Chapter 1

Introduction to Energy Usage, Cost, and Efficiency

1.1 ENERGY UTILIZATION IN THE UNITED STATES

Let us begin by examining energy use in the United States. Figures 1.1 and 1.2 are U.S. energy utilization in 2000 and 2008 as determined by the Energy Information Administration (EIA) and Lawrence Livermore National Laboratory (LLNL). Here, the energy unit used in the figures is quadrillion or quad, and 1 quad = 10^{15} Btu.

Key results from Figures 1.1 and 1.2 as well as energy utilization data from 2000–2008 are summarized in Table 1.1.

Table 1.1 indicates that total energy use in the United States has remained relatively flat for the years 2000–2008. Also, our reliance on "traditional" hydrocarbon energy sources (natural gas, coal, and petroleum) has remained little changed over this near decade. In the future, there is every expectation that alternative energy technologies will grow in importance. For example, wind energy use has increased some fivefold from 2003 to 2008. But in the near term, we should give renewed consideration to the most efficient use of existing energy resources, especially our traditional hydrocarbons. Based on LLNL estimates, Figures 1.1 and 1.2 indicate that overall U.S. energy efficiency is ~42%. The ~58% rejected energy is primarily waste heat from combustion. A motivation for this book is to support existing and planned processing sites and energy facilities to help ensure energy is being used as efficiently as possible.

1.2 THE COST OF ENERGY

We next ask the following question, "Just how important are process energy costs?" Energy costs are often one of the largest single expenses at an industrial processing site along with labor and raw materials. These industrial processing sites would include chemicals and petrochemicals, agrochemicals, pharmaceuticals, plastics, paper and pulp, metal and mining. In these industries, energy costs typically range from about 10% to over 50% of the operating expenses for the site.

To assign an actual dollar cost, we need to pick a price for energy and to estimate a typical process energy load. For the price of energy, we can use the cost of natural gas to industry as a benchmark. Many industries in the United States were built on "$2" natural gas—this "$2" refers to $2 per million British thermal unit (MMBtu) or $2 per thousand standard cubic foot (mSCF). Roughly 1 mSCF of natural gas contains 1 MMBtu. Figure 1.3 shows the average annual industrial price for natural gas from 1973 until 2009. Figure 1.4 shows the average monthly industrial price for natural gas from January 2000 to November 2010 (EIA). Costs in Figures 1.3 and 1.4 are not adjusted for inflation. Starting in about 2000, there has been an upward trend in natural gas price coupled with large short-term price swings. For example, in 2005, Hurricanes Katrina and Rita contributed to spot market natural gas prices climbing to $15+ per MMBtu for short periods of time.

Next, we can address, "What is a typical process energy load?" A large industrial (chemical plant or refinery) may use $50–100 \times 10^9$ Btu/day for heating and power generation. This is the energy required to produce steam and electricity for process use. A medium-sized industrial or a large university may use $10–20 \times 10^9$ Btu/day for heating and power generation.

Using a long-term projected price of $8 natural gas ($8 per MMBtu) as a fuel cost, the utility cost for a large industrial may be on the order of 200×10^6 per year, and a
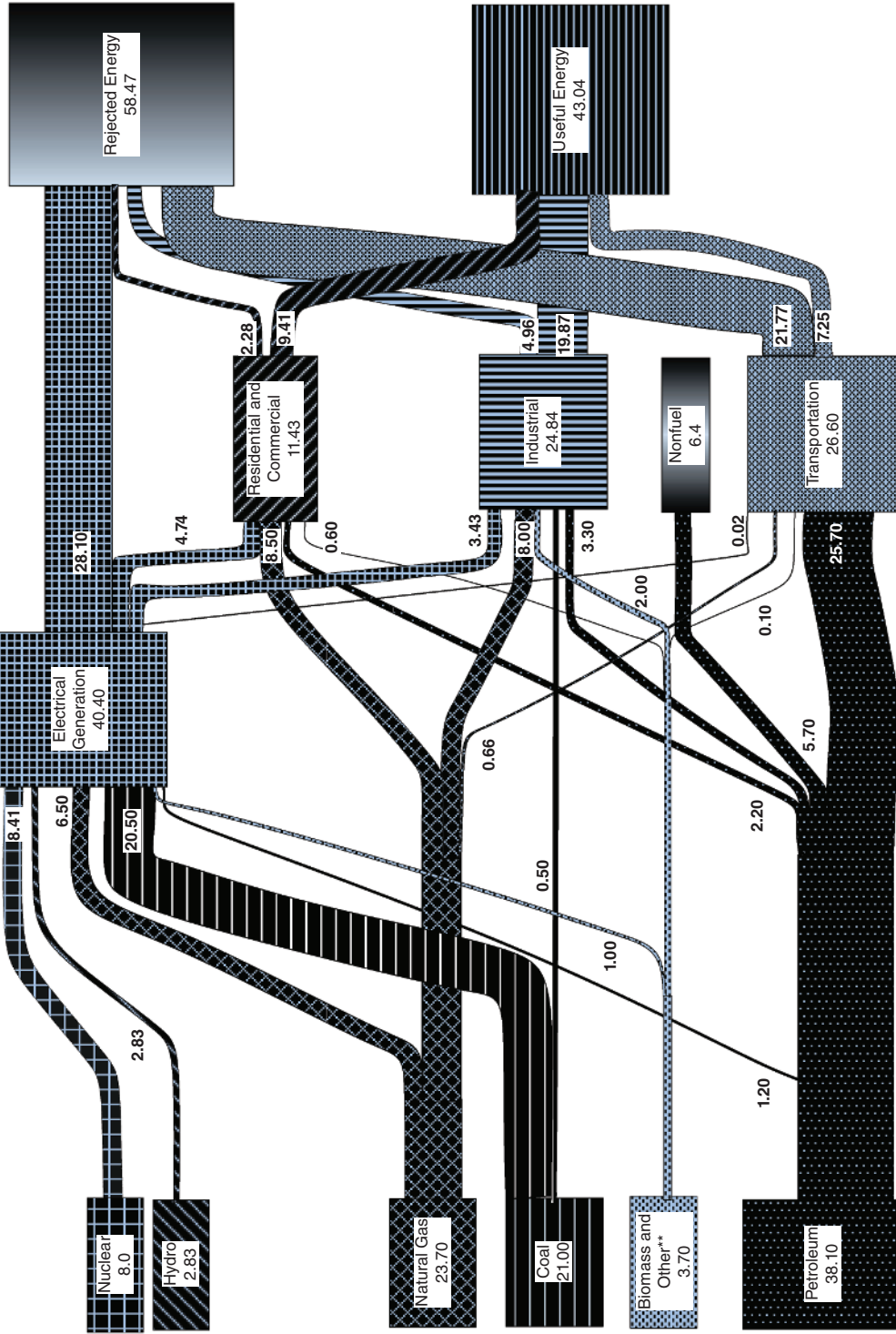
Figure 1.1 Energy use in the United States (EIA and LLNL; see the References for the Web site) in 2000. In this figure, nonfuel from petroleum feed is, for example, petroleum used as a chemical feedstock.
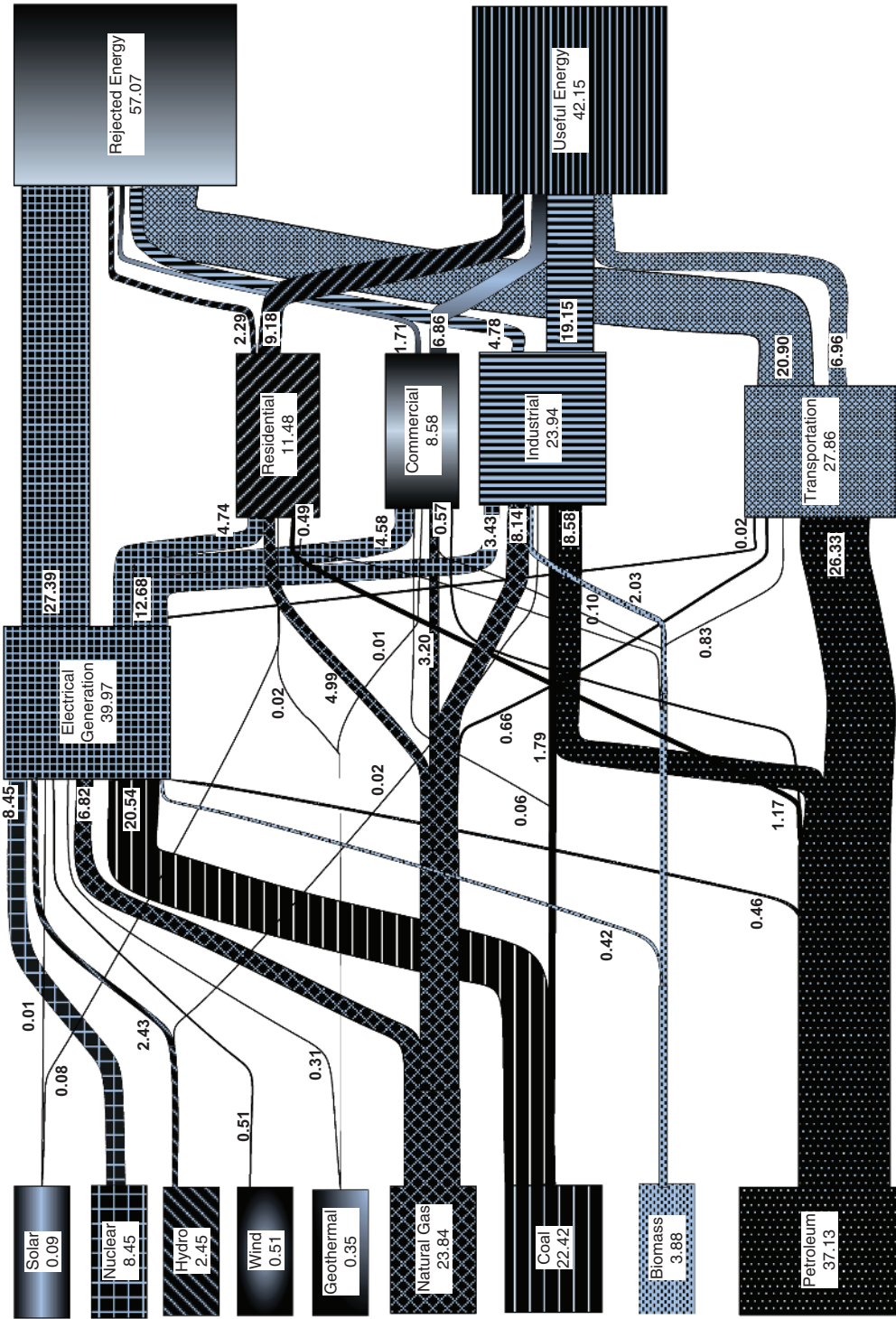
Figure 1.2 Energy use in the United States in 2008 (EIA and LLNL).

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Table 1.1   Summary of Energy Use (Quadrillion British Thermal Unit) in the United States from 2000 to 2008 (EIA)

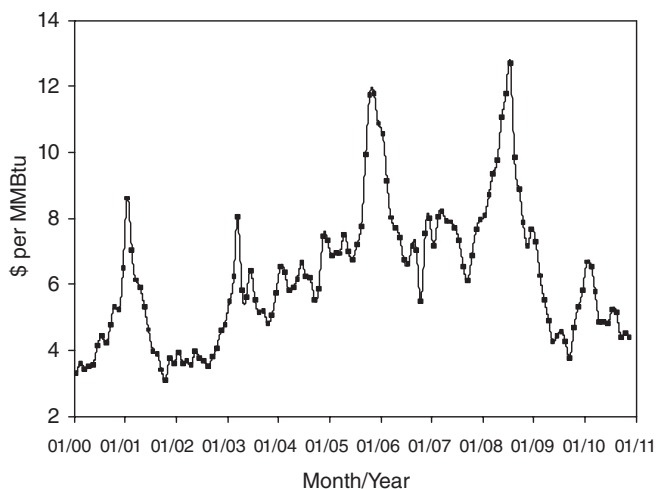|	2000	2001	2002	2003	2004	2005	2006	2007	2008
Total energy use	98.5	97.0	97.0	98.1	100.2	100.4	99.8	101.5	99.2
Energy from									
Solar				0.06	0.06	0.06	0.07	0.08	0.09
Nuclear	8.0	8.0	8.10	7.95	8.22	8.16	8.21	8.41	8.45
Hydro	2.83	2.30	2.60	2.82	2.69	2.70	2.86	2.46	2.45
Wind				0.11	0.14	0.17	0.26	0.31	0.51
Geothermal				0.33	0.34	0.34	0.34	0.35	0.35
Natural gas	23.70	23.20	23.20	22.90	22.93	22.50	22.19	23.63	23.84
Coal	21.0	21.90	22.30	22.32	22.46	22.79	22.44	22.76	22.42
Biomass	3.7*	3.3*	3.2*	2.81	3.02	3.15	3.37	3.61	3.88
Petroleum	38.10	38.0	38.10	38.80	40.29	40.39	39.95	39.81	37.13
Energy from natural gas, coal, and petroleum	82.28	83.10	83.60	84.05	85.68	85.68	84.58	86.30	83.39

*The biomass data for 2000–2002 include wood and waste, geothermal, solar, and wind.
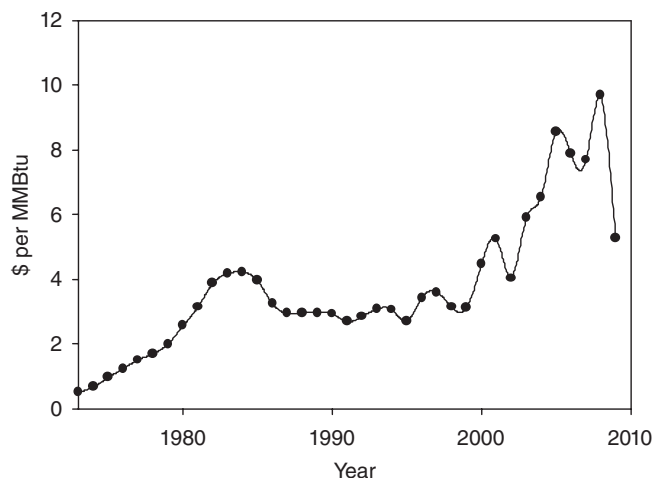
Figure 1.3   Industrial price for delivered natural gas (dollar per MMBtu) and yearly average price from 1970 to 2009 (EIA).

Figure 1.4   Industrial price for delivered natural gas (dollar per MMBtu) and monthly average price from January 2000 to November 2010 (EIA).

medium-sized industrial or large university may see utility costs near 40×10^6 per year. Utility costs may be higher if electricity is purchased from the local utility and steam is generated in boilers, as opposed to taking advantage of combined heat and power generation opportunities.

We can see that energy costs are a significant consideration in most processes. Increasing worldwide demand for energy is expected to keep utility costs on a positive slope. There is a need for careful assessment of the energy currently being used in a process coupled with a systematic approach for reducing this energy use. In many processing plants, electricity is both purchased and generated, and in deregulated areas, plants may sell electricity to the open market. Fluctuating energy costs (see Figure 1.4) necessitate

a careful coupling of process energy needs with utility production planning and utility purchase.

1.3   ENERGY EFFICIENCY

There are two commonly used definitions of efficiency, η, one based on the first law of thermodynamics and a second definition based on the second law of thermodynamics. From the first law of thermodynamics, we can write

$$\eta_{1st} = \frac{\text{Usable energy output from the system}}{\text{Energy supplied to the system}}. \quad (1.1)$$

Here, we account for the energy supplied to the system and the usable energy from the system. From the second law of thermodynamics, we can write

$$\eta_{2nd} = \frac{\text{Minimum theoretical energy required}}{\text{Energy actually used}}. \quad (1.2)$$

Both definitions will find use in the energy and power calculations performed in this text. As Equation (1.2) requires additional development, examples and problems in this chapter will just focus on Equation (1.1).

In many efficiency calculations, Equation (1.1) can be directly used. In some cases, especially when a specific operation is using or producing electricity (e.g., a turbine), Equation (1.2) proves more beneficial. For power (electricity) generating systems, overall performance is often provided by an alterative form of Equation (1.1)—the plant net heat rate,

Plant net heat rate

$$= \frac{\text{Energy supplied to the system, Btu}}{\text{Usable electrical energy output from the system, kW-h}}.$$

$$(1.3)$$

EXAMPLE 1.1 *Utility Company Power Plant Energy Efficiency*

A coal-fired utility company power plant is shown in Figure 1.5. Here, time is not considered—we are just looking at the energy flows resulting from 1000 lb of coal being added to the boiler. The values provided in Figure 1.5 represent energy inputs to each operation; for example, energy to the boiler from the coal feed is 12,720,000 Btu. Part of this 12,720,000 Btu will be sent to the turbine (as steam) and part will be lost to the stack. Of the 11,194,000 Btu sent to the turbine, 5,261,000 Btu is used for electricity generation. The turbine here is a "condensing steam turbine." This is also typically referred to as a bottoming cycle as all the available energy in the steam for power generation is extracted in the turbine and then the steam is condensed. The 4,933,000 Btu of thermal energy rejected to the environment is required to condense low-pressure steam from the turbine. This condensing allows the boiler feedwater to be recycled as it allows the boiler feedwater pressure to be increased using a pump. The return boiler feedwater contains 1,000,000 Btu.

It is possible to directly convert the energy flows in Figure 1.5 to energy transfer rates, for example, 1000 lb of coal per hour would generate 12,720,000 Btu/h. It is also possible to consider the energy flows in Figure 1.5 to be directly scalable; for example, 2000 lb of coal would generate 25,440,000 Btu. For now, we can use the energy values in Figure 1.5 to determine the efficiency of the boiler, the turbine, and the generator and also the overall process thermal efficiency (sometimes termed the plant net thermal efficiency) and the power plant net heat rate (British thermal unit per kilowatt-hour).

In this example, we are just accounting for energy flow within the utility plant fence line. We are not accounting for transportation and distribution losses. Exported power to the grid often experiences 5–8% transmission and distribution losses before that power can be utilized at the end application (see Problem 1.5).

SOLUTION It can sometimes be confusing trying to consistently determine unit by unit and overall system efficiencies using Equations (1.1) and (1.3). It can be helpful to think of each unit (or system) as a cost center. For example, the boiler "purchases" 12,720,000 Btu of coal and "sells" 11,194,000 Btu to the turbine and takes back "credit" 1,000,000 Btu as condensate return. The efficiency of the boiler is

$$\eta_{Boiler} = \frac{(11,194,000 - 1,000,000)}{12,720,000} = 80.1\%.$$

The turbine is needed to generate electricity, and here the turbine purchases 11,194,000 Btu and "delivers" 5,261,000 Btu for electricity generation. The efficiency of the turbine is

$$\eta_{Turbine} = \frac{5,261,000}{11,194,000} = 47.01\%.$$

For the overall thermal efficiency, 12,720,000 Btu of coal is supplied to the plant, and 4,844,000 Btu of electricity is delivered for transmission and sale. Here 365,000 Btu of electricity for coal handling, including coal conveyors and coal crushers or pulverizers, is used internally and is not available for "sale"—internal use of electricity is often termed a parasitic load. The utility plant net heat rate is defined as the British thermal unit supplied to the plant divided by the kilowatt-hour of electricity delivered for transmission:

$$\frac{12,720,000 \text{ Btu}}{1420 \text{ kW-h}} = 8957.7 \frac{\text{Btu}}{\text{kW-h}}.$$

Efficiency results for the coal utility plant are summarized in Table 1.2.

It is often convenient to represent the energy flows in Figure 1.5 on a Sankey diagram, which is shown in Figure 1.6a. From the Sankey diagram, where the energy flow is normalized to 100 input units (Figure 1.6b), it is easy to see the overall plant thermal efficiency is 38.08%, here

$$\frac{4,844,000 \text{ Btu}}{12,720,000 \text{ Btu}} = 38.08\%. \qquad \blacksquare$$

EXAMPLE 1.2 *Topping Cycle Cogeneration Plant Energy Efficiency*

A natural gas-fired topping cycle cogeneration facility is shown in Figure 1.7. It is termed a topping cycle because electricity is generated from the steam before the steam is used by the process. The topping cycle uses a back-pressure or "let-down" steam turbine. Unlike the condensing steam turbine of Example 1.1, steam exhaust from a back-pressure turbine still has energy that can be useful in
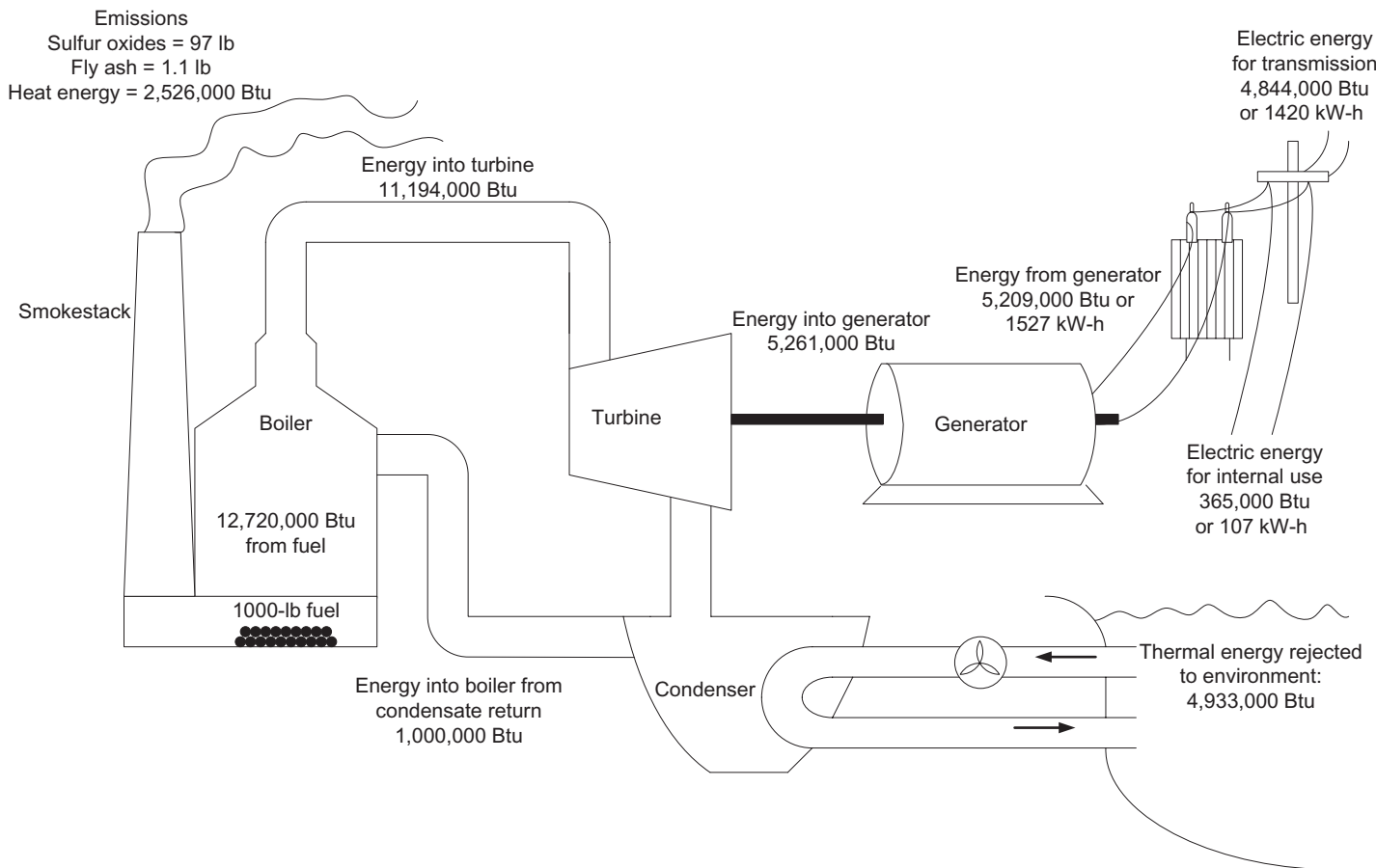
Figure 1.5 Coal-fired electric power plant (adapted from Priest, 1973).

the process. The thermal energy (steam) from the turbine is used for heating within the processing plant and the condensate is returned to the boiler. In a topping cycle cogeneration facility, the ratio of the process steam demand to the process electricity demand is generally large; this is typical of the needs found in a brewery or distillery. The values provided in Figure 1.7 again represent the energy input to each operation. Determine the efficiency of the boiler, the turbine, the generator, and also the overall process thermal efficiency and the cogeneration plant heat rate (British thermal unit per kilowatt-hour). Finally, draw the Sankey diagram with energy flows normalized to 100 input units (British thermal unit).

SOLUTION The efficiencies for the topping cycle are provided in Table 1.2. For the overall thermal efficiency, 12,720,000 Btu of natural gas is supplied to the system, 1,720,000 Btu is available for transmission as electricity (to the process), and 8,439,000 Btu is used as heat in the process. The Sankey diagram is shown in Figure 1.8. ■

EXAMPLE 1.3 *Gas Turbine Cogeneration Plant Energy Efficiency*

A natural gas-fired turbine cogeneration facility typical of a processing plant or university is shown in Figure 1.9. The values provided in Figure 1.9 are the energy input to each operation. Compressed air and natural gas are mixed and combusted in the turbine system. The hot-pressurized exhaust gas loses pressure as it drives the turbine. Part of the energy from the turbine is used to compress the incoming air; part is used to generate electricity; and the remainder used for steam generation. The figure shows that the turbine shaft (here a single shaft) turns both the generator and the air compressor. The energy from the turbine that drives the air compressor (6,400,000 Btu) will add to the energy of the incoming air stream. In later chapters, we will account for energy losses in the compression process. If we examine the mechanical energy from the turbine (6,400,000-Btu compression + 4,250,000-Btu electricity), ~60% of this mechanical energy is used to drive the compressor. The compression process can be viewed as a recycle energy stream—this energy (6,400,000 Btu) from the turbine is actually returned to the turbine by increasing the air feed stream pressure and temperature.

The hot and nearly atmospheric pressure exhaust gas from the turbine (8,470,000 Btu) passes to a waste heat boiler (WHB), which recovers energy, as steam, for use in the process. The steam from the boiler is used for heating within the processing plant and the condensate is returned to the boiler. Determine the efficiency of the boiler, the turbine, and the generator in this power plant. Also determine the overall plant thermal efficiency and the cogeneration plant net heat rate (British thermal unit per kilowatt-hour). Finally, draw the Sankey diagram with energy flows normalized to 100 input units (British thermal unit).

Table 1.2   Efficiencies for Different Energy System Configurations

Operation	Coal Utility Plant	Topping Cycle	Gas Turbine
η_{Boiler}, boiler efficiency	$\dfrac{10{,}194{,}000}{12{,}720{,}000} = 80.1\%$	$\dfrac{10{,}176{,}000}{12{,}720{,}000} = 80.0\%$	See discussion* $\dfrac{6{,}070{,}000}{8{,}470{,}000} = 71.7\%$
$\eta_{Turbine}$, turbine efficiency	$\dfrac{5{,}261{,}000}{11{,}194{,}000} = 47.0\%$	See discussion following this table*	See discussion following this table*
$\eta_{Generator}$, generator efficiency	$\dfrac{5{,}209{,}000}{5{,}261{,}000} = 99.0\%$	$\dfrac{1{,}720{,}000}{1{,}737{,}000} = 99.0\%$	$\dfrac{4{,}208{,}000}{4{,}250{,}000} = 99.0\%$
Overall plant thermal efficiency or plant net thermal efficiency	$\dfrac{4{,}844{,}000}{12{,}720{,}000} = 38.08\%$	$\dfrac{10{,}159{,}000}{12{,}720{,}000} = 79.86\%$	$\dfrac{10{,}278{,}000}{12{,}720{,}000} = 80.8\%$
Plant net heat rate	$\dfrac{12{,}720{,}000 \text{ Btu}}{1420 \text{ kW-h}}$ $= 8957.7\dfrac{\text{Btu}}{\text{kW-h}}$	See discussion* $\dfrac{12{,}720{,}000 \text{ Btu}}{504 \text{ kW-h}}$ $= 25{,}238\dfrac{\text{Btu}}{\text{kW-h}}$	See discussion* $\dfrac{12{,}720{,}000 \text{ Btu}}{1233 \text{ kW-h}}$ $= 10{,}316\dfrac{\text{Btu}}{\text{kW-h}}$
Incremental heat rate		$\dfrac{4{,}281{,}000 \text{ Btu}}{504 \text{ kW-h}}$ $= 8494\dfrac{\text{Btu}}{\text{kW-h}}$	$\dfrac{6{,}650{,}000 \text{ Btu}}{1233 \text{ kW-h}}$ $= 5393.3\dfrac{\text{Btu}}{\text{kW-h}}$

*Calculation of these quantities requires additional discussion, which is provided in the text below.
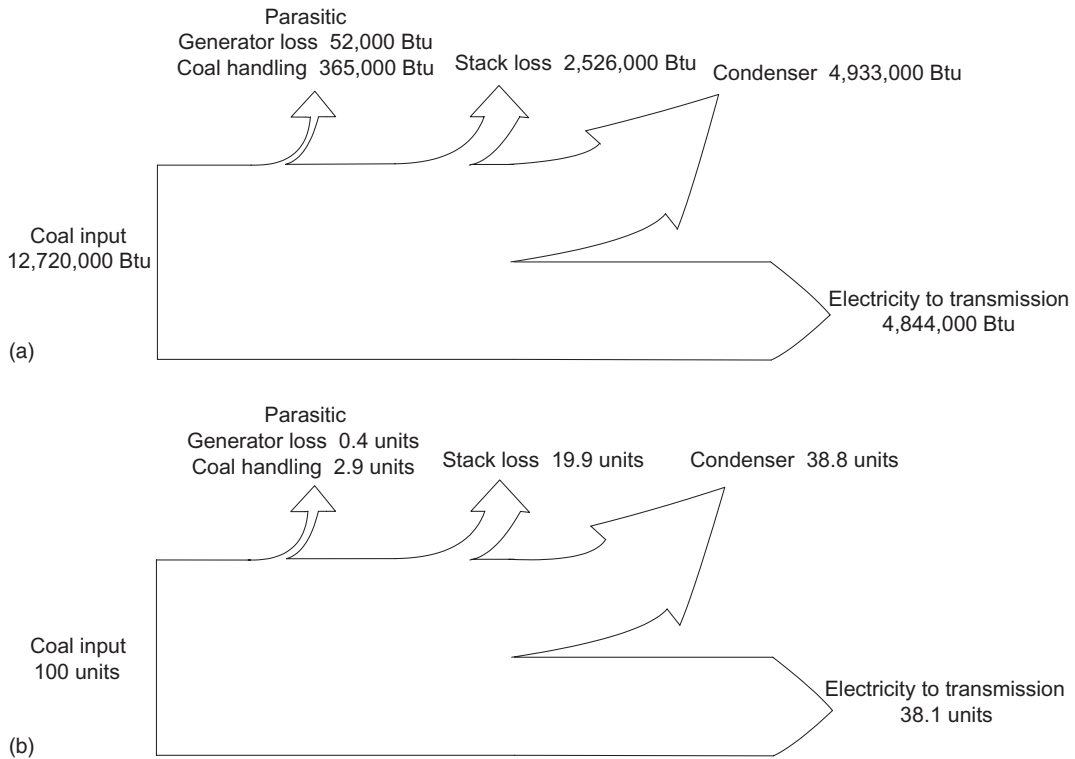
Figure 1.6   (a) Sankey diagram for conventional electricity generation from a coal-fired utility. (b) Sankey diagram for conventional electricity generation from a coal-fired utility with input normalized to 100 units.
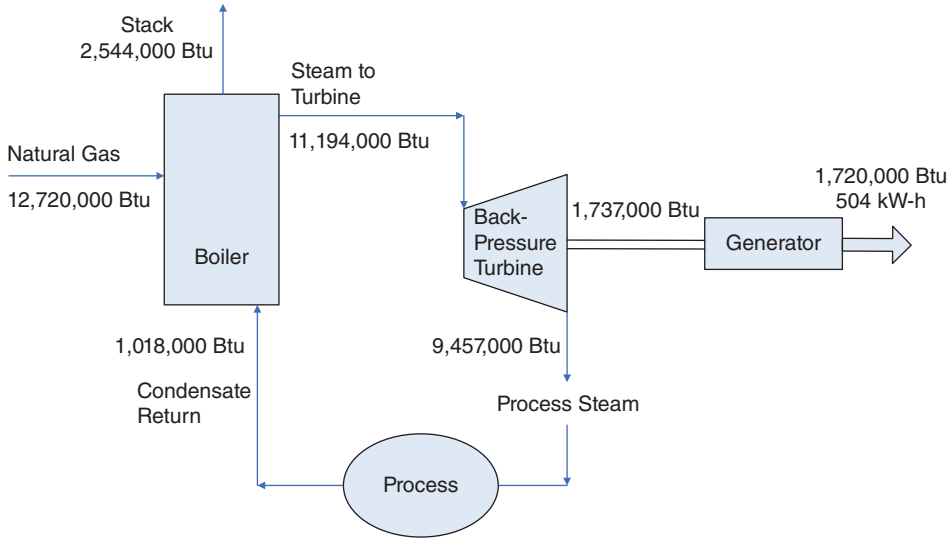
Figure 1.7 Industrial topping cycle cogeneration system.
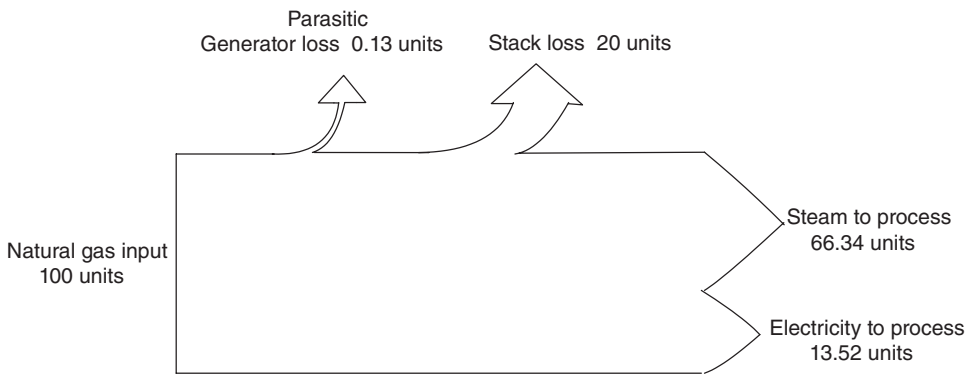
Figure 1.8 Sankey diagram for topping cycle cogeneration facility.

Figure 1.9 Gas turbine cogeneration system.

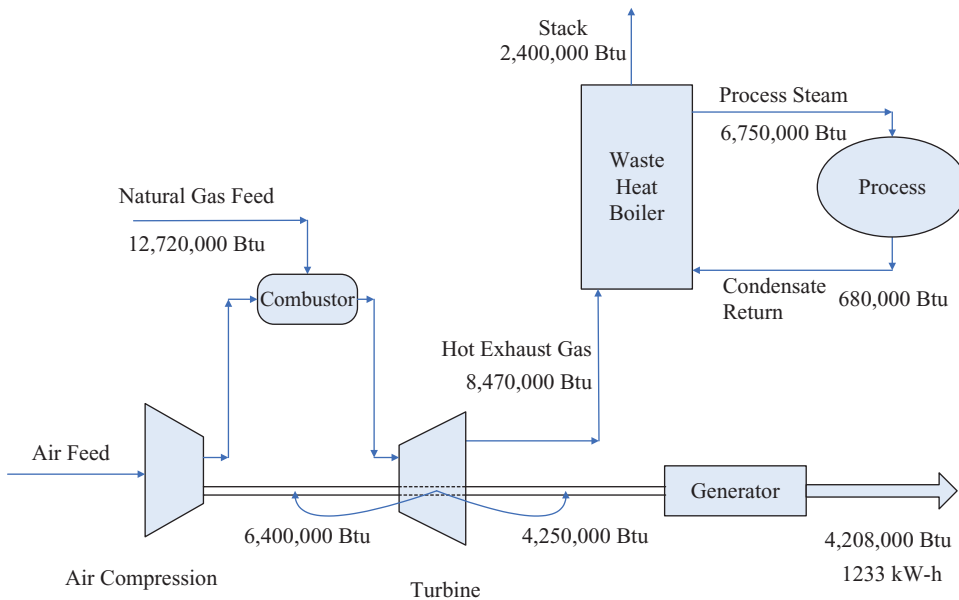*SOLUTION* The efficiencies for the gas turbine-based cogeneration system are provided in Table 1.2. For the overall thermal efficiency, 12,720,000 Btu of natural gas is supplied to the system; 4,208,000 Btu is available for transmission as electricity (to the process); and 6,070,000 Btu is used as heat in the process. The Sankey diagram for the gas turbine system is shown in Figure 1.10. ∎

From Table 1.2, the use of the first law efficiency is reasonable for boiler calculations where the fuel to the boiler is fired and the combustion gas is immediately used to raise steam as in Examples 1.1 and 1.2. The calculated efficiency of the boiler in Example 1.3 (the waste heat boiler) can be misleading—we must appreciate that energy (and temperature) has been extracted from the combustion gas prior to the waste heat boiler, which reduces the apparent first law efficiency. In comparison, when additional fuel is added to the hot exhaust gas entering the waste heat boiler, in order to raise additional steam for the process, the efficiency of this "supplemental firing" approaches 99%.

The turbine efficiency for the coal plant is based on all available energy entering the turbine and on the complete extraction of all useful energy to electricity. For both the topping cycle and the cogeneration system, part of the available energy to the turbine is used to produce electricity, but part of the energy remains, which is used as heat within the process. Here, for turbine calculations, efficiencies based on the second law of thermodynamics (Eq. (1.2)) will be developed.

The overall plant thermal efficiency also requires discussion. The thermal efficiency is

$$
\text{Thermal efficiency} = \frac{\left(\begin{array}{c} \text{Usable electrical energy output} \\ + \text{ Heat energy used by the process} \end{array} \right), \text{Btu}}{\text{Energy supplied to the system, Btu}}. \tag{1.4}
$$

The thermal cycle efficiencies in Table 1.2 range from 38.1% for the simple cycle (power only) coal plant to 80.8% for the process cogeneration facility (combined power and process heat use). The underlying justification for much of the energy optimization in this chapter is the efficiency gains made possible when moving from utility plant simple cycles to combined cycle processing facilities. But to be fair, we do need to appreciate that in these efficiency calculations, we are treating electrical energy the same as thermal energy. Clearly, electrical energy is more valuable than thermal energy. Electrical energy can be transported long distances, and low-temperature, low-pressure thermal energy is often of little value. For cogeneration applications to be economical, there must be a home (or need) for all the generated thermal energy.
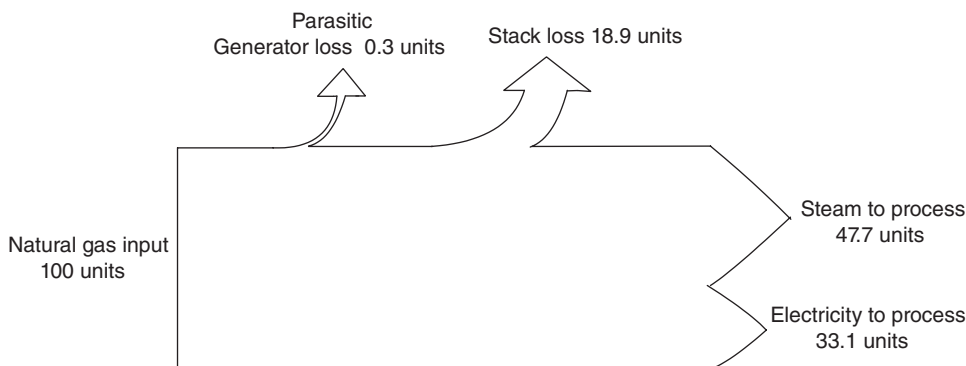
Plant net heat rates are often used to compare utility plants to process cogeneration facilities. This is especially true when inefficient utility plants with heat rates >10,000 Btu/kW-h are compared to process cogeneration facilities. For cogeneration facilities, a better maker is an incremental heat rate (also shown in Table 1.2), which is defined as

$$
\begin{aligned}
&\text{Incremental heat rate} \\
&= \frac{\left(\begin{array}{c} \text{Energy supplied to the system} \\ - \text{ Heat energy used by the process} \end{array} \right), \text{Btu}}{\begin{array}{c} \text{Usable electrical energy output from the} \\ \text{cogeneration system, kW-h} \end{array}}. \tag{1.5}
\end{aligned}
$$

For example, for the cogeneration system,

$$
\text{Incremental heat rate} = \frac{(12,720,000 - (6,750,000 - 680,000))}{1233}
$$

$$
= \frac{6,650,000}{1233} = 5393.3 \frac{\text{Btu}}{\text{kW-h}}.
$$

What is beneficial from these examples is to observe from the Sankey diagrams that different cogeneration configurations can produce different amounts of steam and electricity for use in a process. Also, cogeneration systems show a higher thermal efficiency when compared with utility plants, as the steam generated in cogeneration systems is condensed in the process. In utility plants, low-temperature, low-pressure steam is condensed by cooling water. Plant net heat rate values from Table 1.2 can facilitate the analysis of self-generated versus purchased power (electricity) as we will see in the next examples.

Parasitic
Generator loss 0.3 units

Stack loss 18.9 units

Natural gas input
100 units

Steam to process
47.7 units

Electricity to process
33.1 units

Figure 1.10 Sankey diagram for gas turbine cogeneration system.

1.4 THE COST OF SELF-GENERATED VERSUS PURCHASED ELECTRICITY

Overall process efficiency can often be improved by self-generating electricity and recovering combustion energy for use as heat in the process—cogeneration. Understanding the costs of self-generated electricity and utility company supplied electricity is important in order to accurately access cogeneration opportunities. Based on the heat rate determined in Example 1.1, we can determine the break-even cost for the utility company to supply electricity. The efficiencies in Example 1.1 can be considered relatively independent of the size of the utility plant.

EXAMPLE 1.4 *The Break-Even Cost of Purchased Electricity*

Using our results from Example 1.1, we can discuss the cost of electricity purchased from the utility company. For example, if coal is $5 per MMBtu, the fuel cost to generate electricity would be 8957.7 Btu/kW-h × $5 per MMBtu = 4.48¢ per kilowatt-hour.

Also from Example 1.1, if the fuel was switched from coal to natural gas, we would anticipate a lower plant net heat rate as the parasitic electricity load for coal handling would be eliminated. With natural gas fuel, the expected utility plant heat rate would be

$$\frac{12{,}720{,}000 \text{ Btu}}{1527 \text{ kW-h}} = 8330 \frac{\text{Btu}}{\text{kW-h}}.$$

Using this heat rate and with $8 natural gas ($8 per MMBtu), the cost for the utility company to generate electricity is 6.66¢ per kilowatt-hour.

In addition to fuel costs, there would be an expected operation and maintenance (O&M) cost at roughly 0.5¢ per kilowatt-hour and a 0.2¢ per kilowatt-hour transmission cost. So, for a 8957.7 heat rate coal plant, a "break-even" cost for electricity generation would be ~5.2¢ per kilowatt-hour and for a 8330 heat rate natural gas plant ~7.4¢ per kilowatt-hour. A coal plant will have additional costs associated with environmental cleanup compared to a natural gas-fired plant. For example, from Figure 1.5, a 20-MW coal-fired utility plant must address the release of about 1275 lb/h of sulfur oxides to the atmosphere. In fact, for a new construction coal plant, the costs associated with meeting environmental regulations can easily wipe out any savings when compared to a natural gas-fired plant. The effect of potential long-term emission fees on existing coal-fired plants (including CO_2 capture and sequestration costs) is detailed in Chapter 16. ∎

We can next discuss the cost of self-generated electricity.

EXAMPLE 1.5 *The Cost of Self-Generated Electricity without Cogeneration Credit*

Consider the cost of generating electricity from the gas turbine-based cogeneration system of Example 1.3. With $8 natural gas,

the fuel cost to generate electricity is 10,316 Btu/kW-h × $8 per MMBtu = 8.25¢ per kilowatt-hour. With O&M cost again at roughly 0.5¢ per kilowatt-hour, the cost for self-generation would be ~8.8¢ per kilowatt-hour, which is 68% more than the break-even cost of electricity from a coal-fired utility and 18% more than the break-even cost of electricity from a natural gas-fired utility. Of course, here we have not yet valued the generated steam used in the process. ∎

A utility company will produce and often purchase electricity from a number of sources using fuels including coal, natural gas, hydro, and nuclear energy (see Figures 1.1 and 1.2). Coal accounts for ~50% of utility electricity generation here in the United States. Generally, based solely on electricity generation costs, a cogeneration facility cannot compete with electricity generation from a utility company. To keep the economics favorable for a cogeneration system, there must be a home for the generated steam. This "home" is typically the industrial process as indicated in Figures 1.7 and 1.9. In some cases, a portion of the generated steam can also be sent to a steam turbine to produce additional electricity in a combined cycle cogeneration plant. Most cogeneration facilities use natural gas-fired turbines as shown in Figsure 1.9. We must also appreciate that as natural gas fuel costs rise, electricity purchased from a utility company becomes increasingly favorable as their fuel mix (coal, natural gas, hydro, and nuclear energy) and longer-term fuel contracts help stabilize electricity cost.

Finally, in Examples 1.4 and 1.5, we did not include capital costs, which we will do in Example 1.6. The costs in Examples 1.4 and 1.5 represent "incremental costs," assuming the generation resource is already in place.

EXAMPLE 1.6 *The Cost of Self-Generated Electricity with Cogeneration Credit*

In Example 1.5, cogeneration electricity costs were skewed because we did not value the generated steam. This example considers replacing an existing process utility system—a steam boiler and utility company electricity purchase, with a gas turbine cogeneration system. The calculations in the example can be found in the Excel file **Example 1.6.xls**; see Section 1.7 for details on installing Excel example files and developed software.

SOLUTION Current Plant

A processing plant is currently purchasing 1000 kW from the local utility and is obtaining some 4800 lb/h of steam from a stand-alone boiler. The process uses ~1000 Btu from each pound of steam (British thermal unit per pound steam from the boiler—British thermal unit per pound in the condensate return). Within the processing plant, steam is thermally valued at $9 per 1000 lb and purchased utility costs are 7¢ per kilowatt-hour

plus a demand charge of $7 per kilowatt-month. The plant operates 8000 h/year.

We first determine the hourly utility cost:

$$\text{Electricity cost:} \left(\frac{\$0.07}{\text{kW-h}} \right) (1000 \text{ kW}) = 70\frac{\$}{\text{h}},$$

Electricity demand charge:

$$\left(\frac{\$7}{\text{kW-month}} \right) (1000 \text{ kW}) \left(\frac{12 \text{ months}}{\text{year}} \right) \left(\frac{1 \text{ year}}{8000 \text{ h}} \right) = 10.50\frac{\$}{\text{h}},$$

$$\text{Steam cost:} \left(\frac{\$9}{1000 \text{ lb}} \right) \left(\frac{4800 \text{ lb}}{\text{h}} \right) = 43.20\frac{\$}{\text{h}}.$$

The total utility cost is $123.70 per hour or $989,600 per year.

Cogeneration Facility

We want to evaluate replacing our boiler/purchased electricity with a gas turbine-based cogeneration facility with performance values based on Example 1.3. A gas turbine cogeneration system (turbine and heat recovery boiler) will have a total installed cost of $1100 per kilowatt, and natural gas costs are $8 per 10^6 Btu:

$$\text{Installed cost:} \left(\frac{\$1100}{\text{kW}} \right) (1000 \text{ kW}) \left(\frac{0.16 \text{ CRF}}{\text{year}} \right) \left(\frac{1 \text{ year}}{8000 \text{ h}} \right)$$

$$= 22.00\frac{\$}{\text{h}}.$$

In the installed cost calculation, we are using a capital recovery factor (CRF) of 0.16, which converts the total installed cost (including tax and depreciation considerations) to a uniform annual cost. The CRF is developed in Chapters 2 and 16:

$$\text{Natural gas cost:} \left(\frac{10,316 \text{ Btu}}{\text{kW-h}} \right) (1000 \text{ kW}) \left(\frac{\$8}{10^6 \text{ Btu}} \right)$$

$$= 82.53\frac{\$}{\text{h}}.$$

We must also check if the cogeneration system will supply enough usable heat in the waste heat boiler to meet our steam needs:

$$\text{Usable heat:} \left(\frac{10,316 \text{ Btu}}{\text{kW-h}} \right) (1000 \text{ kW}) \left(\frac{47.7 \text{ steam units}}{100 \text{ units in}} \right)$$

$$= 4,920,732\frac{\text{Btu}}{\text{h}}.$$

The factor

$$\left(\frac{47.7 \text{ steam units}}{100 \text{ units in}} \right)$$

comes from the gas turbine Sankey diagram (Figure 1.10). And the steam generation would be

$$\text{Steam generation:} \left(4,920,732\frac{\text{Btu}}{\text{h}} \right) \left(\frac{1\text{-lb steam}}{1000 \text{ Btu}} \right)$$

$$= 4921\frac{\text{lb steam}}{\text{h}}.$$

The steam generated from the cogeneration system would exceed the 4800 lb/h currently needed, and some design changes in the cogeneration system may be considered:

$$\text{O\&M (operation and maintenance) costs:}$$

$$\left(\frac{\$0.005}{\text{kW-h}} \right) (1000 \text{ kW}) = 5\frac{\$}{\text{h}}.$$

The cost of the cogeneration system is $109.53 per hour. The profit if the cogeneration system was installed would be $14.17 per hour or $113,376 per year. This is profit as we have accounted for the installed cost of the cogeneration system. The profit from a cogeneration can be very sensitive to fuel costs and purchased electricity costs (see Problem 1.3). Do note that nearly 75% of the cogeneration profit can be traced to the utility demand charge. The demand charge is explained in Chapter 12. ∎

1.5   THE COST OF FUEL AND FUEL HEATING VALUE

Before we finish our discussion of energy, the cost of energy, and energy efficiency, it is important to understand the energy content or the heating value of a fuel and how fuel is priced.

EXAMPLE 1.7   *A Special Caution: The Fuel Heating Value*

Let us start our discussion of the fuel heating value by developing the efficiency equation for the boiler shown in Figure 1.11. You may want to return to this example again after reading Chapter 5, where we develop energy balances, but please do read this example before moving to the other chapters.

We define

F_{fuel}	= fuel flow rate, lb/h;
HV	= fuel heating value, Btu/lb;
$F_{\text{boiler feedwater}}$	= boiler feedwater flow rate, lb/h;
F_{steam}	= steam flow rate leaving the boiler, lb/h;
$\hat{h}_1$	= specific enthalpy of boiler feedwater at boiler inlet, Btu/lb; and
$\hat{h}_2$	= specific enthalpy of steam leaving boiler, Btu/lb.

Here, fuel to the boiler supplies heat to create a steam stream, which is at a flow rate F_{steam}. Condensate and makeup water are

returned to the boiler at a flow rate, $F_{\text{boiler feedwater}}$. The F_{steam} may or may not equal $F_{\text{boiler feedwater}}$ depending on boiler blowdown. Blowdown is used to control solid buildup in the boiler. The boiler efficiency is

$$\eta_{\text{boiler}} = \frac{\text{Energy in steam exiting boiler} - \text{Energy in feedwater}}{\text{Energy in fuel}}$$

$$= \frac{F_{\text{steam}}\left(\hat{h}_2 - \hat{h}_1\right)}{F_{\text{fuel}}(HV)}, \tag{1.6}$$

where we have neglected any boiler blowdown, so $F_{\text{steam}} = F_{\text{boiler feedwater}}$.   ■

The fuel heating value HV deserves special comment, and it will be discussed in more detail in later chapters. The fuel heating value can be defined as the amount of heat liberated when 1 lb of fuel is completely burned and the combustion products are returned to the initial fuel temperature. When the water formed in the combustion process is in vapor form, the fuel heating value is the lower heating value (LHV). When the water formed in the combustion process is condensed, the fuel heating value is the higher heating value (HHV). Values for fuel LHV and HHV are provided in Table 1.3.
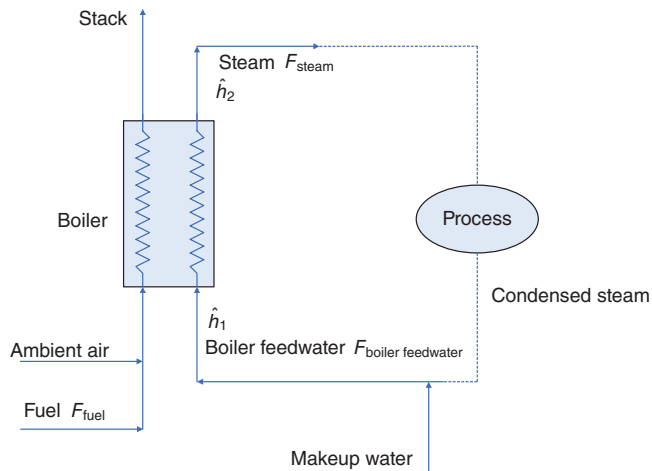
Figure 1.11   Boiler schematic for efficiency calculation.

If we now look at Equation (1.6), for a given set of steam and boiler feedwater conditions (flow rates and enthalpies), the fuel flow rate will be uniquely determined with a known boiler efficiency. However, the boiler efficiency in Equation (1.6) depends on whether the fuel *LHV* or *HHV* is used for *HV* in the equation.

There can be serious consequences when a different fuel heating value (*HHV* vs. *LHV*) is used in efficiency calculations and in subsequent costing calculations. For example, in Table 1.3, the difference in the *HHV* and *LHV* for methane fuel is 2359 Btu/lb. This problem of using *HHV* versus *LHV* is not always obvious. For example, turbine gas manufacturers generally report efficiency based on methane *LHV*. However, methane is priced and purchased on the open market based on its *HHV*.

Generally throughout this chapter, I prefer to use the fuel *LHV* in efficiency calculations—when combustion products exit the stack, water is in the vapor state. Here, then, fuel costs must also be on (or converted to) an *LHV* basis. One exception is optimal cogeneration dispatching, discussed in Chapter 12. In this chapter, all efficiencies and costs were determined based on the fuel *HHV* as this proved more convenient in the development of the economics-driven optimization model. To avoid confusion, power system calculations should explicitly note the use of *HHV* or *LHV* values.

1.6   TEXT ORGANIZATION

In this chapter, we want to provide a platform to explore the connection between the processing side and the utility side of an industrial plant. The processing side is often designed using commercial simulators including Aspen PLUS by Aspen Technologies, HYSYS (as Aspen HYSYS by Aspen Technologies or UniSim Design by Honeywell); and PRO/II by Simulation Sciences Inc. A key feature of these programs is the inclusion of rigorous thermodynamics, which allows the solution of unit operation material and energy balances and quantification of chemical mixture separation in distillation columns and other staged devices.

There are also commercial programs including Gate-Cycle™ (from General Electric) and IPSEpro (from

Table 1.3   Fuel Lower Heating Value (*LHV*) and Higher Heating Value (*HHV*) at 77°F, 1 atm (Bathie, 1996)

Compound	State	LHV (Btu/lb)	LHV (kJ/kg)	HHV (Btu/lb)	HHV (kJ/kg)	HHV–LHV (Btu/lb)	HHV–LHV (kJ/kg)
Methane	Gas	21,501	50,012	23,860	55,499	2359	5487
Ethane	Gas	19,141	44,521	20,911	48,638	1770	4117
Propane	Liquid	19,927	46,351	21,644	50,343	1717	3992
n-Butane	Liquid	19,493	45,342	21,121	49,128	1628	3786

SimTech Simulation Technology) that allow utility system calculations. These programs focus on gas turbine system and steam turbine system design and off-design performance calculations. For off-design turbine calculations, manufacturer-provided performance curves are often utilized.

However, these process design programs and utility design programs do not generally share information. Clearly, an important problem is matching the design energy needs of the process to the best utility system design. Even more challenging is matching the changing energy needs of the actual operational process to the off-design performance of the plant utility system. This book addresses these important issues and hopefully lays the foundation for improved and optimal utility management.

Here we examine how computer-based solutions to process material and energy balances are obtained, allowing the user to construct a simplified Excel-based process simulation for energy tracking and energy forecasting. For the utility plant, we provide rigorous thermodynamics with all thermodynamic functions callable from Excel, Visual Basic for Applications (VBA), or C programs. This approach—an Excel-based process plant simulation and rigorous utility side calculations—allows the design of a utility system that matches the processing plant needs. Most important is that we show both design and off-design performance calculations for utility systems, which are necessary for the optimal operation of the process utility system.

Throughout this chapter, Excel is utilized in problem solutions. Straightforward problems can be solved directly in Excel. As problem complexity grows, Excel with VBA and Excel with VBA and C/C++ are utilized for problem solution. Here, Excel serves as a very convenient interface between the user and these low-level languages.

Chapter 2 provides an introduction to process economics. Here, Excel and Excel with VBA are used to solve economics problems. We show how variables and calculation results can be moved between the Excel sheet and VBA macro subroutines, VBA subroutines, and VBA functions. The concept of economic uncertainty is introduced with the use of Monte Carlo simulations.

Chapter 3 discusses computer-aided solutions of material balance problems using the sequential modular approach and Excel spreadsheets. We need to calculate material flow rates in an industrial process in order to determine energy requirements as well as for design and control purposes. Recycle loops in the process require iterative calculations, and here convergence strategies are explored. The concept of elementary material balance modules, with both natural and alternative specifications, is introduced. Alternative specifications often require the use of single-variable search techniques for problem solution. VBA provides a convenient platform for both recycle acceleration schemes and single-variable search strategies.

Chapter 4 presents computer-aided solutions of material balance problems using the simultaneous or equation-based approach and Excel spreadsheets. We provide a general discussion of the Gauss–Jordan matrix elimination method to solve linear equation sets. Linear material balance problems are then solved using the Gauss–Jordan method. The Newton–Raphson method is developed to allow solution of nonlinear material balance equation sets. These solution methods (Gauss–Jordan and Newton–Raphson) are provided both as VBA subroutine procedures or C callable dynamic link libraries (DLLs).

Appendix A (suggested reading after Chapter 4, Section 4.1) serves to introduce C coding, and a tutorial on C programming is provided in Appendix A—Tutorial. In Appendix A, we show the power in connecting Excel to low-level languages—specifically C code. Here, we construct DLLs of C/C++ code to allow the seamless transfer of variables, vectors, and matrices between Excel ↔ VBA ↔ C programs. In Appendix A, we focus on simple examples to show that the transfer of variables and vectors between Excel and C is straightforward. The transfer of matrices is more difficult and requires understanding of column-major and row-major matrix storages. To help understand the transfer of matrices, the Gauss–Jordan method (from Chapter 4, Section 4.1) is developed in C. In Appendix A—Tutorial, we repeat several examples from Chapter 2 to allow the comparison of VBA code and C code.

Chapter 5 incorporates energy balances into elementary process modules and investigates the impact these energy balances have on the sequential and equation-based solution approaches. Energy balances can necessitate the use of inner (energy balances) and outer loops (recycle loops) when the modular approach is used. Energy balances are shown to cause no additional computational difficulties when the equation-based approach (Newton–Raphson method) is used. The solution of reactor energy balances is particularized to plug flow reactors where both the Euler method and the Runge–Kutta fourth-order method are employed to size tubular (plug flow) reactors.

Chapter 6 introduces data reconciliation and gross error detection. Data from an actual plant are not "perfect"—for example, these data will not close material balances or energy balances. For data reconciliation problems with linear (material balances) or nonlinear (energy balances) constraints, the Solver optimization routine available in Excel allows direct solution. For data reconciliation problems with linear constraints (or linearized nonlinear constraints), we also develop Lagrange multipliers for problem solution. We introduce gross error detection (the global test method) and gross error identification (the measurement test method).

Chapter 7 begins our examination of cogeneration systems and system performance in both design and off-design operations. Solution of cogeneration system

performance is explored using ideal gas physical properties. We also introduce our Excel callable sheet functions for steam properties. Callable steam properties allow the heat recovery steam generator (HRSG) performance to be determined under off-design operation including supplemental firing.

Chapter 8 explains the construction of the thermodynamics package (*TPSI+*) for cogeneration and combustion calculations. Equations of state for calculating needed thermodynamic properties are based on the work of Reynolds (1979) and developed within a C program. We extend Reynolds's work with the inclusion of refrigerants. Thermodynamic properties from accurate equations of state for pure components can be combined to allow prediction of thermodynamic properties for combustion mixtures. The C program is linked to Excel sheets as a DLL, and all source code for (*TPSI+*) is provided to allow the user to make modifications.

Chapter 9 examines cogeneration system performance in both design and off-design operations using real fluid properties; real fluid properties (*TPSI+*) are developed in Chapter 8. The examples and problems in Chapter 9 parallel those in Chapter 7 allowing comparison of ideal gas and real fluid calculations.

Chapter 10 explores the optimal design of cogeneration systems with known and fixed steam and electrical demands—the CGAM problem. First, the solution of the CGAM cogeneration design problem with ideal gas properties is examined. We next use our thermodynamics package (*TPSI+*) to solve the cogeneration design problem with real fluid properties. *TPSI+* is shown to produce results equivalent to commercial utility design codes such as GateCycle from General Electric Corporation. The use of *TPSI+* also allows incorporation of more realistic cogeneration system constraints in the design problem when compared to the original CGAM problem. Steam generation in the HRSG is explored for both the design and off-design (supplemental firing) cases. Heat conduction problems and performance analysis in the HRSG naturally lead to partial differential equations, and here, a solution using finite difference approximations is developed.

Chapter 11 applies data reconciliation and gross error detection techniques developed in Chapter 6 to data from an operational cogeneration system. Here we can take advantage of the provided thermodynamics package (*TPSI+*) to solve material and energy flows. We also show the difficulties in determining the exact location of a gross error in large energy systems.

Chapter 12 provides for multiperiod energy management and energy dispatching in a cogeneration system. Data from an operational gas turbine cogeneration system were collected for over a 1-year period and steady-state equipment efficiencies were determined. Forecasting energy costs is discussed. A mixed-integer linear programming (MILP)

is developed to solve for multiperiod optimum energy management strategies. The Excel add-in What's Best is used to solve the MILP energy dispatch problem; What's Best has been supplied by LINDO Systems for use with this chapter. The model developed here has been successfully used to lower utility costs at an operational cogeneration facility.

Chapter 13 demonstrates how an energy integration analysis in a processing plant can be performed. Minimum hot and cold utility requirements can be determined. In existing plants, these values can be used as energy targets and compared to current usage. Improvements and changes in the existing heat exchanger network can then be evaluated. We provide a heat exchanger network synthesis program *THEN* (~3000 lines of code), which aids in the construction of an optimal heat recovery network. The heat exchanger network synthesis program is a legacy Fortran code, and we show how this code, or any executable code, can be incorporated into Excel with Excel serving as both pre- and postprocessors.

Chapter 14 extends the energy analysis of Chapter 13 to include the integration of the utility system, which supplies hot and cold utilities as well as electrical power. Here, the real fluid cogeneration system developed in Chapters 9 and 10 is modified to meet the energy requirements of a process. The thermodynamics program (*TPSI+*) is also used to develop a steam-based turbine system to meet process energy needs. In a large complex, individual processing plants typically share a common utility system. The potential for energy exchange throughout the total site is explored and the optimal design and synthesis of the site utility system is discussed.

Chapter 15 explains how emissions from heat and power generating systems can be predicted; this is especially important in nonattainment areas. Emissions based on simple stoichiometric and equilibrium calculations are introduced. Equilibrium calculations require the use of thermochemical data. Rigorous modeling of methane combustion in gas turbines is explored by modeling the turbine as a series of stirred tank and plug flow reactors. A reduced kinetics set based on GRI-Mech 3.0 is solved using the ordinary differential equation (ODE) solver CVODE (from LLNL). CVODE is made available as a callable routine from Excel.

In Chapter 16, we explore the impact of CO_2 capture on a conventional coal-fired utility plant. Our Excel-based thermodynamics functions (*TPSI+*) are utilized to predict the performance of a steam turbine-based utility plant operating in the design or off-design mode. Off-design operation is required as the capture process will extract steam from the utility plant for regeneration. We introduce levelized economics, which allows utility pricing; levelized economics is explored for comparison of energy systems. The chapter concludes with examples showing how utility plant performance and economics are altered if CO_2 capture is implemented.

In Chapter 17, we discuss levelized costing of alternative energy systems. We show the connection between levelized costs and the price we must pay for utilities if the alternative technology is implemented. There are many factors that go into determining levelized costs, and we detail the levelized cost determination process for an organic Rankine cycle. In the final example, we introduce the next generation of nuclear reactors.
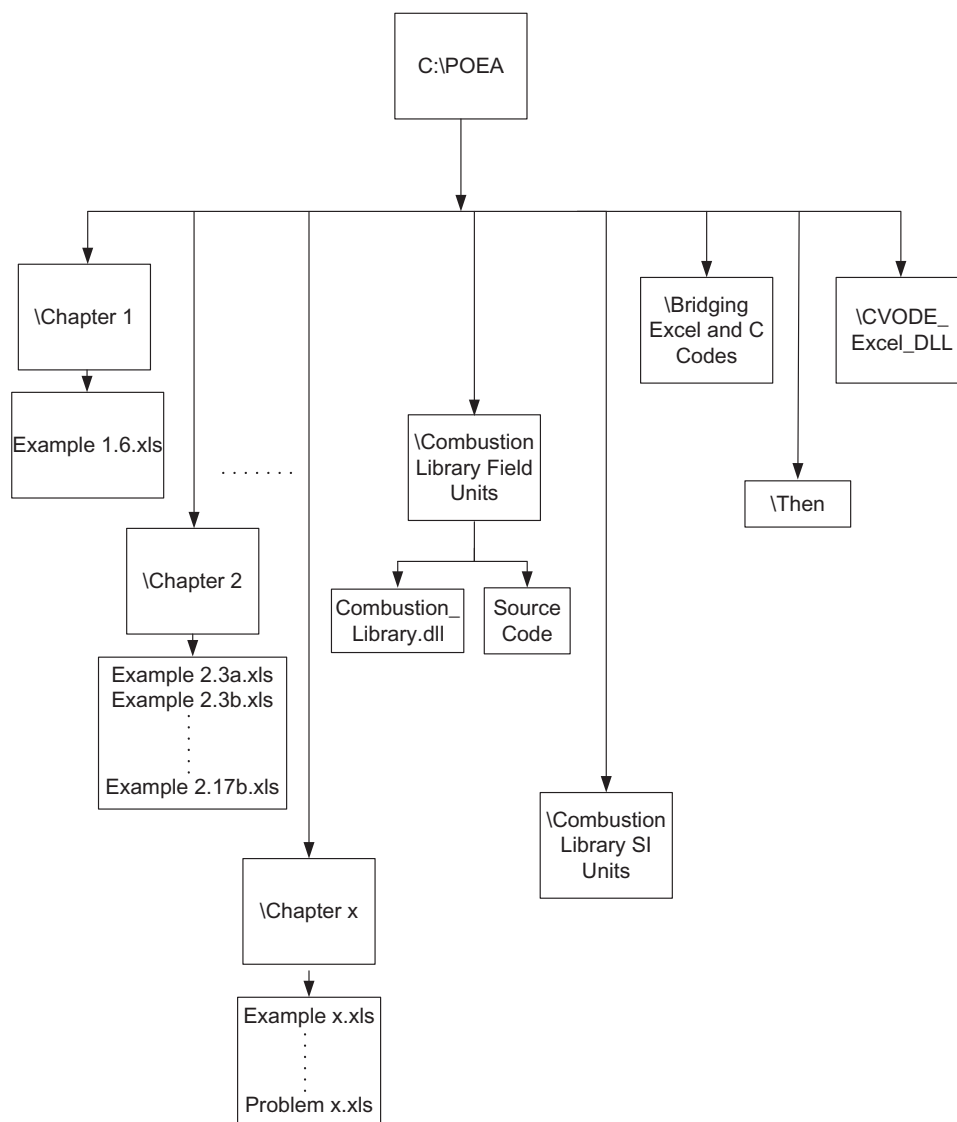
In this book, all examples and chapter problems are fully worked and available at the Wiley Web site. All computer codes including the rigorous combustion thermodynamics programs and heat exchanger network synthesis are provided as open software. I have been fortunate to teach the material in this book in undergraduate classes and in areas where the students had difficulty. I have tried to supply additional explanation and discussion. I have tried to

keep in mind that practicing engineers may be using this book. I appreciate the time demands on practicing engineering, and I have tried to keep the book as self-contained as possible.

1.7   GETTING STARTED

Solutions to all example problems and chapter problems as well as all developed software programs (including all source codes) are available at the Wiley Web site. The POEA folder from the Web site should be copied onto the C drive of your computer as C:\POEA; all provided materials should be in a single folder as shown in Figure 1.12.

Figure 1.12 shows that within the folder POEA, you should find "subfolders": Chapter 1–Chapter 17 holding

Figure 1.12   Required folder locations for examples, problems, and all provided codes.

solutions to all the chapter examples and some chapter problems. Within the folders Combustion Library Field Units and Combustion Library SI Units, you will find the source code for the thermodynamics program *TPSI+* as well as dynamic links to the source code. The source code for *THEN* Teaching Heat Exchanger Network analysis is provided in the subfolder Then. The executable version of *THEN* (Then.exe) is found in the folder Chapter 13; you should initially run Then.exe from the Excel files provided in Chapter 13. The subfolder CVODE_Excel_DLL holds an Excel callable version of the ODE solver CVODE available from LLNL. CVODE is part of the Sundials suite at LLNL, which also provides other advanced numerical methods; these programs (source code) are available at no cost for noncommercial use. Bridging Excel and C codes holds programs developed in the chapter including the Gauss–Jordan and Newton–Raphson methods. This folder also holds examples and a tutorial on how to connect Excel to C code and how to use C++ 2008 Express. Many of the example files and problem solutions utilize programs within various folders in POEA; in other words, examples and problems in one subfolder may include paths to programs in other subfolders. It is important that POEA be assembled as shown in Figure 1.12. Once you become familiar with paths between programs, it is easy to combine files and programs in any folder that you may want to create.

I used the acronym POEA to hold all work related to process optimization and energy analysis. As you work on examples and chapter problems, it may be best to keep them in a separate work folder within \POEA. In many cases, it will be convenient to copy an example problem and to use it as a starting point for the next example. For some of the more complicated examples and chapter problems, there are template Excel sheets provided in \ POEA. These Excel template files can be saved to your work folder. In \POEA, you will also find template Excel sheets that allow connection (established path) to all provided software.

We developed all programs in Excel 2003 and C++ 2008 Express. All programs were also tested in Excel 2007 and Excel 2010. When using Excel 2007 or 2010, there can be a warning that some settings are no longer supported. This will not affect any calculations in the Excel sheets and you can simply press *continue*.

In this text, the standard add-ins provided with Excel—Goal Seek and Solver—are used in many single-variable and multivariable nonlinear optimization problems. Mixed-integer linear problems (Chapter 12—Optimal Power Dispatch in a Cogeneration Facility and Chapter 14—Utility System Superstructure) are solved using the Excel add-in What's Best from LINDO Systems. LINDO Systems has agreed to supply the needed version of What's Best at no cost—details for downloading this software can be found at the Wiley site.

When installing What's Best 10.0, the default path will be to Microsoft Office. Users will have different versions of Microsoft Office, so you will have to establish the path between our provided Excel files and your installed version of What's Best in order to link the WBA.xls file. This is accomplished when you first open the Excel file containing What's Best (this will only occur in files utilizing What's Best) → click on update → edit links → change source → here you will need to give the path to wba.xla; for example, in Excel 2003 C:\Program Files\Microsoft Office\Office 11\ Library\Lindo WB\WBA.xla; in Excel 2007\Office 12\; and in Excel 2010\Office 14\ → click on check status → OK (the status should now appear as source is open).

1.8   CLOSING COMMENTS

In Chapter 1, we introduced the cost to produce electric power from utility-based coal or natural gas plants as well as natural gas-fired turbine cogeneration facilities. In later chapters, we will develop more complete economics as well as detailed design and off-design performance calculations for these energy systems. There are opportunities to improve efficiency by understanding and modeling these generation facilities.

The most common mistake in power output calculations and energy costing analyses is a lack of consideration of fuel *LHV* versus *HHV*. Project mistakes on the order of 20% can occur when *LHV* efficiency and power output values from vendors are mixed with fuel sales based on *HHV* (L.J. Braquet, pers. comm.).

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EIA, Data in Table 1.1 and Figures 1.3 and 1.4 can be found at the EIA Web site http://www.eia.doe.gov/dnav/ng/hist/n3020us3M.htm. Natural gas costing data are in dollar per 1000 ft^3 converted to dollar per MMBtu (accessed July 2010).

EIA and LLNL, Energy flow data in Figures 1.1 and 1.2 can be found at the LLNL Web site https://publicaffairs.llnl.gov/news/energy/archive. html. In these two figures, we have added energy imports to the appropriate energy source and we have subtracted energy exports from the provided numbers to help maintain the overall energy consumption balance. (accessed July 2010).

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PROBLEMS

1.1 *Automobile Efficiency*   Energy transfer rates (power) in a typical automobile at normal highway speed are indicated in Figure P1.1. Determine the efficiency of the automobile with power values as shown in Figure P1.1.

1.2 *Efficiency and Plant Net Heat Rate*   Determine the relation between the overall plant thermal efficiency as given by Equation (1.1) and the plant net heat rate as given by Equation (1.3).

1.3 *The Effect of Natural Gas Pricing on Cogeneration Profitability*   In Example 1.6, we determined the profit if our
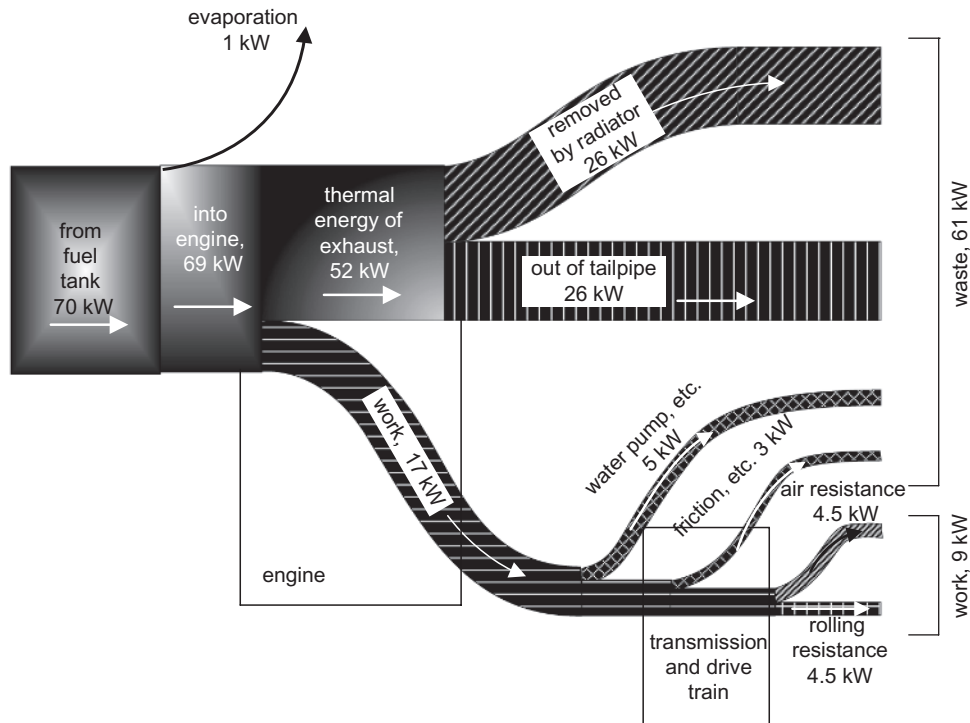
Figure P1.1   Automobile energy transfer rates at steady state and at normal highway speed (adapted from Hobson, 2004).
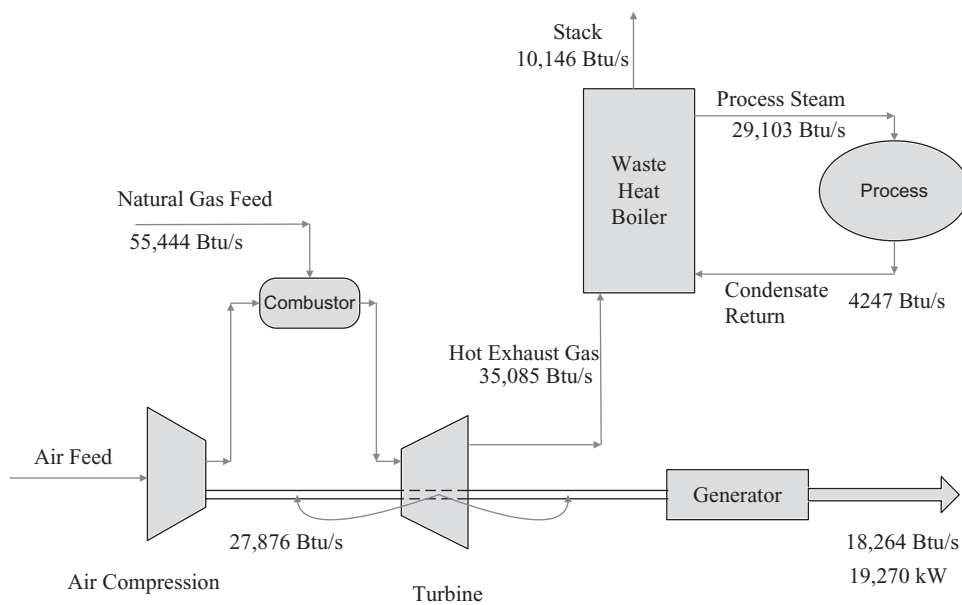
Figure P1.4   Gas turbine cogeneration system.

existing system, consisting of a stand-alone boiler for steam generation and electricity purchase, was replaced with a cogeneration system. As noted in the discussion of Example 1.6, cogeneration profitability is affected by natural gas costs. Determine a price for natural gas when the cogeneration system is no longer profitable.

Solution: The solution can be found using the Excel file **Example 1.6.xls**. If you are not familiar with Excel, you may want to wait until after reading Chapter 2 before using the Excel file. Otherwise, simply vary the natural gas cost (or use Goal Seek) until the profit = 0; at $9.37 per 10^6 Btu, cogeneration is no longer profitable assuming all other costs remain constant.

We can consider the costs as provided in Example 1.6 to be long-term or levelized costs. Levelized utility costs are explained in Chapter 16. Cogeneration profitability is also strongly affected by the net heat rate, and cogeneration heat rate quickly erodes in part load operation as detailed in Chapters 7 and 9.

1.4 *Gas Turbine Cogeneration Plant Energy Efficiency* A gas turbine-based cogeneration facility is shown in Figure P1.4. The values provided in Figure P1.4 are the energy input rate to each operation. You will note that energy balances do not close "perfectly." There are thermal losses in the process that are not directly shown in the figure. Determine the cogeneration plant net heat rate as British thermal unit per kilowatt-hour and also develop the Sankey energy flow diagram.

1.5 *Coal Energy Efficiency* Determine how much of the energy originally available in coal is ultimately delivered as electricity to the end user. Account for the energy requirements at each stage including raw coal → extraction → processing → transportation → conversion to electricity (see Example 1.1) → electricity grid transmission → end use. Here, you will need to use outside references; see, for example, Dorf (1978, 2001) or other sources.

1.6 *Who Owns Possible Environmental Credits from a Cogeneration System?* In Example 1.6, we developed the cost savings that may be possible if a cogeneration system is used to replace an existing stand-alone boiler with electricity purchase from a utility plant. Here we want to explore the possibility of emission reduction, specifically carbon dioxide reduction, if this cogeneration system is installed. An interesting issue with a cogeneration system may be: Who should receive environmental credit for any emission reduction?

Assume the cogeneration system in Example 1.6 is installed, thereby replacing the existing natural gas-fired stand-alone boiler and electricity purchase from a coal-fired utility plant (as in Figure 1.5). Allow that the combustion of 1 MMBtu (or 1 mSCF) of natural gas releases about 120 lb of carbon dioxide. Burning 1000 lb of coal releases about 2400 lb of carbon dioxide. Determine the total carbon dioxide emissions at the processing site (within the fence line) and the utility plant (within the fence line) both before and after cogeneration installation.