10 to 15 years for PC-based systems and 15 to 20 years for proprietary distributed control systems. The cost of upgrading I&C in coal-fired plant is estimated to range from $1 to $6 million (Ferrer, Green Strategies for Aging Coal Plants, 2008). This cost is relatively small when compared with some other steam plant upgrades of the power cycle equipment, which may cost up to 5 times as much. DCS vendors (ABB, Seimens, Emerson) claim heat rate improvements of 2-5 % can result from upgrading to a modern DCS and advanced control technologies. The improvement could be even higher if the energy saved from fewer trips were properly accounted for, and if system-wide real-time optimization were included.

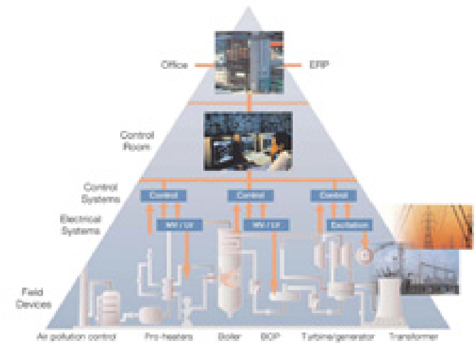


Figure 5.2 – Hierarchy of control in a fossil fuel plant, (ABB Solutions for Fossil Fuel Power Plants)

Power Plant Automation Standards and Best Practice

The International Society for Automation (ISA) is the source of many useful and authoritative standards on industrial instrumentation, controls and optimization. The ISA has formulated a collection of standards specifically for power plants: ISA SP 77 Fossil Fuel Power Plant Standards

Power Plant Automation Systems Overview

The main automation systems in a steam power plant are listed below. Protective safety systems and most non-boiler service systems are out of scope of this handbook.

Boiler-Turbine Control

– Unit load control (Megawatt control)
– Combustion/Firing rate control
– Fuel Master, Fuel/Air Control
    Excess Air Control
    FD Fan Control, Furnace draft pressure(ID fan) control
    Feedwater flow (drum level) control
– Gas flow distribution (gas recirculation) control
– Turbine-generator control
  Turbine Control valves
– Superheat & reheat temperature control
– Special monitoring:
    Gas analysis : O2, CO
    Air flow, fuel flow

Burner Management
- Boiler startup / shutdown system
- Fuel management systems : pulverizer, PA fan control
- Furnace monitoring: Flame stability

Emissions Control
- NOx control
- SO2 control
- Special monitoring:

  Particulate count in flue gas

Condenser & Condensate Controls
- Condensate controls (Water level in de-aerator tank etc.)
- Coolant controls (circulating water control, cooling tower control)

Fuel Preparation Systems

Soot-Blowing Systems

Water Treatment Systems

Additional plant-wide automation 'systems'
- System-wide (multiple unit or 'site') optimization
- Power Management System
- Asset Management System
- Motor Controls System

The interrelated set of boiler-turbine controls are shown in the figure below:

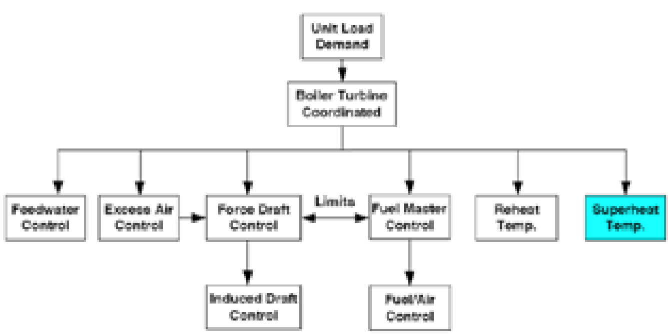


Figure 5.3 – Utility Boiler and Turbine Control System, ABB Power Systems, Application Guide,2008

Plant Operating Modes

A power plant is usually designed for a certain operating mode. An operating mode is a combination of a plant's duty-cycle and load response.

Duty Cycle

A duty-cycle is a unit's loading during a given time period. The typical unit duty cycles are:

– Base loading	:	unit operated at constant load 24 hrs/day, 7 days week. (nominally 8000 hrs/yr)
– Shift loading	:	unit operated at constant load during each 8-hour shift, reduced (banked) in-between
– Day/Night loading	:	unit operated at constant load during day, then banked or shutdown overnight

For a typical PC utility boiler, a cold restart after a complete shutdown may take between 6 to 12 hours. A unit operating in reduced or banked mode can be hot-started in a much shorter time. A 'banked' unit operates at much below its capacity, in anticipation of being dispatched to handle peak loads. This is sometimes referred to as 'spinning reserve'.

Load Response

Load response is usually dominated by one of the following:

- Frequency response: operated at nominal load (one of above) but modulated to compensate for network frequency disturbances. In frequency response, the turbine governor responds immediately to the frequency drop that accompanies an increase in end-user demand for electricity in the network.
- Load-following: a unit may be asked to operate anywhere between 30% and 100% of its MCR as part of a load dispatch system, and where it may be required to change load at a rate of as much as 5% per minute (IEA Coal Online - 2, 2007).

In most response modes, the unit load demand is established by a remote dispatcher, part of a wide area networked load control system. Load-following is an increasingly more common mode of operation in deregulated or liberalized markets, as shown by average availability figures in the region of 85% for sub-critical PC plants (IEA Coal Online - 2, 2007).

Flow Rates

The plant's operation may also be expressed in terms of main steam flow rates to the high pressure turbine. Some important main steam flow rate terms are:

- Valves Wide Open (VWO) plus 5% - condition applies to units specified to run with a 5% overpressure

- Peak – the maximum capacity, which is used for sizing of all other systems, including auxiliaries. This flow is not maintained for long periods.
- Maximum Continuous Rating (MCR) – the steady-state maximum flow condition
- Minimum flow – the minimum stable flow condition

Boiler-Turbine Control

Boiler vs. Turbine Following Modes

The boiler can store energy and supply it to the turbine-generator's control valve at a certain 'throttle' pressure. The control valve regulates steam flow for initial response to demand. In some turbine-generators, finer control is provided by a bank of nozzles per turbine stage; at most, only 1 such nozzle will be throttled at any given time. See the Turbine-Generator section for more description on turbine control actuators and position control.

The boiler responds much more slowly to demand, through changes to fuel firing rate, due to its larger mass and thermal storage capacity. In boiler-following mode the turbine-generator provides megawatt control and the boiler catches up to restore throttle pressure. In turbine-following mode the boiler provides the initial demand response by increasing firing rate and hence throttle pressure; the turbine-generator follows by adjusting its control valves to maintain throttle pressure. Boiler-following mode is more responsive but less stable than turbine following mode, and puts more thermal stresses on the turbine.

Constant Pressure vs. Sliding Pressure Operation

In the modes discussed above, the boiler (hence throttle) pressure is basically fixed. The boiler is fired at a rate that will produce enough steam for the turbine to satisfy electrical power demand. The turbine steam valve(s) are modulated to maintain a constant pressure at the turbine inlet. Throttling of the turbine valve at lower loads will reduce steam pressure and temperature downstream of the turbine inlet, which reduces turbine efficiency.

In sliding-pressure operation, boiler pressure is allowed to vary with load, the steam turbine valves may be left open, and steam production is controlled by adjusting boiler pressure. The boiler must still be fired to produce the required the steam flow to satisfy demand. Sliding pressure operation is more efficient at lower loads, due to lower first-stage turbine throttle losses (hence higher, and better controlled inlet temperatures) and reduced boiler feedwater pump power when compared to the higher, fixed-pressure operation. The higher first-stage temperature also increases reheat steam temperature at low load, which further reduced heat rate. Sliding (or variable) pressure operation, however, is slower to respond to demand - the typical demand response rate is 50% of the rate under constant pressure operation.

(Babcock & Wilcox, 2005). Boiler thermal stresses are also greater in sliding-pressure operation, due to increased cycling of the boiler.

As a matter of practice in sliding-pressure operation, the turbine inlet valves are generally held at a constant position between 20% and 70% load; outside of this range, the unit is operated at constant pressure. Between 70 and 100% load, the operating curves for the two modes are identical (ABB Inc. Plant Automation, 2006). This level of throttling capability can provide reserve steam to meet sudden increases from lower demand (IEA Coal Online - 2, 2007).

If rapid response to demand is required, one technique is to divert some steam from feedwater heating so that it can be instead expanded in the turbine to generate power; the section on Condensate Controls and the Schwarze-Pump case discuss some of the efficiency trade-offs for this technique.

Another means of variable pressure control is by the use of large division valves in the superheater flow links (Black&Veatch 2008) . This method keeps the boiler operating at higher pressures and therefore does not benefit from BFW pump power reduction.

Sliding pressure method is also suitable for once-through supercritical designs, where more rapid output changes can be achieved because of their lower thermal inertia. Once-through boilers can increase output by 5% per minute, compared with a typical 3% per minute for drum boilers (Luby, 2003, as cited in (IEA Coal Online - 2, 2007).

Case Example
Unit C of the E.ON Scholven Power Plant, Germany

Figure 5.4 – ABB AG Power Technology Systems, 2006

The power produced in the Scholven power plant covers approximately 3% of the overall power demand in Germany, with gross output of 2,200MW.

Because of the new market situation, unit C, initially intended for base-load operation, is now being used in the medium load range. An inlet-pressure control mode (the turbine controlling the pressure and thus supporting the boiler), plus natural and modified sliding-pressure modes with an adjustable degree of turbine throttling (turbine or boiler following mode) needed to be implemented. In order to be able to follow the signal issued by the network controller, the control concept must provide for frequent load ramps and load deltas with high load variation rates, without any equilibrium conditions during load reversals for secondary control purposes.

The primary grid frequency control of the unit is responsible for the balance between the power generation and load consumption in the grid. The grid secondary control (load-frequency control) is provided by a load dispatcher, which regulates the agreed load exchange between the interconnected power supply partners and the overall grid.

Due to the complexity of the primary and secondary control tasks, a model-based unit control system (ABB's MODAN) was chosen. The model uses the two main manipulated variables 'fuel flow' for the boiler and the 'turbine control valve' in a coordinated mode. This is done by considering internal dynamic models for live steam pressure and unit load. [If further control actions in the condensate heating line are available, such as speed-controlled condensate pumps or valves, the second unit control variant MODAKOND can be applied.]

This control strategy and operating mode has improved plant efficiency for primary frequency control through reduced throttling of the turbine control valves. An added benefit has been reduced control activity which allow for smoother operation of main components like pulverizers, FD and ID fans, thereby reducing plant operation costs. (This case text provided by ABB AG, Power Technology Systems, 2006)

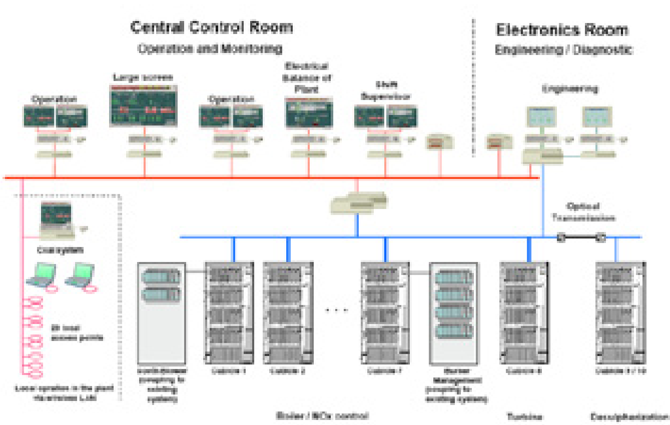


Figure 5.5 – Boiler automation system for Scholven unit, ABB AG Power Technology Systems, 2006

Coordinated Boiler-Turbine Control

In older plants, fuel flow control, boiler pressure and turbine steam flow control were separate control loops to accommodate either boiler or turbine following modes. These base control loops acted independently, making it difficult to optimize the process, and frequent operator intervention was required. During large process upsets it was difficult to maintain the steam conditions within acceptable limits, especially in multi-boiler and steam header plants. When large enough, such a process upset would result in a boiler trip.

Benefits of Coordinated Control

Boiler-turbine coordinated control combines the two control strategies by distributing some demand responsibility to both boiler and turbine for improved overall response and stability. The distribution of demand provides advantages similar to that of feed-forward control and reduces continuous interactions between these control loops; an advantage for precise load control in a wide-area load dispatch system (Babcock & Wilcox, 2005). Coordinated control can be used with either constant or sliding pressure operation.

Coordinated control is especially suited for load-following operation, where maintaining efficiency at low loads is important for a unit's economic viability. This operating mode responds well to load dispatcher signals which allocate more generation capacity to plants with higher efficiencies. Coordinated control provides the operator with the flexibility to choose between base-loading and ramp-loading (load following). The control technology may be either model-based or using feedback loops. Feedback control is improved by using feedforward and adaptive tuning techniques. The increased stability of coordinated control allows the unit to be operated closer to its optimum at base loads, and more efficiently under low loads. The combined effect of coordinated control is a heat rate improvement of 4% to 7% (Ferrer, Small-Buck Change Yields Big-Bang Gain, 2007).

Pre-packaged controls in the turbine-generator equipment may not be able to participate in a coordinated control scheme. In such cases, it is recommended to simply remove or bypass these controls in favor of a coordinating controller. See the Turbine-Generator section for more description on turbine controls.

Coordinated Control Demand Development

In coordinated control, a limited megawatt error signal offsets the throttle pressure error, allowing the turbine to sustain initial megawatts until the boiler catches up. A similar strategy provides the boiler demand signal. Adaptive tuning improves the controller's sensitivity to different process time constants and for changes in energy storage after large load changes (ABB Inc. Plant Automation, 2006). Dynamic functions are used as the source of feedforward to overcome inertia in either turbine or boiler. The boiler feedforward may be a simple model using time delays.

For a description of model-based control, see the **Scholven case** text in this handbook. For details on development of the unit load demand signals, see the references: (ABB Inc. Plant Automation, 2006; ABB Inc. Plant Automation, 2006) and (Babcock & Wilcox, 2005).

Combustion Control

A combustion control system modulates the supply of fuel to the furnace and also the amount of air supplied for combustion of that fuel to satisfy the demand for energy. This fuel/air supply is also known as the firing rate, so this system is sometimes referred to as 'firing rate control'. The air/fuel ratio of a 'typical' boiler is controlled to within +/-2% of excess air (ISA 2005)

Fuel Control

A typical PC boiler combustion (or firing rate) control system receives a demand signal from the integrated boiler-turbine control system and trims it with error signals from main steam temperature and feedwater flow. The resulting firing-rate demand is distributed to the subsidiary fuel flow control and air flow control via a 'fuel-air master' controller. The fuel flow control compares its demand signal to the total fuel flow for all pulverizers. The resulting command signal is sent to the pulverizer's group master controller which applies the error signal in parallel to all pulverizers, along with a demanded air flow, which is PID-controlled on each pulverizer (Babcock & Wilcox, 2005).

Air Flow Control for Combustion

This section is adapted from an article in Power Engineering by Richard Vesel (Vesel, 2007):

(The drive power aspects of draft fans are discussed in the **Drive Power- Fan sections** of this handbook.) Airflow control is essential to efficient and safe combustion process. Methods of airflow control vary with the basic boiler type; the descriptions in this section apply to a sub-critical, PC boiler design.

The basic combustion (primary and secondary) airflow control strategy is: the fuel-air master receives a boiler firing rate demand signal from which it calculates a total air demand based on current fuel feed rates. The air flow demand is compared with actual flows summed from transmitters in the primary and secondary air streams. This error signal is used by the secondary (FD) fan controller to adjust motor speed or the damper position to modulate the flow.

These final control elements must be accurately and speedily positioned for even basic control schemes to be effective. Inaccurate or weak damper drives cause poor combustion control response and reduced efficiency. See the section on **Process Actuators** for more details on damper actuators. An opportunity to improve airflow control method is when a plant must upgrade the main draft air driver systems with higher power motors to make up for additional resistance from post-combustion flue gas processing (SCR and FGD among them) as described in the section on **Emissions Controls**. A plant can realize large energy benefits by controlling main air flow with variable speed drives such as VFDs.

Air Flow Control for Draft Control

Furnace draft pressure control is a 'housekeeping' loop within combustion control. The ID fans serve to regulate furnace draft backpressure so that flue gasses can be exhausted at the correct flowrate. ID fans are controlled by a feedforward program based on air flow demand, corrected by a furnace pressure deviation from setpoint.

Air Flow Control and Energy Efficiency

Excess O2, CO and NOx are the critical pieces of information needed to properly manage combustion air flows. The solution that achieves and maintains essentially complete combustion while minimizing production of NOx relies on the controlled feeding of air into the combustion zone at various stages and in just the right amounts. This promotes burning at temperatures high enough to consume all available fuel, but low enough (that is, under 2,800 deg-F or 1550 deg-C) to avoid production of NOx in great quantities.

Other effects of this staged combustion process are: elevation of flue gas temperatures and higher temperatures in the upper interior, as well as the backpass of the boiler. Ash may reach fusion temperatures to form an especially tenacious slag on boiler tube surfaces. CO-rich ‘dark’ zones in the lower furnace can chemically attack boiler tubes, so ‘underfire air’ has been used to reduce this problem. With these various competing needs, the air balancing act within the boiler becomes even more delicate, more difficult to model and control, and harder to maintain under dynamic load conditions. Poor air control wastes fuel and degrades heat rate, both of which increase costs.

The problems associated with outdated damper drives are described in **Process Actuators**. Plant owners can improve performance and reduce cost of ownership by replacing traditional fan-motor-damper arrangements with fan-motor **variable frequency drive (VFD) system**. A VFD provides variable speed control of a fan in response to a signal from a controller. Response times for VFD are a bit slower than direct damper control due to fan and motor inertia. However, if precise control are used on trimming dampers, then optimal results can still be realized. Dampers are also increasingly important for control adjustments at speeds less than 33% of maximum (ISA 2005).

Automation Potential for Energy Efficient Design

Efficiency gains in combustion process have a direct impact on fuel costs (which are 45-55% of the cost of the generated electricity- (IEA Coal Online - 2, 2007)) and plant heat rate. The thermal efficiencies of boilers are already high (up to 94%) and, according to the IEA’s Coal Online it ‘appears unlikely that further large gains in the efficiency of heat recovery from state-of-the-art PC boilers can occur’.

Such thermal efficiencies are calculated from steady-state mass and energy balances, however, they do not consider the detrimental effects of unstable operation. Unstable firing rates will deter operators from keeping the boiler operating near its design constraints and optimum efficiency point.

Unstable boiler operation may occur after a retrofit to low NOx burners, or after switching to different fuels. Other contributors to instability may be due to uncorrected deadband or non-linearities in the throttle control valve(s). If the current control system gains are too high, then the response to load demands may also lead to swings in firing rate. One consequence of swinging between under- and over-firing is instability in the flue gas and thermal distributions within the furnace, leading to poor heat transfer at water wall tubing. Another disadvantage of unstable conditions is revealed in high carbon-in-ash losses; these contribute to a higher heat rate and indicate incomplete burnout.

It is estimated that stabilizing firing rate, furnace draft and air flow can give 1-2% improvement in heat rate most units (ABB). A simple approach to curing boiler instability is to reduce the gain such that ramp rates start low, and then accelerate if the ramp direction demand persists. (Ferrer, Small-Buck Change Yields Big-Bang Gain, 2007). **This large impact on energy efficiency should put combustion controls at the forefront of a plant controls assessment and/or combustion process optimization effort.**

Combustion Optimization

Combustion optimization is distinct from combustion control, which is essential to control firing rate for basic boiler functionality and safety. Optimization improves upon basic performance. Optimization also implies the use of model-based techniques such as MPC.

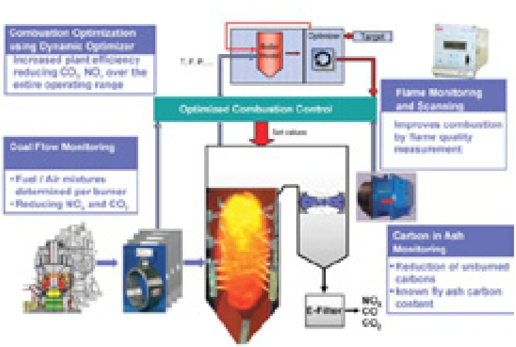


Figure 5.6 – Combustion optimization system schematic, (ABB Fossil Fuel Plants, 2005)

Feedwater Flow Control

Feedwater flow control modulates pump flow to achieve the desired drum water level and water pressure. The main boiler feedwater pumps (BFP) supply feedwater up into the boiler at high pressure where it can begin the water/steam cycle again.

There are 3 different control methods for regulating feedwater flow and drum water level. In single element control, a loop with proportional-integral (PI) control acts on the input signal from drum level transmitter. In two-element control, the outgoing steam flow is used in a feedforward loop, while drum level control continues to correct for level disturbances. Two-element control is most common in industrial boiler applications (Babcock & Wilcox, 2005). In three-element control, a water flow measurement is used in a cascaded fashion. A drum-level error signal is summed with a steam flow feedforward signal to provide the feedwater demand. This demand is then compared with the water flow measurement to provide an error signal input to the inner PI control loop. The more accurate feedwater flow control systems also use shrink-swell compensation to compensate for water density and volume changes as temperature changes.

Demand for Auxiliary Drivepower

Large demand for auxiliary drive power comes from the main and booster boiler feedwater pumps (BFPs). The drive power aspects of the BFP are discussed in the **Drivepower-Pump** sections of this handbook. BFW pumping is a high-system head application for VSD speed control; a large part of the speed control range is used in developing pump head at low flow (ISA 2005). Benefits are therefore lower than in high-flow, low-head systems, but VSDs are still worthwhile in this application when compared to throttling.

The ability of VFDs to provide over-speed capacity (within the service factor of the motor and pump) may be useful in boilers which are designed with extra margin for overpressure operation. This extra capacity may be needed to supply peak loading on hot summer days.

Another auxiliary load on many boiler designs comes from the relatively lower power boiler recirculating pump, which moves water between drum and the boiler water walls. This auxiliary load is eliminated in supercritical designs and in some HRSG designs which use natural circulation within the boiler.

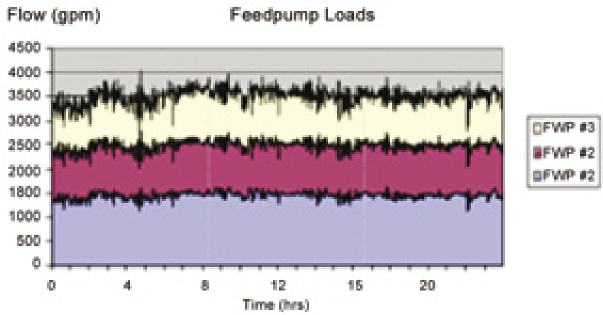
Automation Potential for Energy Efficient Design

Stable feedwater flow control allows the unit to operate closer to its design point for main steam pressure. For a sub-critical unit: each 100 psi increase in main steam pressure decreases heatrate by 35 Btu per kWh at full load (EPRI report CS-4554). Steam pressure in a ‘typical’ boiler is normally controlled to within +/-1% of the desired pressure (ISA 2005).

Case Example

A feedwater pump use at a U.S. pulp and paper mill. As the peak load does not exceed 4,000 gpm (25 l/s), and two of the pumps can produce the required pressure at flow rates of 2,000 gpm (13 l/s) each, operating only two of the pumps would be sufficient.

The savings achievable from shutting down an extra feedwater pump are site-specific, depending on the pump size, the type of the drive (motor vs. turbine driven), price of electricity, etc. A typical range of savings is $50,000-$250,000 per year.



Case text and image from (Immonen, Assessing Industrial Power Plant Operations & Controls, 2003)

Flue Gas Recirculation Control

Flue Gas Recirculation (FGR) is used by some units to decrease the proportion of excess air (O2) in the furnace by partial recycling of flue gas back into the boiler combustion zone. FGR may also have a secondary function of controlling steam reheat temperature. The flue gas is typically extracted from some point after the particulate control equipment and displaces fresh draft air so that the total mass flow through the furnace remains constant.

This section is adapted from material provided by ABB Power Systems, USA:

A typical FGR system consists of one gas recirculation fan with an inlet damper used to control the flow and two outlet dampers to divide the flow to between the burner windbox and the boiler furnace hopper. A load based index adjusts the inlet damper to maintain a ratio of gas recirculation and boiler air flow. A PID controller reacts to the windbox O2 value to maintain a setpoint value of O2 in the windbox at all times. The windbox O2 increases as the windbox damper position increases. The hopper damper demand changes inversely to the windbox damper. The demand to the inlet damper includes a bias from the windbox demand that is included to allow the windbox damper to maintain the windbox O2. The resulting increased boiler efficiency from the reduction in excess O2 is described in **Parameters for Increased Thermal Efficiency**.

FGR Drivepower and Control

FGR is a useful means of controlling excess air, but the FGR fan consumes in-plant operating power and requires maintenance. These extra costs may be higher (per hp) for FGR systems due to the higher temperature and higher particulate count in the extracted flue gas, compared to fresh draft air fans. To avoid excessive blade erosion under thee harsher conditions, these centrifugal fans typically have a less efficient forward-curved blade design (as described in the section on **Fan Power and Energy Efficiency**) which increases the per unit demand for auxiliary power. **A retrofit of the FGD fan motor to VFD speed control will save auxiliary power, especially at low loads, compared to other means of flow control.**

For FGR fans with inlet dampers for flow control, automation can be used to program a smaller opening at low loads to minimize plant auxiliary load. Whether using inlet dampers or VFD, improved flow control will also improve the ability of the O2 and combustion controls, especially during load changes and under low load conditions. Adaptive tuning will improve response across a wider load range, and the distribution of recirculated flue gas may also be optimized for different loading conditions. Another role for FGR automation is to modify the gas recirculation flow in order to reduce the thermal stresses seen during the load changes in the lower operating region.

Turbine-Generator Control

Where the steam flow is used to set the output at part load, there are three potential means of control (throttle, nozzle and bypass governing) to set the flow rate to adjust the power output as required. The turbine governor operates to maintain frequency control during startup or big load changes. After reaching equilibrium, the turbine then goes into load control mode.

Turbine-generator efficiency is typically 43.4% (IEA Coal Online - 2, 2007), expressed as a ratio of output electrical power vs. thermal BTU power entering the HP steam input. Steam turbines cannot use the latent heat of condensation, so this latter energy is often omitted from turbine efficiency calculations. See the **Coordinated Boiler-Turbine Control** section of this handbook on how sliding pressure operating mode can reduce throttling losses across the turbine control valves compared to constant pressure operation. Steam extracted from the turbine stages for feedwater heating reduces unit power generation capacity, but increases thermal efficiency. The automation potential for controlling this flow is discussed in the section on the **Condensate System**.

Figure 5.7 – Turbine Generator unit photo, (ABB Solutions for Fossil Fuel Power Plants brochure, 2007)

Automation Potential for Energy Efficient Design

There are significant energy efficiency benefits in upgrading steam turbine controls to new servo drives (mechanical-hydraulic actuation devices) for the HP and IP control valves as part of a turbine control improvement. Older turbine valve actuation methods suffer from hysteresis, non-linearities, and poor dynamic response. These effects may allow for very poor maximum control accuracy of only +/-10%, and suffer from increased maintenance needs as these older mechanical linkage facilities and drives are more subject to wear and excessive clearance effects.

Upgrading turbine valve servo drives and their controls can improve accuracy to +/-1%. Other advantages of the improved linearity and optimized positioning times are: improved dynamics, smoother operation, reduced throttling losses, and enhanced stability; the following case history describes the benefits in more detail.

Figure 5.8 – Upgraded turbine valve servo drive photo, (ABB Utilities GmbH, 2004)

Case Example
Upgraded Turbine Components and Unit Controls
Blénod Power Plant Units 3 &4, EDF, France

The fossil-fueled units 3 & 4 of EDF's CPT Blénod power plant are more than 30 years old located at Pont a Mousson, Lorraine, France. The maximum net output of the plant is 265 MW.

Figure 5.9 – CPT Blénod Power Plant Units 3 &4, EDF, France

Upgrading measures were sought which could improve the maneuverability and efficiency of the plant. The three technical upgrade requirements were:

- Fast power output increase for the purpose of primary grid frequency control; at an amplitude of up to ± 25 MW within 30 sec
- Participation in 'télérèglage'; the load ramps being specified by the load dispatch center for the purpose of secondary frequency control, at an amplitude of up to ± 50 MW and a gradient of 7 MW/min
- Higher economic efficiency achieved by an enhanced operational efficiency

Plant measurement data and operational experience indicated that the older electrical-hydraulic and mechanical components of the turbine would need an upgrade to ensure the required dynamic response, in conjunction with a new digital turbine controller.

The new digital turbine controller is of a modular and flexible design and provides — in combination with new mechanical-hydraulic activation devices for the HP and IP control valves — the basis for meeting the dynamic demands of the process. The previous mechanical linkage facilities and drives showed excessive clearance and effects of wear and tear. They were replaced by new low-maintenance servo drives which were adapted to the specific needs of the turbine.

The new model-based boiler-turbine unit control system coordinates the operation of the boiler and the turbo-generator set. The unit control explicitly allows for the dynamic and highly varying behavior of the two major components, i.e. the boiler (dynamically slow) and the turbo-generator set (dynamically very fast). Positioning interventions are done via the turbine control valves and the fuel setpoint of the boiler. As a result, the operation can take place both in coordinated boiler-following mode, with the turbine being output-controlled, and in turbine-following mode, with the boiler being output-controlled. The output setpoint is adjusted to the level requested by the power purchaser via an external grid controller and is additionally superimposed on the manually-specified basic unit setpoint.

The economic efficiency of the plant has been enhanced by migrating from constant-pressure mode to sliding-pressure mode. This way, it was possible to reduce the auxiliary power consumption of the feedwater pumps and to increase the overall efficiency of the units. Other benefits of the upgrade are: reduced throttling losses of the turbine, improved control accuracy and smoother operation. Control accuracy is improved from +-10% to +-1%.

With these goals being accomplished, the plant can now demand higher prices when selling its electricity in the power market, as the price for providing secondary-frequency power control is determined on the basis of the maximum possible power amplitude and by the change gradient of the load ramp. Moreover, the plant is also able to participate in the European power market, although this is not in-tended at present.

(Case text adapted from ABB Utilities GmbH, 2004 brochure on Upgrade of Blénod Power Plant)

Excess Air Control

Excess air minimization is a frequently attempted efficiency improvement. The objective is clear, and the savings are easy to quantify in terms of fuel savings. Many successful implementations are currently in use, but significant room for improvement exists. Note that excess air control is one of several other combustion controls; see the handbook section on **Combustion Control** for more details on other methods.

Excess Air Concepts

A primary combustion quality measure is excess oxygen in the flue gas stream. Due to imperfect mixing, the combustion process will require more than the chemical (i.e. stoichiometric) amounts of air for efficient combustion. For a PC drum boiler, the excess air level at 50% load may be controlled to twice that at full load. (Black & Veatch, 1996)

Too little excess oxygen implies incomplete combustion, elevated levels of CO, unburned carbon and volatile hydrocarbons and the potential for loss on ignition (LOI). Too much excess oxygen means lowered efficiency due to unnecessary heating of the unused components of the draft air stream, as well as excessive generation of thermal NOX due to fast combustion in hot zones within the boiler. Between these two extremes is a region of optimal performance shown in the following figure:

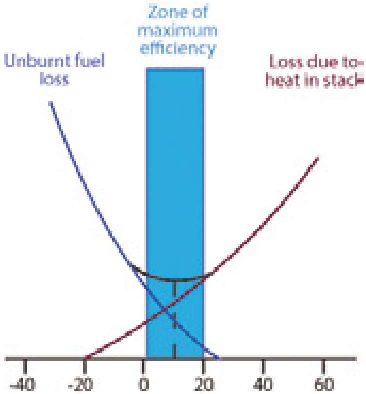


Figure 5.10 – Unburnt fuel and stack loss curves for combustion, (Plantservices.com, 2007)

Measurement of Excess Air

Indicators of incomplete combustion, as well as particulate contamination, used to be available from stack gas opacity monitors. With the advent of direct oxygen measurement sensors for harsh environments, it became possible to reliably and continuously measure excess O2 in the flue gas stream. Measurement of excess air is done by measuring the levels of oxygen (O2) content in the flue gas stream, but air in-leakage also may cause an overestimation of excess air in the furnace. Carbon monoxide (CO) monitors are often used in parallel with oxygen monitors to verify adequate levels in the furnace. Increased CO levels indicate incomplete combustion (Black & Veatch, 1996)

Automation Potential for Energy Efficient Design

Applying the above measurements along with thermal efficiency calculations led to determinations that for most boilers, the 'best' settings for excess O2 fell in the 3 percent to 6 percent range. More detailed thermal modeling and analysis on individual boiler configurations allows for more precise determinations.

Placing O2 under automatic control (a dedicated oxygen trim module) creates an overall optimum level of combustion during steady state operations. The control system calculates and adjusts overall draft air flow based on the observed variations in excess O2, while other controls adjust fuel flow to match load requirements. More advanced furnace designs and complex control schemes allow for individual adjustments to FD, ID, primary, secondary and overfire air flows. Some of these settings are under continuous and full automatic control, while others are manually set via fixed position dampers at individual registers, such as balancing overfire air registers, and bank functions are controlled by master automated dampers.

The O2 control module should also offer automatic override of opacity; this could promote operator confidence and lead to more time in efficient automatic mode (Ferrer, Small-Buck Change Yields Big-Bang Gain, 2007).}

The figures below show that improvement potential still exists among industrial power plants. The leftmost curve shows the O2 variability of boiler ‘A’, plotted against the steam flow. The chart on the right includes a similar plot for boiler ‘B’.

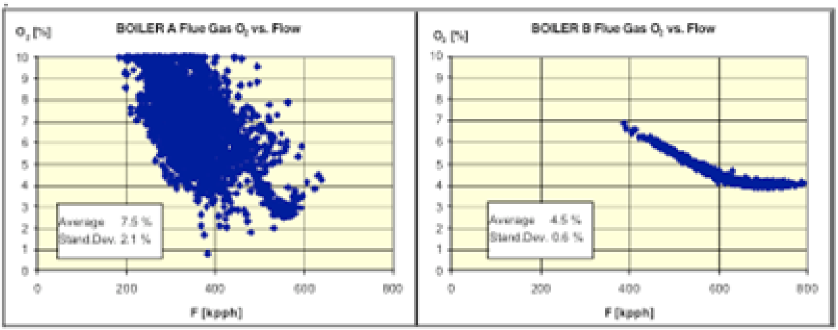


Figure 5.11 – Boiler excess air control (Immonen, Assessing Industrial Power Plant Operations & Controls, 2003)

Both of the steam generators are swing boilers providing industrial process power and hence subject to large variations in steam demand. As can be seen, boiler ‘B’ controls the flue gas O2 content accurately, along the load based setpoint curve. The O2 readings of boiler ‘A’ have a lot of scatter, suggesting that the combustion air controls could be improved significantly (Immonen, Assessing Industrial Power Plant Operations & Controls, 2003).

Benefits of Automatic Excess Air Control

Based on findings from numerous improvement projects and assessments, the typical potential reductions in flue gas O2 range from 0.5% to 2.0%. To estimate the fuel savings, a rule of thumb could be used stating that one percentage-point drop in O2 improves the boiler efficiency by 0.5 %. More accurate estimates require boiler combustion and energy balance calculations. The actual cost reductions depend on the boiler size and the fuel cost, and the range of savings can be wide. The documented annual savings from recent industrial power plant projects were between $30,000 and $200,000 per boiler.

Reduction of furnace excess air can yield a 3% to 5% improvement in heat rate in some older PC steam plants. These gains are typical for plants in which operators spend much time in manual control of air flow to avoid opacity excursions. High opacity means that the exit gas exceeds limits on the total suspended particles (TSP).

Lower excess air can also provide other benefits. The induced draft fan capacity often limits the combustion of other fuels such as waste or biomass. With excess air controls, the overall air demand is lower, so the waste fuel throughput may be increased, thus decreasing expensive fossil fuel usage. The associated savings can exceed those from the efficiency improvements.

Steam Temperature Controls

As firing rate and steam flow decrease from the design full-load conditions, the main and reheat steam temperature tend to decrease, which results in reduced turbine cycle efficiency (according to Carnot cycle theory at the start of this module) For an acceptable efficiency across a wider range of loads, most boilers are designed to maintain steam temperature over a specified load range. The ‘control point’ is the lowest point at which design temperature steam can be produced, typically 60% of the maximum continuous rating (MCR) (Black & Veatch 1996) p.192. Some boilers cannot achieve full superheat at lower loads, and in such cases the temperatures may not improve through better controls. By means of more accurate boiler steam temperature control, it may be possible to reduce temperature variations, and thereby apply a higher temperature setpoint.

Higher steam temperatures have a significant effect on heat rate by improving the fundamental thermodynamic efficiency of the heat engine. These improvements are quantified in the section on **Energy Efficiency Potential of Power Plant Automation**.

Steam Attemperation Concepts

This section is adapted from an ABB Application Guide, (ABB Inc. Plant Automation 2006)

The primary means of controlling main steam temperature is by injecting feedwater sprays into the superheater line, known as ‘attemperation’. The attemperation water, which is 2-5% of the total steam flow, may come from the boiler feedwater pump outlet, or further downstream, just before the economizer inlet. The water is typically sprayed prior to the secondary superheater, as shown in the figure below. From an energy efficiency standpoint, attemperation would be more effective and require lower flows if sprayed further downstream. The risk of water damage to the turbine, however, requires that water have time to mix and evaporate thoroughly before entering the turbine.

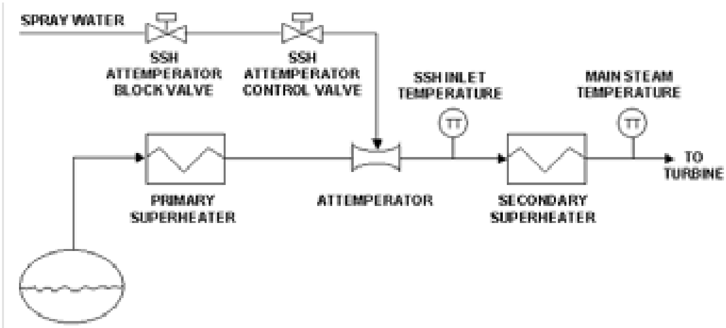


Figure 5.12 – Steam temperature control diagram, (ABB Inc. Plant Automation, 2006)

Attemperation flow may also be tapped directly from a special outlet within the main feedwater pump (IEA Coal Online - 2, 2007). Bypassing feedwater heating has a negative impact on cycle efficiency. See the Pump sections for discussion on the pump power requirements for these two alternatives.

Other means to control steam temperatures are; tilting burners away from the superheater tubes, using bypass dampers in the back-pass or convection portion of the unit (larger boilers that include these dampers can have 12 or more each of the superheat and reheat dampers), or using flue gas recirculation (FGR) to moderate combustion. These methods are typically used for longer-term adjustment (Babcock & Wilcox 2005) compared to the quick action of spray attemperation to provide control of transients. Attemperation flows can be eliminated on supercritical boilers by controlling the firing rate to match the feedwater flow (IEA Coal Online - 2, 2007).

Advanced Steam Temperature Control

Steam temperature excursions are a result of an imbalance between the heat added to the steam by the firing rate and the heat withdrawn, by the steam flow rate. An advanced control strategy will control steam temperature for a drum boiler operating in either constant or sliding pressure mode. Specific algorithms and techniques used by the advanced control strategy include:

- The use of enthalpy calculations to determine the different SSH inlet temperature set points when operating in a variable pressure mode.
- The use of anticipatory logic to account for changes in the boiler energy storage.
- The use of an internal model controller (Smith Predictor) to accommodate for long process time delays (dead time) and lags.
- The use of adaptive tuning to provide controller sensitivity adjustment.
- Advanced Model-Predictive controls can be applied, as part of an overall cycle control optimization

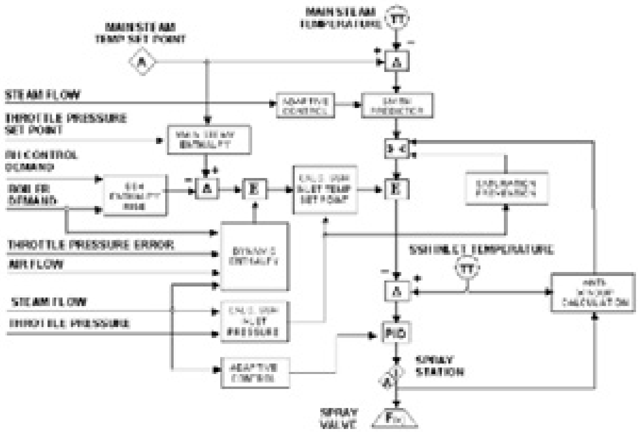


Figure 5.13 - Advanced Steam Temperature control system logic, (ABB Inc. Plant Automation, 2006)

In units with bypass dampers for heat or re-heat temperature control, the accuracy of the control can be improved by using high-torque electric drives for positioning. One problem inherent with these particular dampers is their constant exposure to high-temperature corrosive gases and high levels of fly ash. In time, most of these dampers experience increasing stiction and eventually will degrade into limited range of motion or completely frozen states. See the section **Dampers and Louvers** for more details on these actuators. Upgrading to 'intelligent' drives with built-in diagnostic capability can provide an early warning of damper stiction problems and allow for proactive maintenance on the damper mechanism. Properly operating superheat and reheat damper drives mitigate attemperator spray flows and ash build up, in turn reducing both sootblowing and periodic maintenance in this section of the boiler. Both produce reductions in controllable losses, which improves plant heat rate (Vesel 2007).

Benefits of Advanced Steam Temperature Control

The benefits of advanced steam temperature control are:

- Improved temperature control on process transients caused by changing load, sootblowing, starting and stopping of mills in service
- Improved steady state temperature control when operating under conditions of reduced pressure, slagging.
- Faster ramp rate
- Improved steam temperature control will also reduce the need for attemperation, which improves plant heat rate. (Ferrer, Small-Buck Change Yields Big-Bang Gain, 2007).
- Provides design flexibility to control main steam temperature on drum boilers in either a fixed or variable pressure operation.

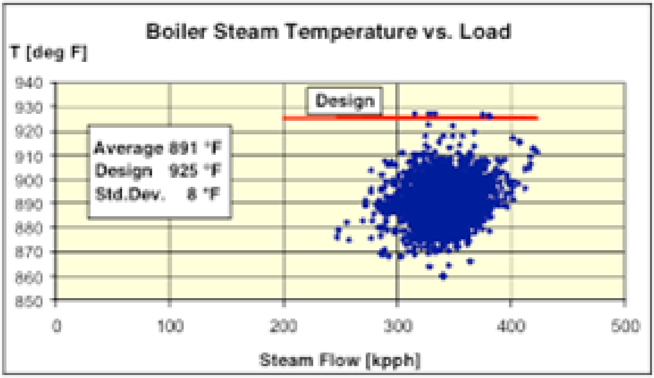
– Avoiding unscheduled outages for superheater tube failure

By means of more accurate boiler steam temperature control, it may be possible to reduce temperature variations, and thereby apply a higher temperature setpoint. The benefits of the higher temperature include increased generation of backpressure power, better condensing power efficiency, and reduced steam use by the drive turbines, all due to the higher steam expansion work available in the turbines (Immonen, Assessing Industrial Power Plant Operations & Controls, 2003). Operating with higher energy content steam allows specific steam consumption to be reduced, with consequent reduction in auxiliary boiler feed pump power.

Case Example
U.S. pulp and paper mill

An example of steam temperature increase potential is shown in Figure below (Immonen, Assessing Industrial Power Plant Operations & Controls, 2003). The steam temperature is shown as a function of the boiler load, to reveal possible load dependency. As load dependent behavior is not obvious in the example, the temperature variations may be attributed to poor control. The standard deviation of the temperature was found to be 8 °F (5 °C), while the average temperature was 34 °F (19 °C) below the design. Therefore, the operators tended to maintain a safety margin of 4 times the standard deviation between the maximum and the temperature setpoint.

By means of better control, the standard deviation could drop to one half, or 4 °F (2.3 °C). By using a commonly accepted safety margin of 3 times the standard deviation, the average temperature could be increased to 913 °F. At this U.S. pulp and paper mill, savings were available from increased backpressure power generation, replacing approximately 0.8 MW of more expensive purchased power. While the annual savings here were approximately $130,000, the range of savings can be wide, anywhere from $20,000 to $300,000 per year, or beyond, on relatively small power boiler systems.



Case text and figure provided by: (Immonen, Assessing Industrial Power Plant Operations & Controls, 2003)

The following calculation case quantifies some of the benefits of advanced steam temperature control:

Calculation Case
Advanced Steam Temperature Control System

This calculation assumes a 500 MW unit with an initial ramp rate of 5MW/min and a main steam temperature set point of 1000 ºF. The fuel savings realized from the initial assumptions are threefold: 1) increasing the main steam temperature set point to its design value of 1005 ºF thus, improving the unit heat rate 2) improving the ramp rate to 10 MW/min thus, reducing the need to purchase power and 3) reducing the number of unscheduled boiler outages as the result of superheater tube leaks. Total fuel savings in excess of $600,000.00 per year is possible with the Advanced Steam Temperature Control System. The calculation of the fuel savings is as follows;

1. Increasing main steam temperature to design;

Main Steam Temp Improvement: 5 °F (2.8 °C)
Unit capacity: 500 MW @ 80% capacity
Fuel Cost: $1.75/MBTU (1MBTU = 1055 MJ)
Main Steam Temp Dev Value: 1.5 BTU/(KWH °F)
Annual savings = (1.5 BTU/(KWH °F) x (5 °F) x (1.75 $/MBTU) x (500 mw x 0.8) x (24 HR/DAY) x (365 DAYS/YR) = $46,000/YR.

The following non-energy efficiency benefits are significant and are quantified below:

2. Improving the unit ramp rate to 10 MW/min;

MWHR/ramp: 18.75 MWHR/ramp
Purchase power penalty: $20/MWHR
Number of ramps per year: 250
Annual savings = (18.75 MWHR/ramp) x (250 ramp/YR) x (20 $/MWHR) = $93,750/YR

3. Avoiding unscheduled outages for superheater tube failure;

Unit capacity: 500 MW
Purchased power penalty: $20/MWHR
Unit downtime per tube failure: 100 HR
Number of tube failure per year: 0.5
Annual savings = (500 MW) x ($20/MWHR) x (100HR) x (0.5/YR) = $500,000/YR.

Case text and values provided by: (Immonen, P., ABB Inc. Plant Automation, 2006)

Burner Management Systems

The burner management system is mainly a protective system to ensure safe operation, startup and shutdown of the burner equipment. Emergency shutdown occurs when high levels of unburned combustibles are detected. Monitoring of the burner performance is by flame scanner, which measures the flame quality. These systems are also collectively known as 'boiler protection systems'.

Burner Controls

The goal of burner controls is maximum burnout of pulverized coal, but with minimum NOX emissions. An advanced burner control system can initiate staged combustion, biased firing or fuel-nozzle tilt (in tangential firing) to adjust the furnace exit gas temperature (FEGT) with load changes, varying fuels or in relation to the state of the furnace wall (as in dirtiness). This allows the superheater or reheater outlet steam temperature, or NOx production in the furnace, or both, to be controlled. Although closely related to burner management, the Pulverizer Controls are discussed in the **Fuel Handling** section.

Boiler Startup and Protection

Automation systems using a nonlinear, model-based multi-variable controller can automatically calculate optimum startup strategy for steam generators. The goal of startup optimization is to optimize fuel consumption and time during the boiler startup process without exceeding the maximum thermal ratings of critical system components.

Boiler Startup Optimization

(This section is adapted from ABB AG Power Technology brochure for E.ON Ingolstadt plant, 2007)

Operating and monitoring are done using the regular process control facilities, as in the figure below showing the functional principle of a startup optimizer. During a startup procedure, the actual values which are cyclically scanned, for temperatures, pressures and steam mass flow rates, are used for adjusting a physical unit model. Based on this nonlinear model, the optimization program applies its predictive optimization routines to the rest of the startup procedure. The resulting startup curves computed on-line are then integrated into the existing unit control concept, serving as corrective setpoint biases. The prediction horizon is 60 to 90 minutes, thus covering the entire length of a boiler startup up to the point where the turbine is rolled on steam. This way the most cost-efficient path overall to reach online operation can be computed. The predicted data is updated every one to two minutes, thus enabling an adequate response to disturbance conditions.

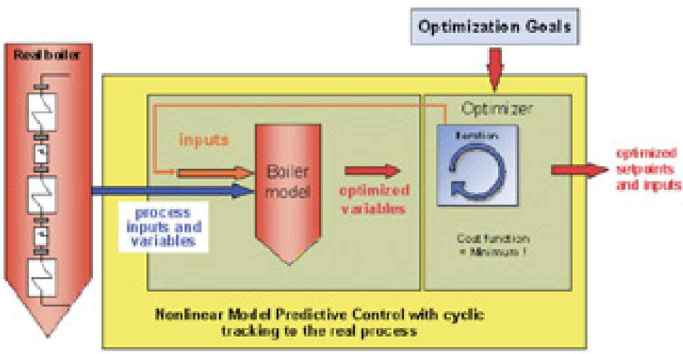


Figure 5.14 – Boiler startup optimization model dada flow., ABB AG Power Technology, 2007

Independent of the cost savings realized, the model-based multi-variable controller also enables a predictive integration of thermal stress data into the closed control loop. The level of flexibility – e.g. covering different unit downtimes – is improved as the physical model is continually adjusted to match the current state of the plant. Moreover, the startup can be adapted to changing basic conditions, such as different fuel costs or maximum permissible loads, by modifying the target function and optimization constraints, respectively.

Benefits of Boiler Startup Optimization

With model-predictive startup optimization, it is possible to run each startup using less fuel, while reducing the usual startup time and stress loading on critical thick-walled components. The savings realized through online optimization are generally within 10 to 20 percent of the normal costs of fuel and auxiliary power, for each power plant startup. Startup times can generally be reduced by increasing the loading of critical thick-walled components or by better exploiting the margins through more homogenized thermal loading. Applying predictive startup optimization in order to reduce the startup time is advisable if the permissible heat-up stress margin is not fully exploited, or if the load is distributed unevenly during startup.

Energy efficiency improvements come from reduced startup fuel burned and/ or shorter startup times. Startup automation with optimization also leads to more consistent startups and lowers the risk of an aborted startup, with the consequent loss of input energy. Coal-fired power plants offer high additional savings potentials, provided that it is possible to shift from startup fuel to coal at an earlier point.

Energy savings accumulate for units in cycling duty. In particular, in the case of frequent brief standstills, when numerous startups are run under similar conditions, the spread of startup costs is obviously reduced. On average, the use of startup optimization results in a significant reduction of startup costs. Even in the case of brief standstills, startup costs can be high, as a high live-steam temperature has to be built up to approach the still high temperatures in the turbine. Taken together, the above improvements increase efficiency by approximately 1% during startup, and also decrease emissions values.

Case Example
Boiler Startup Optimization

The figure below shows a comparison of two startup procedures in the Ingolstadt power plant, unit 4: with BoilerMax (bold lines) and without BoilerMax (thin lines). The upper diagram shows the fuel quantity F_F and the HP bypass position Y_HPB. The diagram in the middle shows the live steam flow F_LS and the generator output P_Gen. The diagram at the bottom shows the temperature differentials DT_SH4H and DT_SH5H occurring in HP headers of the two last superheater levels.

The diagrams show that it was possible to run a similar boiler startup while realizing an approximate 20% reduction of fuel consumption. Such fuel savings are possible, since the steam flow used for starting-up can be decreased by simultaneous and coordinated reduction of the opening of the HP bypass station. In addition, the startup time is slightly reduced.

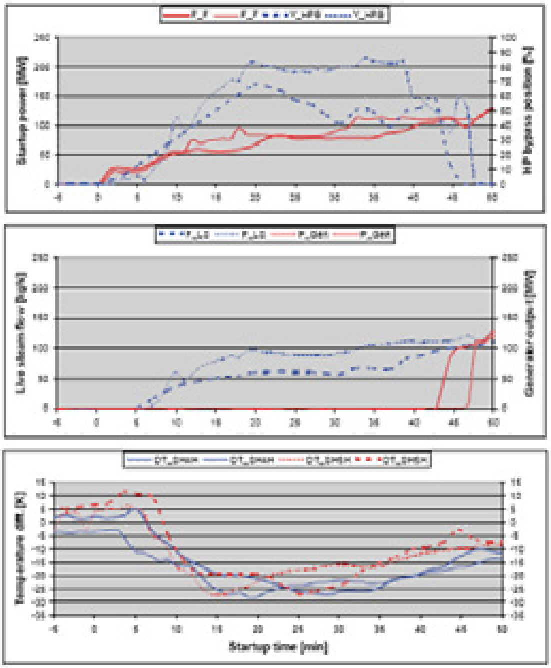


Figure 5.15 – Comparison of two startups with model-based startup optimization. (shown in the heavier dashed and solid lines) and without (thinner lines) ABB AG Power Technology brochure for E.ON Ingolstadt plant, 2007

Emissions Controls

Emissions Concepts

The flue gas contains particulates and other products of combustion which must be cleaned to levels required by environmental regulations (in the USA, these are given by the Clean Air Act Amendments, CAAA). Particulates are removed by electrostatic precipitators (ESPs) or fabric filters.

Sulfur dioxide (SO2) is removed by one of the various flue gas desulphurization (FGD) processes. The wet scrubber process using limestone as the sorbent is the most widely used method. NOx production can be controlled in-furnace by low-NOx burners, air staging, and the use of a re-burn fuel in the upper part of the boiler. NOx can also be removed by injection of ammonia or an ammonia- based compound into the combustion products, with or without the use of a catalyst, processes known as selective catalytic and non-catalytic reduction (SCR or SNCR) (IEA Coal Online - 2, 2007).

Flue Gas Desulfurization (FGD)

One way to limit extra auxiliary loads associated with FGD is to switch to fuels lower in sulfur. The EPRI CQIM model described in the section on **Fuel Handling Systems** provides estimates for the amount of auxiliary power required for different coal types.

Methods to improve the contact between the limestone slurry and the flue gas improve absorption will serve to reduce the auxiliary drivepower required for circulating pumping. Innovative methods using open-spray tower absorbers may reduce auxiliary loads by up to 1% of total generation (Sayer, 1995).

Seawater's alkaline composition enables it to absorb SO2. Seawater FGD scrubbing may be one of the lowest energy alternatives, where environmental agencies grant approval. 'Most Recent Developments and Optimization Aspects for FGD Technologies' Dr. W. Schüttenhelm et al, Power-Gen Europe, Barcelona, Spain, May 25-27, 2004. Seawater FGD techniques eliminate the need for slurry injection and recycle pumping. Dry FGD processes may offer lower auxiliary loads, but with a lower SO2 removal rate (Sayer, 1995). The gypsum or sulfuric acid byproducts of FGD processes can be sold to other industries, which may change the cost-benefit comparisons.

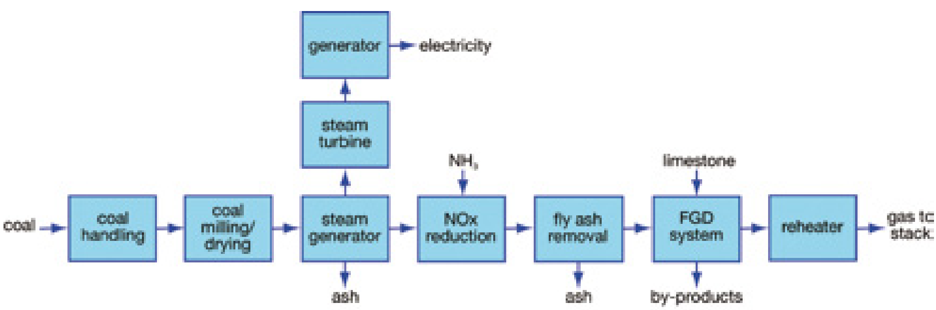


Figure 5.16 – Flow diagram of a typical supercritical PC plant with pollution control (cited in IEA Coal Online - 2, 2007) Rousaki and Couch,2000)

NOx Emissions Reduction

NOx emissions reduction technologies typically involve burner modifications and do not directly add to the plant's auxiliary loads. A NOx conversion which causes increased boiler firing rate instability under upset conditions, however, may lead to a 1-2% increase in heat rate (Ferrer, Small-Buck Change Yields Big-Bang Gain, 2007).

In units equipped with Selective Catalytic Reduction (SCR) equipment, NOx is absorbed by ammonia within a reactor vessel located in the flue gas stream. In addition to reagent pumping drive-power, the pressure drop across the catalytic reactor requires greater ID fan power, bringing the total added SCR auxiliary load to 1% to 1.5% of total generation capacity. The SCR equipment is typically located between the economizer and the air heater. However, in some designs the SCR vessel is located further downstream, after the electrostatic precipitator (ESP). This configuration requires energy to reheat the saturated flue gas to the required reactor temperature, typically 600 ºF (316 ºC) (Babcock & Wilcox 2005). When this energy is provided from auxiliary power, it increases the total SCR system auxiliary consumption to values typically 2.5% of total generation (Sayer, 1995). Other designs bypass some flue gas around the economizer to provide this energy, which also reduces the thermal efficiency of the unit.

Particulate Emissions Control

Fuel ash and unburned carbon particles from coal and oil-fired plants are traditionally removed by electrostatic precipitator (ESP). ESPs have low pressure drop in the flue gas stream and use relatively low electrical power, but the size and power requirements increase as particle size decreases, giving an average auxiliary power consumption of 0.25% of total generation (Sayer, 1995). The alternative (and possibly complementary) methods to ESPs, using fabric filters in ‘baghouses’, works well at capturing fine particles but at the cost of a larger pressure drop and higher fan power, bringing total auxiliary power to 0.35% of total generation. The fly ash collected by these systems can be sold and used for more productive purposes than landfill, which may change the cost-benefit comparisons.

Drivepower Potential for Energy Efficient Design

Emissions control devices add pressure drops to the flue gas stream and significantly increase the requirement for ID fan power, often necessitating installation of a flue gas ID booster fan. Additional drivepower is needed for limestone slurry-feed, absorbent circulation pumps and oxidation air compressors, and the electrostatic precipitator is also represents an auxiliary electrical load. The proportion of plant generating capacity consumed by emissions control systems varies with the degree of emissions reduction:

3% to 5% for reducing up to 90% of sulfur dioxide emissions from coal-fired plants
0.5% to 2.5% for reducing nitrogen oxide emissions up to 80% from all fossil-fired plants
0.5% to 1.5% for controlling particulate emissions from oil and coal-fired plants

The cumulative incremental power consumption for emissions control may be up to 9% of gross generating output (Sayer, 1995). The increased auxiliary load also increases plant net heat rate and the amount of CO2 emitted per generated MWh.

Flow control through use of VFD speed control can reduce pump and fan auxiliary power by 75% at low loads, and will correct for oversizing at full loads, reducing power by 15%. Efficient motors and drive-trains can further reduce power by 5%. A peaking plant that applies the suggested drivepower improvements can substantially reduce the unit auxiliary load.

{Note that gas-fired plants, on the other hand, may only require 1% of generating output for reducing nitrogen oxides (C.P.Robie,P.A.Ireland, for EPRI, 1991), and newly available low NOx combustors and burner tuning methodologies can completely eliminate post-combustion NOx treatments.}

Automation Potential for Energy Efficient Design

A low-capital cost technology to complement low-NOx burners is improved combustion control. Using the automation techniques of co-coordinated boiler-turbine control and advanced realtime control of burners, air flow and gas recirculation can reduce NOx emissions without any increase in auxiliary power. See the section on **Excess Air Control** for details on reducing NOx using control techniques. Continuous monitoring of flue gas is vital for low-NOx burner or combustion methods due to the risk of higher levels of unburned carbon and CO emissions; see the section on **Instruments and Actuators** for more details on analytical devices.

Automation for stabilizing firing rate after a low-NOX burner conversion can also reduce heat rate. Combustion Optimization Solutions (COS) use model-based predictive control techniques to reliably find the most suitable setpoints for improving the heat rate and reducing emissions like NOx. Every ton of NOx production that is avoided during the combustion process, is eliminated from the cost of NOx mitigation or from offset credit purchase requirements. The value of this ranges from $1500 to $3500 per ton at current (2009) pricing.

Automation through intelligent flow control in open-spray FGD systems is an important criterion for the effectiveness of the system. Particle capture in baghouses is directly related to the pressure drop; controlling this through fan speed may increase effectiveness over a wider operating range.

More advanced powering systems may also help improve the effectiveness of ESPs through variation of voltages and polarities. Further advantage may be gained through coordinating ESP and fan flow control for optimum particulate removal at lowest power consumption. Precipitators and bag filters are not required to work at maximum capacity when the plant works at partial load.

Automation allows these emissions control systems to be coordinated with the boiler-turbine controls. Feedforward and adaptive tuning will make the emissions systems respond more intelligently to loads. Integration will allow these systems to participate in plant wide optimization using model-based techniques, The multi-variable capability of model-based control allows the auxiliary ID or booster fan drive power and steam extracted for cold-side SCR can be optimized together with the combustion process, FD fan for any given plant load and coal quality.

Condenser Systems

Figure 5.17 – Condenser cooling system towers, (ABB Ltd., Power Generation Unit, 2006)

Condenser System Concepts

Condensing steam from the exhaust of the turbine into liquid allows it to be economically pumped to boiler pressure, at much lower energy than if it were still in gas phase. Condensing returns the working fluid to the starting point on the thermodynamic cycle, and lowers the turbine exit back pressure and draws steam flow through the turbine. The coolant can be either water or air. Power generation in the US uses 132,000-million gal/day (500 million m^3/day) of freshwater – about 39% of the country's total freshwater usage. Approximately 98% of this water is for once-through cooling (OTC), and therefore is returned immediately to its source (Power Magazine, R. Swanekamp, 2002).

Demand for Auxiliary Drivepower

Due to long-standing environmental regulations for thermal discharge which require an exit temperature of the cooling water that is fairly near to the temperature of its source, once-through cooling systems are no longer feasible. This restriction has led to more closed-loop and air-cooled systems with forced draft towers. A revision to US regulations is expected which may allow once-through cooling systems in some cases, and a substantial increase in cycle efficiency. In all cases, auxiliary power is needed to drive pumps or fans to circulate the cooling media. The main auxiliary drivepower loads are circulating water pumps and cooling tower pumps and fans.

In water-cooled systems, the amount of condenser cooling water required is approx. 0.35 to 0.75 GPM (1.3 to 2.7 l/m) per kW of generating capacity. An approximate figure for power required to circulate this water is 10hp (7500 W) per MW of generating capacity.

In air-cooled condenser designs, the exhaust steam flows through finned tubes and ambient air is pushed through the fins with the help of a large fan. Air-cooled condensers typically operate at a higher temperature than water-cooled versions, which reduces cycle efficiency. An approximated rule of thumb is that for every ten deg-F increase in condensor temperature, there is a 2% heat rate increase.

Drivepower Potential for Energy Efficient Design

Lowering the temperature of the coolant will directly improve the plant heat rate. The condenser efficiency improvement potential is large, given that condensing 'wastes' half of the input heat energy in the cycle.

Location is an important factor in the configuration of the condenser system, as is the design of the LP turbine and the condenser hardware. The condenser is the plant unit most affected by seasonal temperature variations, which have an impact on the thermal efficiency of the entire cycle according to the rules of thumb in **Parameters for Increased Thermal Efficiency**.

Applying the principles from the drivepower module will result in high-efficiency, speed-controlled cooling water pumps delivering cooling effect at a lower pumping power over a broader range of flow. The reduced auxiliary load will lower the net heat rate. The favorable economics of efficient circulation may prompt higher flow designs to deliver more cooling and therefore a reduced heat rate due to improved thermodynamics.

Drivepower demands in air-cooled systems can be further reduced through use of high-efficiency components. Fans with aerodynamic improvements can give up to 80% savings and may be relatively easy to retrofit. Larger cooling tower cross-sections equipped with larger fans using Low Face Velocity (LFV) designs will use much less power, according to the fan affinity laws described in Fan Power and Energy Efficiency.

Adding a micro-mist to the inlet air can provide additional evaporative cooling effect, up to 15 ºF (8 ºC) in some industrial scale systems (RMI, 2007) High-quality, right-sized motors combined with VFD for flow control as described below can yield a combined energy saving of up to 80% of electrical power when running at half-speed. Some of these high-efficiency technologies for air-cooled systems are illustrated in the figure following:

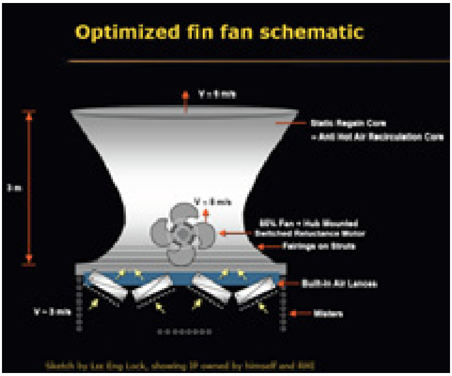


Figure 5.18 – Optimized fin fan schematic, Rocky Mountain Institute, 2007)

Multiple cooling towers each with one or two speed fans are usually brought online individually to handle changes in unit load. Operating all available towers in parallel, each equipped with VFD for fan speed control, provides much improved energy efficiency. This latter design maximizes the surface area for heat transfer and minimizes the fan's electrical drivepower requirements (Rumsey, 2003).

Automation Potential for Energy Efficient Design

Improved and integrated control of condenser coolant systems can provide some surprising efficiency gains. As with other power plant systems, correct and adaptive tuning will allow the condenser coolant systems to deliver at optimum efficiency over a wider range of ambient coolant temperatures and plant loading.

Model-based optimization techniques may also be useful to determine the most efficient cooling water/air flow rates given the increased pumping power - see the case description in the box text below. Automation can also be used to reduce the auxiliary load of these large circulating systems by optimal cycling of the pumps throughout a range of unit operating conditions. Pump system efficiency can be further increased by using constant speed motors for primary pumps, but equipping the secondary pumps with VFDs for trimming flow control.

For cycle designers, it may be useful to think of the LP turbine as a source of steam heat for a combined heat and power plant, even if the heat is only to be used in-plant. Using the steam productively may increase backpressure, but this again is an optimization problem that can be solved using the techniques described in previous sections. Some applications for in-plant CHP are the HVAC system, and fuel drying or pre-heating; these options are explored in the module on **High Performance Design**.

Case Example

Maasvlakte 540 MWe coal-fired plant in the Netherlands

For the Maasvlakte plant in the Netherlands, thermodynamic modeling showed that there was a different optimum flow-rate depending on the temperature of the cooling water (which varies at the plant's location from 1°C to 20°C). At 4°C, the optimum flow rate was 12.2 m/s, while at 20°C it was 18.8 m/s. Results from this modeling exercise were confirmed by actual plant data. An average reduction in the condensor cooling-water temperature from 20°C to 15°C at this plant reduced the heat rate by almost 1%.

(Case data from Kromhaut and others, 2001, and cited in (IEA Coal Online - 2, 2007)

Automation's monitoring functionality can be used to continually check the condenser's heat exchanger performance. The most-common causes of condenser inefficiency are: microbiological growth on the water side, scale formation on the water side, tube pluggage by debris and air in-leakage on the steam side (Buecker, B. of Burns and McDonnell Engineering, Chemical Engineering; Vol. 102; Issue 4, Apr 1995). Online monitoring, combined with modeling of these fouling phenomena can be coupled with a pro-active treatment program to keep the condenser at peak design efficiency.

Condensate System

Condensate System Concepts

The purpose of this system is to collect the condensate (boiler feedwater) leaving the condenser, remove non-condensable gases, raise its temperature through a series of feedwater heaters and then deliver it to the deaerator for additional heating and temporary storage. From the deaerator, the feedwater goes to the boiler feed pump where it is pumped up to near boiler drum pressure at the inlet of the economizer.

Increasing the boiler feedwater temperature effectively increases the upper temperature of the thermodynamic cycle, raising the efficiency. Heating the feedwater using steam extracted from the turbine stages is more thermodynamically efficient than using other nearby sources, such as fuel in the furnace. Up to 30% of steam may be extracted for this purpose, typically at a intermediate and high turbine pressure stages. Designs with higher steam pressures allow a greater number of extraction points and hence greater number of heaters in the 'train'.

Demand for Auxiliary Drivepower

This system's main requirements for auxiliary drivepower come from the condensate and booster pumps. The relatively low-power vacuum pumps are not considered in this discussion. The condensate pump is a low suction head extraction pump which must deliver sufficient discharge head to overcome pressure drops through several feedwater heaters. A booster pump is also sometimes used after the de-aerator to raise pressure to a level sufficient for flow through the high-pressure feedwater heaters. The power demand and control of the main boiler feedwater pump is discussed in the **Feedwater control** section.

Drivepower Potential for Energy Efficient Design

The general case for efficient condensate pump drive power is made in section on **Pump Systems**.

Automation Potential for Energy Efficient Design

Although not strictly 'auxiliary' systems, the feedwater heaters (heat exchangers) and de-aerator's energy efficiency could benefit from continuous monitoring at inlets and outlets for early indication of plugging or fouling problems.

It is almost always more thermodynamically efficient to add another feedwater heater; Welford and others (2002) cited a 0.15 percentage-point efficiency rise for the whole unit through an increase of 20°C (36 ºF) in the final feedwater temperature. (IEA Coal Online - 2, 2007) Reliability and cost issues, however, often limit the total number of heaters; a total of 6-8 heaters is typical. For a small increment in cost, the feedwater heater's reliability can be increased by adding instrumentation and **continuous on-line condition monitoring**. Such extra reliability may favor an additional feedwater heater and be justified by the resulting increased cycle efficiency. One new approach to feedwater heating involves the use of on-site solar equipment to provide thermal energy for feedwater heating during the days peak demand hours.

The steam bypass valves can also benefit from condition monitoring. The enthalpy drop across these valve is large. Valve leakage can be detected by instrumentation on the downstream side of the bypass line. Similar monitoring can be installed on steam traps in all bypass lines. Valve functionality can be continuously monitored for stiction and other control problems which lead to unnecessary loss of steam energy. In a poorly maintained system of steam traps, annual energy losses can easily reach six figure costs.

The model-based optimization techniques developed for combined heat & power (CHP) systems may be applied to feedwater heater train and de-aerator system to achieve the optimal balance between use and production of steam, and allocation to the most efficient heaters (or other users). Such a control strategy could improve the off-design performance of the system, especially at lower-load operation. In industrial boiler systems, the de-aerator and other components with an inventory of steam or water may be used in a steam-leveling strategy to absorb process load swings and increase efficiency (Immonen, Assessing Industrial Power Plant Operations & Controls 2003).

In some units, peaking power supply is achieved by deliberately taking one or more of the top feedwater heaters out of service (Babcock & Wilcox 2005). This practice allows more steam to pass through the turbine, but at a significant cycle energy efficiency penalty. According to EPRI Report CS 4554, taking one top (high-pressure) feedwater out of service increases the heatrate by 94 BTU/kWh, which corresponds to a 1% drop in efficiency in a typical PC unit.

Sometimes efficiency is temporarily sacrificed for higher ramp rates, as described in the following case text; the control strategy for faster ramping temporarily shuts off the flow to one or more LP feedwater heaters. Operators must be made aware that protracted operation in this mode will significantly increase fuel cost and emissions.

Case Example
Schwarze Pumpe, Power Plant, Germany

Schwarze Pumpe in Germany provides an example of large, flexible PC units where two 800 MWe supercritical lignite-fired boilers have been designed to operate at sliding pressure to down to 40% output, with high rates of change, and short hot start-up times. A dynamic control system covers the whole plant, including firing and emissions control as well as the steam cycle. A 6% load change per minute is achievable at Schwarze Pumpe with only minor effects on the main steam and hot reheat steam temperatures, and without turbine throttling or using the storage capacity of the boiler.

Very rapid ramping (for example, by 50 MWe in seconds) requires the use of a degree of steam reserve and temporary changes in feedwater heating. Temporarily diverting steam away from feedwater heating so that more passes through the later turbine stages will have a very negative effect on efficiency in the short term, but this matters less than meeting demand over these transient periods.

(Case text provided by IEA Coal Online – 2, 2007)

Fuel Handling Systems

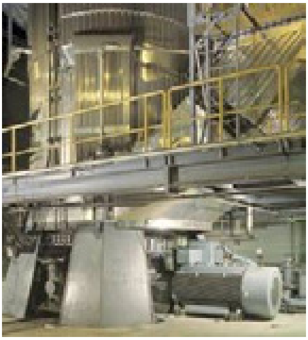


Figure 5.19 – Coal pulverizer with motor, (ABB Motors, 2006)

Fuel Handling System Concepts

Fuel handling involves all the processes needed to prepare the raw fuel for mixing with air and injected into the furnace through burners for combustion. There is a great variety of fuel handling methods, depending on the type of fossil fuel being used. Coal is the most complex fossil fuel, with many compositional and hardness variations, and is this fuel which is the focus of most of this section. Also, because it is a solid, mixing this fuel with air is more problematic compared to gaseous or liquid fuels (Black & Veatch 1996, p.182). The main preparation processes for coal are crushing, drying, and milling, also known as pulverization.

Demand for Auxiliary Drivepower

The main fuel handling demand for auxiliary power in coal plants come from crushers and pulverizers/millers, and the primary air system which heats and conveys the fuel to the burners. The CQIM Coal Quality Impact Model developed by Black & Veatch for EPRI evaluates the total cost (not just delivered cost) due to alternative fuels. One of the 5 main CQIM impact areas is 'Auxiliary Power Requirements'. Changes in auxiliary power are calculated for each fuel variant, and these are related to amount of lost generation and increased fuel burn rate. Note that the CQIM model includes draft fan and other auxiliary loads in addition to those directly involved in coal fuel preparation.

The heating value of coal is given in BTUs per pound, or kilojoules per kilogram (10000 Btu/lb = 23200 kJ/kg). Coal can range from 3500 Btu/lb (culm or waste coal) to 15,000 Btu/lb for dry prime hard coal. Many auxiliary systems must still run and consume drivepower, regardless of the energy (BTU) content of the coal. These systems include fuel handling, ash handling, draft fans and flue gas emissions control equipment. Coal with lower heating values will therefore use a higher percentage of auxiliary power for each unit of converted energy. Also, coals with higher sulfur content will require increased auxiliary power to drive FGD processes.

Drivepower Potential for Energy Efficient Design

The flow control design guidelines described in the drivepower module showed how speed control is most efficient at less than full rated speeds. The 'bypass' method for speed control still used in some coal milling operations is therefore a candidate for design improvement by applying VFDs for speed control.

Case Example
Milling Applications: VFD drive instead of Bypass

In a boiler installation, 20 coal mills with a drive output of 710 kW each are used. A speed-controlled drive with a control coupling or with an AC drive is used to replace the bypass method. The possible saving with a control coupling is about 11 GWh and with an AC drive 23 GWh as shown below. (For a description of bypass flow control, see **Pump Flow Control Methods**)

- Energy saving: 23,000 MWh/year
- Reduction in CO2 emissions: 11,500 metric tonnes/year
- Better boiler control with fewer losses
- Crushing wheels of the mills last longer
- Payback period 2.5 years

(Case text from ABB Drives, 2007)

Pulverizer Applications

In order to accommodate the larger range of operation asked of plants today, as described in the section **Plant Operating Modes**, the designer should consider specifying more, but smaller pulverizers rather than fewer, larger ones. The full load fuel flow rates provided by the basic thermal balance will provide the upper limit of combined pulverizer capacity. A pulverizer's capacity loss due to wear will consume more power as grinding surfaces wear; this increase in power consumption should be part of the sizing criteria for pulverizers. It is common practice to include primary air fan power consumption together with pulverizer power. When pulverizer wear is taken into account, one industry estimate of combined power requirement is 22 kWh/ton (24kWh/metric ton) of coal for a load-following unit. (Babcock & Wilcox 2005).

When pulverizers operating at this capacity are in a typical older PC unit with heatrate of 10,000 BTU/kWh, fired on coal with a heating value of 10,000 BTU/lb, they will consume about 1% of the input fuel energy. This percentage increases with decreasing coal heating value, increasing plant heat rate, and increasing moisture content of the coal.

Automation Potential for Energy Efficient Design

Automation which can shut down one or more pulverizers for low load operation should be coordinated with the combustion and steam temperature control systems to avoid instability immediately after shutdown/startup. This simple automation modification saves energy on units with larger boiler turndown, as is the case in units which are being repurposed from baseload to dispatchable or load-following duty. The automation of pulverizer operation within the combustion control system, however, must accommodate the limited turndown capability of individual pulverizers, which can individually operate in stable fashion only down to about 50% of rated capacity'. (Black & Veatch 1996, p.182)

Another potential improvement is to enable online monitoring of the relative flow of coal in the pipes to individual pulverizers. This data can be used by the combustion controls to achieve better balancing of fuel flow to burners in the boiler burner array. Full closed loop combustion control, with coal-flow monitoring and and air/fuel balancing of the the burner array is technically feasible and cost effective at this time, but the industry is very slow to consider, adopt and apply this technology.

Sootblowing Systems

Sootblowing System Concepts

Accumulation of ash and other products of combustion on the heat transfer surfaces will reduce heat transfer and increase plant heat rate. Sootblowing systems typically use steam or compressed air "cannons" to remove soot from boiler tube surfaces and structures. There are also mechanical vibration, and sonic soot remediation systems which fall into this general category. Plants which have switched from their design fuel to other, lower-quality fuels are particularly susceptible to more ash-related problems. If internal boiler combustion levels or distributions are not managed well, large fused-ash accumulations may form, which may eventually break off and fall, damaging boiler and tubes in the process.

Automation Potential for Energy Efficient Design

Soot-blowing automation can determine where and when to blow soot based upon changes in heat transfer data. Precise control of soot-blowing will improve heat transfer and heat rate of the unit. Soot-blowing also has an indirect impact on energy efficiency in two ways: 1) Soot-blowing consumes power in the form of compressed air or steam 2) Soot-blowing causes sudden changes in heat-transfer which may disturb main steam and reheat steam temperature control, causing swings in control action and increased attemperation use.

An automated soot-blowing system using closed-loop control will consume less power than traditional, open loop control based only on time intervals. A system that is integrated with the rest of the DCS can use online measurement data to compute heat flux, which can then be used for feedback control. This control system could be further improved with **MPC** and thermodynamic models and direct readings from strain gauges (Whitworth, XCEL Energy, 2006)

Automation integration between soot-blowing and steam temperature control systems can reduce temperature instability and improve efficiency. When the soot-blowing system described above is ready to act, it can inform the steam temperature control system which may then take feed-forward compensation measures.

Ash Handling Systems

Ash Handling System Concepts

Ash-handling systems must transport the solid products of combustion, mostly ash and unburned carbon, from a hopper in the furnace floor.

Automation and Drivepower Potential for Energy Efficient Design

In PC boilers, bottom ash removal systems consume electrical drivepower, but do not offer the potential for larger energy efficiency gains as the cube-law systems for fluid and air flow.

Hot, yet unburned carbon in the solid combustion products (and possibly from flue-gas dust collection systems as well) may be reintroduced into the furnace to achieve more complete combustion. Further improvement can be gained by auxiliary systems capable of separating the heavier carbon from the remaining lighter materials in the ash mixture. A ‘carbon reinjection’ system can improve the efficiency of coal-fired boilers by 2% to 4% (Babcock & Wilcox 2005); this improvement is not in thermal efficiency, but calculated on the cost basis of primary coal input.

Module 6
Case Studies In Integrative Design

Module Summary

This module defines a base case plant unit and shows the cumulative effects of drivepower, electrical power system and automation system improvements. Capital investment costs and operating costs are also estimated, for the purpose of a lifecycle cost calculation. This case study will attempt to quantify the benefits in many scales: efficiency/heatrate, ROI payback, fuel amount & cost, NOx & CO2 costs, and power generated available for sale.

> The information in this module section is specific to power generation industries or process plants with on-site power houses. Many sections, however, are also broadly applicable to all industrial steam generation processes.

Causes of Energy Inefficiency

This section reviews the energy efficiency issues relating to auxiliary systems in an 'average' facility.

> Power plants using pulverized coal fuel are averaging 30-35% efficiency, compared to 45% and higher for supercritical or combined cycle designs. This very rough comparison provides some indicators as to where one should focus energy efficiency efforts when confronted with an existing plant or when evaluating alternatives to the 'standard design' of a new plant.

Changes in Available Technology

- In older plants; the initial auxiliary designs are now outdated by advances in controls and materials; VFDs for flow control, power electronics for power quality management, transformer designs with new materials, high efficiency motor design, new materials etc.
- In older plants; lack of control integration between plant units, such as turbine-generator and the boiler control system leaves substantial opportunity for automation improvements

Sub-Optimal Design and Engineering

- Oversized pumps and fans waste energy in throttled operation or in low efficiency operating regimes
- Oversized motors and power supply equipment all operating at low efficiency
- Process design & engineering decisions which unnecessarily increase drivepower loads

Aging

- As plants age they become less reliable and generally less efficient due to corrosion, fouling, wear and other mechanical factors. Feed-water heater heat exchangers, cooling tower heat exchangers, and boiler tubes are all examples of equipment prone to these mechanical factors.
- Steam losses through leaks, heat loss through boiler walls, and other energy losses through excessive attemperation, blowdown, or sootblowing.
- Loss or lack of experienced plant engineering and operations staff, loss or lack of as-is plant documentation.

Changes in Operating Conditions

- Changes in fuel supply from what boilers and burner systems were originally designed for, leading to degraded performance.
- Plants designed originally for base-load operation near their rated output now operating below this capacity due to changes brought on by a deregulated and competitive marketplace. Efficiency and response are reduced at lower loads.

Changes due to Environmental Retrofits

- Addition of emissions control equipment such as precipitators, SO2 scrubbers that restrict stack flow and require greater in-plant electric fan drive power.
- Addition of cooling water environmental protection systems that increase the demand for cooling medium flows and thus electric auxiliary drive power.
- Retrofits, environmental and otherwise, without updating of unit controls, leading to unsuitable control behavior and greater instability, especially boiler instability.

The cumulative negative effect of these causes can be witnessed in existing plant's operation even without a benefit of any formal assessment or extensive data analysis:

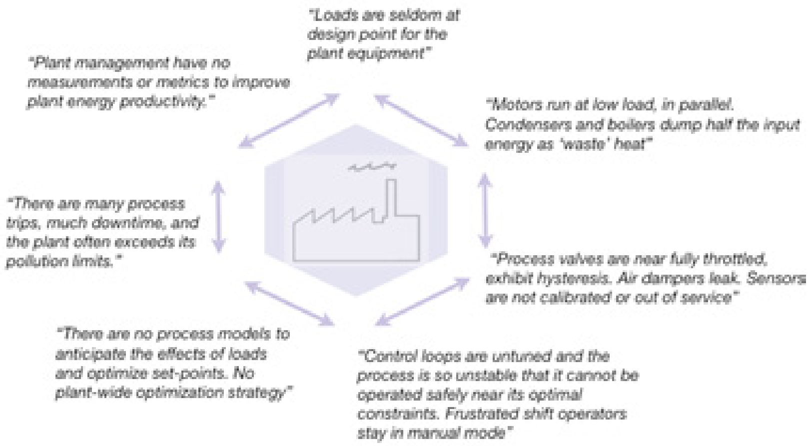


Figure 6.1 –Common indicators of an energy-inefficient plant in operation

Energy Efficiency Design Assessments

Using a systems approach known as 'Integrative Design', much of the plant process and mechanical design will be considered even though the scope of the retrofit may not extend to the boiler or steam cycle (combustion, steam or water path) primary equipment.

This methodology is a type of design assessment, rather than the more widely known and applied 'energy audit' of an existing plant. The focus of this methodology, however, is not on operating procedures or parameter adjustments: these are usually within reach of experienced plant managers. In very simplified terms, an energy audit seeks ways to reduce losses within the constraints of the plant design 'as is', whereas a design assessment uses heat and material balances to provide a higher upper limit to the possible gains from a retrofit.

The Integrative Design methodology does have some steps in common with an operational energy audit: in each, there is a data gathering phase, an analysis phase, a ranking of proposed changes, and then implementation. The ranking of proposed design changes is based on lifecycle cost calculations, tempered by a discussion of such important qualitative factors as compliance, availability and schedule.
The major differences between a typical energy audit and a design assessment methodology are listed in the table below.

Phase	Energy Audit	Design Assessment
Data gathering	Mostly operational data from historical databases, strip charts or testing	Mostly design data ; P&ID drawings, flow sheets, supplier performance data and kits, backed up with operational data.
Analysis	Efficiency calculations	Heat and material balances, and comparison with process models. Pressure drop calculations. Component sizing calculations using iterative approaches.
Proposals	Procedural and small-scale investment	Larger-scale design & equipment changes, automation changes
Ranking	Payback based on short time horizon and solely energy-saving improvements	Payback based on longer time horizon and including other non-energy improvements Ultimate goal is to provide a utility with capacity improvements without having to build new plants.

For power plants, the thermal analysis is the first step in the analysis, as this will provide the basic combustion air, fuel, flue gas and feedwater flow requirements (Babcock & Wilcox 2005). Based on these flows, the major pressure drops may then be calculated, followed by the remaining pipe or duct resistance calculations.

See the section on **Managing Energy Efficiency Improvement** for a discussion of managing both energy and design assessment efforts.

Integrative Design for Auxiliaries

The energy efficiency issues listed in the previous sections are complex and cut across many plant systems. **Integrative Design principles** lend themselves well to improving steam plant designs. Some of the process areas where Integrative Design has been successfully applied are: thermal integration, power systems, designing friction out of fluid-handling systems, superefficient passive or heat-driven (absorption) cooling, superefficient drive systems and advanced controls. (Lovins, 2008).

Integrative Design takes advantage of the fact that efficiencies are multiplicative and not simply additive. For a system with several components in series, such as an electrical drive, a motor, a pump, a pipe, and a valve, the efficiency of the whole system is the product of all the efficiencies as follows:

Esys = Edrive x Emotor x Epump x Evalve x Epipe

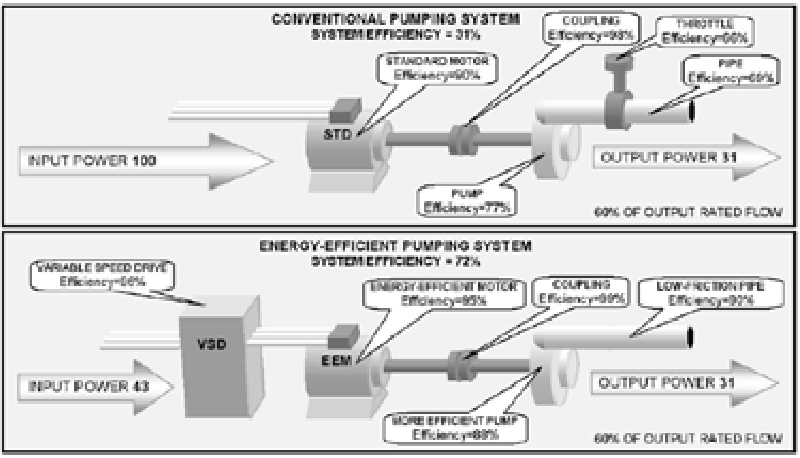


Figure 6.2 – Cumulative efficiency gains in entire pumping system, (deAlmeida, 2006)

Even small gains in component efficiency can lead to very large overall efficiency gains. For example, if each of the above components has 80% efficiency, then overall system efficiency Esys is:

Esys = 0.8*0.8*0.8*0.8 = 41%.

But increasing individual efficiency by just 10% will have a multiplicative effect on overall efficiency:

Esys = 0.9*0.9*0.9*0.9 = 66%

The compounding effect of a 10% increase in component efficiencies thus gives a **60% improvement** overall (old 41% x 1.60 = new 66%).

For the auxiliary systems which are the subject of this handbook, an integrative approach which considers drivepower, electric power supply, and process automation as a whole can lead to a more balanced and energy efficient design.

The component efficiencies in the simplified example given above are seldom static in the real world. Usually, these component efficiencies are dynamic and will change with process flow as shown in the figure below. An integrative design approach considers efficiency over the entire flow range, opening the door for even greater magnification on the gains from efficient designs. For a more complete list of **Integrative Design principles**, see the Appendix section.

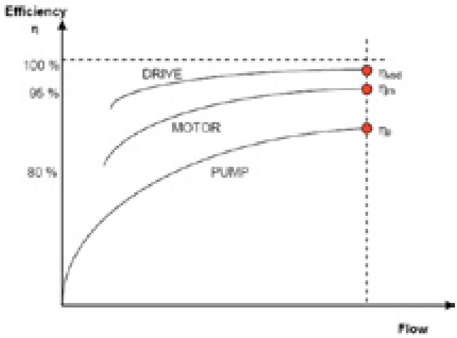


Figure 6.3 – Typical efficiency vs. flow for drivepower components (ABB PumpSave User Manual 4.0)

Energy Efficiency Design Improvements

Base Case Unit

The base case used in this text is a 500MW (gross) single pulverized coal-fired steam electric utility power plant unit with a single, sub-critical, drum boiler sending steam to a single turbine. The base case plant is 25 years old and its design is representative of the newer end of the fleet of coal plants in the US. The target unit has previously undergone retrofits for emissions control; low NOx burners and FGD systems.

The base case plant has old equipment for flow control and drive power, which will be replaced by modern VFD flow control methods and higher efficiency motors and couplings. The context for the activities in this module is a small to medium-sized retrofit project. The cases are divided into smaller scopes than would be normal in retrofit project; this is for calculation purposes to show individual efficiency benefits. Typically several activities would be combined in a larger retrofit project.

Change of Duty from Baseload to Intermediate

The target for this case study is a fixed-pressure unit designed for base-loading that is converted to a variable pressure unit for intermediate (load-following) service and for extended operation at lower loads, typically from 50% to 90% full rated load.

Efficiency Design Improvements

The table below summarizes all the design improvements suitable for a plant of the stated type and project investment scope. The efficiency improvements are incremental and relate only to the direct effect of auxiliary design improvements. (For example, the effects of environmental or balanced draft conversions have an efficiency impact that is independent of how auxiliary design is executed). The non-auxiliary conversion or upgrade costs vary greatly with plant design and are omitted from the discussion.

The design methods and recommendations for auxiliary and automation systems described in this module are largely applicable to many other fossil steam plant designs and situations as well. The table below lists all the proposed auxiliary designs for improved energy efficiency. The numbered proposals are singled out for detailed description and benefits analysis in the following sections.

#	Project or Case	Scope Description & Benefits
1	**VFDs for draft and FGD fan flow control**	**Eliminate flow restricting control methods. May be part of a balanced draft conversion. May also include benefit of peak loading, previously limited by fan capacity on hot days.**
	Upgrade sensors & actuators	Retrofit electro-hydraulic(fturbine) , smart positioners for dampers, louvers
	Balanced draft conversion	Proper furnace draft control using ID fans instead of FD fans and speed control instead of dampers
2	**VFDs for boiler, circulating and condensate pump flow control**	**Eliminate flow restricting control methods; may be part of a feedwater heater upgrade**
3	Motors & drive-trains upgrade	Replace existing motor and drive-trains with right-sized, higher efficiency equipment
	DCS replacement for 20+ years old system	Improved automatic and operator control response
4	**Coordinated boiler-turbine control, sliding pressure operation**	**Coordinated boiler turbine control, use of feed-forward techniques for rapid response. Improved efficiency at low loads**
	Boiler startup optimization	Less fuel, shorter time during startup
5	**Advanced controls for steam temperature control**	**Increase main steam temperature, reheat steam temperature, and ramp rate**
6	**Stabilizing firing rate**	**Improved heat rate, reduced need for attemperation. 1-2 % improvement in heat rate**
7	**Reduction of excess air**	**Decrease the average flue gas O2 of the boilers through improved airflow control.**
8	**Improved Feedwater Pressure & Level Control**	
	General loop tuning	**Manual and adaptive tuning techniques**
9	**Electrical power system upgrade**	Power quality improvements, transformer right-sizing and efficiency upgrade
	Plant availability improvement	Diagnostics, condition monitoring, asset management
	Cooling tower retrofit	Improve drivepower & controls related to condenser systems
	Environmental upgrade	Improve drivepower & controls for FGD, precipitators, catalytic conversion

#	Project or Case	Scope Description & Benefits
	Coal variability enhancements	Coal blending, improved soot blower/water canon systems, mill replacements, fan modifications/rebuilds to accommodate more variability in coal quality with multiple coal sources without loss of efficiency or reliability (Black & Veatch, 2008)
	Feedwater heater upgrade	Improved efficiency with compact heat exchangers + condition monitoring
	Plant Information Management System	PIMS can enable energy efficiency performance of up to improvements of 1.5% through continuous monitoring and warning of plant degradation.

Table 6.1 – Suggested improvement retrofit projects; selected projects are numbered

Unit Improvement Targets

The largest heat rate improvements from the chosen retrofits occur at reduced plant loads and during periods of rapid load ramping which is the new reality for this previously baseloaded plant.

Performance Indicator	Target Improvement	Units	
Heat rate improvement	8%		
Faster ramp rate	2%	of full load rate/min	
Fewer trip	20%	fewer forced outages	
Reduced CO2	8%		
Reduced Fuel consumption	8%		
Target Excess O2 reduction	2.50	%	
Target Main Steam Temp at Full Load	993 → 1000	deg-F	(+4 ºC)
Target Main Steam Pressure at Full Load	2,380 → 2430	PSI	(345 kpa)
Target Reheat Steam Temp at Full Load	975 → 993	deg-F	(+10 ºC)
Target Superheat Spray Flow At Full Load	30	klb/hr	(13.6 tonne/hr)
Target Reheat Spray Flow At Full Load	40	klb/hr	(18.1 tonne/hr)
Total Controllable Losses HR Reduction Target	251	BTU/kWh	(265 kJ/kWh)
Targeted NOx Reduction Level	15%	lb/MMBTU	(g/MJ)

Table 6.2 – Improvement targets of retrofit projects

Implementation Issues

Energy efficiency improvement efforts typically follow the project phases described in the module on **Managing Energy Efficiency Improvements** in this handbook. For an existing facility, measurement, prioritization and budget limitations will ultimately decide which of the proposed improvements are implemented. There is also a preferred technical order to the improvements proposed in the table, which follows the levels in the hierarchy of plant automation described in the **Automation** section. Higher levels of automation are generally dependent on lower levels.

- Upgrade sensors and actuators (especially electro-hydraulic and mechanical components)
- Upgrade motors and drives
- Upgrade Distributed Control System (DCS)
- Upgrade programmable control strategies
- Upgrade programmable optimization routines
- Upgrade plant unit operating manual & procedures

There are limitations to the possible efficiency gains in the context of auxiliary systems redesign or retrofit. Some of the improvements discussed in the section on **High Performance Energy Design**, intended mainly for greenfield plant designs, could achieve 15% net heat rate reductions over older plant designs (from a nominal 10200 Btu/kwh (10.8 MJ/kWh) down to 8700 Btu/kwh (9.2 MJ/kWh).

Base Case Plant Design and Performance Data

As with operational energy audits, a design energy assessment starts with some data identification and data gathering steps. Design data and documentation must also be collected, though, along with calculations/measurements of average heat rate at full and partial loads. Unit data was collected from the following sources:

- GE Handbook, H. Rustebakke, 1983
- Black & Veatch (Drbal,L et al.) Power Plant Engineering , 1995
- IEA CoalOnline , citing various data sources, 2008
- EPRI Field Test on VFD Retrofits, 1993
- ABB: Enel´s Torrevaldaliga Nord : 3 x 660MW units : increased net efficiency from 39% to 45% with emission reductions: SO2/NOx/Dust from 400/200/50 to 100/100/15 (mg/Nm3) , 2005
- ABB: Unit C of the E.ON Scholven Power Plant, 2008
- ABB: PC plant in China; 3 x 700 MW units. Energy performance data, before/after VFDs, 2008

Plant Unit Assumptions

Parameter	Value	Units	SI Units
Average Unit Capacity for period	500	MWe	
Assumed Annual Capacity Factor	70.0	%	
Fuel HHV (typical)	8,895	BTU/lb	20.6 MJ/kg
	0.00890	MBTU/lb	
	112.423	lb/MBTU	
Fuel Cost	$2.470	$/MMBTU	
	$0.0220	$/lb	$0.048/kg
NOx Reduction Value	$2,000	$/ton	$2200/tonne
Fuel % Carbon	48.6	%	
CO2 Reduction Value	$5.00	$/ton	$5.50/tonne
NOx (average for period)	0.210	lb/MBTU	
Net Heat Rate (average for period)	10,211	BTU/kWh	

Table 6.3 – Plant basic and automation parameters

Parameter	Value	Units	SI Units
Operating hours per year (auxiliaries)	8000	hr	
VFD investment cost	$93	$/hp	$125/kW
Induction motor investment cost	$100	$/hp	$135/kW
Cost of electricity when sold	$0.05	$/kWh	
Premium of in-plant electricity	$0.007	$/kWh	
Discount rate	5.0%	%	
Service life remaining	20	years	
Oversized motor efficiency penalty	0.1	%	
Baseline annual generated energy	3,066,000,000	kWh	
Baseline heat input	31,306,926	MMBtu	33×10^{15} J
Cost of saved fuel	$0.025	$/kWh	

Table 6.4 – Drivepower parameters

Parameter	Value	Units	SI Units
Transformer investment cost	10,000	$/MVA	
Average Power Output (70% of rating)	350	Mwe	
Transformer Load losses	$3,000	$/kW	
Transformer Core losses	$1,500	$/kW	
SVC investment cost	$50,000	$/MVAR	

Table 6.5 – Transformer & SVC parameters

% Full flow	% Total	Annual hrs	Capacity factor %
100%	5	400	5%
90%	10	800	9%
80%	20	1600	16%
70%	25	2000	18%
60%	25	2000	15%
50%	10	800	5%
40%	5	400	2%
30%	0	0	0%
20%	0	0	0%
	100	8000	70%

Table 6.6 – Operating profile for all auxiliaries

Load Name	ID	Rated hp	In use	Rated Set hp	Control method	Load factor	Operat-ing hp	% Gross
Boiler feedwater pump	BFW	14,000	2	28,000	Slip	0.81	22,680	4.8%
Condensate pump	HW	2,250	1	2,250	Throttling	0.75	1,688	0.4%
Circulating water pump	CW	3,400	2	6,800	Throttling	0.85	5,780	1.2%
Forced draft fan (blower)	FD	2,250	2	4,500	Inlet vane	0.52	2,340	0.5%
Primary air fan	PA	2,250	2	4,500	Inlet vane	0.49	2,205	0.5%
Induced draft fan	ID	4,500	2	9,000	Inlet vane	0.78	7,020	1.5%
SUM ALL LARGE MV motors							41,713	
Boiler circulating water pump	BCW	600	3	1,800	Throttling	0.82	1,476	0.3%
Service water pump	SW	400	1	400	Throttling	0.82	328	0.1%
FGD slurry pump	FGDS	600	1	600	Throttling	0.82	492	0.1%
Cooling tower fan	CT	600	2	1,200	Inlet vane	0.82	984	0.2%
Pulverizers	PV	450	5	2,250	Bypass	0.66	1,485	0.3%
Air compressor	AIR	480	1	480	Bypass	1.66	797	0.2%
All other auxiliary loads	AUX	4,300	1	4,300	N/A	0.53	2,279	0.5%
FGD booster fan	FGD	6,500	1	6,500	Inlet vane	0.66	4,290	0.9%
TOTAL				66,480			54,171	11.5%
SCR circulating pump	SCR	400	1	400	Throttling	0.82	328	0.1%

Table 6.7 – Auxiliary systems fan and pump drivepower

Auxiliary systems fan and pump drivepower (Table 5) represent a significant proportion of plant generating capacity in our base case example.

– All pumps = 7.2% of rated generating capacity
– All fans = 3.6% of rated generating capacity

This upgrade activity seeks to reduce the energy consumption of these auxiliaries across the entire operating profile. The common operating profile (Table 4) is approximated for all pumps and fans, and reflects the unit's new role in intermediate service and longer operation at lower loads.

Fan Input Parameters (per fan)		FD	ID	FGD
Fan type		centrifugal	centrifugal	centrifugal
Impeller type curve		backward	forward	forward
Nominal volume flow	cfm	450,000	600,000	1,200,000
Total pressure increase	in water*	12	17	18
Nominal fan efficiency	%	80.00%	55.00%	60%
Flow control method		inlet vanes	inlet vanes	inlet vanes
Motor efficiency	%	96%	96%	96%
Motor supply voltage	V	4.1kv	4.1kv	4.1kv
Transmission efficiency	%	100%	100%	100%

Table 6.8a – Operating parameters for fans

Pump Input Parameters (per pump)		BFW	CW	HW
Nominal flow	gpm	2800	180,000	5500
Liquid density (water: SI = 1 kg/l)	lb/cu.ft	62.4	62.4	62.4
Efficiency	%	85%	85%	85%
Static head	ft	5	10	1
Nominal head	ft	900/2300	55	650
Max head	ft	1000/2500	75	750
Flow control method		slip	throttling	Throttling
Motor efficiency	%	95%	95%	95%
Motor supply voltage	V	4.1kv	4.1kv	4.1kv
Transmission efficiency	%	98.50%	98.50%	98.50%

* 1 inch of water = 0.0025 bar = 0.25 kpa

Figure 6.8b Operating parameters for pumps

Base Case Plant Improvement

#1 Improved Fan Flow Control

In the base case plant unit there are 2 FD fans, rated at 2250 hp (1680 kW) each and 2 ID fans rated at 4500 hp (3357 kW) each, in parallel, all of centrifugal design, all using inlet guide vanes for flow control. On hot summer days, peak loading of the unit was limited by the FD fan capacity. A single FGD booster was later installed, rated at 6,500 hp (4850 kW).

Retrofit Description

In the retrofit project, all fans were equipped with VFDs for speed control and the inlet vanes were locked in open position.

		FD	ID	FGD
Number in operation	#	2	2	1
Required input motor power; rated, including 10% margin	hp	1065	3190	6184
Annual energy consumption with existing flow control	kWh	3,472,721	10,403,631	20169878
Annual energy consumption with VFD flow control	kWh	2,474,608	7,413,469	14372748
Annual energy saving kWh	kWh	998,113	2,990,162	5,797,130
Efficiency gain %	%	28.7%	28.7%	28.7%
Annual saved energy when sold	$	$2,495	$7,475	$14,493
Annual saved fuel qty	lbs	1,088,493	3,260,924	6,322,065
Annual saved fuel cost	$	$23,915	$71,645	$138,900
Annual saved fuel cost premium	$	$6,637	$19,885	$38,551
Annual heat input saving	MMBTU/year	9,682	29,005	56,234
Annual CO2 reduction	tons	970	2,905	5,633
Annual CO2 charge saving	$	$4,849	$14,527	$28,165
Improvement in heat rate	%	0.03%	0.10%	0.19%
Annual saving TOTAL	$	$37,897	$113,532	$220,108
Investment cost	$	$99,045	$296,670	$575,112
Payback period	years	2.4	2.4	2.4
Net Present Value	$	$373,234	$1,118,190	$2,167,925

Divide lbs by 2.2 to get kg. Multiply MMBtu by 1055 to get MJ.

Table 6.9 – Main benefits analysis for fans, per fan

#2 Improved Pump Flow Control

The boiler feedwater (BFW) pumping system in the base case plant unit has 2 multi-stage, split-casing centrifugal BFW pumps each supplying 50% of the capacity. Each BFW pump is rated at 14,400 hp (10,740 kW). Control valve throttling was originally used for flow control, then it was replaced by hydraulic slip-type coupling for speed control some years ago.

The cooling water circulating water (CW) pump in the base case plant unit is a low head, high capacity axial design. There are 2 such pumps rated at 3217 hp (2400 kW) which together consume approximately 0.8% of rated generating capacity for the unit. The cooling system is closed loop and the pump is a vertical, wet pit type, and control valves are used for throttling flow control.

The condensate or hotwell (HW) pump in the base case plant unit is a single pump rated at 2144 hp (1600kW) and consumes approximately 0.1% of rated generating capacity for the unit. This pump is a 2-stage centrifugal design. An additional HW pump is installed for redundancy, but does not normally operate.

Retrofit Description

The pumps were equipped with VFDs for speed control and the hydraulic couplings were removed. Previous studies (by ABB, Black & Veatch, EPRI) have indicated that VFDs provide a 10% reduction in input electrical power compared to slip-type couplings, even at 100% throttle flows. This advantage increases to 15% for flows between 50% and 75% of full throttle, which more closely reflects the operating profile of the base case plant unit. See the section on **Pump Flow Control** for more details on these flow control comparisons. The benefits in the table below were calculated using the 15% improvement factor. If throttling were used for BFW pump flow control, then the advantage of using VFDs for flow control would vary from 10% at full throttle to 30% at half throttle flows. Note also that most simple tools for benefits analysis are not valid for large BFW pumps with multi-stage designs.

An alternative to retrofitting both CW pumps with VFDs is to retrofit only a single pump and use automation to start/stop the other pump to reduce the plant auxiliary load. The automation control logic could use the unit load and turbine back pressure as inputs.

		BFW	CW	HW
Number in operation	#	2	2	1
Required input motor power; rated, including 10% margin	hp	11,423	3240	1170
Annual energy consumption with existing flow control	kWh	41,109,000	15,758,502	5,216,951
Annual energy consumption with VFD flow control	kWh	34,942,500	7,372,117	2,716,618
Annual energy saving kWh	kWh	6,166,500	8,386,385	2,500,333
Efficiency gain %	%	15.0%	53.2%	47.9%
Annual saved energy when sold	$	$15,416	$20,966	$6,251
Annual saved fuel qty	lbs	6,724,882	9,145,779	2,726,740
Annual saved fuel cost	$	$147,750	$200,939	$59,908
Annual saved fuel cost premium	$	$41,007	$55,769	$16,627
Annual heat input saving	MMBTU/year	59,817	81,351	24,254
Annual CO2 reduction	tons	5,992	8,149	2,430
Annual CO2 charge saving	$	$29,959	$40,744	$12,148
Improvement in heat rate	%	0.20%	0.27%	0.08%
Annual saving TOTAL	$	$234,133	$318,419	$94,934
Investment cost	$	$1,062,293	$301,320	$108,810
Payback period	years	4.5	1.0	1.2
Net Present Value	$	$1,855,521	$3,666,885	$1,074,277

Divide lbs by 2.2 to get kg. Multiply MMBtu by 1055 to get MJ.

Table 6.10 – Main benefits analysis for pumps, per pump

#3 High-Efficiency Motors & Drive-trains

Retrofit Description

Existing motors were replaced with high efficiency, low power-factor motors. Any applications with negative NPV (shown in red in the table below) would not be considered as candidates for this kind of retrofit.

Main Benefits Analysis

Motor & Drivetrain Improvement		Motor		
		FD	ID	FGD
Existing motor rating (per unit)	Hp	2,250	4,500	6,500
Existing motor efficiency	%	85.0%	85.0%	85.0%
Existing transmission efficiency	%	97.0%	97.0%	97.0%
New motor efficiency	%	96.5%	96.5%	96.5%
New transmission efficiency	%	99.0%	99.0%	99.0%
Oversized hp	hp	1,185	1,310	316
Oversized %	%	52.7%	29.1%	4.9%
Oversized motor efficiency penalty	%	5.3%	2.9%	0.5%
Annual energy saving kWh	kWh	651,714	1,707,351	2,820,990
Efficiency gain %	%	18.8%	16.4%	14.0%
Annual saved energy when sold	$	$1,629	$4,268	$7,052
Annual saved fuel qty	lbs	710,727	1,861,954	3,076,433
Annual saved fuel cost	$	$15,615	$40,908	$67,591
Annual saved fuel cost premium	$	$4,562	$11,951	$19,747
Annual heat input saving	MMBTU/year	6,321	16,562	27,364
Annual CO2 reduction	tons	633	1,659	2,741
Annual CO2 charge saving	$	$3,166	$8,295	$13,706
Improvement in heat rate	%	0.02%	0.06%	0.09%
Annual saving TOTAL	$	$24,973	$65,423	$108,096
Investment cost	$	$106,500	$319,000	$618,400
Payback period	years	4.3	4.9	5.7
Net Present Value		$204,719	$496,328	$728,715

Divide lbs by 2.2 to get kg. Multiply MMBtu by 1055 to get MJ.

Table 6.11 – Main motor and drivetrain benefits for fans, per motor

Motor & Drivetrain Improvement		Per Unit -->		
		BFW	CW	HW
Existing motor rating (per unit)	hp	14,000	3,400	2,250
Existing motor efficiency	%	85.0%	85.0%	85.0%
Existing transmission efficiency	%	98.5%	97.0%	97.0%
New motor efficiency	%	96.5%	96.5%	96.5%
New transmission efficiency	%	99.0%	99.0%	99.0%
Oversized hp	hp	2,578	160	1,080
Oversized %	%	18.4%	4.7%	48.0%
Oversized motor efficiency penalty	%	1.8%	0.5%	4.8%
Annual energy saving kWh	kWh	5,689,926	2,201,555	954,702
Efficiency gain %	%	13.8%	14.0%	18.3%
Annual saved energy when sold	$	$14,225	$5,504	$2,387
Annual saved fuel qty	lbs	6,205,154	2,400,908	1,041,151

Motor & Drivetrain Improvement		Per Unit -->		
Annual saved fuel cost	$	$136,331	$52,750	$22,875
Annual saved fuel cost premium	$	$39,829	$15,411	$6,683
Annual heat input saving	BTU/year	55,194,843,186	21,356,078,337	9,261,039,336
Annual CO2 reduction	tons	5,529	2,139	928
Annual CO2 charge saving	$	$27,644	$10,696	$4,638
Improvement in heat rate	%	0.19%	0.07%	0.03%
Annual saving TOTAL	$	$218,030	$84,360	$36,583
Investment cost	$	$1,142,250	$324,000	$117,000
Payback period	years	5.2	3.8	3.2

Divide lbs by 2.2 to get kg. Multiply MMBtu by 1055 to get MJ.

Table 6.12 – Main motor and drivetrain benefits for pumps , per motor

#4 Boiler Turbine Coordinated Controls and Sliding Pressure Operation

This retrofit is worthwhile, but automation auxiliaries cannot claim all benefits due to sliding pressure mode; it is therefore excluded from the summary of benefits.

#5 Advanced Steam Temperature Control

The existing control used the two parallel spray valves to control the final main superheat (SH) steam temperature. The control strategy included two PID controllers in a cascade configuration. The outer PID calculated a setpoint for the average of the two attemperator outlet temperatures. A feedforward based on the unit load demand was used as a valve demand reference. The system uses a single spray valve to control the final reheat (RH) steam temperature. A feedforward based on the unit load demand is used as a valve demand reference.

The sample data set, however, showed that the steam temperatures were uncontrolled at the low or ramping loads, which degrades heatrate for the unit's new role providing intermediate (load-following service. In the base case unit, the standard deviation of the main steam temperature was found to be 8°F due to unstable operation and control action. Operators typically maintained a safety margin of 3 to 4 times the standard deviation between the maximum and the temperature setpoint (ABB, Immonen 2006) and this was reflected in the average main steam temperature, which was 30 °F below the design point (1005°F), at 975 °F. Similar instability and lower average temperatures were observed for reheat temperatures as well.

Retrofit Description

An advanced steam temperature control strategy was implemented to control steam temperature for a drum boiler operating in either constant or sliding pressure mode: see the section on **Advanced Seam Temperature Control** for design details. Using these techniques, the standard deviation is more than halved to only 3°F, which means the average main steam temperature can be maintained at 993°F, an increase of 18 °F. Similar improvements were obtained for the reheat steam temperature.

Main Benefits Analysis

For a sub-critical unit: each 50°F increase in main steam temperature decreases heatrate by 70 Btu per kWh at full load, and which corresponds to an increase in cycle efficiency of approximately 0.7% (Babcock & Wilcox 2005). For reheat temperature increase of 50°F the heatrate decrease is 65 Btu per kWh. The 18 °F increase in main steam temperature yielded the following benefits.

Results	Units	Baseline	Reduced Baseline	Amount of Reduction
Average Heat Input based on Rating x Annual Capacity Factor	BTU/h	4,248,000,000	4,227,000,000	20,218,000
Fuel Input	lbs/h	477,546	475,274	2273
Annual Fuel Cost	$/year	$76,469,102	$76,105,142	363,960
Baseline CO2 Emission	lbs/h	850,988	846,938	4,050
Baseline CO2 for 12 Months	Tons CO2/yr	3,727,327	3,709,586	17,740

Divide lbs by 2.2 to get kg. Multiply MMBtu by 1055 to get MJ.

Table 6.13 – Effect on baseline performance of increased main steam temperature

Side Benefits Analysis

- Reduced attemperation spray flows: these are accounted for separately in a later case
- Faster unit ramp rate
- Fewer outages due to tube leaks

#6 Stabilization of Firing Rate

The existing controls included the interface to the regional power system dispatcher (ISO) that sends a unit load target. The Unit load demand was used as a setpoint and feedforward to the boiler master and turbine load control. The unit load ramp rate was typically 4 to 6 MW/min based on operation perception of limiting boiler ramps to 20 psi/min.

The sample data set, however, showed, unstable firing rate and reduced heat rate, with marked deterioration since the unit had converted to low-NOx burners. Superheat and reheat attemperation spray flows had also reached record high levels of 96 klb/hr and 110 klb/hr respectively.

Retrofit Description

In conjunction with the controls retrofit, the response was re-programmed to be slower at start of a ramp, and greater acceleration is allowed when drum pressure is greater than 1260 psig.

Main Benefits Analysis

These modifications, in conjunction with the upgraded advanced steam temperature controls, reduced instability and superheat and reheat attemperation spray flows to 30 klb/hr and 40 klb/hr respectively, with the following estimated benefits:

Results	Units	Baseline	Reduced Baseline	Amount of Reduction
Average Heat Input based on Rating x Annual Capacity Factor	BTU/h	4,247,776,000	4,178,413,824	69,362,176
Fuel Input	lbs/h	477,546	469,749	7798
Annual Fuel Cost	$/year	$76,469,102	$75,220,434	$1,248,668
Baseline CO2 Emission	lbs/h	850,988	837,092	13,896
Baseline CO2 for 12 Months	Tons CO2/yr	3,727,327	3,666,463	60,864
Improvement in heat rate	%			1.633%

Divide lbs by 2.2 to get kg. Multiply MMBtu by 1055 to get MJ.

Table 6.14 – Effect on baseline performance of decreased superheat and reheat attemperation flows

#7 Improved Airflow Control - Excess O2 Reduction

Prior to all retrofits, two FD fans were used to control the boiler combustion air flow in the base case unit. The control response was adjusted based on whether one or two fans were in automatic service. The air flow control included the typical cross-limit by the fuel flow as described in the **Combustion Control** section. The sample data set, however, showed a 0.5% variation in O2 at all loads, and worries about opacity excursions led to much manual control.

Retrofit Description

In a control system retrofit, a dedicated oxygen trim control module was installed to adjust the measured air flow as needed to keep the O2 at the load based setpoint. The process variable is the lower of the two O2 analyzer inputs. The trim control module also uses the more precise airflow control provided by VFD-equipped FD and ID fans to achieve overall optimum levels of combustion, as described in **Air Flow Control for Combustion**. Furthermore, air heater seals were inspected and worn/broken ones were replaced, to eliminate outside air leaks from entering the flue gas stream.

Main Benefits Analysis

Improved control and stability allowed full-time automatic control and an average reduction in excess O2 from 3.7% to 2.5% and the following benefits. The first 0.5% of reduction came from the air heater seal replacements, and the net reduction from 3.2% to 2.5% was obtained through the controls improvement:

Results	Units	Baseline	Reduced Baseline	Amount of Reduction
Average Heat Input based on Rating x Annual Capacity Factor	BTU/h	4,247,776,000	4,229,430,400	18,345,600
Fuel Input	lbs/h	477,546	475,484	2062
Annual Fuel Cost	$/year	$76,469,102	$76,138,842	$330,260
Baseline CO2 Emission	lbs/h	850,988	847,313	3,675
Baseline CO2 for 12 Months	Tons CO2/yr	3,727,327	3,711,229	16,098

Divide lbs by 2.2 to get kg. Multiply MMBtu by 1055 to get MJ.

Table 6.15 – Effect on baseline performance of decreased excess oxygen

#8 Improved Feedwater Pressure & Level Control

The base case unit's drum level is regulated by two motor-driven Boiler Feedwater (BFW) pumps each with a variable speed (VFD) drive as a result of the retrofit described in **Improved Pump Flow Control**. Single element-three element control strategy is employed for drum level control as described in **Feedwater Flow Control**.

The unit's transition to intermediate (load-following) service with higher ramp rates and increased operation at lower loads, however, led to instability and lower average main steam pressure 2,436 psi compared to the design point at 2,500 psi when operating in constant pressure mode at higher loads.

Retrofit Description

The new control system uses shrink-swell compensation to maintain drum level even at the faster unit load ramp rates. Adaptive tuning is also employed to allow the controllers to respond most accurately across the expanded load range.

Main Benefits Analysis

The steam pressure standard deviation was reduced, allowing a higher average pressure operation at 2,480 (an increase of 44 psi). For a sub-critical unit: each 100 psi increase in main steam pressure decreases heatrate by 35 Btu per kWh at full load (EPRI report CS-4554).

Results	Units	Baseline	Reduced Baseline	Amount of Reduction
Average Heat Input based on Rating x Annual Capacity Factor	BTU/h	4,247,776,000	4,241,369,600	6,406,400
Fuel Input	lbs/h	477,546	476,826	720
Annual Fuel Cost	$/year	$76,469,102	$76,353,773	$115,329
Baseline CO2 Emission	lbs/h	850,988	849,704	1,283
Baseline CO2 for 12 Months	Tons CO2/yr	3,727,327	3,721,705	5,621

Divide lbs by 2.2 to get kg. Multiply MMBtu by 1055 to get MJ.

Table 6.16 – Effect on baseline performance of improved feedwater level & pressure control

#9 Electric Power System Improvement

Unit Transformers / Bus		Gen Step-Up	Aux 1A	Aux 1B	FGD Boost
Primary	kV	19	19	19	19
Secondary	kV	525	6.9	6.9	13.8
Rating MVA	MVA	520	40	40	10
Existing PF	N/A	0.91	0.85	0.85	0.85
Existing efficiency at oper. pt.	%	99.1%	97.2%	97.2%	97.2%
New PF	N/A	0.94	0.9	0.9	0.9
New efficiency	%	99.7%	98.0%	98.0%	98.0%
Existing Reactive Power (based on capcity factor)	MVAR	159.5	21.1	21.1	5.3
New Active Power	MW	361.5	36.0	36.0	9.0
Change in Active Power	MW	11.5	2.0	2.0	0.5
Cable type	n/a	4x3C, 300mm	4x3C, 100mm	4x3C, 100mm	4x3C, 100mm
Cable length	ft	150.0	700.0	700.0	700.0
Existing Total Power (based on capacity factor)	MVA	384.6	40.0	40.0	10.0

Divide lbs by 2.2 to get kg. Multiply MMBtu by 1055 to get MJ.

Table 6.17 – Power system improvements

The base case unit's GSU and auxiliary transformers are old. The PF on the generator and plant network sides is relatively low.

Retrofit Description

New, right-sized transformers, active power factor correction on auxiliary network to increase power factor.

Main Benefits Analysis

Improvements		Gen Step-Up	Aux 1A	Aux 1B	FGD Boost
Annual energy saving due to transformer	kWh	16,800,000	1,348,564	1,348,564	337,141
Annual energy saving due to PF increase	kWh	84,000,000	8,428,523	8,428,523	2,107,131
Annual energy saving kWh	kWh	100,800,000	9,777,087	9,777,087	2,444,272
Efficiency gain %	%	0.6%	0.8%	0.8%	0.8%
Annual saved energy when sold	$	$252,000	$24,443	$24,443	$6,111
Annual saved fuel qty	lbs	109,927,528	10,662,410	10,662,410	2,665,603
Annual saved fuel cost	$	$2,415,179	$234,260	$234,260	$58,565
Annual saved fuel cost premium	$	$670,320	$65,018	$65,018	$16,254
Annual heat input saving	MMBTU/ year	977,805	94,842	94,842	23,710
Annual CO2 reduction	tons	97,945	9,500	9,500	2,375
Annual CO2 charge saving	$	$489,727	$47,501	$47,501	$11,875
Improvement in heat rate	%	3.29%	0.32%	0.32%	0.08%
Annual saving TOTAL	$	$3,827,226	$371,221	$371,221	$92,805
Investment cost	$	$8,200,000	$400,000	$400,000	$100,000
Payback period	years	2.2	1.03	1.03	1.03
Net Present Value	$	$39,495,700	$4,226,240	$4,226,240	$1,056,560

Divide lbs by 2.2 to get kg. Multiply MMBtu by 1055 to get MJ.

Table 6.18 – Benefit analysis results

Summary of Benefits

The combination of all the energy efficiency retrofit improvements, shown in the table below, reduced the heat rate in the base case plant by 8%, with a payback of less than 2 years.

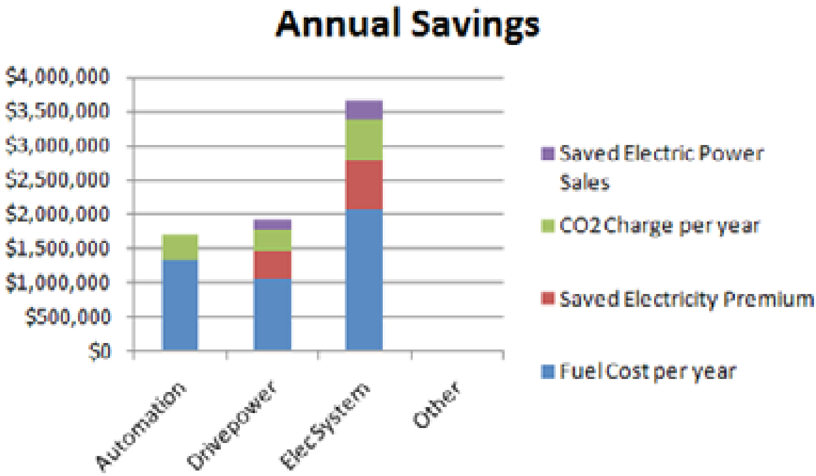
		Automation	Drivepower	Elec System	Total	New
Results		**Improvement**	**Improvement**	**Improvement**	**Improvement**	**Baseline**
Average Heat Input Rate	BTU/h	87,960,600	71,272,115	135,981,755	**295,214,470**	3,278,635,530
Fuel Input Rate	lbs/h	9,889	8,013	15,287	**33,189**	368,593
Fuel Cost per year	$/year	$1,332,255	$1,079,490	$2,059,585	**$4,471,330**	$49,658,345
Saved Electricity Premium	$/year	$0	$390,876	$734,337	**$1,125,213**	
CO2 Emission Rate per hour	lbs/h	17,622	14,278	27,242	**59,142**	656,833
CO2 Emission Rate per year	tons CO2/ yr	77,183	62,540	119,321	**259,044**	2,876,928
CO2 Charge per year	$	$385,917	$312,698	$596,604	**$1,295,220**	$14,384,640
Heat Rate Improvement	BTU/ kWh	**2.46%**	**1.99%**	**3.80%**	**8.26%**	10211 → 9431
Saved Electric Power Sales	$	$0	$144,500	$276,067	**$420,567**	
Unit Capacity	MW	0.00	7.23	14.02	**21.25**	
Total Annual Savings		**$1,718,172**	**$1,927,565**	**$3,666,594**	**$7,312,331**	
Investment Cost	$	$1,500,000	$6,516,935	$9,100,000	**$17,116,935**	
Payback Period	years	0.87	3.4	2.5	**2.4**	
Net Present Value	$	$19,912,221	$17,504,785	$39,593,865	**$74,010,872**	

Divide lbs by 2.2 to get kg. Multiply MMBtu by 1055 to get MJ.

Table 6.19 – Effect on baseline performance of all improvements

Conclusion and Comments

The cases were restricted to a single unit, but a true integrative design approach would investigate possibilities for thermal and control integration with other units and even other nearby facilities. Integrated (real-time) control between plant units may provide a relatively low-cost way to optimize production for energy. The base case unit is analyzed in isolation, but environmental services for cooling or pumped storage may provide opportunities for improved auxiliary and cycle efficiency.



Software Tools for Energy Benefits Analysis

The benefits analysis performed on the base case plant was aided by the spreadsheet tool: ABB Power Systems Valuation Tool, 2009.

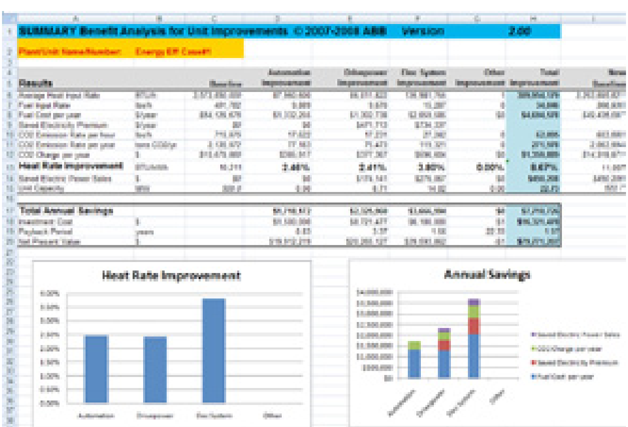


Figure 6.4 – Screenshot of the ABB Power Systems Valuation Tool, Version 3, 2009

Module 7
Managing Energy Efficiency Improvement

Module Summary

This module presents tools and methods for managing energy efficiency evaluations and improvement efforts. This module provides methods for assessing energy performance and for executing energy improvement design and engineering projects.

The information in this module may be generally applied to process industries; industry-specific text is shown in a shaded box.

Indicators of Energy Inefficiency

Energy inefficient design is easier to see in an existing plant with an operating history than in one that is still on the drawing board. The table and figure below show some indicators of 'energy-inefficient' design in an operating plant which may prompt managers to take the next step toward an energy performance assessment.

Plant Characteristic	Status
Overall design type	far from current state of the art
Actual capacity	significantly less than full design capacity
Age of the plant systems	More than 17 years old
History of its major systems	multiple, minor retrofits
Regulatory/energy price conditions	in-plant power is priced at cost, and other protective subsidies/regulations abound
Management of control, safety and pollution, availability	no plant control strategy, patchwork compliance, no pro-active reliability program
Number of trips	many
Length of time in which major control loops are in manual control	> 25%
Amount of operator tweaking, length and amount of operator intervention in startups	Much operator intervention, manual control
Exceeds pollution/emission limits	yes, often
Plant documentation	not 'as-built' , with 'as is' murky
Quality and documentation of control logic	not easily fathomable by anyone

Figure 7.1 – Indicators of energy project management problems

Energy Assessment Processes

Full plant performance assessments are typically $50,000 to $90,000 and loop performance analysis packages for a full plant can be implemented and monitored for as little as $50,000. Each can uncover costly control problems in air flows (and elsewhere) that can reach six or even seven figures a year, depending on plant size and the severity of the problem(s). At a 500 MW plant, for example, improving heat rate 1 percent can result in annual fuel savings exceeding $800,000.

Motor Energy Assessment

A motor energy assessment must collect the following data from supplier and plant documentation, equipment strip charts, or DCS logging systems:

- Number of motors, their size, maintenance records
- Duty cycle and load profile
- Input power from 3-phase wattmeter measurements
- Number and type of throttled loads
- Output power from process measurements
- Efficiency: nameplate less 1% for each rewind

Plant Design & Modeling Tools

Many tools exist for engineers to calculate energy performance at the component level, but fewer tools exist which take a wider, integrative view of the plant's energy performance. An example of the former are the US DoE calculation tools for Motor, Pump & Fan sizing and selection ; these are not for plant 'design', but are useful for subsystem engineering.

Design Tools

The greatest benefit to integrative energy design would come from integrating some of the component calculations mentioned above into the leading plant design packages. The design tools most relevant for engineers & designers today perform 2D schematic and 3D design and some cost analysis. Engineers use design software tools to maintain a consistent view of the evolving design data and allow project leaders to enforce some best practice workflow rules. Further benefits would be gained if the cost-analysis functions could have built-in support for some of the most common life cycle cost (LCC) energy calculations.

Integrated design tools make it easier to configure modeling and analysis tools described in the next section - the effort involved in collecting data from multiple incompatible tools can otherwise be as much effort as creating the model itself.

Modeling and Simulation Tools

Modeling tools can perform the necessary energy and mass balances to give an integrated view of the plant performance. Configuring and running such simulations, however, requires special training and is usually reserved for R&D or thermodynamic engineers who may not be part of a retrofit project team. As a result, the potential of these tools is not realized in many projects.

Ease of use is greatly increased by having a pre-built library of components which can be assembled according to the plant PFDs. One vendor, AspenTech, claims that their process engineering design tools can provide 5-20% energy saving due to built-in energy pinch analysis, process simulation, and model-based cost analysis. Other modeling tools which have pre-built components and functionality for power plant modeling are GE's Gate Cycle and ABB's PowerCycle packages. PowerCycle enables design of thermodynamic loops similar to a P&I scheme and to generate the mathematical model automatically in the background. The tool has a comprehensive library, which contains major plant components and its connections as well as modules for control of variables and signal transmission.

Formal Energy Optimization Methods

Steam power plant modeling tools generally use one or more of the following formal energy analysis methods:

- Exergy / Available Energy Analysis
- Pinch Technology / Thermal Integration
- Process Integration
- Data envelopment analysis (DEA)
- Stochastic-frontier method
- Steam pricing

A description of these methods is beyond the scope of this handbook, but details can be found in some of the texts listed in the **References** section.

Importance of Design Documentation

Good retrofit or new-plant (greenfield) design begins with good input documentation which reflects the 'as-is' (and 'as-built') state of the plant. The two most important design documents are the PFDs (Process Flow Diagrams) and the P&IDs (Piping and Instrumentation Drawing), examples of which are shown in the figures below.

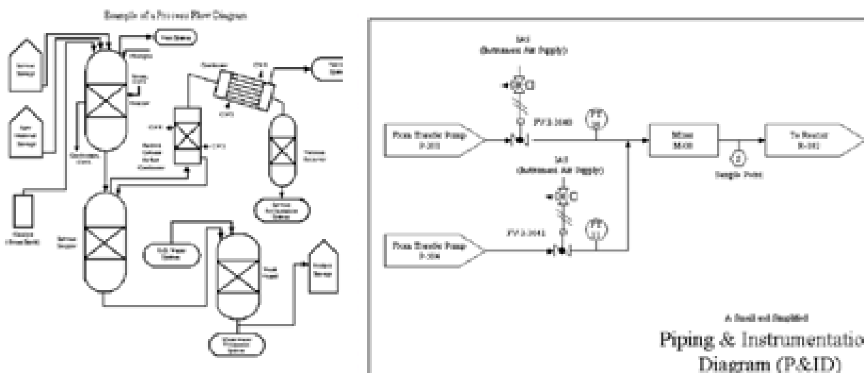


Figure 7.2 – Sample PFD on left, Sample P&ID on right, (Wikipedia / Chemical Eng'g World)

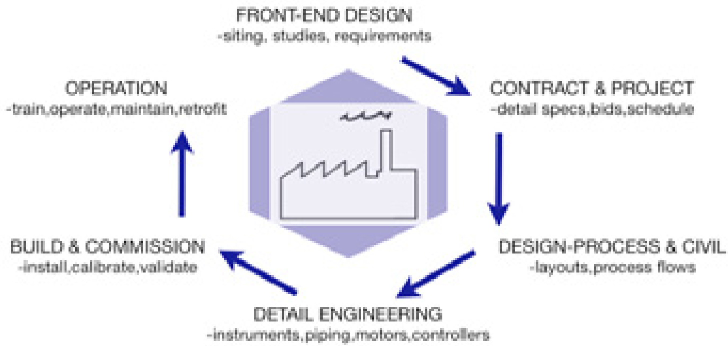
A P&ID is a full diagrammatic representation of a process plant. Each piece of equipment is shown along with its connectivity to other equipment. It may be regarded as an enhanced process flow diagram that shows, in addition to the process itself, details such as control and instrumentation equipment, pump and pipe sizes etc. Each instrument / piece of equipment is shown by a symbol denoting its type (pump, sensor, valve etc.) and a unique identification number or tag for differentiation from others (Wikipedia / Chemical Eng'g World)

Large Capital Project Processes

A glance at the section on '**Barriers to Energy Efficient Design'** shows that fragmentation of disciplines and supply chain is a significant contributor to energy deficient outcomes. The fragmentation of today's complex projects needs 'integrative' project methods to achieve greater unity of design and more opportunities for plant-wide energy efficiency measures. Another, kinder word for fragmentation is 'componentization' and it has led to improved equipment performance, but it has large hidden costs, especially in complex, large scale projects with life cycle costs far greater than the initial construction expense.

Project Phases and Energy Efficiency Impact

Phases in a large capital project involve many disciplines (Civil, Electrical, Automation, Chemical or Process) in many companies and time zones. Integrated energy design should therefore be practiced as a seamless part of the project execution model.



The figure above shows the typical plant project phases, and the figure below shows some pitfalls in each of these steps which can lead to an energy-inefficient outcome.

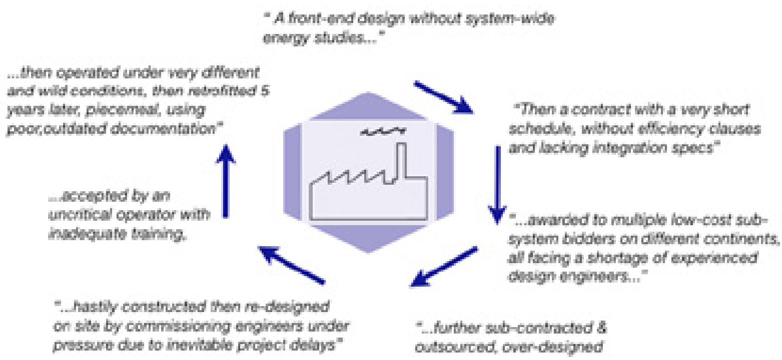


Figure 7.3 – Indicators of project management problems with energy efficiency impact

Integrated Approach to Energy Project Management

For project, bid and plant managers, the following project guidelines were inspired in part by successful RMI design charrette methods. A design 'charette' is a technical review process which originated in the field of architecture. Some important points for project managers to consider:

- Use lifecycle costing to fearlessly retire or retrofit energy-hogging assets, even before they have been fully depreciated. Use a fair rate of return for energy performance and re-consider the standard assumptions in your costing model.
- Budget time and money for front-end energy design studies. Recruit best in-house designers, or get outside help, to study energy balances, sitting opportunities, renewable energy designs.
- Replace low-bid contract with multiple and specific energy performance guarantees. Low-bid projects cut energy corners, use conservative designs. Stipulate energy performance, and agree on measurement.
- Use an agile project execution model which allows iteration on the original requirements. Avoid the 'big freeze' on the design before all important data is in. Use input to continuously iterate on the assumed requirements. Insist on early submission of vendor information.
- Involve energy end-users as much as possible, in all project phases. Involve plant site operators or others to represent the energy end-users. Show the PFDs and P&IDs to operators as early as possible.
- Appoint an energy steward to enforce energy standards in your project or plant, a senior person who will be as respected (and accountable) as safety experts are today.
- Appoint an interface manager to map & manage interfaces & ensure whole-design consistency. The interface manager ensures that disciplines, suppliers and operations are communicating & using a common energy philosophy and design model of the evolving plant.
- Seek a single contractor and not multiple vendors where feasible. Give project, and responsibility, to a firm with broad, multi-disciplinary experience; do not fracture design through 'divide and conquer' contracting.
- Be energy critical during plant retrofit work acceptance. Don't rush: ensure all units work together under all loads – this is typically the last chance to hold suppliers to their word.

Benefits of Integrated Project Management

The up-front attention to real end-use demand will actually reduce the total number of engineering hours, especially during the later project phases of when interfaces (i.e.: different sub-systems) must come together and be tested.

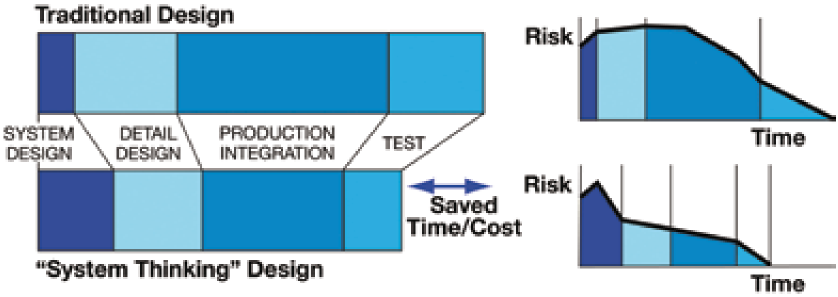


Figure 7.4 – Project hours reduction with a systems approach Honours,E.C. (2004) cited in (Natural Edge Project, 2007)

Advantage of the Main Contractor Role

The Main Automation and Main Electrical Contractor (MAC/MEC) project roles help to tie together the design and implementation of diverse plant units to make plant optimization interfacing easier. One function of these roles is to ensure that the required signals and interfaces are present to allow integration and optimization between sub-units and across the entire plant. Do not underestimate the importance of clear and comprehensive documention, and rigorous communication and review of these signals and interfaces as part of project execution.

Module 8
High Performance Energy Design

Module Summary

This module presents energy-efficiency designs and technical innovations which may be above the investment and risk thresholds of a modest retrofit project. The constraints of legacy equipment in retrofit projects also limit the potential to design-in large energy efficiency gains. A new plant or unit project, however, provides a chance for the designer to use best-in-class equipment and methods across all systems. In new projects, the energy targets can be ambitious and should aim for the maximum allowed by the process thermodynamics.

The information in this module section is specific to power generation industries or process plants with on-site power generation. Many sections, however, are also broadly applicable to all industrial steam generation processes.

Tunneling thru the Cost Barrier

Solutions that apply **Integrative Design** principles on greenfield or large re-development projects can achieve lower total-system capital costs in addition to lower total-system energy consumption compared to non-integrated designs. An energy effective design that has lower initial cost is much more likely to be approved. No net or marginal loss of service or quality is suffered in such a solution.

Auxiliaries in Best-Available-Technology Plants

Supercritical and Ultra-Supercritical Boilers

Supercritical boilers operate at pressures above the top point of the water-vapor dome. These designs eliminate the drum, and water is in continuous phase change within the wall tubing. The higher operating steam parameters give this design higher efficiency than sub-critical boilers, and state of the art units have reached 47% of LHV, some examples are Nordjyllandsværket in Denmark, and Haramachi No 2 and Misumi No.1 in Japan.

Although metallurgical advances are the main driver in SC or USC designs, modern, efficient auxiliaries are also key enablers. Control systems are one of the key enablers of super-critical boilers that dominate new plant designs. By exactly matching flow through the boiler tubing to the demands of the system, the control system has eliminated the need for a water drum and allowed higher steam parameters, lower system inertia, and much greater efficiency. Greater familiarity with the capabilities of control system technology will help engineers to push the envelope even further to ultra-supercritical designs, achieving synergies with developments in metallurgy.

The higher pressures of supercritical designs increase the auxiliary drive power required by the boiler feedwater pumps. This extra power is worth the gain in thermodynamic efficiency - for otherwise similar configurations, the move from high subcritical to low supercritical steam conditions is said to confer an efficiency advantage of approximately two percentage points (Weirich and Pietzonka, 1995).

Circulating Fluidized Bed (CFB) Furnaces

In CFB combustion designs, the fuel is spread over a deep wide area (the bed) and hot air is forced through the bed to supply combustion and to lift and separate the individual fuel particles so that they behave like a fluid, In the context of CO2 reduction, CFB can accommodate a wider variety of fuels, including biomass. CFB furnaces can co-fire with up to 20% biomass (Ferrer, Green Strategies for Aging Coal Plants, 2008).

Auxiliary drivepower enters the picture through the fuel preparation required for handling and feeding a variety of fuels, and also in higher-volume ash-removal systems. This is balanced against the reduction in power required for fine pulverization of the fuel, which is unnecessary in CFB boilers.

Waste to Energy

A facility with CFB combustion may be equipped with recycling capacity for Refuse-Derived Fuel (RDF) and therefore qualify for more environmentally sustainable energy production. On-site processing of the RDF will require significant amounts of auxiliary power, however.

Combined Cycle Gas Turbines

CCGT plants adds a Brayton gas turbine cycle ahead of the Rankine water-steam cycle to achieve even higher efficiencies. The exhaust from the gas turbine is a source of heat for the heat recovery steam generator (HRSG). Some PC steam plants may lend themselves to conversion to CCGT by installing gas fired gas turbines at site and use gas turbine exhaust heat to heat boiler feedwater. In such cases both the coal fired boiler and the gas turbine are used at the same time. This conversion design is especially useful on coal fired boilers that were de-rated due to excessive NOx or furnace slagging (Eng-Tips Power Generating Forum, Dave Fitz, 2006).

Auxiliary electric drivepower is necessary for gas turbine startup and fuel pumping requirements, but auxiliary control can play an even larger role in energy efficient operation of CCGT plants through optimal operation and allocation of the multiple sources and sinks for heat and power generation and consumption.

Integrated Gasification - Combined Cycle IGCC

The IGCC process burns coal, but it begins with a low-oxygen gasification unit to produce synthetic gas, which is then combusted in the gas turbine of a CCGT unit. IGCC plants have lower emissions of pollutants and higher efficiencies than PC steam plants. IGCC is key to realizing the industry's vision of 'clean coal', but some challenges remain before plants can be scaled up to match the largest coal plants today. The capital cost of an IGCC plant is estimated to be 10-16% higher than a PC plant of similar capacity (Pew Center on Global Climate Change 2005). Recent price volatility in natural gas are delaying the anticipated trend toward IGCC plant types, as discussed in **Trends in Steam Plant Designs and Efficiency**. In one recent project in Netherlands (ABB/Nuon), the gasifier converts coal and biomass into syngas, which is used to fuel the combined-cycle units.

Significant new auxiliary drivepower is needed for coal slurry pumps and air/oxygen compressors, as well as an extra pumping of economized boiler feedwater to the syngas cooler.

Gas-Gas Reheat for Flue Gas Desulfurization (FGD)

Flue gas reheat after flue gas desulphurization (FGD) systems can scavange additional heat from the thermodynamic cycle if they use steam heating, as commonly applied in the USA, but newer FGD systems have feed/effluent gas/gas heat-exchangers that avoid losses from this source (IEA Coal Online - 2 2007). See the section on **Automation – Emissions Controls** for details. This type FGD design, however, requires additional auxiliary speed control and automation.

Powering and Re-Powering with Biomass

Biomass combustion is mainly carbon-neutral and should therefore be exempt from any potential CO2 charges. Most power plants fired on PC can co-fire up to 4-5% biomass without significant degradation and without furnace re-design (Ferrer, Green Strategies for Aging Coal Plants, 2008). The practical upper limit to co-firing with biomass in existing PC plants may be as high as 20% (Pew Center on Global Climate Change 2005), but at the expense of decreased efficiency. According to Robinson and co-authors in their Assessment Potential of CO2 Reductions due to Biomass, 2003, co-firing with 10% biomass can achieve carbon mitigation at a cost of $8-$27 per metric ton CO2.

Wood shavings and straw have been the most common source of biomass, but recent US energy legislation enables the use of other sources such as fresh wood (Lahoda, Arndt, & Hanstein, 2006). The reliability of an economical supply of wood fuel is an important requirement for continually high biomass co-firing. The definition of 'biomass' in the EU is limited to about 15 different materials; all else is considered simply waste and may not be processed into energy that is considered carbon-neutral.

Repowering a PC furnace to burn a higher proportion of biomass requires design changes and possibly a complete conversion to a new furnace technology, such as that described in the section on **Circulating Fluidized Bed Furnaces**. Maintaining steam and re-heat steam temperature is another challenge when firing with larger fractions of biomass. By increasing stability, auxiliary automation systems can help increase the plant efficiency to levels required for economic biomass co-firing while maintaining megawatt output.

Auxiliary fan power systems are also critical to the economic co-firing with biomass. Drivepower must be efficient and sufficient to provide the increased excess air, which ranges from 15% to 50% for bark, wood and most biomass fuels (Babcock & Wilcox 2005). The controllability of VFD-equipped draft fan systems allows for more efficient operation for varying proportions of biomass. Biomass fuels have varying particle sizes, are more volatile when dry and therefore they tend to burn more in suspension compared to coal (Babcock & Wilcox 2005). Automatic control of VFD-equipped draft air flows can provide a more uniform distribution, as described in **Air Flow Control for Combustion**, and hence more complete and efficient combustion.

Biomass need not be co-fired in the main boiler furnace to provide its heat benefits to the main cycle. Heat from external biomass combustion can be used to pre-heat air or feedwater for the main boiler. Separate biomass combustion may be an alternative source of steam for a low-level banking of the unit.

Combined Heat and Power / Co-Generation

Also known by acronyms CHP or COGEN, this plant design puts the turbine steam to productive use for industrial processes or for district heating. Location is a powerful determinant of the viability of a CHP design, as is the existing turbine design when plant conversion is being considered. A variant on CHP uses steam or heated water for desalination purposes. The energy efficiency bonus of eliminating condenser heat waste is illustrated in the Sankey energy flow diagram below:

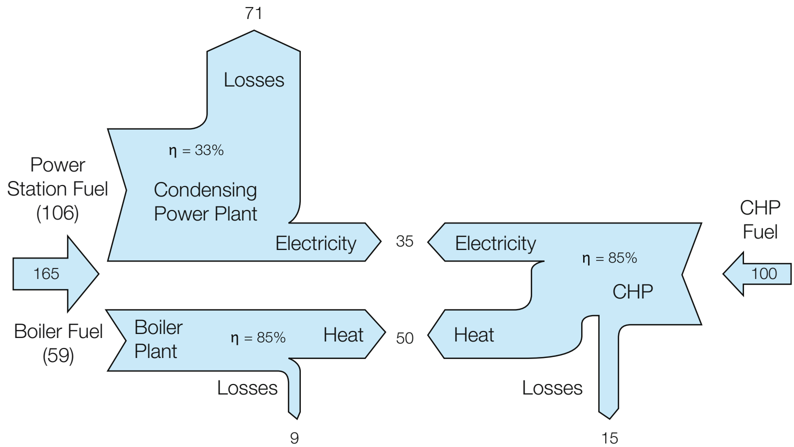


Figure 8.1 – Sankey energy flow diagram for CHP vs. conventional steam plant, Ref : ABB

The energy balance shows that the thermal efficiency of CHP plants is high (85%+) and approaches (and is ultimately limited by) the efficiency of the boiler itself. A full accounting of all benefits of CHP to industrial users and society in general is available in ‘Small is Profitable’ (Lovins,A, 2006).

There is significant potential for CHP: as of 2008 only 9% of all electrical power generation comes from co-generation plants (2008, US DoE).

Energy Storage Systems

Power plant units can operate continuously at their optimal efficiency design loads if there is an economical way to store the produced energy for transmission at later periods of high demand. Another advantage of energy storage is that it displaces spinning reserve or ‘banked’ plants.

Pumped Storage

Locations fortunate enough to have nearby volumes at higher elevations may use these for energy storage. Drivepower from periods of low demand is used to pump water to the lake at higher elevation, from which hydro power can be generated during (peak) periods of higher demand.

Battery Storage

Battery storage and inverter technology for energy storage (see case below) is a viable replacement for fossil fueled spinning reserve.

Case Example
Battery Energy Storage System

Golden Valley Electric Association in Fairbanks, Alaska contracted with ABB to construct a Battery Energy Storage System (BESS). The BESS will automatically pick up 26 megawatts of load for 15 minutes, or 40 MW for 7 minutes. The switch from power line to battery and back to power line is seamless and goes unnoticed by the customers, so the prime function of the BESS is to provide spinning reserve in case of power plant or transmission line equipment failure.

The two primary subsystems in BESS are the IGCT converter and the Ni-Cd battery. The battery is the energy storage medium. The IGCT converter is the interface between the DC battery voltage and the 60 Hz AC GVEA system voltage. The converter transformers match the converter output to the 138 kV system voltage. The BESS can be programmed for the following modes: Spinning Reserve, Automatic Scheduling, Support for Scheduled Load Increase, Automatic Generation Control, Var Support, Power System Stabilizer and Charging.

Carbon Capture and Storage

There are many technologies proposed for capturing then storing the CO2 released during fossil fuels combustion. Post-combustion ammonia absorption is the nearest to market, and will require significant additional amounts of auxiliary drivepower for circulation pumping, CO2 liquification, and high pressure pumping into permanent storage locations, Optimization and automation of the CCS system will also play a key role in making this technology viable. However, current energy consumption estimates for the new auxiliary systems required for CCS are from 25-35% of gross plant output. This implies that for every standard PC plant of a given size, say 500MW net output, that is replace by a CCS plant, up to 40% more coal will have to be consumed to get the same net electrical output. That is, three new SC units will have the output of two old subcritical units.

Alternative Design Options

These design options in the table below leverage existing technologies and approaches to improve the energy productivity of traditional fossil-fired steam plants, but feasibility (shown as Risk vs. reward in the table) varies due to business or technical constraints in existing plant design.

Activity	Risk	Reward
Make commercial use of the byproducts of emissions control systems: Fly ash in the flue gas is removed by existing fabric bag filters or electrostatic precipitators, and can be used in high-quality cement production.	LOW	MED
Install FGD systems which can process FGD by-products into fertilizer or sulfur-based chemicals for other processing plants	MED	MED
Use turbo-expanders on blow-down lines to recycle blow-down steam thermal, kinetic energies.	MED	LOW
Buy energy efficiency as a service provided by vendors willing to stand by their claims for their equipment and designs. Vendors and engineering service providers could provide premium/penalty contract options for efficiency improvement guarantees.	LOW	MED
Draw some of the intake air for Forced Draft (FD) fans from inside the main unit building, near the top. This recycles heat lost from much auxiliary equipment, plus the heat losses through boiler furnace refractory linings (which deteriorate with age). Integrate the FD fan intake with the building HVAC system to ensure satisfactory air flows. Consider ductwork to lead heated air from the step-up transformer fan cooling system to the FD fan intake.	LOW	MED
Use the low-cost 'waste' heat from the LP turbine in an absorption chiller, assuming there is a nearby demand for cooling. This chiller may be cost-effective even if applied only to in-plant and office HVAC cooling needs.	MED	HI
Apply flue gas and/or condenser waste heat towards additional coal drying, especially if lignite coal is used; lignite has a high moisture content. According to EPRI, a CFB dryer technology which removes nearly a quarter of the coal's moisture before the coal is fed into the power plant boiler may yield a 2.8% to 5.0 % efficiency improvement. (EPRI, 2005)	MED	MED
Use acoustic detonation waves for cleaning ash deposits from boiler heating surfaces, a lower energy alternative than current sootblowing practice..	MED	MED
Use co-generation with solar-thermal energy. Though still in the conceptual design phase, the technologies exist to provide heat for feedwater heating and/or steam generation from a solar-thermal plant, thus reducing fossil fuel consumption. (EPRI, 2008)	HI	HI
Use engineered osmosis to recover waste heat from condenser systems. EO uses special membranes for separation of water, driven by low amounts of heat from condenser cooling systems. This technology could be used in conjunction with desalination facilities.	HI	HI

Smart Grid and Efficient Generation Technologies

The Smart Grid begins with Efficient Generation

- Smart Grid, Smart Utility, and Efficient Generation are terms encompassing plant improvements, renewable source power generation, load-flow management, automation, and systems integration. The term ‘smart grid’ refers to a wide range of technologies and operating procedures that will make today’s power system into one that is largely automated, applying greater intelligence to operate, monitor and even heal itself. The smart grid will use the same basic power delivery infrastructure in use today, but also will draw on advanced monitoring, control and communications technology.
- Widespread adoption of the converter technology used in VFDs will allow trains and other vehicles to re-generate power during braking and supply it to the network. This same technology also enables battery-powered vehicles and distributed solar or wind generators to supply the grid..

Importance of Demand Side Management

No discussion of energy efficiency is complete without acknowledging the Khazoom-Brookes postulate (similar to the ‘rebound’ effect for end-use power consumption) in which a free market translates efficiency gains into a reduced price per energy service. This then attracts increased demand for and investment in that energy service, which leads to a net gain in absolute energy consumption. This postulate is counterintuitive and its implications can be disturbing to well-meaning engineers devoted to efficiency improvements. The postulate states that ‘energy efficiency improvements that, on the broadest considerations, are economically justified at the micro-level, lead to higher levels of energy consumption at the macro-level.’ This discussion leads the reader beyond purely technical topics, but it may lead progressive utility investors to also consider demand-side reduction strategies in conjunction with the plant efficiency measures proposed in this handbook.

Several utilities have committed large sums of capital to invest in demand-side reduction activities, to the tune of hundreds of millions of dollars per organization. This is being facilitated in many states, led by California, which have decoupled tariffs, such that utilities are not going to lose revenue as a consequence of their demand-side reduction activities. This is an alternate means for a utility to avoid disappearing reserves, while they anticipates a high cost of emitting CO2, or find it difficult to impossible to locate and license new coal-fired generation facilities.

Appendix A
Technical Symbols

The following tables of common electrotechnical symbols and SI units are from ISO 31 and IEC 60027. This ISO standard 31 is being superseded by the harmonized ISO/IEC 80000 standard.

Mathematical Symbols for electrical quantities (general)

Symbol	Quantity	SI unit
Q	quantity of electricity, electric charge	C
E	electric field strength	V/m
D	electric flux density, electric displacement	C/m^2
U	electric potential difference	V
φ	electric potential	V
ε	permittivity, dielectric constant,	F/m
ε_o	electric field constant, $\varepsilon_o = 0.885419 \cdot 10^{-11}$ F/m	F/m
ε_r	relative permittivity	1
C	electric capacitance	F
I	electric current intensity	A
J	electric current density	A/m^2
x, γ, σ	specific electric conductivity	S/m
ρ	specific electric resistance	$\Omega \cdot m$
G	electric conductance	S
R	electric resistance	Ω
θ	electromotive force	A
S	apparent power	W, (VA)
P	active power	W
Q	reactive power	W, (var)
φ	phase displacement	rad
ϑ	load angle	rad
λ	power factor, λ = PIS, λ cos φ [1)]	1
δ	los angle	rad
d	loss factor, d = tan δ [1)]	1
Z	impedance	Ω
Y	admittance	S
R	resistance	Ω
G	conductance	S
X	reactance	Ω
B	susceptance	S
R	impedance angle, γ = arctan X/R	rad

Table A.1 – Technical symbols (ABB Switchgear Manual, 2005)

Mathematical symbols for magnetic quantities (general)

Symbol	Quantity	SI unit
ϕ	magnetic flux	Wb
B	magnetic flux density	T
H	magnetic field strength	A/m
V	magnetomotive force	A
μ	permeability	H/m
μ_o	absolute permeability, $\mu_o = 4\,\pi \cdot 10^{-7} \cdot$ H/m	H/m
μ_r	relative permeability	1
L	inductance	H
L_{mn}	mutual inductance	H
η	efficiency	1
s	slip	1
ρ	number of pole-pairs	1
w, N	number of turns	1
n_{tr} (t)	transformation ratio	1
m	number of phases and conductors	1
k	overvoltage factor	1
n	ordinal number of a periodic component	1
g	fundamental wave content	1
d	harmonic content, distortion factor	1
k_r	resistance factor due to skin effect	1

1) Valid only for sinusoidal voltage and current

Note: For US/English version of these symbols, see IEEE 280 Standard Letter Symbols for Quantities Used in Electrical Science and Electrical Engineering

Appendix B
Steam Plant Cycle & Equipment

Thermodynamic Cycle

The following diagrams and text are adapted from (IEA Coal Online - 2, 2007)

The proportion of the heat supplied that is converted into mechanical work is referred to as the efficiency of the cycle. For the ideal engine, the efficiency is related to the initial and final temperatures of the system, as follows: $h = (T1–T2)/T1$ (1) where h is the efficiency and T1 and T2 are the upper and lower (initial and final) temperatures between which the engine operates, expressed in degrees Kelvin. The lowest temperature in the steam-turbine cycle depends on the temperature of the coolant water that cools the steam and condensate leaving the low-pressure outlet of the turbine system. The idealized thermodynamic steam-water (Rankine) cycle, with superheating, is illustrated on the figures below. Pressure vs. Volume (right side) and Temperature vs. Entropy (left side)

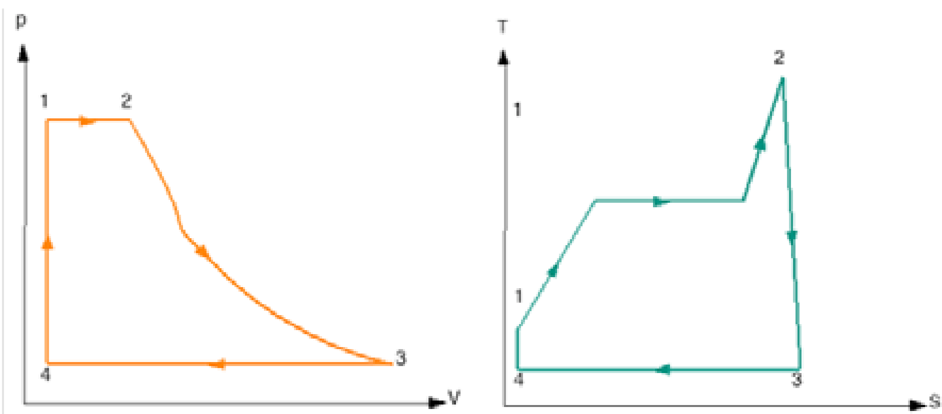


Figure B.1 – Idealized Rankine cycle P-V and T-S diagrams, (IEA Coal Online - 2, 2007)

Sites with access to cold sea water can reach lower bottom-end temperatures in the cycle, and so achieve higher efficiencies. For an upper temperature of 600°C (typical of a state-of-the-art supercritical turbine) and lower temperature of 20°C (typical for sea-water cooling at a North European coastal location), the theoretical maximum efficiency given by equation (1) is 66%. In practice, steam-cycle efficiencies are much lower, in the low 40s% for sub-critical boiler units.

Steam Cycle Equipment

The main steam power plant physical units fall into these categories, with common terminology:

- Furnace ('Fire-side') , incl. coal handling, burners and stack exhaust
- Boiler ('Water-side') , ('Steam path')
- Turbine ('Steam path')
- Condenser ('Water-path')
- Plant Auxiliary Systems
- Generator and electric power supply network ('Electrical BoP')

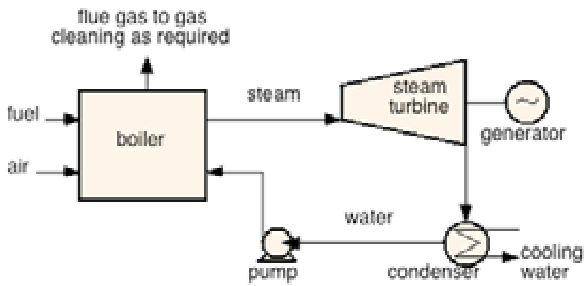


Figure B.2 – Steam cycle fluid flow and main equipment, (IEA Coal Online - 2, 2007)

Cycle Operation

A drum-type subcritical PC boiler takes the pressurized and preheated boiler feedwater from around 250–260°C up to the evaporation point, then superheats it to 540°C or above before sending to the high- pressure turbine. In the steam turbine, the steam is expanded while its energy is converted into mechanical work as it passes over static and moving blades within high-pressure (HP), intermediate-pressure (IP) and low-pressure (LP) turbines, which are usually compounded on to one shaft that drives the generator. .All large steam-turbine cycles incorporate reheat of the intermediate-pressure steam from the high-pressure turbine exit, and multiple stages of feedwater pre-heating using steam extracted from the turbine to maximize efficiency. Steam emerging from the LP turbines is condensed, then pumped back to the boiler after pre-heating, thus completing the cycle

The thermal efficiency of state of-the-art PC plants is 45–47%, LHV (Lower Heating Value) basis, at cold sea-water cooling locations. Such plants use main steam conditions well into the supercritical range, with pressures approaching 30 MPa and temperatures around 600°C Because of the degree of scope for achieving further efficiency improvements through moving to even higher steam conditions, materials-development programs are in progress in different parts of the world to reach them.

Together with cycle design advances, these are expected to realize power-plant efficiencies well beyond 50%, LHV basis (IEA Coal Online - 2, 2007).

Boiler Operation

The figure below shows a drum-type subcritical boiler in simplified diagrammatic form. The economizer, forming the last stage of the boiler's convective section, takes the incoming feed-water's temperature to about 60°C below evaporation temperature for sending on to a steam drum/evaporator recirculation loop. The economizer takes the flue gases down to around 350°C. Lower-temperature heat, down to about 100–150°C, is recovered by transferring the heat to the incoming combustion air using an air heater. This final stage of heat recovery is the air heater, which generally takes the flue gas temperature down from the economizer exit temperature of 350–400°C to 120–150°C

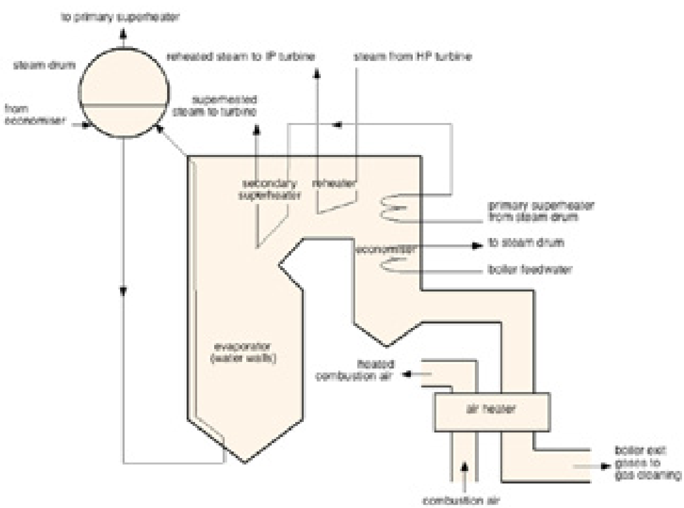


Figure B.3 – Steam generator main equipment, (IEA Coal Online - 2, 2007)

Evaporation takes place using mainly radiant heat, which is transferred to water-carrying tubes forming the wall of the furnace zone of the boiler. The ensuing water/steam mixture passes to a large steam drum, which allows the steam to separate, and the water returns to the evaporator. Either forced or natural circulation is used to send the water round the loop. Steam leaving the drum is then sent to the primary superheater. In both subcritical and supercritical boilers, the superheat and reheat heat-transfer surfaces are mounted above the furnace and in the convection section of the boiler. Super-heaters and re-heaters are generally of a pendant and/or horizontal type, each with at least two stages (for simplicity, only two for superheat and one for reheat are shown on the figure)

Appendix C
Integrative Design Principles

Integrative Design is founded on 'Whole System Thinking' principles. These principles also appear in the related fields of System Engineering, Sustainability Engineering, Industrial Ecology, and meta-design. Integrative design principles are reminders to engineers to look in the places where people, by nature, are not equipped to easily visualize. The four 'corners' which may hide design problems and opportunities are:

Hidden Quantity	Reason why
Things that add up slowly, over time	we tend to focus on the 'now', and less on the far future
Things that multiply along a long path	we tend to focus on the 'here' and less on the route
Things at the edges	we tend to focus on the center and less on the periphery
Things in people's heads	we tend to focus on the objective, and less on the subjective

Think Lifecyle: to see small things accumulating over a long time

Choose quality for reliability, over initial cost

Choose service over product

- Select high-efficiency and high-quality components,
  - The higher initial costs will be repaid in saved energy within a short period and in reduced downtime over a long period...
  - Increased reliability has an direct energy efficiency benefit via reduced unstable or unproductive (ex: startup) operations

- Get fine control of your power input
  - Seek controllability in pumps, fans, burners so that you provide only the power that the process needs, and no more than necessary

Think Bottom Up: to see things multiply along a long path in space

Reduce demand first, then size supply
Reduce downstream loss first, then upstream

Bottom-up thinking moves in the opposite direction of the process flow of fluid, heat or even of information & signals. 'Start with what you need to have or deliver, then work back to supply'.

- Start downstream to design systems with lower capacity requirements
  - Reduce and rationalize end-use demand first : gather data to estimate the REAL end-use loading, then work backward to the power source, reducing losses along the way, Finally, size the supply according to the now-reduced loads

- Keep capacity design margins small
  - It will be cheaper to add extra capacity when requirements increase. Consider a parallel standby unit instead of oversizing the main unit.

- Recover and re-use process energy
  - Use any means, mechanical or chemical, to retrieve what the process doesn't want…

Compounding over Time

Efficiencies compound upward along the flow path, and, because energy is an operating cost, these savings also compound over time.

Compounding over Capital Cost

There is third major compounding effect, and that is the capital equipment cost. A reduction of downstream loads usually means that upstream supply equipment can be safely downsized, which also usually means lower installed costs. Take full advantage of this effect by doing a bottom-up energy assessment of the candidate designs when the plant is still on the drawing board, rather than waiting for a retrofit.

Think Interfaces: to see things at the edges

Put system before components
Put application before equipment

- Practice good thermal integration
  - Connect sources with sinks, aspire to know and use all the available energy ('exergy'), including ambient energies…

- Harmonize the interfaces in both project and plant
  - In your project - between the disciplines & between suppliers. In the plant - between diverse process units & between black-boxes.

- Instrument and monitor your power usage in real-time
  - Specify many, smart transmitters, placed so operators can see the process eat your power across plant units: use data to trend & manage energy KPIs at plant level.

- Make models and use them to control and teach
  - In your project - to tune your design. In the plant - to enable real-time advanced control to keep process stable & at constraint.

'Interface busting' is made more difficult in a world of highly componentized plant equipment. Component-based engineering comes with hidden costs, namely losing the ability to optimize the whole system to its real energy constraints. This lost opportunity can be visualized as wasted volume when constructing a sphere of large blocks vs. smaller ones. Integrated design guidelines insist that vendors provide smaller, less-specialized component units with richer physical & programmatic interfaces. Avoid big isolated non-integrated feature-bloated and often more expensive components or systems, using this rule..

Think People & Process: to see how people think, feel and work together

Put people before procedures & hardware

Put people in charge

- Put away the standard design - go for a walk
  - Ask for time to study alternatives, nature, and talk to operators of the last 'standard design' plant

- Use an agile project execution model
  - Involve operators or others to represent the energy end-users, iterate on the assumed requirements

- Appoint an energy steward
  - An energy steward should be as respected as safety experts are today.

- Seek a single contractor, not multiple vendors
  - Give project, and responsibility, to a firm with broad, multi-disciplinary experience. Do not fracture design through 'divide and conquer'

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On-Line Resources

Supplier Corporate Sites:

- ABB Inc., **http://www.abb.com/energyefficiency**
  - ABB Power Generation Solutions & Products has brochures, case studies
- Alstom Power, **http://www.power.alstom.com/home/**
  - Info on power plant integration
- Siemens Power Generation, **http://www.powergeneration.siemens.com**
  - Pages & tech papers on steam power plants
- Honeywell ACS, Power Solutions, **http://hpsweb.honeywell.com/Cultures/en-US/IndustrySolutions/Power**
- Schneider Electric, **http://www.criticalpowernow.com/**
  - White papers, efficiency calculators , but focus on low voltage

Engineering Services Corporate Sites:

- Foster-Wheeler Global Power Group , **http://www.fwc.com/GlobalPowerGroup/**
  - Many good technical papers on CFB, biomass co-firing, materials
- Black & Veatch Energy , **http://www.bv.com/markets/energy/**
  - Article on coal plant retrofits
  - **www.bv.com/services/Climate_Change_Solutions/En**...
- GE Power, **http://www.gepower.com/home/index.htm**
  - Has design guides and handbooks, section on Clean Coal (IGCC)
- Bechtel Power, **http://www.bechtel.com/power.html**
  - Has several project cases
- Burns & Roe Power and Energy , **http://www.roe.com/power_index.htm**
  - Not much online
- KBR (Kellogg,Brown & Root) , **http://www.kbr.com/publications/coal.aspx**
  - Articles on coal gasification
- Intergraph Process,Power & Marine , **http://www.intergraph.com/ppm**
  - 2D, 3D design software packages
- AspenTech , **http://www.aspentech.com/**
  - Modeling and simulation software tools
- CH2M Hill, **http://www.ch2m.com/corporate/services/sustainable_solutions**
  - EPC with good energy efficiency credentials

- Arup, **http://www.arup.com/**
  - EPC with good energy efficiency credentials, mostly built environment
- Rumsey Engineers, **http://www.rumseyengineers.com/**
  - Specialist in energy efficiency engineering, mostly HVAC
- Southern Company, **http://www.southerncompany.com/planetpower**
  - One example of a utility with a progressive energy efficiency profile

Journals, Articles & News Sites:
- Energy Central , **http://www.energycentral.com/**
  - Have a large tech white paper library
- Power Engineering International, **http://pepei.pennnet.com/**
  - Good articles on steam plant efficiency, retrofits
- Plant Engineering LIVE, **http://www.plantengineering.com/**
  - Many white papers, links on 'energy efficiency'
- Plant Systems, **http://www.plantservices.com/**
  - Excellent VFD articles, sustainability links
- Connecting Industry, **http://www.connectingindustry.com/**
  - Section on energy management
- International Journal of Energy Research
  - http://www3.interscience.wiley.com/journal/3343/home

Academic Sites:
- The Natural Edge Project, **http://www.naturaledgeproject.net**
  - Course in whole system design, with pumping system case
- Engineering News Record, Power & Industrial, **http://enr.construction.com/infrastructure/power_industrial/default.asp**
  - Industry news
- Energy Storm, **http://www.energystorm.us/**
  - Citations, abstracts only
- University of Pittsburgh, Mascaro Sustainability Initiative, **http://www.mascarocenter.pitt.edu/**
  - Mostly built environment, but some power infrastructure as well
- Massachusetts Institute of Technology, Eng'g Systems Div. **http://esd.mit.edu/**
- NTNU Norway , **http://www.ntnu.no/**
- MIT's Center for Engineering Systems Fundamentals , **http://cesf.mit.edu/**
  - For schools : start when they are young!

Professional & Association Sites:
- Motor Decisions Matter **http://www.motorsmatter.org/**
  - Public awareness, Motor Planning Kit
- Pump Systems Matter, **http://www.pumpsystemsmatter.org/**
  - Great papers,tools,links
- Air Movement and Control Association (AMCA) International, **http://www.amca.org/**
  - Non-profit supplier assoc.; has Best Practices for fan systems(US DoE Sourcebook, 2006)(US DoE Sourcebook, 2006)

Industry and Expert Sites:
- Electric Power Research Institute , **http://my.epri.com**
  - Non-profit R&D and consulting organization, utility & industry funded
- Eng-Tips Forums, **http://www.eng-tips.com/**
  - Peek inside the daily work of practicing engineers
  - A great powergen engineering forum
- CR4 Engineering forum, **http://cr4.globalspec.com/**
  - Large forums with hi quality posts
- Leonardo Energy, **http://www.leonardo-energy.org**
  - Global community of sustainable energy professionals
  - Have a slide library for energy educators, design guides on power quality…
- National Assoc. of Energy Service Companies, **http://www.naesco.org/**
  - Demand side programs, but some relevant recommendations
- The Design Futures Council, **http://www.di.net/articles/archive/the_design_futures_council/**
  - Mainly architectural design, but some good, general material
- Pew Center on Global Climate Change, **http://www.pewclimate.org/**
  - Non-profit, non-partisan think tank

Authorities : US & International Sites:
- International Energy Agency (IAE) , **www.iae.org**
  - Global data on coal applications
- IEA Clean Coal Centre, **http://www.iea-coal.org.uk**
  - Unbiased info on coal tech
  - IEA Coal Online, **www.coalonline.org**
- ISO, **http://www.iso.org/iso/hot_topics_energy**
  - Int'l standards organization, with emerging energy mgmt. standards
- World Energy Council , **http://www.worldenergy.org/**
  - Pubs on power plant efficiency, energy policies…(World Energy Council, 2007)
- Consortium for Energy Efficiency (CEE) , **http://www.cee1.org/**

- US Dept. Of Energy, Energy Eff.& Renewable Energy, **http://www1.eere.energy.gov/industry/**
  - Industrial Technologies Program
- ISA Instruments and Automation society, **http://isa.org/**
  - Standards and industry organization
- IEEE Power & Energy Society, **http://ieee.org/portal/site/pes**
  - Good links, active forums
- IEEE Industry Applications Society, **http://ewh.ieee.org/soc/ias/cms/**
- National Academy of Engineering **http://www.nae.edu**
  - Educating the Engineer of 2020: Adapting Engineering Education to the New Century
- American Assoc. of Eng'g Education (ASEE), **http://www.asee.org/**
  - Accreditations, Prism magazine, Journal of Eng'g Education
- American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE), **http://www.ashrae.org/**
- American Society of Mechanical Engineers, **http://www.asme.org/**
- EU Intelligent Energy programme : **http://www.energypath.eu/**
  - For schools , high-schools

Revision History

Ver	Date	Author	Change Description
2.4	23.03.2009	RPM	Torque vs speed info and calculations
3.0	26.03.2009	RPM	Added Arash Baebee comments to VFD section
3.1	12.04.2009	RWV	Final Edit before layout

Contact us

ABB Ltd
P.O. Box 8131
CH – 8050 Zurich Switzerland
Phone: +41 (0) 43 317 7111
Fax: +41 (0) 43 317 7321

www.abb.com

ABB PSP Marketing - North America
29801 Euclid Avenue
Wickliffe, OH 44092
Phone: +1 440-585-8484
Fax: +1 440-585-7944

pspmarketing@us.abb.com

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