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Power Generation Technology Guide

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Preface

The improvment of basic living standards is the highest priority of a majority of the world’s countries. An essential requirement to achieve this end is the generation of adequate power. Unfortunately, the generation of power usually gives rise to environmental and social costs as well as benefits. The production of greenhouse gases that can lead to global warming is one such cost. Indeed, the potential for global warming is one of the key factors motivating a greater emphasis in recent years on the introduction of power generation technologies that release minimal greenhouse gases.

The 1992 United Nations Framework Convention on Climate Change (UNFCCC) recognizes the need to stabilize greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system. Developed country Parties to the convention are committed to “promote, facilitate and finance, as appropriate, the transfer of, or access to, environmentally sound technologies and know-how to other Parties" in order to help countries limit their greenhouse gas emissions. In this context, the First Conference of the Parties to the UNFCCC recognized that additional information, including an inventory and assessment, needed to be compiled on environmentally-sound and economically-viable technologies, and on know-how conducive to mitigating climate change.

Given the needs of Parties to the UNFCCC for better information on “climate-friendly” technologies and the significant role that power generation plays in both economic development and in the generation and/or mitigation of greenhouse gases, the purpose of this guide is to provide concise and objective information enabling a better understanding of some 20 power generation technologies and the differences between them. The guide also explains the basics of energy planning and hence should be of use to non-expert decisionmakers who do not have the luxury of devoting full time to mastering the details of the planning process. There is no perfect technology universally suited to the wide range of different national circumstances, budgets, and other constraints. However, it is both possible and desirable for non-specialist decisionmakers to gain insight into the most appropriate technologies for given situations, and thus it is hoped that the present guide will lead to better decisionmaking at both the national and international levels.

Acknowledgments

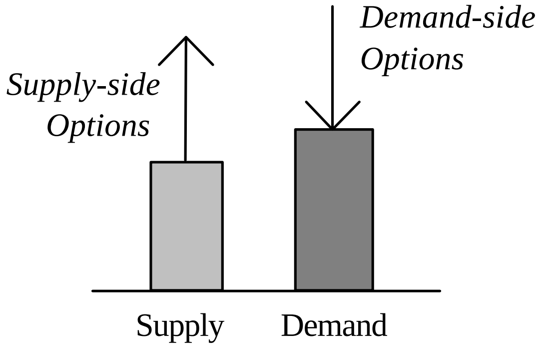
I would like to thank several colleagues at the International Academy of the Environment — William Westermeyer, Philippe Alirol, Andrea Baranzini, and Mike Hiniker — for their careful reading of earlier Guide drafts. Their comments and suggestions have helped widen the scope, improve the style, and refine some details of this Guide.

Moreover, thanks are due to the *Swiss Federal Office of Environment, Forests and Landscape (FOEFL)* which provided a financial grant supporting the research and preparation of this Guide.

Introduction and Summary

This Guide describes performance, costs, and resource implications for a wide range of ***power generation technologies*** used to supply ***electricity*** in energy markets. It also outlines an ***energy planning*** process to match these supply-side technologies with demand-side needs in regional, national or local markets. In taking a planning-oriented approach to describing power generation, the Guide shows how technology characterizations can be used to support decisionmaking in the energy planning process. Particular attention is given to considerations of a technology's environmental impacts, including its potential implications for ***climate change.***

Matching Supply and Demand in Electricity Markets:



Projections of demand for electricity are the initial input to energy planning. Planning attempts to meet future demand in growing electricity markets with a wide range of supply and demand-side options. Supply-side options can increase the supply of electricity by establishing new electricity generation facilities, improving the efficiency and performance of existing facilities, and reducing losses in electricity transmission and distribution. Demand-side options can reduce the demand for electricity by changing end-use consumption patterns. In general, a mix of supply and demand-side options can be implemented so that supply and demand are in equilibrium over the time horizon for which planning is made.

In most industrialized countries, electricity markets are mature. In these markets, the performance and efficiency of supply-side technologies is high, supply is in equilibrium with demand, and projected demand growth represents an incremental change to existing supply potential. Demand-side options are extensively used to keep future demand at levels that can be met by existing supply capacity. They are often a cost-effective alternative, and usually, the only alternative, to establishing new power generation capacity.

In many developing countries, electricity markets are often supply-constrained. In these nascent electricity markets, the performance and efficiency of supply-side technologies can often be improved, demand is substantially greater than supply, and projected demand is significantly greater than existing supply potential. A wide range of supply and demand-side options can be implemented in these markets. Through supply-side options improving supply technology performance and efficiency, and demand-side options enhancing end-use efficiency, requirements for additional supply capacity can be minimized. New electricity generation facilities can be established to meet these minimum, nevertheless substantial, requirements for additional supply capacity.

While decisionmakers and energy planners must consider a full mix of supply and demand-side for implementation, their task of assessing power generation technologies remains a primary one in most applications where additional capacity is required. This Guide limits its focus to energy planning for new power generation capacity, assessing prospective technologies from various perspectives, and showing how these assessments can be used as energy planning proceeds.

Power Generation Technologies:

To provide a balanced view of supply-side technology options, a total of 20 commercially available technologies are assessed. Included are conventional as well as innovative and state-of-the-art technologies from each of the three primary energy source groups: fossil fuel, nuclear, and renewable. The technologies examined include:

Fossil fuel based technologies:

- coal-fired steam turbine plant
- diesel engine
- combustion turbine
- gas turbine combined cycle
- atmospheric fluidized bed combustion of coal (AFBC)
- integrated coal gasification with combined cycle (IGCC)

Nuclear fuel based technologies:

- pressurized water reactor (PWR)

Renewable energy source technologies:

- biomass gasifier - diesel engine
- biomass gasifier - combustion turbine
- biomass gasifier - combined cycle (BIG/CC)
- solar photovoltaic
- solar thermal - parabolic dish
- solar thermal - parabolic troughs
- solar thermal - central receiver
- horizontal axis wind turbine (HAWT)
- large-scale hydropower (dam and reservoir)
- small-scale hydropower turbine (run-of-river)
- geothermal - dry steam plant
- geothermal - single flash plant
- geothermal - binary plant

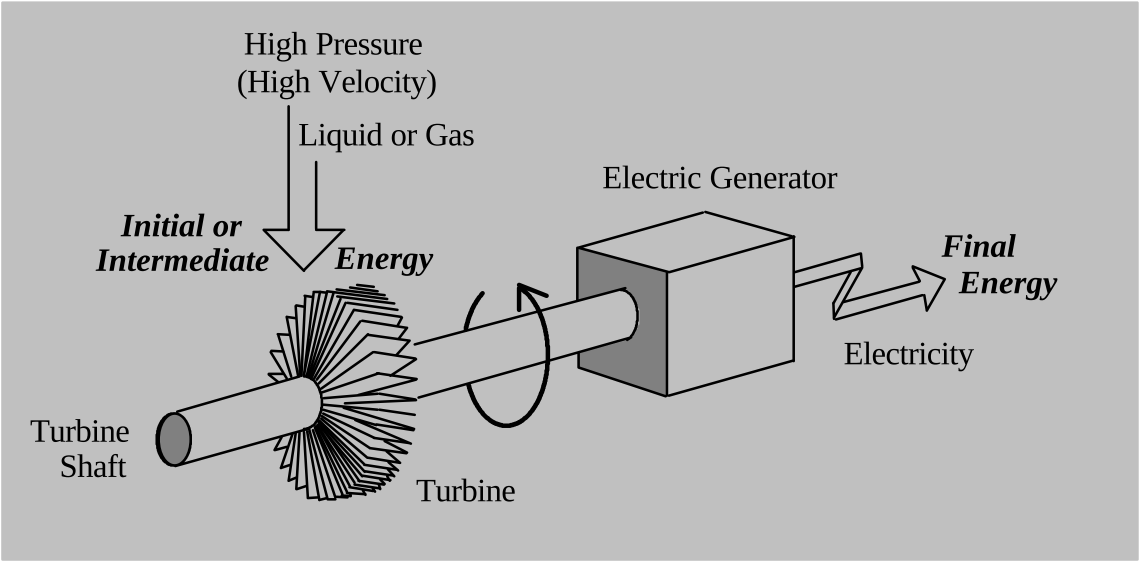
These technologies do not create energy, but rather they convert the energy inherent in various natural resources – initial energy – to a usable form such as electricity and/or heat – final energy. For this reason such technologies are often referred to as ***energy conversion technologies***. Initial energy always comes from the earth's natural resource base. Natural resources such as fossil or nuclear fuels are depleted by extraction. Thus the initial energy they provide is said to be ***non-renewable***. By contrast, water, wind, biomass, and solar resources provide initial energy without depleting natural resources and are thus said to be ***renewable*** energy sources. In both cases, power generation technologies usually utilize a turbine to convert the initial energy of a natural resource into electricity (see box 1) that is subsequently supplied to energy markets.

Box 1: Turbine Power Generation

The common central mechanical component of nearly all power generation technologies in commercial use today, with the exception of solar photovoltaics and diesel engines, is the ***turbine***. In these technologies, energy in the form of a high pressure gas or fluid flows through a turbine to produce electricity. The high pressure in the working gas or fluid:

- is created via a combustion process for fossil fuel and biomass based technologies;
- is created via a nuclear fission process for nuclear fuel based technologies;
- is tapped directly as initial energy from the earth's natural resource base for most renewable energy technologies (wind, solar, geothermal, and hydropower).

The high pressure gas or fluid passes through the blades of the turbine, causing the turbine to rotate rapidly, and thus the gas or fluid energy is converted into rotational energy. The rotating turbine shaft turns the axle of an electric ***generator*** that converts the turbine's rotational energy into electricity, the desired energy output.



Each of the technologies listed above represents a distinct option that can be selected as a source of supply for electricity. However, selecting appropriate options can be complicated. As each technology has different characteristics depending on the nature of its primary energy source and the processes required for energy conversion, performance, costs, and resource implications differ widely from one technology to another. Based on a range of specific needs and constraints, decisionmakers will seek to choose for implementation the technology option (or *mix* of options) which is most appropriate for a particular application.

Selecting the 'Best' Technology Option:

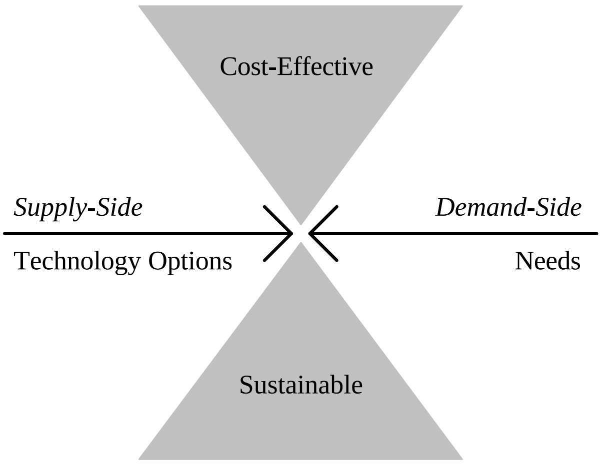
Developing electricity generating capacity to supply energy markets is a time- and capital-intensive activity. Large power plants can take over 5 years to build and their capital costs can exceed 1 billion US$. Because demand in energy markets can vary significantly over the time it takes to construct a power plant, estimates of current as well as future demand are critical determining factors for capacity requirements of power generation facilities. In view of the high capital outlays needed to construct a power plant, installed capacity should not significantly exceed projected demand if supply-side power generation is to be ***cost-effective.*** Moreover, as capital, fuel, and labor costs vary considerably from one technology to another, the choice of technology selected will also influence cost-effectiveness.

Once a power plant is built, it can be expected to generate electricity for 15-30 years. During its lifetime, a power plant will have significant interactions with natural and human systems: natural resources will be continuously consumed or tapped as a primary energy source; plant wastes and gaseous emissions may be introduced into the surrounding natural environment; and human resources will be needed for plant operation and maintenance. For power generation to be a ***sustainable*** long-term activity, primary and human resources must be in sufficient and continuous supply, and interactions with the surrounding and global environment must be benign. Furthermore, power generation activity should go beyond merely supplying electricity to the marketplace. It should also benefit local populations with opportunities for social and economic development. Benefits could include, for example, job creation in technology production and in service industries supporting power generation and distribution. In view of the substantial long-term interactions power generation activity has with natural and human resources, as well as the fact that these interactions are different for each power generation technology, it is important to identify which technologies can best support the sustainable development of local, national, and regional economies.

Choosing the most appropriate technology option for electricity supply in a particular application requires decisionmakers to evaluate a diverse and complex set of technical, financial, social, economic, and environmental issues. In order to assess how well different technologies can favorably address these issues, timely and accurate information characterizing each technology must be accessible. To help ensure that this information is systematically analyzed, a structured planning process is often used to support decisionmaking.

Energy Planning:

The energy planning process aims to match supply-side technology options to demand-side needs in the most cost-effective and sustainable manner possible. The process often involves several steps comprising an ***energy planning cycle.*** In the planning cycle, a large initial set of technology options are screened against a set of decisionmaking criteria designed to filter out inappropriate technologies. When carefully formulated, decisionmaking criteria can help ensure that planning results in the identification of options with adequate performance that are both cost-effective and capable of generating power sustainably for many years. Ideally, when the process is completed, the technology, or mix of technologies, which best satisfy decisionmaking criteria, can be deployed to provide new electricity generation capacity.



Energy planning cycles in use today vary from country to country, and, within countries, from one institutional or commercial setting to another. While the number, nature, and scope of elements comprising a planning cycle may differ, most modern planning cycles contain three essential steps. These steps include evaluations of technology performance, power generation costs, and resource implications of power generation. This Guide presents a simplified three step modern energy planning cycle through which technology options can be evaluated. By following a modern energy planning cycle, this Guide describes essential decisions that need to be made in energy planning and provides pertinent data relating to these decisions for the 20 technologies assessed.

<u>Steps in the Energy Planning Cycle:</u>

A) Assessing Demand and Identifying Technology Options

The first step in energy planning is to estimate future electricity demand and then to identify which technology options can meet this demand. Projections of demand depend on population forecasts and migration trends as well as on socio-economic and industrial development activity. In addition to near-term estimates of demand, estimates of demand over the assumed lifetime of the facility are required. In many electricity markets, administrative and pricing mechanisms can be used to promote improved end-use efficiency and energy conservation. When such demand-side management mechanisms can be implemented, estimated demand levels can be adjusted downward and hence also the need for additional generating capacity.

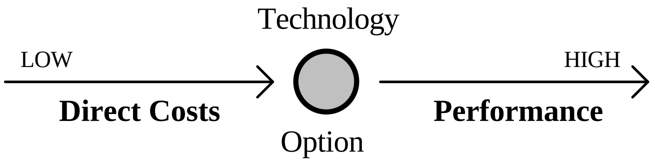
Once (adjusted) demand levels are estimated, capacity requirements for electricity generation facilities can be determined. Based on capacity characterizations of power generation technologies, planners can begin to identify those technologies that can meet demand. Power generation facilities must have sufficient capacity to meet average demand

and be flexible enough to respond to hourly, daily, and seasonal variations in these levels. Additionally, facilities must be reliable, have minimal downtime, and possibly allow for capacity enhancements in the future. The technical characteristics of available technology options must, *a-priori,* be assessed to determine which ones have appropriate ***performance*** characteristics capable of meeting demand-side requirements. In completing Step A of the planning cycle, a subset of technologies capable of meeting estimated demand are selected.

B) Assessing the Direct Costs of Technology Options

For each technology option meeting Step A performance criteria, the costs of generating power are determined in Step B of the planning cycle. Power providers seek technology options with low electricity generation costs, i.e., ***direct costs*** for capital, operations, maintenance, and fuel. State-run utilities seek to do this in order to keep the price of electricity to end-users low and to minimize budgetary pressures on national financial resources. Independent power providers – in addition to providing competitive prices for electricity to end-users – seek least-cost options to maximize profits. To identify least-cost power generation options, financial information on the directs costs associated with various technology options must be evaluated and compared. Through a ***least-cost planning*** procedure, only those technologies identified as being cost-effective are retained. Those technologies that are clearly not competitive on a cost basis are normally rejected, but in some cases may be retained if compensating financial mechanisms such as subsidies, tax credits, grants, or concessional loans are present to offset their higher direct costs.

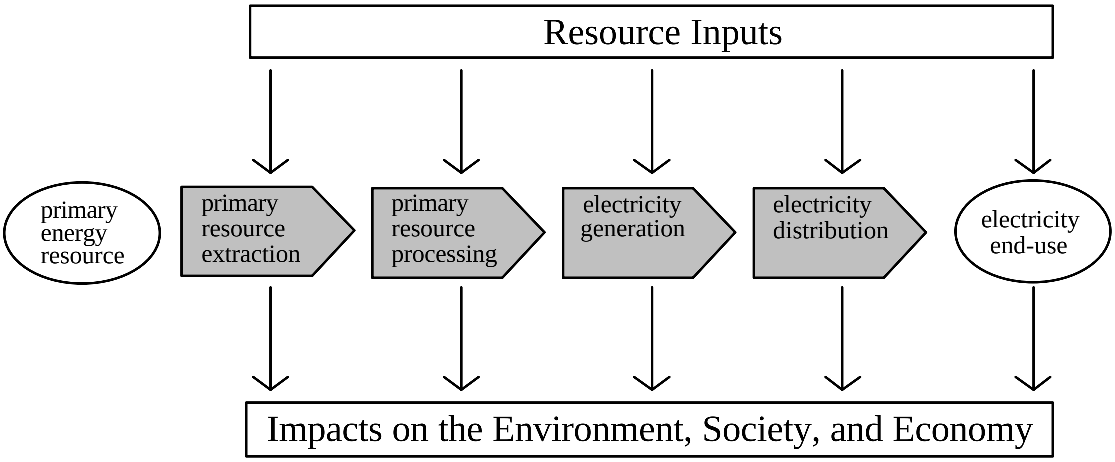
Assessing technology options from performance and direct cost perspectives represent two important steps in energy planning. The direct costs required as input to a technology should be kept low, and the relevant performance parameters needed to meet demand levels should be adequately high to provide desired benefits to end-users. One principal axis of analysis for each of the technology options being evaluated thus comprises direct costs and performance characterizations.

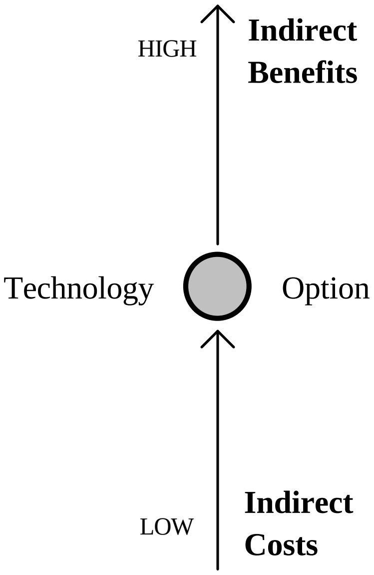


C) Assessing the Resource Implications of Technology Options; Indirect Costs & Benefits

The long-term sustainable generation of power by a technology requires that its linkages to primary resource bases and the natural environment are benign, and that linkages to human systems provide maximal opportunities for enhanced social and economic development. Sustainable power generation may require resource inputs such as domestic primary energy resource reserves, a suitable transportation and electricity distribution infrastructure, and a highly skilled labor force for power plant operation. Sustainable power generation may also require low air pollution levels to the local environment, low water consumption, and high job creation in the national economy. Step C of the energy planning cycle focuses on how well technologies meet sustainability requirements and identifies those technologies which can promote the sustainable development of the local/national society and economy.

The importance of a technology's linkages with natural, human, and environmental resources implies that energy planning must do more than evaluate technologies in isolation. This is often accomplished through an integrated approach, wherein technology-resource combinations are evaluated. ***Integrated resource planning*** (IRP) is one such approach. It permits planners to understand what the resource implications will be at each stage in the ***full energy cycle*** – from primary energy resource extraction to final energy end-use – of each technology option they examine. Whenever resource interactions are encountered, planners should investigate how sustainable the interaction may be.





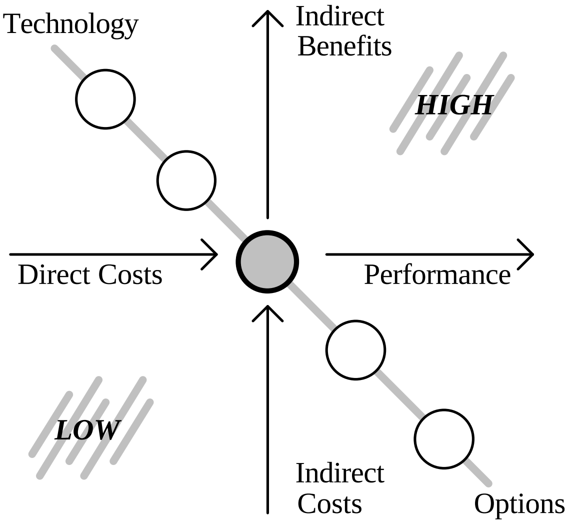
In prior decades planning has focused on identifying, acquiring, and deploying centralized, high-performance, least-cost supply-side technology options. Little attention had been given to sustainable development considerations in this process. Since the Rio Earth Summit, however, governments, development banks, industry groups, and non-governmental organizations have placed significant emphasis on the sustainable development implications of power generation. By examining the ***indirect costs and benefits*** of technology-resource combinations to human and environmental systems, and including them alongside performance and direct cost analyses, and national development objectives, technologies that promote sustainable development can be identified. The second principal axis of analysis for power generation technologies thus comprises indirect costs borne to support a technology and indirect benefits accrued by utilizing it. Along this axis, high indirect benefits to social and economic development are sought while keeping indirect costs to the natural resource base and the local, regional, and global environment as low as possible. Accordingly, selection criteria are developed in Step C to identify the *'best'* technology option for a given application. In completing Step C, this option is chosen for implementation.

In summary, the energy planning process attempts to match supply-side power generation technology options with demand-side needs in the most cost-effective and sustainable manner possible. Throughout the planning cycle, information on each technology's performance characteristics, direct costs for electricity generation, resource implications, and associated indirect costs and benefits are used to compare the relative strengths and weaknesses of available technologies so that options can be identified which have:

- *high performance*
- *high indirect benefits*

and

- *low direct costs*
- *low indirect costs*



<u>Structure of this Guide:</u>

This Guide comprises three sections covering the simplified three-step energy planning cycle presented above:

A. Assessing Demand and Identifying Technology Options

B. Assessing the Direct Costs of Technology Options

C. Assessing the Resource Implications of Technology Options

The complete energy planning cycle is shown schematically in figure 1. In the following sections, these steps are sequentially described. Drawing on information compiled for the 20 technologies assessed in the Guide's Annexes, relevant information for decisionmaking is presented as decisions are encountered in the energy planning cycle. All referenced information is provided in the Guide's four annexes as follows:

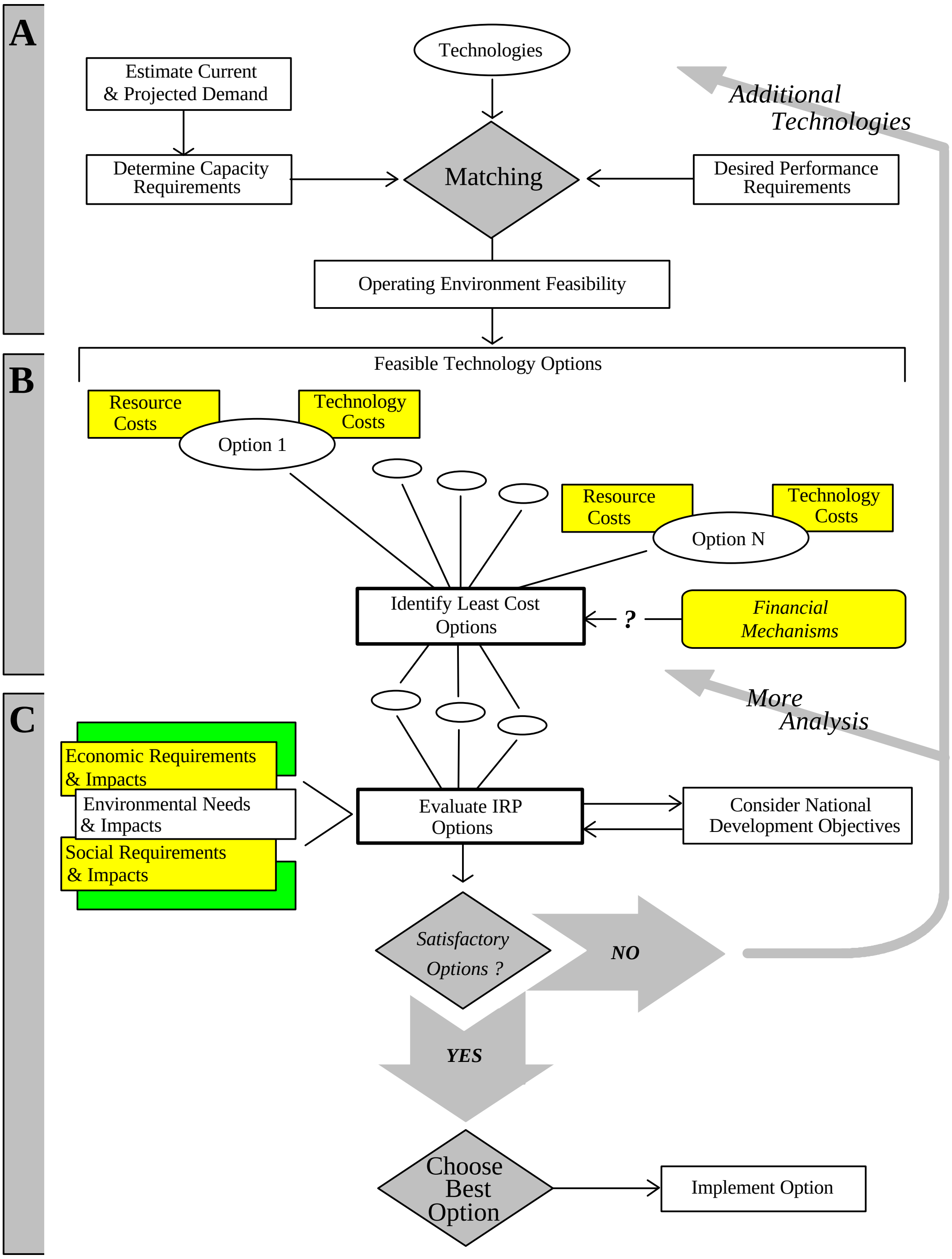
- **Annex I** provides characteristics of performance, direct costs, and indirect costs and benefits for each of the 20 technologies in a compact ***tabular format***. Reference sources for the data presented in these tables are noted therein.

- **Annex II** summarizes technology characterizations ***in chart form.*** These charts permit technology comparisons to be made for each technology characteristic examined in the energy planning cycle. All charts are prepared using the data from tables in Annex I.

- **Annex III** provides ***two-page fact sheets*** for each technology. They contain, in addition to the data presented in the tables of Annex I, more detailed information on the characterizations made as well as a description of how each technology functions.

- Finally, a list of the ***technical and economic assumptions*** made in preparing the data of Annexes I, II, and III is provided in **Annex IV.**

Following the annexes, near the end of the Guide is a ***glossary.*** It should be referenced at any time that concise definitions are needed for a better understanding of the text and annexes.



A) Assessing Demand and Identifying Technology Options

B) Assessing the Direct Costs of Technology Options

C) Assessing the Resource Implications of Technology Options

Figure 1: A Modern Energy Planning Cycle

A) Assessing Demand and Identifying Technology Options

A.1 Demand

The initial input to the energy planning cycle is an estimate of current and projected demand for electricity in the area to be served by a new power plant (in general, planning will consider the deployment of several power plants; here, focus is given to one of these). Demand estimates require, *a priori*, a geographical specification of the ***service area*** and a comprehensive inventory of energy service needs for each of the demand sectors present therein (e.g., households, industry, agriculture, transport, commerce, etc.). While current and near-term demand in a service area is relatively easy to estimate, forecasts of future demand over a 15-30 year timeframe – a typical plant lifetime – are not. This is particularly true for countries with rapidly growing economies – i.e., in emerging developing countries – with many new consumers and/or new service needs. The major factors influencing future demand growth in such countries, shown in figure 2, must be appraised before demand can be reliably estimated.

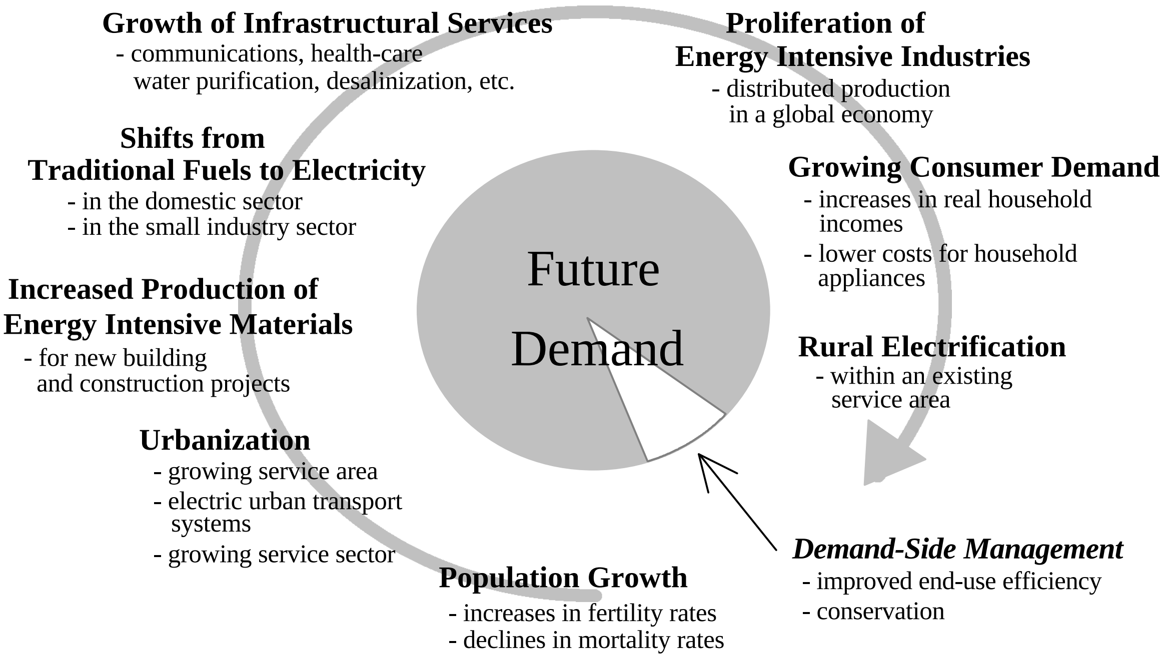


Figure 2: Factors Influencing Future Growth in the Demand for Electricity

In electricity markets, efforts may be made to moderate demand through ***demand-side management*** programs. These programs encourage improved end-use efficiency and energy conservation through administrative and pricing mechanisms. When demand-side management mechanisms will be established in a market, demand forecasts should be adjusted downward appropriately. Planning then proceeds to examine this net level of demand.

In general, two adjustments must be made to estimates of net demand levels before power generation capacity requirements can be defined. Firstly, an appraisal must be made of requirements for the ***transmission and distribution*** of electricity produced by the plant. The service area of the plant must be within economic transmission distances of the plant site. Capacity requirements will be strongly influenced by whether demand is based in a growing, centralized, high-consumption service area served by a pre-existing transmission and distribution ***grid,*** or based in a limited growth, remote, low population center to which grid extension is neither technically practical nor economically attractive. In both cases, an appraisal must be made of electricity ***line losses*** that will result from transmission and distribution. Power generation capacity needs are then adjusted upwards from demand level estimates by an amount equal to anticipated line losses. Secondly, if an objective of planning is to ensure continuous power to a service area during the presence of forced plant outages, scheduled maintenance, and fuel or other needed resource shortages, contingency plans must include a ***reserve capacity.*** When reserve capacities (ranging, on average, from 20-30%) are desired, power generation capacity requirements are further adjusted upwards from basic demand levels.

A.1.1 Demand Level Variations

The level of electricity demand within a service area varies considerably depending on the time of day. Demand is high during the day and low at night in proportion to fluctuations in human activity. Power generation facilities must therefore have sufficient capacity to meet demand levels during daily ***peak periods***, even though much of this capacity remains idle during the rest of the day (***off-peak periods***). In addition to these daily variations in demand levels, seasonal variations may also be present, and so a facility must also be able to adjust to meet seasonal demand fluctuations.

Energy planners refer to electricity demand levels as load levels and typically plot load levels as a function of time on a daily and seasonal basis in order to determine minimum power generation capacity requirements within an area served by one or more power plants (see figure 3). Such plots, referred to as ***load patterns,*** are used when deciding which technology, or combinations of technologies, can be most cost-effectively employed to meet demand. Within a load pattern, the constant and variable components of load are readily identified on a daily or seasonal basis. The *'illustrative'* load pattern presented below depicts this. The ***baseload*** is that segment of the load pattern that is always present at a constant level throughout the day *or* year. The ***peak load*** is the portion of the load pattern between the enhanced peak and the baseload level which occurs regularly, with some variability in shape, at certain well defined times during the day *or* year. Although daily and seasonal peaks are found in most load patterns, their magnitude, breadth, and precise shape differ significantly from each other depending on the geographic, economic, and cultural setting of the service area. Whereas load patterns can be estimated, their precise plotting is an empirical task, based on years of data.

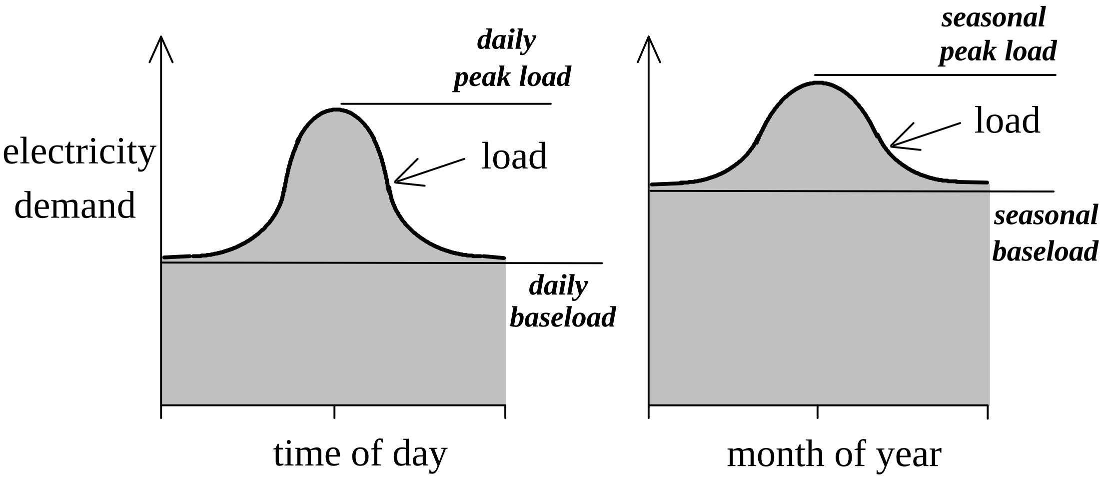


Figure 3: Load Patterns

The shape of the load patterns is oversimplified for illustrative purposes: there may be several peaks in daily and seasonal plots, and peaks are generally not symmetric. The main point is that demand levels fluctuate significantly on both daily and seasonal timescales in a more or less predictable way for any given service area with established consumption patterns.

A.2 Matching Supply with Demand

With reliable estimates of current and future electricity demand, evaluations can be made as to which supply-side power generation technologies can meet demand levels. Matching supply with demand requires a knowledge of technology performance characteristics. In this section major performance considerations of importance in the energy planning cycle are presented and discussed.

A.2.1 Technologies and their Capacities to Generate Power

The capacity of power generation technologies to produce power, varies considerably. Typical single wind turbines, for example, produce power outputs of 10-200 kW, whereas typical fossil fuel fired steam power plants produce power outputs in the range of 50-500 MW (see Box 2 for a description of units). The maximum power level a given power plant can produce is called its ***capacity rating***. For each technology, a limited range of capacity ratings are commercially available.

The power generating capacity of technologies is a key variable in the decisionmaking process to acquire and deploy them. Matching capacity to expected demand levels, rather than simply maximizing power output, is the main challenge involved in pre-selecting technologies that meet demand. Only by estimating current power demand, as well as expected demand over the lifetime of a power plant, can the appropriateness of various technologies be evaluated.

Box 2: Energy and Power

In order to perform an activity, a physical quantity known as energy is required. Energy, which is always supplied by an energy source, is thus needed to light a lightbulb, run a machine, heat a home, set a car in motion, etc... ***The level of activity which can be performed by an energy source is directly proportional to the amount of energy it supplies.*** Power, on the other hand, is a related but different physical quantity. ***Power is the rate at which energy is supplied by an energy source.*** The level of activity that can be performed by an energy source in a fixed amount of time is directly proportional to the amount of power the energy source delivers. All forms of power, including electrical power, are measured in terms of **Watts (W).** Energy is measured in **Watt hours (Wh).**

Household appliances provide an idea of the amount of power a Watt represents. The power intake requirements of some common devices are:

- typical lightbulb: 100 W
- small television: 200 W
- microwave oven: 700 W
- two burner electric stove: 2,000 W

Increasingly larger quantities of power are expressed in terms of kilowatts, megawatts, gigawatts, and terawatts:

- 1 kW = 1 kilowatt = 10^3 W = 1,000 Watts
- 1 MW = 1 megawatt = 10^6 W = 1,000,000 Watts
- 1 GW = 1 gigawatt = 10^9 W = 1,000,000,000 Watts
- 1 TW = 1 terawatt = 10^{12} W = 1,000,000,000,000 Watts

The electricity needs of a rural town with a population of 10,000 are about 10 MW, while the needs of a modern city with a population of 500,000 are roughly 1 GW. By contrast, the total power consumed by the world's 5,700,000,000 inhabitants is on the order of 10 TW. Aircraft jet turbines provide an idea of how much hardware it takes to generate large quantities of power. At full thrust, the 4 gas turbine engines of a Boeing 747 Jumbo Jet commercial aircraft produce about 150 MW of combined power.

The amount of energy consumed by a given device over a certain time is equal to the power intake of the device multiplied by the amount of time that power is consumed. For example, in order to keep a typical lightbulb on for 1 hour, the amount of energy required is (100 W) x (1 hour) = 100 Wh. Correspondingly, ***the amount of energy supplied by a power source over a given time is equal to the power output of the source multiplied by the amount of time that power is supplied.*** For example, the amount of energy produced by a 100 MW power plant in 1 hour is 100 MWh, and in one year is 876 GWh ... enough energy for a Boeing 747 Jumbo Jet to circumnavigate the earth about 500 times.

Many energy reports express energy figures in Mega-Tonne Oil Equivalent (Mtoe) units. The conversion factor to MWh is given by **1MWh = 11.63 Mtoe,** which is the amount of energy contained in 11,630,000 tonnes, or 86,000,000 barrels, of crude oil.

Technologies should be selected based on their ability to generate the levels of power needed to serve a given area. Remote rural service areas with small populations (< 10,000 inhabitants) and limited small-scale cottage industries, can be served as an off-grid application of technologies with power generation capacities in the kW range (1-1,000 kW). Installations can include single, or multiple, small power generating units. For larger service areas, technologies with power generation capacities in the MW range (1-1,000 MW) serving a grid are appropriate.

Refer to: ➔ Annex II Chart 1 : kW Capacity Ranges
➔ Annex II Chart 2 : MW Capacity Ranges

A.2.2 The Operating Availability of Technologies

Power generation technologies are not maintenance free. A power plant employing a given technology is expected to have outages, some planned for scheduled maintenance and some unplanned due to component failures. During an outage, the plant does not produce power. The amount of time over which an outage occurs is referred to as ***downtime***. Scheduled downtime is needed to perform necessary maintenance thus ensuring optimal plant performance and preventing, as much as possible, unscheduled downtime. Generally, the more complex and process-intensive a power generation system is, the more scheduled maintenance is required. Fortunately, scheduled maintenance can be performed at times of the day when power demand is low and alternate power from a stand-by unit or another plant in the grid can be made available. In this way ***uninterrupted power*** can be supplied to consumers. When unscheduled downtime occurs due to technology failures, consumers may experience electricity outages until repairs are made or an alternate power source can be brought on-line.

The greater the operating availability of a plant relative to unexpected downtime, the greater its ***reliability.*** High plant reliability, is an important criteria in technology selection. Taking into account scheduled downtime and anticipating unscheduled downtime from previous experience, ***operating availability*** is defined as the percentage of time during that a plant can engage in power generation. In general, most modern power generation technologies have operating availability levels greater than or equal to 85%.

Box 3: Operating Availability

Operating availability, is defined numerically as:

operating availability = (1 - *planned outage rate*) x (1 - *unplanned outage rate*) x 100

the planned outage rate is generally specified by the manufacturer as the number of hours of maintenance needed per a stated number of hours of operation, while the unplanned outage rate can only be estimated based on the experiences of existing plants employing a similar technology.

Refer to: ➔ Annex II Chart 3 : Operating Availability

A.2.3 Technologies that Meet Demand Fluctuations

As mentioned in Section A.1.1, power utilities supply electricity to service areas in which demand fluctuates daily and seasonally. To do this they use three types of generating facilities, each employing different technologies with different duty cycles. Technology ***duty cycles*** are classified as:

baseload:	running most of the time on a daily basis and serving the baseload of the load pattern
intermediate:	running daily at times when demand is above the baseload level and serving that portion of demand between the daily peak and the daily baseload
peaking:	running only at certain times of the year and serving: a) exceptionally high daily peak loads, and b) the portion of demand between seasonal peaks and the seasonal baseload. In both cases, baseload and intermediate duty cycle technologies would not have sufficient capacity to meet load requirements
intermittent:	intermittent duty cycle technologies are solar, wind, and certain hydropower technologies which run whenever possible, given that they are dependent on the availability of sunlight, wind, or water

Baseload duty cycle technologies are designed to run continuously – for the entire time of their operating availability, which should be high – and serve a large service area of several hundred megawatts. They run at a nearly constant high-capacity level just below their capacity rating. As a result of their high capacity ratings, baseload technologies have high capital costs, however, they often run on lowest cost primary energy source available in stable supply. Coal and natural gas fired steam and combustion plants as well as nuclear fueled steam and large-scale hydroelectric plants represent typical baseload facilities. Baseload plants can produce 100 MW to over 1000 MW of electricity, depending on the technology employed.

Intermediate duty cycle technologies serve the daily peak load. Their operation is often more labor intensive than that of baseload facilities due to daily start-up, monitoring, and shut-down procedures, and thus they can have higher operating costs. The capital costs of these technologies vary according to their capacity, and this depends on the ratio of daily peak load to baseload for the service area. Common intermediate facilities include gas turbine and hydroelectric plants, producing electricity in the 50 to 300 MW range.

Peaking duty cycle technologies often run in a stand-by mode, becoming operational only when the service area load approaches the capacity limits of the baseload and/or intermediate facilities. This may occur during extreme hot or cold weather conditions when users have heating or cooling needs above normal levels. Peaking duty cycle technologies often run on high grade oils or natural gas so that they can be engaged promptly in an on-demand basis. Typically these facilities are diesel engines or gas turbines respectively supplying on-demand electricity in the 20 MW or 100 MW range.

Intermittent duty cycle technologies can not supply continuous power due to the intermittent nature of primary energy supply. This class of technologies principally includes those using solar and wind energy as their primary energy resource. Their power output cannot be controlled since high intensity solar radiation or high velocity winds vary with weather conditions. Unavoidable inconsistencies in primary energy resource availability – due to darkness, cloudcover, or calm windstream – limit the performance of solar and wind energy technologies. Constraints are also encountered in hydroelectric facilities, as when feeding water flows are insufficient for continuous operation. Applications of intermittent duty cycle technologies are therefore limited to applications that do not need continuous on-demand power, permit energy storage for use during non-producing periods, or integrate intermittent technologies with baseload or intermediate duty cycle facilities. In the latter integrated scheme, intermittent facilities can provide significant supplements to electricity production by other sources, and thus grid connection of intermittent technologies is desirable. The penetration of intermittent facilities in integrated applications is usually limited to low and moderate levels. At high levels, operational difficulties and high costs result when gross adjustments of production levels by conventional facilities are required to fill the gap between variable intermittent production and fluctuating service area demand.

Technologies with different duty cycles can be mobilized to serve the fluctuating demand levels in a service area. Another approach to the problem of meeting demand fluctuations is ***load management,*** an element of demand-side management. Load management is used to modify the shape of load patterns by influencing user demand for electricity. If the magnitude and width of peaks in the load pattern can be made managed – made smaller or shifted – demand-side pressure on utilities for new or additional peaking and/or intermediate duty cycle facilities can be reduced, and in some cases eliminated. This is important since electricity production costs for peaking and intermediate duty cycle facilities are often substantially higher than their baseload counterparts. Methods of load management include promoting conservation and efficient end-use of electricity. Although outside the scope of this Guide, load management, and more generally, demand-side management, play crucial roles in decisionmaking to match production capacity to demand.

Refer to: ➔ Annex II Chart 4 : Duty Cycles

A.2.4 Technology Capacity Factors

Each power plant has a rated capacity, that is the maximum power output it is capable of delivering during normal operation under ideal conditions. Theoretically, if operating at the capacity rating, the plant can produce a certain maximum amount of energy during a year. Over the course of a year, however, the amount of energy produced by the power plant is less than this maximum amount for a three reasons. First, the operating availability of the technology in the plant is less than 100 percent. Second, the plant may not be run on a continual basis during the time it is available (e.g., it may be an intermediate duty cycle facility that runs only during the daytime hours). Third, during the time it does run it may be run at less than full capacity. The ***capacity factor*** for a plant facility takes these facts into account and provides an indication of the total energy a plant actually produces during a year of normal operation. The capacity factor for a plant, expressed as a percent, is the ratio of energy actually produced by a plant during a year to the theoretical maximum amount it could produce if operating at its capacity rating throughout the year.

Capacity factors will always be less than 100 percent for the reasons mentioned above. Also to be considered are variations in a facility's capacity factor over time due to constraints of a technological nature. For example, new coal-fired power plants run with a capacity factor of about 40 to 60 percent during the 'breaking-in' of their first two years of operation, and about 60-70 percent in subsequent years until later stages of plant life when their capacity factors decline due to reduced stress limits of their combustion components. On the other hand, hydropower plants, which require no breaking-in and do not employ a combustion process, normally run with 40-50 percent capacity factors throughout their lifetime.

Knowing the capacity factor a technology can be run at is critical to decisionmaking. The capital cost of technologies are spread over electricity generation costs per kWh during a plant's lifetime. The price of electricity to users thereby reflects capital costs. Low capacity factors and/or short plant lifetimes increase the cost of electricity to users. Conversely, high capacity factors and/or long plant lifetimes decrease electricity costs to users.

Box 4: Capacity Factors

The amount of energy, E, produced by a plant with a rated capacity of P MW running for 1 year at full capacity is:

$$E = P \times 1 year \times \left[\frac{365 days}{1 year} \times \frac{24 h}{1 day} \right] = (8760 \times P) MWh$$

As an example, consider a 125 MW gas turbine power plant. The above calculation gives E = 1.1 x 10^6 MWh = 1.1 TWh. However, the amount of energy actually produced by the power plant will be less than this maximal amount. Suppose the power plant has an operating availability of 85 %, is used as a baseload duty cycle facility running 100% of the time (during its operating availability), and is run at 80 % of its rated capacity for technical reasons. Its capacity factor, CF, will be:

$$CF = 0.85 \text{ x } 1.0 \text{ x } 0.8 = 68\%$$

and thus the amount of energy, E', the 125 MW plant can actually produce in a year is:

$$E' = CF \text{ x } E = 0.68 \text{ x } 1.1\ TWh = 0.75\ TWh$$

The capacity factor thus provides an idea of how much energy the plant produces in a year, and its average power output during the year, P', will be:

$$P' = CF \times P = 0.68 \times 125\ MW = 85\ MW$$

This average power output is considerably less than the plant's rated power generation capacity of 125 MW. Because average power output is always less than the theoretical full power maximum, the average power output of a power plant should be in slight excess of estimated maximum demand requirements.

A.2.5 The Feasibility of Technology Options

Knowledge of capacity ranges, operating availability, duty cycles, and recommended capacity factors for a large set of technologies considered in Step A of the energy planning cycle, helps planners choose appropriate technology options for a given application. For each of these potential options, a technology's performance characteristics are capable of meeting demand requirements. However, due to the operating environment specificities of some technologies, not all potential options will be feasible in all settings.

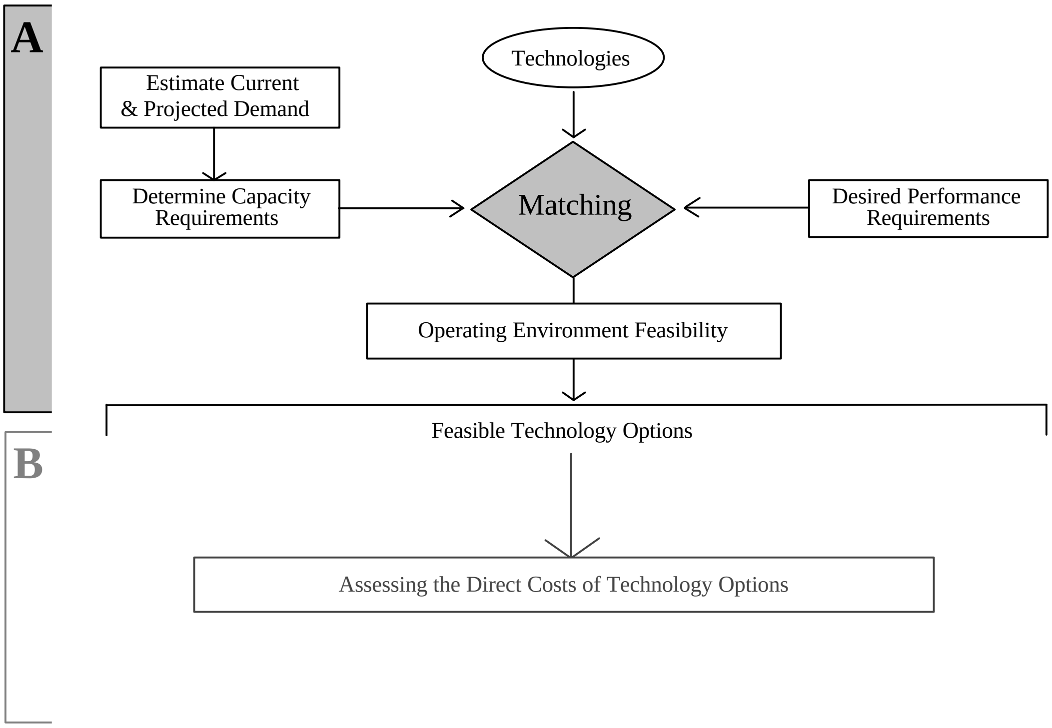
Power generation technologies are not stand-alone structures. Rather they operate under a set of enabling environmental conditions. As a fundamental prerequisite, a technology's primary energy source must be in supply at the plant site. Environmental conditions related to primary resource accessibility must be, *a-priori,* satisfied if a technology is to be productively engaged. Some examples are:

- Large dam and reservoir hydro-power plants require large bodies of water within national boundaries and suitable topographical variations in local geography.
- Solar power generation favors low latitude regions with relatively cloud free weather conditions during most of the year.
- Wind turbines require local wind regimes that are consistently strong throughout most of the year.
- Geothermal facilities require a local geothermal resource.
- In order to avoid additional transport infrastructure and high associated costs, fossil fueled power generation requires plant siting near a fuel source; near an existing gas pipeline, refinery, coal mine, barge and/or rail transport facility, or major port. Furthermore, when national resources are used as the primary energy source, fuel reserves must be large enough to provide fuel to these plants – and other competing applications – over a their roughly 30 year lifetime.
- For nuclear plants, a country's access to enriched uranium may be a constraining factor. Site stability is also an important factor as nuclear plants require siting in regions free from major earthquake risk (or must be earthquake proofed).

In addition to requirements for readily accessible primary energy resources, all technologies have land requirements, and many have water requirements for steam and/or cooling water cycles integral to their functioning. Except in unusual circumstances, these latter requirements can be met in most settings. High land or water requirements may, however, present land-use or water-use conflicts with competing applications. Hence, technologies with high land and/or water requirements can present high indirect costs to society (see Section C on indirect costs).

Although beyond the scope of this Guide, the above discussion points out the need for a thorough assessment to be made of technology-specific requirements relating to environmental needs. Feasibility studies are needed in cases where a site's potential to meet these requirements is uncertain. If operational requirements cannot be met, the technology is generally not further considered.

Step A of the energy planning cycle is completed once the initial set of technologies examined are screened to ensure their performance meets demand requirements and that their operating specificities can be accommodated. While the set of technology options emerging from Step A are all feasible, consideration must be given to their relative costs of generating electricity. Feasible technology options are thus evaluated on financial grounds in Step B of the planning cycle where assessments are made of each option's direct costs of power generation.



Section A Reference Sources :
1, 24, 25, 28, 32, 33, 41, 43

B) Assessing the Direct Costs of Technology Options

Although each feasible technology option selected in step A of the energy planning cycle meets demand requirements, the financial costs associated with power generation for each technology differ. An analysis of power generation costs for each option is used to identify which options have the lowest financial costs.

B.1 The Direct Costs of Power Generation

The ***direct costs*** of power generation are those costs directly associated with:

- acquiring and installing the technology
- engaging a labor force to operate and maintain the technology
- purchasing the fuel needed to generate electricity

Direct costs thus comprise three categories: ***capital costs*** of plant and equipment, ***operations and maintenance costs***, and ***fuel costs***. Not included in directs costs are related costs for: fuel transport, the disposal of wastes generated by the plant, electricity transmission and distribution, administration and marketing, etc.

Power generation technologies have varied physical characteristics and operating requirements. To make meaningful economic comparisons of technology options, it is desirable to compare technologies based on levelized costs. ***Levelized costs are costs per kilowatt-hour of electricity*** generated by a power plant. An advantage of analyzing levelized direct costs is that they permit projects with different economic lifetimes and capacity factors, as well as different absolute requirements for capital, operations and maintenance, and fuel, to be placed on the same footing, i.e., costs per kWh. They also permit project cost projections for varied discount rates to be calculated and compared. In this section, the levelized direct costs of power generation are described.

B.1.1 Capital Costs

Capital costs include costs for the primary energy conversion technology (e.g., turbine, diesel engine, photovoltaic panels, etc.), all auxiliary equipment needed for its functioning (e.g., fuel regulator, boiler, cooling tower, generator etc.), and construction costs for the plant housing. Capital costs are thus the ***total plant cost*** for a plant that is completely installed, fitted, and ready to produce electricity.

For a given technology, a plant's capital costs vary in proportion to its capacity rating. The larger a plant's capacity, the greater its capital costs. For most technologies, capital costs vary almost linearly with a plant's capacity rating over a broad capacity range. For example, an 10 percent increase (decrease) in capacity raises (lowers) capital costs by roughly the same 10 percent. For certain technologies, however, economies of scale exist, and larger plants have lower capital costs than those resulting from such a linear extrapolation. Yet even for these latter technologies, costs can sometimes be roughly approximated by linear extrapolation over limited capacity ranges.

By virtue of this linear relationship between capital costs and capacity rating of plants, capital costs are usually measured in terms of cost per ***kilowatt of capacity (kWe).*** For example, if the cost of a 1 MW diesel power plant is $1 million and that of a 10 MW power plant is $10 million, then the capital cost of a diesel power plant is $1 for each Watt of capacity installed. Equivalently, this cost can be expressed as being $1,000 per kilowatt of capacity as is more typical in the power industry. Capital costs per kWe are highly technology dependent, varying from a cost of slightly less than $1,000 for gas turbine technologies to roughly $6,000 for solar photovoltaic technologies.

Refer to: ➔ Annex II Chart 5 : Capital Costs per kWe

B.1.2 Levelized Capital Costs

Capital costs vary considerably from one technology to another. However, these costs cannot be assessed in isolation as they are just one factor determining the capital cost per kilowatt-hour of energy generated by a technology. Other factors include the economic lifetime of the technology, the capacity factor at which the technology will be run, and the prevailing discount rate governing future cash flows associated with the capital investment. For technologies with longer lifetimes, capital costs can be amortized over longer time periods, lowering the capital cost component of energy produced relative to technologies with shorter lifetimes. Similarly, the higher the capacity factor of a technology, the greater the total amount of energy it will generate during its lifetime, thus, since its capital costs are fixed, higher capacity factors lower the capital cost component of produced energy. Furthermore, higher discount rates raise the annual cost of capital in a power investment relative to lower rates. In order to make meaningful comparisons of different technology options, it is necessary to compare technologies based on levelized capital costs, which specifically take lifetime, capacity factors, and discount rates into account. Box 5 provides details on how this is done.

Box 5: Levelized Capital Costs

Capital investments in the power generation industry are often made through an investment sequence spread over the economic lifetime of a power plant. Here it is assumed that the investment is facilitated through a loan at an interest rate equal to the prevailing discount rate, r, at the time capital is purchased which is herein assumed to be the start-up date. Loan principal is equal to the total initial cost of the plant, and repayment is made in yearly installments over the plant's lifetime. As calculated here, capital costs do not include the cost of land, interest charges during construction, or working capital.

According to these assumptions, the **Annualized Cost** of capital equipment, C_{AC}, for a power plant (not including operations and maintenance or fuel costs) is given by:

$$C_{AC} = \left(\frac{Initial\ Cost}{kWe}\right) \bullet \left[\frac{r(1+r)^{l}}{(1+r)^{l}-1}\right] \bullet \left[\frac{1}{CF}\right] = capital\ cost\,/\,kWh\,/\,yr$$

where r = the discount rate, l = economic lifetime, and CF = capacity factor (%). The annualized cost represents the annual cost of capital per kW of generating capacity over the lifetime of a power plant (discounted to the start-up date).

The Levelized Cost per kWh of a plant's capital equipment, $\boldsymbol{C_{LC}}$ **,** is thus:

$$C_{LC} = \left(\frac{Initial\ Cost}{kWe}\right) \bullet \left[\frac{r(1+r)^{l}}{(1+r)^{l}-1}\right] \bullet \left[\frac{1}{CF}\right] \bullet \left[\frac{yr}{8760hr}\right] = capital\ cost\,/\,kWh$$

Levelized costs for capital quoted in the Annexes are calculated using this latter formula.

B.1.3 Levelized Operations and Maintenance Costs

Operations and maintenance (O&M) costs include the labor, equipment, and service charges associated with normal operation of a given power plant. As presented in the Annexes, they also include charges related to ancillary fuel and waste processing at the plant, but do not include transportation charges of fuel and wastes to and from the plant.

For a given technology, O&M costs represent average annual costs for fixed operations activity – depending on plant capacity – and variable maintenance activity – increasing annually as total accumulated power production by the plant increases. These costs are estimated based on prevailing labor, equipment, and service costs. Fixed operations costs are levelized according to the capacity factor of the plant; higher capacity factors imply higher operations costs. Variable maintenance costs are annual averages based on the plant's capacity rating and capacity factor. Both of these costs can be estimated from information provided by manufacturers and utilities. Their sum gives total levelized O&M costs. Box 6 describes how levelized O&M costs are calculated.

Levelized O&M costs vary from one technology to another, although to a lesser degree than do capital costs. For a given facility, levelized O&M costs vary depending on whether a power generation facility is employed in a baseload, intermediate, or peaking duty cycle. In general, levelized O&M costs are lower for baseload facilities than for intermediate and peaking facilities.

Box 6: Levelized O&M Costs

Annual fixed operations costs, $\boldsymbol{O_F}$**,** for a plant of given capacity, assume full-capacity plant operation. $\boldsymbol{O_F}$ must be levelized using the capacity factor, *CF,* to give annual levelized operations costs O_L:

$$O_L = O_F \bullet CF \text{ = operations costs / kWh}$$

Yearly variable maintenance costs, M_V, are for schedule maintenance only and do not include extraordinary charges for maintenance and repair work associated with unscheduled downtime. Annual maintenance costs are added to yearly levelized operations costs to give annual total levelized O&M costs:

$$OM_L = O_L + M_V = \text{O\&M costs / kWh}$$

B.1.4 Levelized Fuel Costs

Fuel costs for oil, petroleum, natural gas, coal, biomass, and uranium are based on a plant's annual fuel consumption using the average prevailing prices of these resources in a given reference year and country setting. Renewable technologies, with the exception of biomass plants, use no fuel (although in some settings resource access fees may apply).

For a given power plant, levelized fuel costs are calculated based on its capacity rating, capacity factor, the energy content of the fuel consumed, and the energy conversion efficiency of the technology used (cf. Box 7).

Box 7: Levelized Fuel Costs

Fossil and biomass fuels are the primary energy source for the majority of the world's power plants. In order to make estimates of fuel costs for any one of these power plants, several technical parameters must be specified:

G = the grade of fuel used, or more specifically, its heat value (in Btu/kg)

P = the purchase price of fuel used (in price/kg)

e = the conversion efficiency of the technology employed (in Btu/kWh)

The levelized fuel cost, F_L , for power generation by the power plant is then:

$$F_L = \frac{P \bullet e}{G} = \text{fuel costs / kWh}$$

note: The conversion efficiency for technologies is often expressed as a percentage called the lower heat value (LHV) efficiency and denoted as E. Since 3,413 Btu of energy is equivalent to 1 kWh of energy, E is obtained from e defined above according to:

$$E = 3{,}413 / e$$

From a strategic standpoint, in order to keep the direct costs of power generation low, energy planners seek to employ technologies that use primary energy resources in cheap and abundant supply. It should be emphasized, however, that fuel costs are only one of several components in the cost structure of power generation. Identifying least-cost technology options requires assessments of total direct costs – including capital and O&M costs – for a range of technologies. Only by evaluating technologies based on their levelized total direct costs can least-cost options be identified.

B.1.5 Levelized Total Direct Costs

The levelized total direct costs of power generation are obtained by summing the levelized costs for capital, operations and maintenance, and fuel for a technology. This has been done for the 20 technologies assessed in this Guide; results are presented as charts in Annex II.

Box 8: Levelized Total Direct Costs

Following the definitions given in Boxes 5, 6, and 7 above, levelized total direct costs for power generation are derived using the following formula:

$$DC_L = C_L + OM_L + F_L = \text{direct costs / kWh}$$

Refer to: ➔ Annex II Chart 6-8 : Levelized Total Direct Costs for Power Generation assuming discount rates of 5, 7, and 10 %

B.2 Factors Influencing Direct Costs

B.2.1 Power Plant Lifetimes

A power plant is a capital intensive facility, and as such, is designed to operate over a long time horizon. In this way the high capital costs of power generation technologies can be amortized over many years to bring average production costs down.

As a technology ages, its operating efficiency decreases, i.e., more primary energy input is needed for a fixed electrical energy output, and forced outage rates increase due to component failures. At some point in the later stages of a technology's life-span, variable costs due to repairs and refurbishments, as well as lost revenue due to outages, result in costs of continued operation that exceed financial returns. At that time, it is preferable to shut the plant and establish new generating capacity. In some cases, these older plants can be left idle, and re-used when additional capacity is needed on a limited basis.

The average expected lifetime of a plant varies depending on which technology is used, what duty cycle and capacity factor it operates with, and how well it is maintained. Experience provides some useful estimates for lifetimes of different types of plants. For example, hydropower plants have average lifetimes of over 50 years, coal-fired steam plants about 30 years, wind turbines about 20 years, and diesel engines about 15 years.

Refer to: ➔ Annex II Chart 9 : Power Plant Lifetime Estimates

B.2.2 Power Plant Lead-times

When a decision is made to augment power generation capacity in a service area, the service area is often already experiencing a capacity shortage. Thus, bringing capacity on-line as quickly as possible is usually an important requirement. The ***lead-time*** is defined as the total period of time from the day plant construction begins to the time power is first generated. In situations where generating capacity is needed immediately, technologies with shorter lead-times are favored over those with longer lead-times. Furthermore, the financial requirements for power projects are usually very sensitive to the time required to erect a plant. When a technology's capital costs are high, and investment schedules include high pre-operation expenditures, short lead-times are advantageous. Conversely, in situations where power planning is done well ahead of additional capacity needs and/or financing does not imply high initial outlays, lead-time may be of lesser importance.

The more complex a technology, the more involved its construction is, and/or the greater the number of sub-contractors required for its construction, the greater chances are that initially estimated lead-times will be surpassed. Keeping lead-times as short as they can possibly be requires experienced project management, and regular progress reviews. Minimum lead-time estimates, assuming ideal construction conditions, are expressed in years and months in this Guide.

Refer to: ➔ Annex II Chart 10 : Power Plant Lead-times

B.3 Investment Decisionmaking and Least-cost Planning

Capital costs for electricity generation facilities are high relative to yearly revenue from the sale of electricity generated. In any large capital investment decision it is critical to know from the outset whether the total cost of acquiring and installing capital is financially feasible. For state-run utilities, the availability of financial resources from national budgets may be limited and/or restricted due to competing demands from other needs, including accumulated debt servicing outlays. Complete and accurate estimates of total capital costs are needed to assess whether an investment can be financed from within the national budget. When external financing is sought from bilateral sources and/or a commercial or development bank, it is often on a ***'project financing'*** basis, i.e., the total financing sought must be balanced by the project's ability to generate repayment through its cash-flow. When debt or equity financing is sought the investment project must be projected to be profitable in order to interest external investors. Whatever mode of financing is sought, it is necessary to demonstrate that a large capital investment is sound. While knowledge of total capital costs is important in gauging whether sufficient funds are available or can be obtained for a power project, such information does not indicate how sound an investment the project may be.

A power generation project is judged to be a sound investment if over the lifetime of the project, on a discounted cash flow basis, inward cash flows (revenues) deriving from the project are estimated to be greater than or equal to outward cash flows (costs) required to sustain it. Analyses of a project's ***'net present value'* or NPV** allow this determination to be made (see Box 9 below). Revenues are accrued by the sale of produced electricity in units of kilowatt-hours to users according to a rate structure that sets the prices users pay. Rate structures are determined by utilities, independent power providers, and state agencies. The price for electricity set forth in rate schedules depends on a multifaceted scheme that sets a per kilowatt-hour price for electricity which reflects the total direct costs of power generation, transmission, and distribution. Generation costs are the levelized costs discussed above for capital, operations and maintenance, and fuel costs associated with a power plant. Added to these costs are levelized costs for electricity transmission and distribution; for administrative activity including management, marketing, and distribution servicing; and finally, for insurance, taxes, and non-capital related debt servicing (assuming capital debt servicing charges are already reflected in levelized capital costs). Moreover, if state and/or external extra-national subsidies have been granted, the extent to which levelized costs are offset must be determined. Once all costs and subsidies have been accounted for, rate schedules can be constructed.

Rate schedules must specify final electricity prices that permit full power generation and distribution cost recovery for a sustainable power sector. State-run utilities aim to match revenues to these costs over the lifetime of a power plant, while independent power providers (IPPs) seek revenues in excess of these costs by an amount known as a profit margin. IPPs seek margins in excess of the local discount rate; that is, in excess of returns they could expect in local money markets at minimal risk.

Box 9: Net Present Value (NPV)

The financial analysis performed to assess the soundness of an investment project is called net present value analysis. A project's **net present value (NPV)** is the difference between its market value and its cost based on a discounted cash flow (DCF) method wherein future cash flows are adjusted to their present values. An NPV is positive if value will be added by a project - *revenues exceed costs* - and negative when value will be lost by a project - *costs exceed revenue.*

The NPV of any prospective power plant project can be estimated based on expected costs for power generation, transmission, distribution, and administration, combined with forecasts of future revenues from the sale of electricity generated by the power plant. Any project with a positive NPV is economically attractive to pursue, while those with negative NPV are not. When several potential power projects are being considered and compared, the most financially attractive project amongst them is the one with the greatest positive NPV.

In order to calculate the NPV of a power project, cost and revenue estimates must be made over the lifetime of the project. Both costs and revenues that are part of the project's cash flow, must first be estimated:

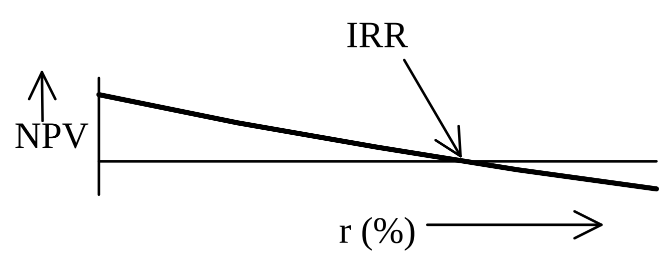
Period (yrs)	:	**i**	1	2	3	...	j	...	f
Cash Flow	:	$\mathbf{C_i}$	C_1	C_2	C_3	...	C_j	...	C_f

The yearly cash flow, C_j , is equal to total revenues in year j minus total costs in year j, thus net cash inflows (revenues) in year j result in positive C_j and net cash outflows (costs) in year j result in negative C_j. The cash flow, C_j , for each year of plant operation from the initial year i to the final year f must be estimated from cost and revenue projections of the project. C_i is the initial (year zero) cash outflow (which is negative as it includes up-front capital costs before operations begin and before revenues are generated). In any given economic environment, there will be a prevailing discount rate, r, which is used to discount the value of project cash flows. The discount rate used is often the interest rate at which loans for the project are secured. The NPV is then:

$$NPV = \sum_{j=i-f} C_j / (1+r)^j$$

➔ From a strictly financial perspective, *an investment should be accepted if its NPV is positive (or zero) and rejected if it is negative*

The above expression for an investment's NPV is often used to estimate the investment's **internal rate of return (IRR).** The IRR is the rate of return on investment for the power project, and it is the required return that results in a zero NPV when it is used as the discount rate. By varying the discount rate r in the above expression for NPV, the following curve is obtained:



The curve, called the ***NPV profile,*** intersects the x-axis where r = IRR. While state utilities invest in projects with an IRR equal to or slightly greater than the prevailing discount rate, independent power producers within the private sector seeking profits only invest in projects with an IRR several percentage points greater than the discount rate.

Both state-run utilities and IPPs seek to identify least-cost supply options capable of meeting demand by minimizing the direct costs of power generation, transmission, distribution, and administrative activity. In many applications, transmission, distribution and administrative costs are not sensitive to the choice of the power generation technology; thus, the problem of identifying least-cost supply options simplifies to one of identifying least-cost power generation options. The technology options emerging from step A in the energy planning cycle with the lowest direct costs can be identified from the data presented in the Annex (cf. Section B.1.5).

Once least-cost options are identified, an ***integrated supply curve*** can be constructed in order to identify the lowest cost investment sequence for power generation. Integrated supply curves rank, in order of increasing direct costs, the amount of energy potential provided by each potential option. The example in Box 10-A illustrates how such a curve is constructed.

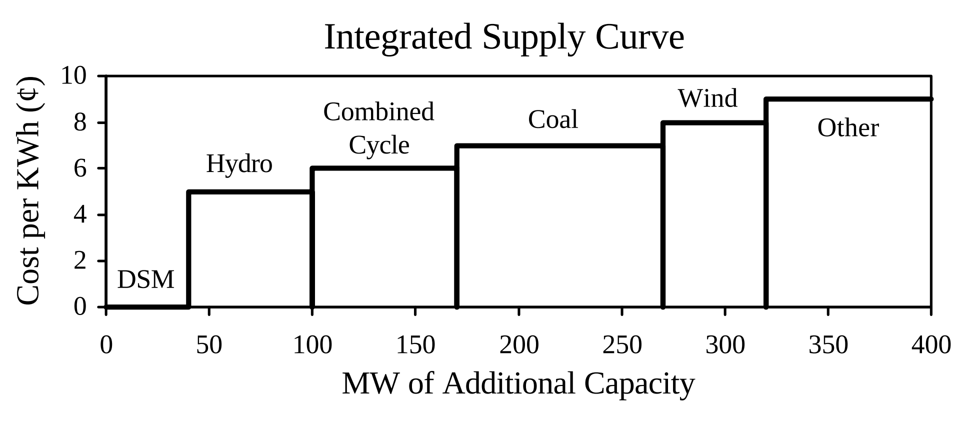
Box 10-A: Integrated Supply Curves: an example

Suppose energy planners seek to meet growing demand in a service area with new power generation capacity. Current power generation facilities serving the area provide 500 MW of electricity supply. Planners project consumption levels to grow by 20 percent in 3 years, and 40 percent in 5 years, due to rising population and increasing industrial activity. They thus seek to provide additional power generation capability of 100 MW in 3 years time and a further 100 MW in 5 years time. Their analysis of levelized total direct costs for additional power generation indicate, that in order of increasing direct costs, hydropower at 5¢/kWh, natural gas combined cycle at 6¢/kWh, coal-fired steam turbine power at 7¢/kWh, and wind power at 8¢/kWh are the least-cost options. Other more expensive renewable options also exist (biomass at 9¢/kWh, solar thermal at 11¢/kWh, etc.). Each least-cost option has the potential to supply a quantifiable and limited amount of power to the service area. Feasibility studies carried out by engineers indicate that:

- availability of water resources limit hydro-electric power generation to 60 MW;
- port facilities for LNG (liquefied natural gas) imports limit combined cycle generation to 70 MW;
- the supply of low-cost local coal limits power generation from coal to 100 MW;
- wind conditions limit wind power generation to 50 MW.

Additionally, suppose that an energy conservation study indicates that after one year of application, demand side management (DSM) techniques, of negligible cost, can reduce electricity consumption in the service area by a sustainable 8 percent or 40 MW.

The integrated supply curve for power generation is:



The curve clearly indicates that the least-cost option for supplying the first 100 MW of new capacity in 3 years is to use DSM and hydro. For the second 100 MW of capacity in 5 years, combined cycle and coal are indicated, however, the coal-fired plant minimum size is 75 MW, and only 30 MW additional to the 100 MW combined cycle plant will be needed to meet supply requirements. Thus, rather than building excess capacity in a coal plant, planners may consider using the next lowest cost option - wind power; which has a minimum plant size of order 1 MW - to meet supply requirements.

As yet, no mention has been made of potential financial mechanisms that may exist to offset the relatively high cost of renewable energy options such as solar, wind and biomass based technologies. At the national level, mechanisms such as subsidies and tax credits may be available, making the direct costs of renewable technologies more competitively priced relative to fossil fuel and hydroelectric technologies. In a developing country context, mechanisms such as grants and concessional loans from bilateral aid organizations and multilateral financial institutions can offset the higher cost of renewable technologies. While limitations in magnitude of total offset funding and/or resource availability for renewable options exist, such offsets nevertheless make it more economical for renewable technologies to enter into the mix of supply-side power generation.

Whenever financial mechanisms are present, planners should adjust integrated supply curves so that modified total direct costs of renewable options are compared with other options. Although the particulars of each case vary considerably, another example in Box 10-B shows, in general, how integrated supply is affected by subsidies. As the example demonstrates, the least cost options identified when financial mechanisms are present can be distinctly different from those identified in the absence of such mechanisms.

Box 10-B: Integrated Supply Curves: w/ financial mechanisms

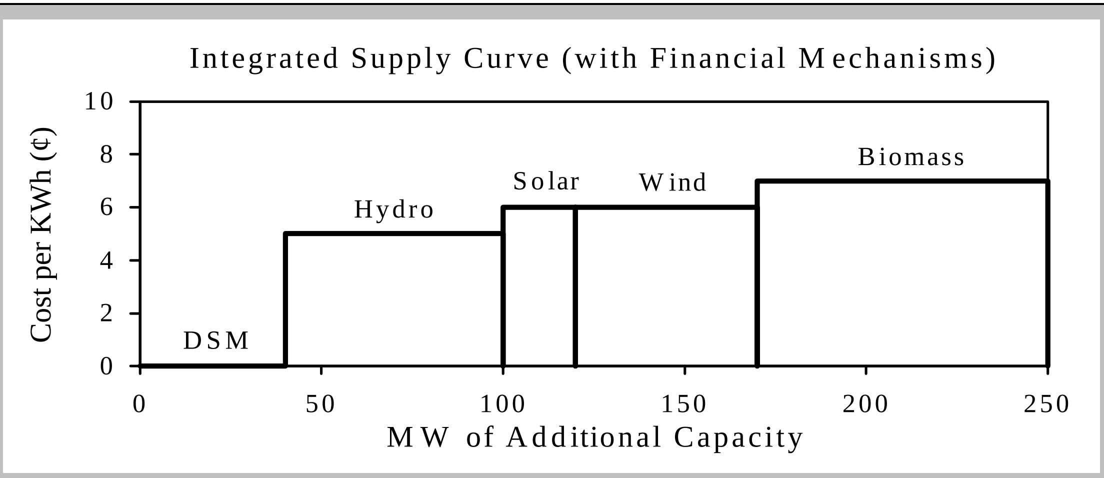
The problem faced by the planners in Box 10-A remains the same: to provide the service area with additional power generation capability of 100 MW in 3 years time and a further 100 MW in 5 years time. Suppose the service area is in a developing country eligible for funding from the Global Environment Facility (GEF) and that energy planners are aware of GEF subsidies available to offset the higher cost of renewable energy technologies. Assuming that grants are available from GEF to cover agreed incremental costs of renewable technology power plants above baseline fossil fuel plants; i.e., the costs of a renewable plant less that of an equivalent capacity fossil fuel plant. The assumed baseline scenario is:

- a natural gas combined cycle power plant of 70 MW average capacity and total direct costs of 6¢/kWh;
- a coal-fired steam turbine plant of 80-100 MW average capacity and total direct costs of 7¢/kWh.

Feasibility studies show the potential capacity and total direct costs of the renewable options are:

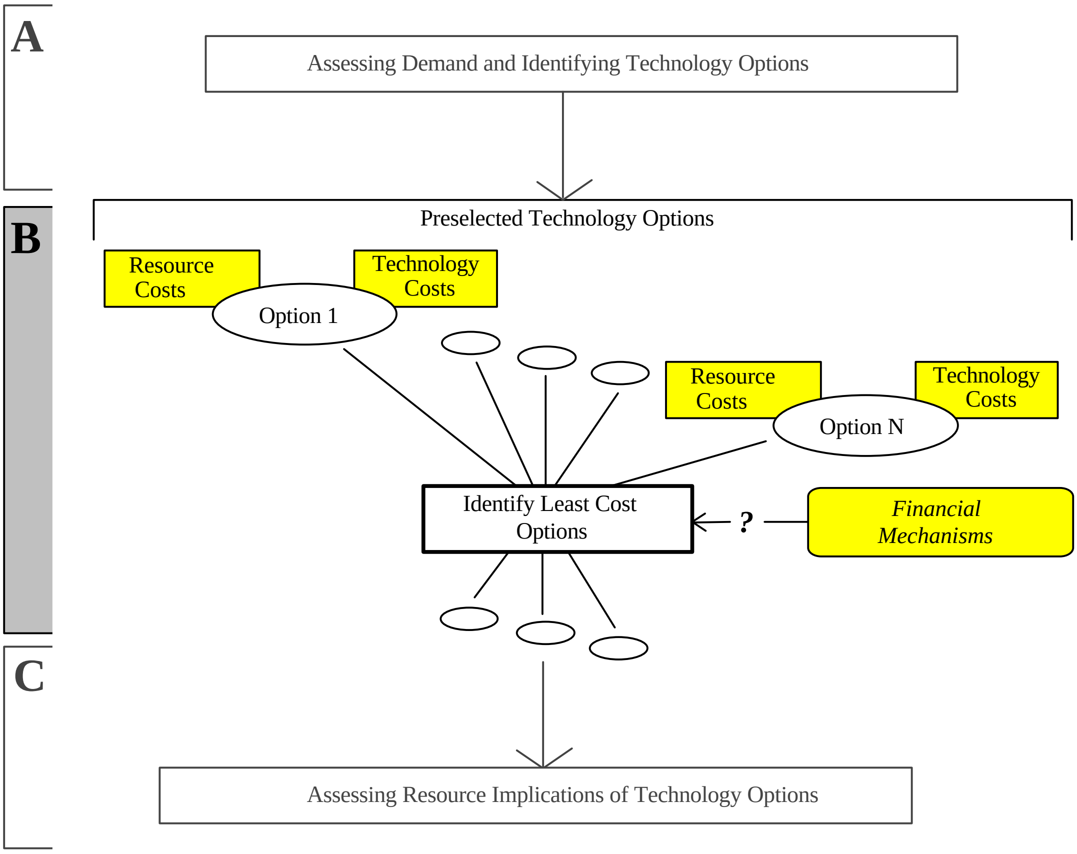
- a solar thermal plant of 20 MW average capacity and total direct costs of 11¢/kWh;
- a wind power plant, or wind farm, of 50 MW average capacity and total direct costs of 8¢/kWh;
- a biomass-fired plant of 80 MW average capacity and total direct costs of 9¢/kWh.

If the incremental costs for solar and wind plants are offset relative to the combined cycle baseline plant, and those for a biomass plant are offset relative to the coal-fired baseline plant, the integrated supply curve for power generation in the presence of GEF subsidies to offset incremental costs is:



The curve indicates that the least-cost option for supplying the first 100 MW of new capacity in 3 years is with DSM and hydro. For the second 100 MW of capacity in 5 years, replacing combined cycle and coal as least-cost options is a combination of solar, wind, and biomass plants.

In summary, Step B of the energy planning cycle is a procedure permitting identification of least-cost options for power generation. An analysis of these options using an integrated supply curve provides planners with an assessment of how, in an integrated manner, least-cost options can, often in combination, be deployed to meet demand levels. Planners are then able to identify a least-cost investment sequence for power generation facilities. However, it must be kept in mind that so far only the direct financial costs of resources and technologies for power generation have been considered. Not included in least-cost planning methods are ***indirect costs and benefits*** associated with the impacts of



power generation technologies on the environment, economy, and social development. Before any investment decisions are made, indirect costs and benefits, which are often substantial, must be assessed for each of the least-cost options identified in step B. Step C of the energy planning cycle considers the resource implications, and related costs and benefits, of technology options.

Section B Reference Sources :
2, 5, 8, 21, 35, 43

C) Assessing the Resource Implications of Technology Options: Indirect Costs & Benefits

All power generation technologies consume a primary energy resource to produce electricity. For many technologies, resources must be extracted, transported, processed, consumed, and waste by-products treated, in order to generate electricity that is subsequently distributed for end-use consumption. This sequence of processes and activities is known as the complete ***energy cycle*** for power generation.

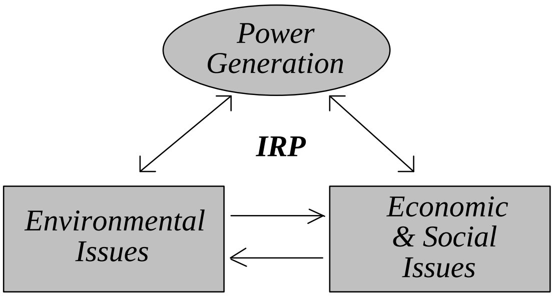
The energy cycles for technologies will be differ depending on which primary energy resource they consume. Natural and human resources of varying intensity provide inputs to processes and activities in the energy cycle, and to the production, use, and disposal of the power generation technology itself (i.e., throughout the whole *'technology lifecycle'*). Beyond resource needs which make-up input to the energy cycle, various outputs from the energy cycle will have impacts on external resource systems. Examining resource links in the entire energy cycle, from resource extraction to power generation and use, is critical to ensuring sustainable long-term energy production.

In Step C of the energy planning cycle, an assessment is made of ***resource implications*** associated with technology options emerging from Step B. Both indirect inputs and outputs characterizing the utilization of particular technology-resource combinations are discussed. An assessment of the resources needed and of the environmental and socio-economic impacts generated by a given technology, yields a full portrait of ***indirect costs and benefits.*** It is essential that an appraisal of a wide range of resource-related variables be integrated into the energy planning process so that power generation proceeds sustainably, providing maximum indirect benefit and minimal indirect cost to the society it serves.

C.1 Integrated Resource Planning

An appraisal of resource requirements and of the positive and negative impacts and associated indirect costs of technology-resource combinations is known as ***integrated resource planning (IRP).*** In contrast to least-cost planning where only direct costs are considered, integrated resource planning examines resource inputs and outputs throughout the entire energy cycle of power generation.

Integrated resource planning addresses the environmental, social, and economic issues that are intricately entwined with power generation; it seeks to maximize indirect benefits and minimize indirect costs. The central, and thus strategic role in sustainable development played by integrated resource planning presents an opportunity as well as an challenge to energy planners.



An IRP energy cycle diagram serves as a simple means of identifying resource implications for a technology. An IRP diagram should be constructed and evaluated for each technology emerging from step B. A complete IRP diagram could include all of the energy cycle processes and activities, as well as all of the input and output variables identified in the figure 4. Additionally, an analysis of resource interactions throughout the complete lifecycle of the technology could also be performed in order to identify benefits to the economy and costs to the environment associated with technology production and disposal.

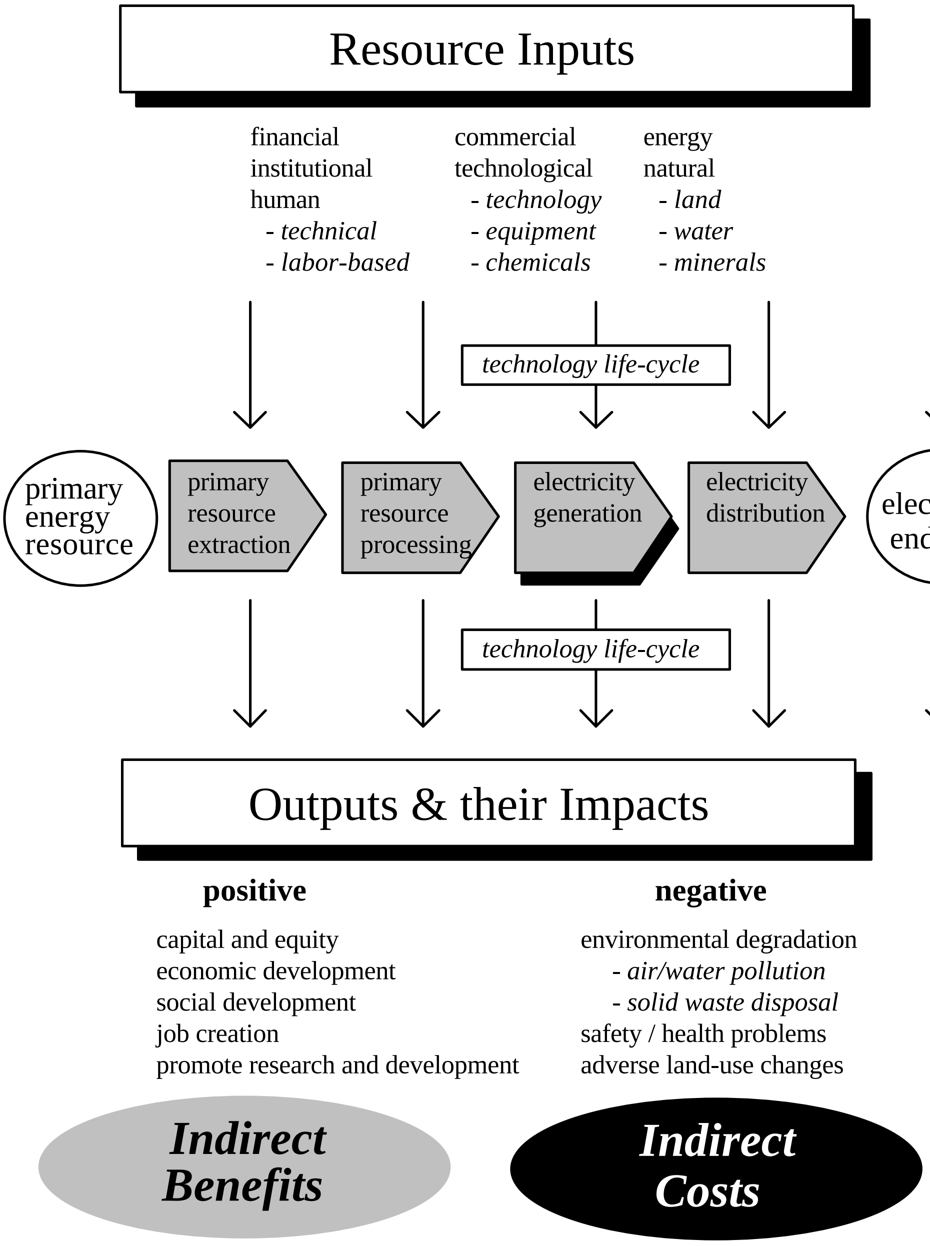


Figure 4: IRP Diagram for the Full Energy Cycle of Power Generation

In order to support and exploit electricity generation at a power plant, a whole range of resource inputs are required throughout the energy cycle. In addition, each activity in the cycle has outputs that impact human and natural systems in nearby regions. These impacts, both positive and negative, manifest themselves as indirect costs and benefits of the technology-resource system.

Many of the input and output parameters in an IRP diagram are difficult to estimate or project with great accuracy, nevertheless, taken together, they do have an important bearing on the selection of a particular technology-resource combination to meet regional, national, or local energy needs. Although energy sector decisionmaking for power projects has traditionally focused on direct cost evaluations and least-cost planning, there is a growing appreciation of the need to extend this focus to examine the resource implications of power generation technology deployment through IRP analyses. A technology's resource requirements and its indirect environmental, social, and economic costs and benefits are often substantial when considered over the lifetime of a power plant. In view of their importance, efforts are underway to establish a methodology through which indirect costs and benefits can be quantified and thus analyzed alongside direct costs in the least-cost planning process (see Box 11).

Box 11: Internalization of Costs (and Benefits)

Indirect costs and benefits could be more easily evaluated if they could be quantified in monetary terms and used to adjust direct costs. This, however, is often very difficult to do. The process is referred to as ***the internalization of costs*** *(and benefits).* Fully internalized costs would permit least-cost planning to account for indirect costs and benefits.

fully internalized cost = direct costs + indirect costs - indirect benefits

The World Trade Organization, is trying to develop a standardized methodology for cost internalization. Although significant progress is being made, the underlying problem is that different observers may assign different monetary values to a single observable cost or benefit. At the national level, integrated resource considerations will vary depending on national economic development objectives and on the level of sensitivity a nation's policy-makers and citizens have to improving social conditions and protecting the environment.

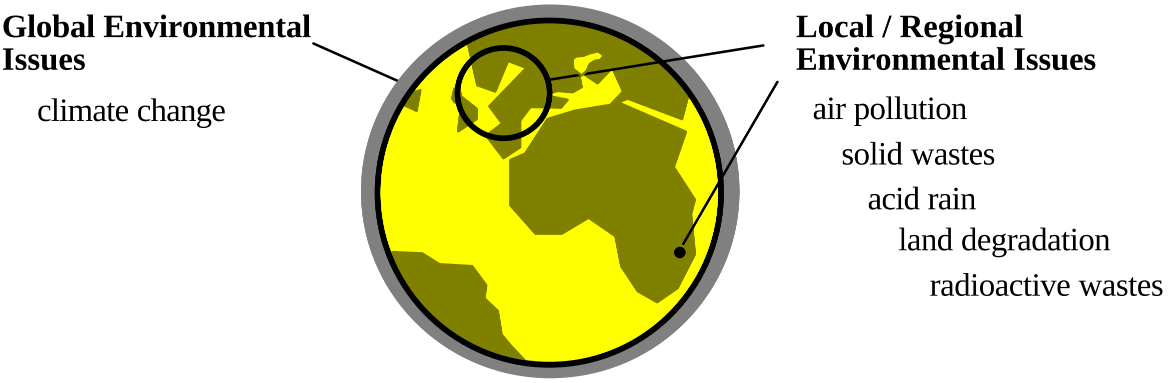
Although it is beyond the scope of this Guide to fully elaborate an IRP diagram for each of the technologies assessed, basic information on some of the indirect costs and benefits associated with each of the technologies is given in the following sections which discuss several important environmental, social, and economic issues of power generation.

C.2 Environmental Issues of Power Generation

An important component of integrated resource planning is an assessment of environmental impacts and their indirect costs. Although regimes to internalize these costs are only slowly being developed, local and regional environmental concerns now play an increasingly greater role in power generation decisionmaking.

Oil and coal-fired plants can emit considerable quantities of sulphur dioxide which, through interactions with atmospheric moisture, can create highly acidic and corrosive acid rain on a regional scale. Nitrogen oxide emissions, which are also emitted, greatly contribute to local smog and related health problems. Nuclear power has the unresolved problem of long-term storage of radioactive wastes, which are a serious hazard to living organisms. It is not only fossil fuel and nuclear plants that pose local environmental problems; power generation from renewable resources may do so as well. Large hydro-electric power plants often involve displacing population centers and entire ecosystems from the land areas used to establish reservoirs for these plants. Their construction also generates significant solid waste in the local area. Biomass-fired power plants can produce local pollution problems, and when the forests used to fuel such plants are not sustainably managed, forest and woodland degradation can result, sometimes leading to desertification. Wind power causes noise pollution and may disrupt habitats for indigenous wildlife.

In addition to considerations of environmental impacts in local and regional settings, global environmental issues such as climate change have recently influenced the decisionmaking process. Rising atmospheric concentrations of greenhouse gases, such as CO_2 from human activity, have the potential to trigger adverse changes in the earth's climate. In light of this, so called ***climate friendly technologies*** with substantially reduced CO_2 emissions relative to conventional technologies, have become increasingly attractive.



Major Environmental Issues of Power Generation

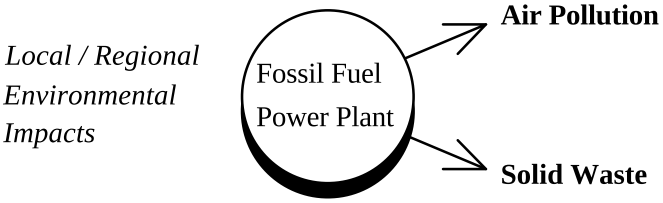
In order to begin examining ways to minimize local, regional, and global impacts on the environment due to power generation, results from a full assessment of technology specific environmental impacts are needed as an input to the IRP process. Cleaner and more energy efficient fossil fuel technologies, as well as renewable energy technologies, have an increasing role to play in the power generation arena. IRP planning can enhance prospects for their identification and deployment.

C.2.1 Local / Regional Environmental Issues of Power Generation

Impacts of certain methods of power generation on the local and/or regional environment can be significant when not properly managed. Different classes of technologies – fossil fuel, nuclear, and renewable – pose very different environmental problems. The problems they pose, and management strategies to limit their environmental impacts, are discussed below.

C.2.1.1 Local / Regional Environmental Impacts of Fossil Fuel Plants

Local and regional environmental impacts occur throughout the full energy cycle of fossil fuel power generation (see figure 5). These are mainly in the form of air pollution and solid waste production. Additionally, to comprehensively account for all impacts, a lifecycle analysis for all of the technologies used in the full energy cycle could be made to identify environmental impacts associated with their production and disposal.



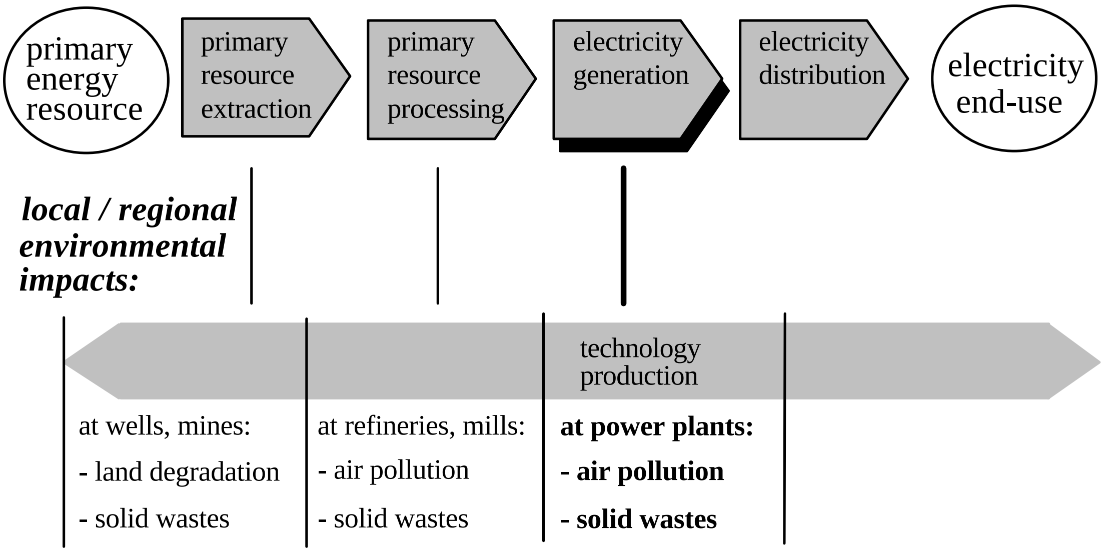


Figure 5: Local / Regional Environmental Impacts from the Full Energy Cycle of Fossil Fuel Power Generation

Fossil fuel combustion (natural gas, oil, and coal) gives rise to various undesirable emissions. The combustion of fossil fuels leads to emissions of nitrogen oxides, NO_X. For oil and coal combustion, major emissions also include sulphur oxides, SO_X, particulate matter, and fly-ash. These pollutants are emitted from the plant as flue gas. Oil and coal plants also produce solid waste pollutants containing carbonaceous, sulfuric, and metallic compounds that must be disposed of appropriately.

Air Pollution

All fossil fuel power plants emit nitrogen oxides, NO_X, as a by-product of the combustion process. When exhausted into the atmosphere NO_X leads to low-level ozone formation. Fossil fuel combustion in power plants accounts for over half of global man-made NO_X emissions (lightning and biogenic processes in soils are the main natural sources).

Once in the lower atmosphere as a primary pollutant, NO_X molecules react photochemically when exposed to sunlight to form secondary pollutants known as photochemical oxidants; the most prevalent of these is ***ozone.*** Although naturally formed ozone is beneficial at high altitudes in the stratosphere, ozone and other oxidants in the lower atmosphere contribute to urban smog. When inhaled, such oxidants aggravate asthma and increase the respiratory tract's susceptibility to infection. Oxidants also affect plant life by reducing photosynthetic activity. This results in reduced crop yields and retarded growth in certain tree species. Furthermore, a portion of primary NO_X emitted into the atmosphere results in the formation of nitric acid that leads to ***acid rain,*** a highly acidic form of precipitation. By increasing acidification in soils and waters, acid rain poses a substantial threat to forests, vegetation, and freshwater ecosystems. Depending on meteorological conditions, the pattern of acid rain deposition from an NO_X emitting plant begins at the plant site and can extend several hundred kilometers downstream in the direction of prevailing winds. Wind transport of acidic compounds can thus result in acid rain effects at locations far from the plant site.

According to their grade and source, oil and coal contain varied amounts of sulphur impurities. During combustion, these sulphur impurities oxidize forming primary SO_X pollutants (i.e., SO_2 and SO_3). Fossil fuel combustion in power plants accounts for nearly 80 percent of global man-made SO_X emissions (one-tenth of sulphur oxides in the atmosphere arise from such natural sources as volcanoes and biogenic processes). When emitted into the atmosphere, some SO_2 converts into SO_3. Once in the atmosphere, SO_3 compounds combine with atmospheric moisture and/or precipitation to form sulfuric acid, a highly acidic and corrosive liquid. Sulfuric acid can subsequently precipitate as acid rain. Like NO_X, SO_X has a residence time in the lower atmosphere of several days. Thus although its atmospheric concentrations are greatest near plant sites, prevailing winds are capable of transporting acidic compounds over several hundreds of kilometers and depositing acid rain at distant sites.

The extended range of acid rain – or snow – deposition caused by both NO_X and SO_X (responsible for about one-third and two-thirds of the problem respectively) makes it a regional environmental problem capable of affecting not only local ecosystems, but also ecosystems at a significant distance from the emitting plant. Affected areas are often within the territory of countries other than the source country. In order to address this long range and often transboundary problem, policies and mechanisms have been developed over the past two decades. At the national level, pollution reduction legislation has been established in many countries (the Clean Air Act in the United States is a good example). At the international level, countries have negotiated and adopted the Convention on Long-range Transboundary Air Pollution in 1983. Now ratified by forty industrialized countries, the Convention promotes and strengthens unilateral mechanisms for pollution reduction, resulting in reductions of NO_X and SO_X emissions by Convention Parties.

Finally, fossil fuel plants also emit particulate matter and fly ash. Trace metals and carbonaceous matter comprising these latter forms of pollutants pose threats to the respiratory function of humans, animals, and plants in the immediate are of a plant. Airborne metals are a toxin if assimilated by organisms after entry via the respiratory system. Fly ash or *'soot'* interferes with respiratory function by blocking intake orifices. Long-term exposure to both can lead to chronic illness in humans and animals, and to decreased viability of plant ecosystems.

Numerous *'air-cleaning'* technologies exist to control air pollution from power plants. ***Flue gas desulphurization*** (FGD) is commonly used to reduce SO_X emissions from coal plants and from oil plants burning low grade fuels (sulphur content of 1.5 percent or greater). FGD is based on ***emissions scrubbing,*** which for desulphurization involves passing the flue gas through a slurry of water and dissolved limestone which absorbs the roughly 90 percent of the SO_X component of emissions. A similar scrubbing process to absorb NO_X compounds in the flue gas also exists, although it is less often used. Particulate matter and fly ash is extracted from a plant's flue gas using either ***baghouses*** (bag-like mechanical filters) or ***electrostatic precipitators*** (particle ionization and recovery). The former are more effective than the latter. For both, coal-fired plants require higher capacity units (about ten times higher) than oil-fired plants.

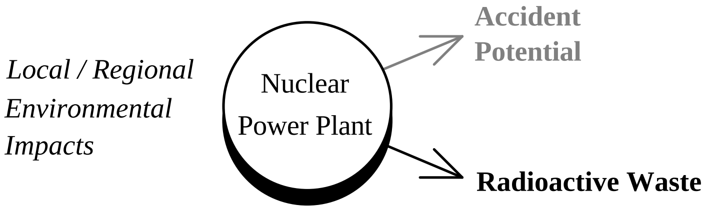
As air cleaning technologies require additional capital and operations, they increase direct costs for a power plant. For example, costs for FGD and electrostatic precipitators increase total plant capital costs by 15-25 percent and plant operational costs by 0.5-1 ¢US per kWh of generated electricity. An assessment of air cleaning costs should be a part of any oil or coal power plant planning.

Refer to: ➔ Annex II Chart 11 : NO_X Emission Ranges
➔ Annex II Chart 12 : SO_2 Emission Ranges

Solid Waste

When properly processed and managed, solid wastes from fossil fuel power plants are non-toxic and environmentally benign, with minimal negative impact on human and natural systems. The FGD process results in the production of an environmentally benign sludge of calcium-sulfate which can be safely stored in landfills. The particulates and fly ash collected from baghouses and electrostatic precipitators have uses in cement manufacture and various landfill applications. Coal plants also produce bottom-ash in the plant boiler that be treated and landfilled. Treatment of bottom ash involves the use of water which must be suitably purified before release to the environment. Additionally, fossil fuel power plants produce small amounts of sludge from cooling water demineralization which is readily landfilled. Although all of the solid wastes mentioned above can be safely landfilled, landfills can be unsightly, and appropriate land for such sites is unavailable in many locales.

C.2.1.2 Local / Regional Environmental Impacts of Nuclear Plants



Nuclear-based electricity generation produces both high and low level radioactive wastes. When properly processed and controlled, these waste products do not pose an immediate threat to human and natural systems. However, the possibility of serious accidents and failures in nuclear plants or waste storage facilities can result in the uncontrolled release of highly radioactive materials with catastrophic impacts on humans and the environment.

Natural radioactivity gives rise to an average background level of radiation in the terrestrial environment. The degree of threat to human health and natural ecosystems rises proportionally to any increase in exposure to radiation above the natural background level. Because nuclear power generation involves the utilization of concentrated sources of radioactive fuels and involves the production of radioactive wastes, any *uncontrolled release* of such materials will threaten human and natural systems. The challenge of nuclear power generation is ensuring that the release and/or disposal of radioactive materials takes place in a *controlled* manner.

Within the full energy cycle of nuclear power generation (figure 6), the potential for radioactive materials to be introduced into the environment exist in primary resource extraction and processing and in power generation at the plant. Both resource extraction at the mine, and uranium enrichment at the processing center result in the production of low-level radioactive waste. These hazardous waste by-products must be properly disposed to avoid posing threats to the local environment.

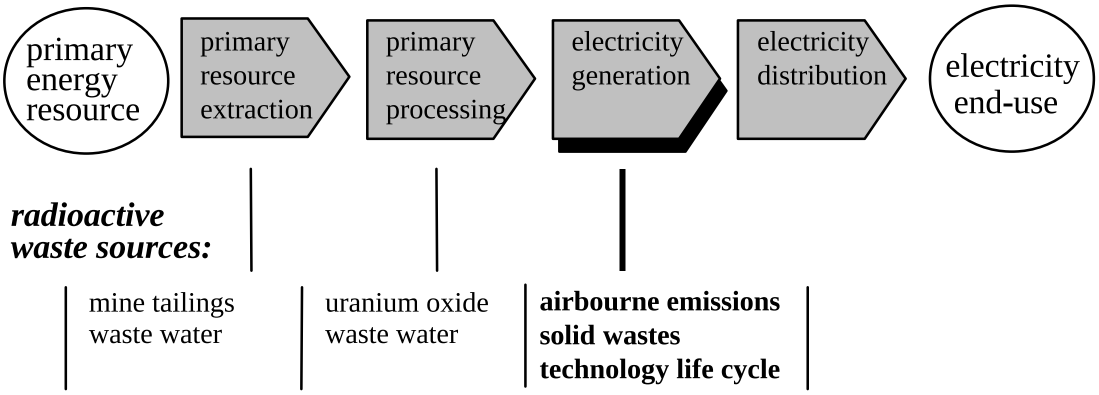


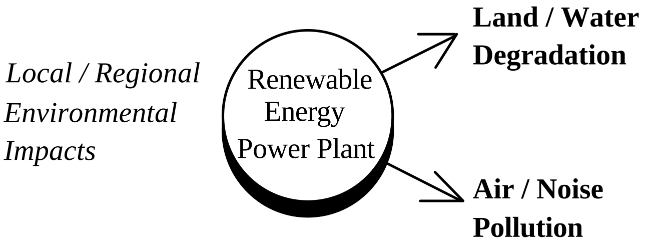
Figure 6: Local / Regional Environmental Impacts from the Full Energy Cycle of Nuclear Power Generation

When electricity is generated from nuclear power plants, additional sources of radioactive wastes are encountered. Principal among these are high-level radioactive solid wastes in the form of spent fuel rods from a plant's reactor core and by-products of spent-fuel reprocessing. As these materials are highly radioactive they must remain isolated in remote disposal sites or stored in secure repositories for extremely long periods of time (i.e., thousands of years), during which interactions with humans and ecosystems must be avoided. While efforts continue to identify a solution the problem of nuclear waste disposal, storage in, geologically secure repositories appears to be the most promising option. To date, political and social acceptance of this approach has been difficult to attain. While the costs of handling and disposal of radioactive solid wastes from a plant during its lifetimes are high, it should be noted that a considerable hidden cost of nuclear facilities is associated with their decommissioning and dismantling at the end of their operating lifetime. Experience in developed countries indicates that in many instances these costs are comparable with total capital costs for plant construction.

Principal obstacles to the increased use of nuclear power are the threats of nuclear accidents and nuclear weapons proliferation. Any unmanageable event leading to a substantial uncontrolled release of radioactive gases and/or solid wastes from nuclear plants to the environment can have serious to catastrophic consequences to humans and natural systems. Both equipment failure and human error can potentially lead to such uncontrolled releases. Although nuclear power plants have many safety mechanisms built-in to plant facilities, and error elimination routines integrated into operations and maintenance procedures, public concern over the potential for accidents remains high. At the national level, it is thus difficult in many countries to establish sites for new nuclear power plants due to opposition from local communities. Uncontrolled releases of nuclear radiation to the environment also result from the use of nuclear weapons. At the international level, there are obstacles to nuclear power dissemination in developing countries due to political concerns over the potential for nuclear weapons proliferation during fuel reprocessing.

C.2.1.3 Local / Regional Environmental Impacts of Renewable Plants

On the whole, renewable energy technologies have low negative environmental impact relative to fossil fuel and nuclear technologies. Nevertheless, an examination of the full energy cycle for power generation from renewable energy sources indicates that local and/or regional environmental impacts can occur in both primary resource extraction and electricity generation (see figure 7). The nature and scope of such impacts vary considerably according to the type of renewable plant examined. For example, land and water resource degradation are potential regional problems associated with both hydroelectric and biomass plants, while air and noise pollution are potential local problems associated with geothermal and wind plants respectively.



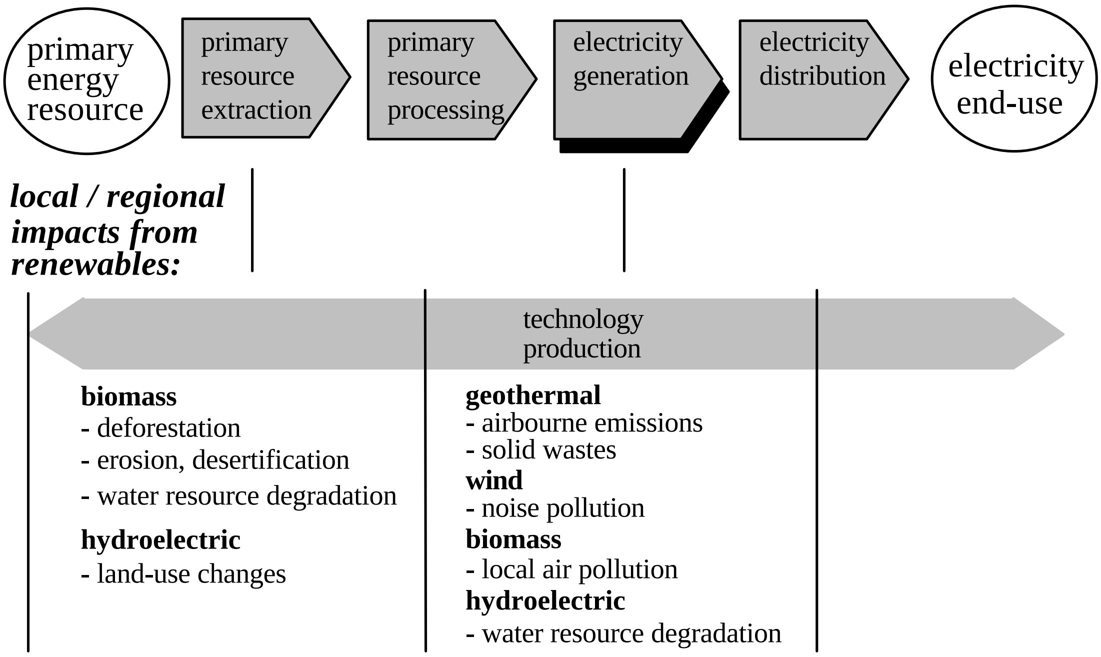


Figure 7: Local / Regional Environmental Impacts from the Full Energy Cycle of Renewable Power Generation

Furthermore, as with fossil fuel and nuclear technologies, a lifecycle analysis for all of the technologies used in the full energy cycle of renewable power generation could be made to identify environmental impacts associated with their production and disposal.

Impacts associated with various renewable technologies are briefly discussed below.

Hydroelectric Power:

High capacity dam and reservoir hydro-plants require the inundation of large land areas for the establishment of reservoirs, causing serious disruption to pre-existing human settlements and ecosystems in the inundated areas. As a result of this land-use change, affected populations will require relocation and valuable economic activities such as agriculture and forestry may be lost. Additionally, both upstream and downstream from the plant, surface water uses and ground water resources may be negatively impacted. Alterations in the flow of water, sediment, and nutrients downstream from dam and reservoir hydro-plants are often significant. The fertility of downstream agricultural sites and the supply of nutrients to fish estuaries may therefore be reduced. Countering the negative environmental impacts above are several positive benefits of dam and reservoir plants. Reservoirs can be used to provide a stable supply of drinking water, and dams can provide flood protection, for local populations. Additionally, reservoir water can be used to recharge downstream ground water resources and support recreational activities.

Lower capacity run-of-river hydro-plants power plants need no reservoir, although they may require the inundation of small areas of land for their operation. Little or no land-use changes are implied for these plants. Moreover, depending on the size of a run-of-river facility, changes in water, sediment, and nutrients flows downstream are minor or insignificant.

Biomass Power:

Most of the environmental impacts associated with power generation from biomass arise during primary energy resource extraction. When intensive harvesting of forest resources is not accompanied by sustainable forest management, problems are encountered. Stripping steeply sloped forests and woodlands can result in serious erosion of topsoils. Excessive and indiscriminate harvesting of trees from old-growth forests causes soil degradation and erosion. Permanent deforestation can result from both of these practices. On a limited scale, the subsequent use of deforested areas for residential, agricultural, and other productive uses is desirable. However, when affected land is left idle, desertification can result. Permanent deforestation also contributes to local biodiversity loss by disrupting ecosystems and destroying wildlife habitat. In cases where biomass is grown on a renewable basis in plantations and/or managed forests, the above problems can be avoided. Intensive biomass production from such sources, however, often requires the substantial use of chemicals and fertilizers that threaten the integrity of groundwater and nearby lakes, ponds, and streams.

Air pollutants are a by-product of biomass-based electricity generation. These include NO_X emissions, particulates, and fly ash. The effects of NO_X emissions on the local environment, and the methods used to control particulates and fly ash, are similar for biomass and fossil fuel based power generation (see Section C.2.1.1).

Wind Power:

Producing no air or solid waste pollution, wind power is environmentally benign. However during normal operation, wind turbines produce significant levels of local noise pollution. These levels, that increase both with turbine capacity and the number of turbine units used, require that wind power sites be sufficiently distant from residential areas. Required site distances from residential areas range from 500-2,500 meters, depending on the level of noise produced by the site.

Geothermal Power:

The environmental impacts of geothermal power plants vary depending on the nature of the geothermal source and the type of technology used by the plant. Along with the useful steam deriving from gas dominated geothermal wells are several toxic gases which must be vented to the atmosphere. Amongst these are methane, hydrogen sulphide, and ammonia. In addition the above gases, useful steam from fluid dominated geothermal wells is accompanied by a variety of solids entrained in geothermal fluids including chlorides, sulphates, and fluorides. In some technologies geothermal substances are released to the environment, while in others they remain largely contained and are re-injected to into wells adjacent to the extraction well. Whatever release to the environment of geothermal gases, and fluids with entrained solids does occur, it must be properly managed so as to ensure the safety and health of workers and populations adjacent to the plant site.

Potential environmental impacts of geothermal power generation, which could occur in rare circumstances, are land subsidence and induced seismicity. Most modern technologies employ re-injection of geothermal fluids into source wells which can reduce the potential for these impacts.

Solar Power:

Throughout their full energy cycle, solar energy systems (both thermal and photovoltaic) have negligible environmental impact. Environmental impacts associated solar energy technologies can occur however during their manufacture. In contrast to the manufacturing process for other power generation technologies, the production of solar energy system components (mirrors and photovoltaic plates) requires several toxic and explosive gases. If released to the environment, these substances could pose an immediate danger to workers and local populations.

C.2.2 Global Environmental Impacts of Power Generation: Climate Change

Recent scientific studies indicate that emissions of ***greenhouse gases*** into the atmosphere can lead to ***global warming;*** an increase in the average surface temperature of the earth (see Box 12). Through global warming the energy budget of the atmosphere is altered, inducing changes in global circulation patterns and regional variations in climate.

The cumulative impact of these changes is called ***climate change.*** Many of the predicted changes in the earth's climate will have adverse environmental impacts on a global scale. Because fossil fuel combustion is one of the main sources of greenhouse gas emissions, climate change is now identified as a global environmental impact of power generation activity.

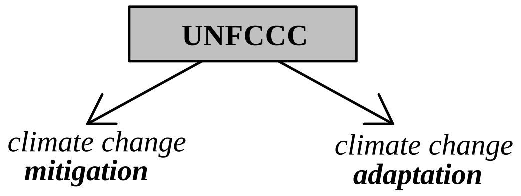
Based on the scientific theory of climate change, computer simulations known as *global circulation models (GCMs)* are used to predict the nature and effects of climate change during the next century. Although considerable uncertainty remains in the magnitude, likelihood, and regional importance of impacts, GCMs are able to broadly indicate what environmental impacts will be associated with future climate changes. GCM results suggest that while predicted changes may be beneficial in certain regions, most regions will be disadvantaged by the impacts of climate change. The predicted adverse impacts of climate change include:

- a rise in sea-level;
- damaged coastal ecosystems;
- permafrost and glacial melting;
- increased desertification;
- changes in wind patterns;
- changes in vegetation zones, and;
- increases in both the frequency and severity of climatic extremes such as drought, heat waves, cyclones, tornadoes, precipitation, and flooding.

The regionally specific social and economic impacts of these environmental changes could include:

- costly coastal adaptation measures and/or coastal flooding;
- displaced population centers and increased environmental migration;
- changes in agricultural growing times, regions, and yields;
- drought and famine;
- changes in disease patterns;
- changes in social energy requirements;
- changes in tourism patterns, and;
- increased storm-related casualties.

The possibility of such undesirable climatic impacts has sparked intense international activity to delineate how the society can address climate change. Safeguarding the climate system while satisfying the energy consumption needs of society is, and will continue to be, a major international challenge. Commitments undertaken by countries to respond to this challenge are articulated in the United Nations Framework Convention on Climate Change (UNFCCC). Among these, countries have made commitments to pursue sustainable development. To reach this goal, the Convention calls on countries to ***mitigate*** climate change through reductions in emissions of the

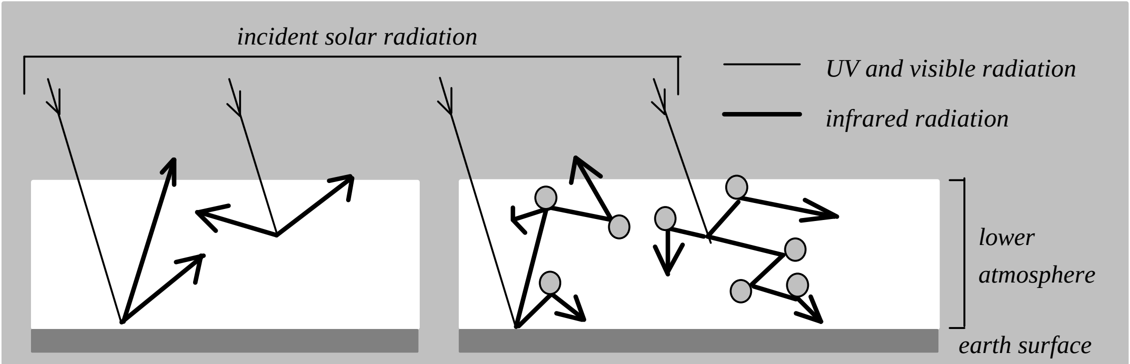


greenhouse gases and to ***adapt*** to whatever climate change does occur in the future. This Guide examines issues related to climate change mitigation, specifically addressing how emissions of greenhouse gases from power generation can be reduced.

Box 12: The Science of Climate Change

Solar radiation, arriving at the top of the earth's atmosphere predominantly at ultra-violet and visible wavelengths, generates heat in the atmosphere and at the earth's surface through radiative interactions with constituent molecules. The resulting heat energy propagates in the lower atmosphere at long-wavelengths in the infrared spectrum. Certain gases naturally present in the atmosphere, **carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4), ozone (O_3), and water vapor (H_2O),** share the ability to scatter this infrared radiation within the lower atmosphere near the earth's surface. The potential to scatter infrared radiation varies from one gas to another depending on its molecular structure and the amount of time is resides in the atmosphere. The overall effect of the infrared scattering caused by these gases is known as (positive) radiative forcing. Apart from water vapor, GHGs have long lifetimes in the atmosphere relative to the timescale of meteorological mixing processes that distribute them throughout the earth's atmosphere. Because of this, each gas is uniformly distributed within the atmosphere eventhough its sources of emission and re-absorption at the earth's surface are not. The strength of the radiative forcing caused by a given GHG is therefore the same for all locations.

Through radiative forcing, the prementioned gases create a surface warming effect in an analogous way to the glass walls of a greenhouse, thus they are called *greenhouse gases or GHGs.* The heat *'trapped'* by radiative forcing maintains globally averaged temperatures at the earth's surface of 15°C, in contrast to a value of only -18°C that would result in the atmosphere if GHGs were absent. This natural warming caused by GHGs, known as the ***natural greenhouse effect,*** is essential as it establishes and maintains surface temperatures high enough to support the global ecosystem.



atmosphere without greenhouse gases
radiative forcing by GHGs absent
heat escapes atmosphere

NO warming effect

atmosphere with greenhouse gases (circles)
radiative forcing by GHGs present
heat trapped in atmosphere

greenhouse warming effect

Radiative Forcing and the Greenhouse Effect

The relative contribution each GHG makes to the greenhouse warming effect depends on two factors: the amount of the gas present in the atmosphere (i.e., its atmospheric concentration, ***C***), which is uniform across the globe at any given time; and its potential to cause radiative forcing (i.e., its global warming potential, ***GWP***) which depends on its molecular structure and atmospheric lifetime. The effective GHG concentration in the atmosphere is formed by summing the factors ***C • GWP*** for all GHGs present in the atmosphere. If effective GHG concentrations rise, the strength of the greenhouse effect is enhanced, and globally averaged surface temperatures will gradually increase. Conversely, if effective GHG concentrations fall, the strength of the greenhouse effect is reduced, and globally averaged surface temperatures will gradually decline. The gradual nature of temperature changes reflects the long response time of a large terrestrial atmosphere to reach new levels of thermodynamic equilibrium.

Studies of palaeo-records from glacial ice cores indicate, that during intervals of one thousand years or more, effective GHG concentrations have varied over the past 220,000 years. Both global cooling and global warming have with temperature changes of up to ± 4 °C. These temperature changes have led to gradual climatic variations on both global and regional scales.

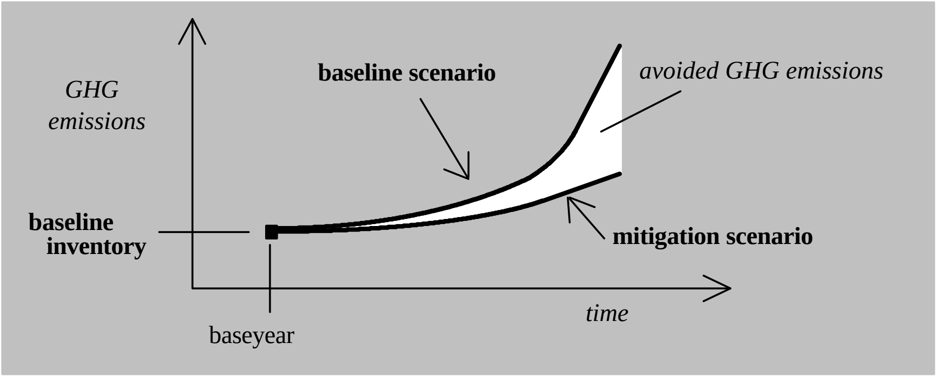
Anthropogenically induced emissions of GHGs have increased substantially over the past 250 years in proportion to increases in world population and industrial development. These emissions have lead to sharp increases in atmospheric GHG concentrations above natural background levels. Hence an ***enhanced anthropogenic greenhouse effect*** is present and becoming more pronounced. Scientific observations indicate an increase in globally-averaged surface temperatures is already occurring, and models project a temperature increase of 1-4 ° C by the year 2100. This change is significantly more abrupt than earlier changes inferred from palaeo-records.

In accordance with their commitments to reduce greenhouse gas emissions, parties to the UNFCCC seek to identify mitigation options that can lead to levels of GHG emissions lower than current and future *business as usual scenarios.* Box 13 describes how the Convention can help promote the development of national policies and measures for reducing greenhouse gas emissions.

Box 13: The Framework Convention on Climate Change & Greenhouse Gas Emission Reductions

As a major commitment under the UNFCCC, Parties are required to formulate, publish in the form of national communications to the Convention's Conference of Parties (COP), and implement programmes containing measures to mitigate climate change. Mitigation can be advanced through measures that reduce emissions and enhance sinks of greenhouse gases (GHGs). In order to identify mitigation options, national sources and sinks of GHGs must first be identified. Thus Parties are required to compile and report a national inventory of anthropogenic GHG emissions by sources and removal by sinks. Sources of GHGs arise from various sectors of a country's economy; i.e., energy, agriculture, forestry, industrial, transport, and service sectors. GHG sinks are primarily biotic resources in the agro-forestry sector.

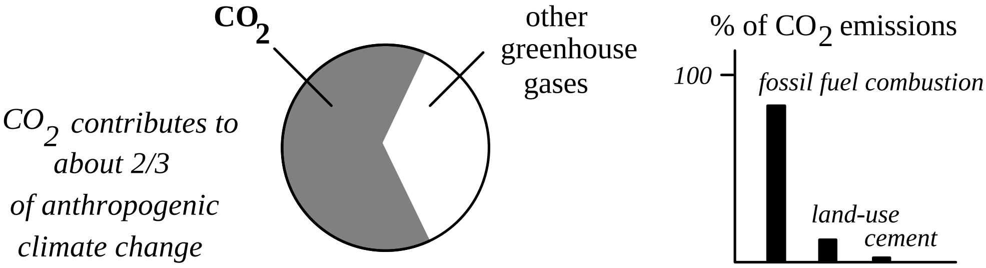
The national inventory accounting for all GHG emissions from sources and removal by sinks during a given baseyear, usually 1990, is called a ***baseline inventory.*** Based on their baseline inventories, as well as projections of social and economic activity for their country, Parties can construct a ***baseline scenario*** of national net GHG emissions over selected time horizons. This is usually done for short, medium and long timeframes of 1-5, 10 and 50 years respectively. Baseline scenarios estimate net GHG emissions from the projected development of the national economy under the assumption that no measures would be introduced to reduce net emissions (often called a ***business as usual scenario***).



Through an analysis of the baseline scenario, measures are identified that could reduce net GHG emissions from business as usual levels. For each identified measure, estimates are made of the emission reductions possible and the cost to achieve such reductions. Mitigation scenarios comprising varied sets of identified measures to be implemented over time are then constructed and the amount of GHG emissions avoided under each mitigation scenario – relative to the baseline scenario – can be estimated. Typical mitigation options include the greater use of climate friendly technologies and industrial process methods, efficiency improvements in the production and use of energy, and modifications in consumption patterns by end-users in all sectors.

C.2.2.1 Energy Related CO_2 Emissions as the Major Cause of Climate Change

Significant sources of greenhouse gases are associated with activities to support growing populations in all regions of the world: enhanced agricultural production, land use changes, waste disposal practices, unmanaged biomass burning, and most importantly, fossil fuel based energy consumption. Fossil fuels are used to provide energy for industrial production, power generation, transportation, and residential heating. By contributing the most to enhanced, anthropogenically induced radiative forcing in the atmosphere, **emissions of the greenhouse gas carbon dioxide, CO_2, from energy consumption activities represent the leading cause of climate change.** For this reason CO_2 is often referred to as the principal greenhouse gas. Excluding cement production and land-use changes causing net deforestation, anthropogenic CO_2 emissions mainly derive from the combustion of fossil fuels for energy consumption. Fossil fuel combustion is thus said to represent a ***source*** of CO_2. While ***sinks*** providing for the uptake of CO_2 are present in the natural environment,



The CO_2 Contribution to Climate Change and CO_2 Emission Sources

such sink mechanisms are incapable of sequestering the large quantities of CO_2 released into the atmosphere by anthropogenic sources (cf. Box 14).

Box 14: The Carbon Cycle

Natural sinks of CO_2 are capable of absorbing atmospheric CO_2, and thereby reducing atmospheric concentrations of this gas. Important CO_2 *sinks* include the oceans, marine organisms, soils, forests, and plants. Contrarily, these natural constituents of the earth are also important CO_2 *sources*, accounting for 97% of total CO_2 emissions into the atmosphere; only the remaining 3% derive from anthropogenic emissions. CO_2 sources and sinks exchange CO_2 to establish the global ***carbon cycle*** which governs the level of CO_2 concentrations in the atmosphere.

With industrialization and increased population levels, CO_2 has been introduced into the atmosphere by anthropogenic sources primarily associated with fossil fuel combustion. Natural CO_2 sinks are unable to absorb all of the CO_2 deriving from human activities. Thus cumulative increases in atmospheric CO_2 concentrations have and continue to occur over time. The possibility remains that anthropogenic sinks can be established in order to offset some of the build-up of CO_2 in the atmosphere. Carbon sequestration programs promoting the establishment of new and permanent forests are a climate change mitigation activity based on this approach.

C.2.2.3 Power Generation Technologies and CO_2 emissions

CO_2 emissions are a direct by-product of the fossil fuel combustion that provides energy for electricity generation, transportation, industrial production, and for heating and services in commercial and residential sectors. Among these activities, electricity generation is the largest and most rapidly growing, currently accounting for about one-third of anthropogenic CO_2 emissions. Adding to this figure emissions resulting from industrial power generation for process heat and motive force, ***emissions from power generation account for nearly one-half of anthropogenic CO_2 emissions.***

Net CO_2 emissions associated with power generation arise ***as fossil fuels are combusted*** to generate a highly pressurized and heated gas used to turn a turbine. Since most of the energy derived from the combustion process is energy released from the fuel through CO_2 formation, ***CO_2 emissions are an unavoidable by-product of fossil fuel based power generation*** (see Box 15). Apart from some relatively minor emissions of CO_2 associated with geothermal power generation, nuclear and renewable power generation do not give rise to net CO_2 emissions.

Box 15: CO_2 Emissions from Fossil Fuel Combustion

Fossil fuels are comprised of hydrocarbon molecules containing various amounts of carbon and hydrogen. In the fossil fuel combustion process, these molecules react at high temperatures with oxygen molecules to form CO_2 and H_2O. With each resulting CO_2 and H_2O molecule thus produced, heat energy is released. It is this heat energy which is converted into electricity by energy conversion technologies.

Different hydrocarbon compounds contain different relative proportions of carbon and hydrogen in their make-up. Fossil fuels can thus be classified according to the ***carbon to hydrogen (C/H) ratio*** in their constituent hydrocarbon molecules. Coals have relatively high C/H ratios when compared to oil, and in turn oil C/H ratios are high relative to natural gas. Fossil fuels with low C/H ratios produce relatively more heat energy from carbon relative to hydrogen than do fuels with high C/H ratios. Therefore, fuels with lower C/H ratios emit less CO_2 per unit of heat energy produced than fuels with higher C/H ratios. Because of this ***CO_2 emissions per unit of heat energy produced are lowest for the combustion of natural gas, highest for the combustion of coals; with oil or oil distillates having intermediate values.***

Emissions of CO_2 per unit of energy produced by the power plant combustion represent the main CO_2 source in the full energy cycle of fossil fuel based power generation. However, sources of CO_2 emission are also present in fuel extraction, production, processing and distribution. An examination of emissions resulting from these other processes in the full energy cycle provides a comprehensive assessment of overall levels of CO_2 emitted (see figure 8). A similar examination of the full energy cycles of nuclear and renewable power generation indicates that although CO_2 is not emitted during electricity generation (geothermal power is an exception), some CO_2 emissions are associated with their full energy cycles.

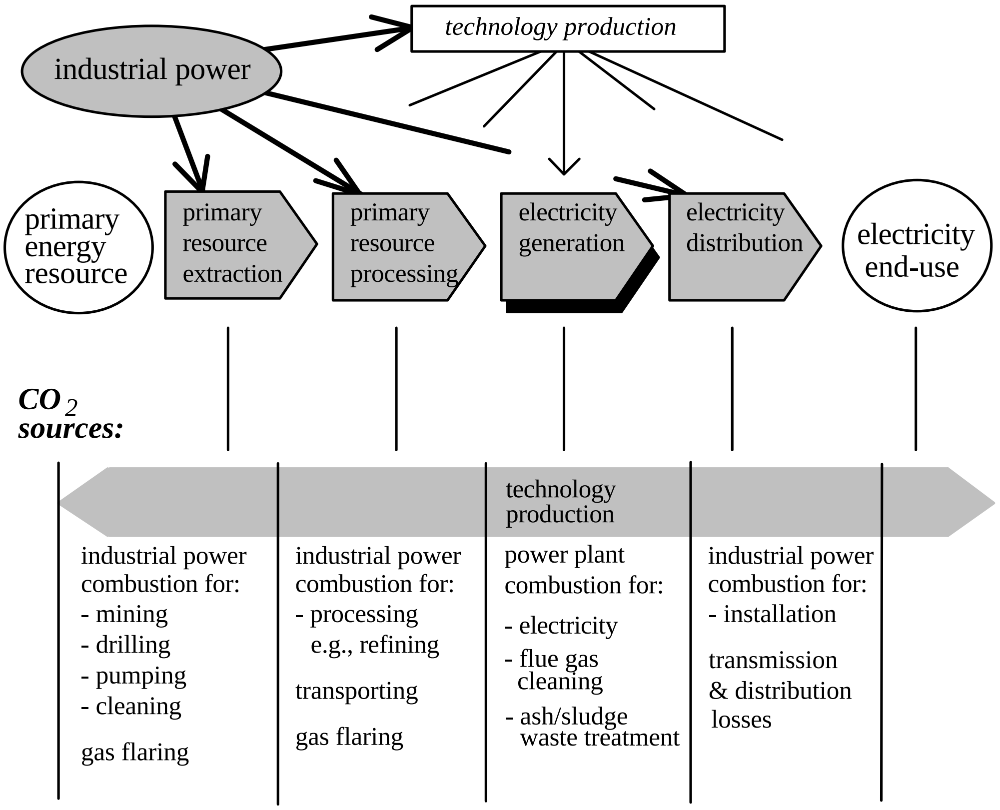


Figure 8: Sources of CO_2 Emissions from the Full Energy Cycle of Fossil Fuel Power Generation

Although it is beyond the scope of this Guide to quantify levels of greenhouse gas emissions throughout the full energy cycle for various technologies, quantitative data is provided for CO_2 emissions from power plant electricity generation for the 20 technologies assessed. A method of appraising the relative CO_2 emissions of different power generation technologies is to compare ***CO_2 emissions in kilograms per MWh*** of delivered energy for each technology. Those technologies with low CO_2 emissions, relative to a reference technology with high emissions (e.g., a coal-fired steam facility) are, by this measure, the most climate friendly technologies.

Refer to: ➔ Annex II Chart 13 : CO_2 Emissions

International efforts to mitigate the build-up of CO_2 concentrations are gaining momentum. Also regulatory instruments such as emission quotas and carbon taxes could affect the power generation industry in the near future. Hence, the CO_2 output of energy conversion technologies is an important parameter to consider in the planning process for new capacity. Enhanced diffusion of modern state-of-the-art power generation technologies can substantially reduce global emissions of CO_2. In industrialized countries where installed power generation capacity is in quasi-equilibrium with demand, these technologies can be employed to replace older less efficient plants. In developing and newly industrializing countries, where growing demand is much greater than installed capacity, emission reductions from business as usual scenarios can be achieved through the increased use of more efficient and modern energy conversion technologies in new power plants.

An important objective of energy planners is to identify those technology options which meet local, national, or regional energy demand, development objectives, financing opportunities, and natural and human resource constraints. An additional objective can be to identify options that can substantially reduce CO_2 emissions relative to a business as usual scenario. In parallel, it is the responsibility of national decisionmakers to formulate measures to mitigate climate change through greenhouse gas emission reductions.

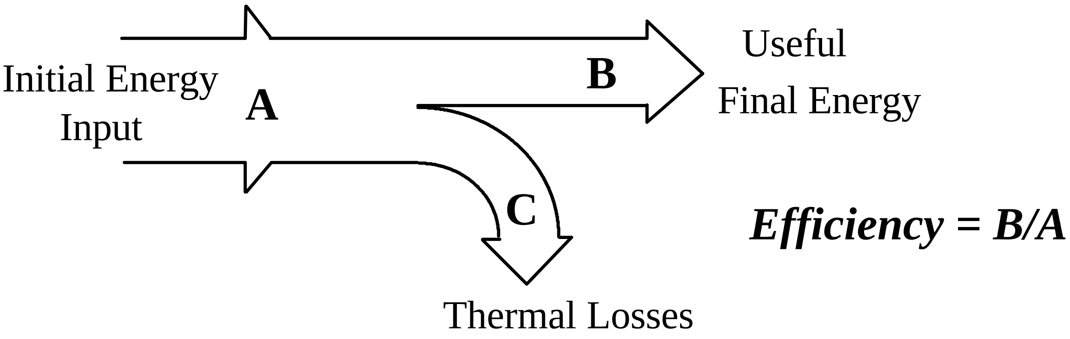
C.2.2.3 Reducing CO_2 Emissions from Power Generation

Essentially, there are four approaches that can be used to reduce CO_2 emissions from power generation:

- enhancing the combustion efficiency of fossil fuel plants
- switching fuels in fossil fuel plants from high carbon to low carbon fuel sources
- switching from fossil fuel plants to nuclear and renewable plants
- capturing and storing CO_2 from the exhaust gas of fossil fuel plants

This section briefly discusses the first three approaches.

In making energy conversions from initial energy – provided by a primary energy resource – to useful energy for consumption (e.g., electricity), some initial energy is converted into heat or radiation energy. As these latter quantities of energy are often not used, they are referred to as ***thermal losses***. The ***efficiency*** of a power generation technology is the ratio of useful final energy output to the total initial energy input. Because of thermal losses – inherent in all conversion technologies – this ratio is always less than one.



Improving the conversion efficiency of power generation technologies is an area of major research and development. In the case of fossil fuel technologies, substantial efficiency improvements yield greatly reduced CO_2 emission levels since less fuel must be burned, and thus less CO_2 emitted, for a given useful final energy output level. A conventional coal-fired steam turbine plant, for example, has an efficiency of about 37% in optimal running conditions. That is, 37% of the extractable initial chemical energy stored in the coal is converted by the plant into electricity, while the remaining 63% is converted primarily into heat of the plant's flue gas and spent cooling water, and thus represents thermal losses.

An approach to obtain greater conversion efficiencies of power generation systems is to make use of the heat energy, or thermal losses, generated by these system. The heat generated by the conversion process can be utilized for water and space heating applications serving homes and buildings in the area local to a power plant. This is the concept behind the ***cogeneration of heat and power (CHP)*** technology applications. In such applications, where process heat constitutes useful final energy, efficiencies can approach the 60-80% range.

Another approach to improve system efficiencies involves utilization of thermal losses in a plant's primary turbine as energy input into a secondary turbine. This is the principle behind ***combined cycle*** power plants which use the heated gas exhausted from the plant's primary gas turbine to generate steam that drives a secondary steam turbine. The overall efficiency of modern natural gas fired combined cycle systems approaches 60 percent.

Enhancing the energy conversion efficiencies of future technologies is different from improving energy efficiency in existing power generation and end-use technologies. The goal of the latter is to enhance the efficiencies of installed technologies by improving the ways in which they are operated or used. As an example, coal benefication – the cleaning of coal prior to combustion – in a conventional coal-fired power plant can result in more efficient combustion, and thereby improve the plant's efficiency by about 1 or 2 percent. In the end-use sector, more efficient insulation and lighting fixtures can, for instance, reduce the overall energy needed from existing power generation technologies.

Greater ***end-use efficiency,*** provided by better end-use practices and improved end-use technology efficiency, substantially reduces primary energy consumption from existing technologies. Numerous studies point to enhanced end-use efficiency measures as being able to make the most important contribution to reduced CO_2 emissions in the future.

Furthermore, among fossil fuels, natural gas combustion yields less CO_2 emissions than oil or coal combustion, by about 30 percent and 50 percent respectively, on an equivalent energy output basis. In view of this fact, ***fuel switching,*** from coal or oil to natural gas in fossil fuel based plants can be an effective measure for emissions reductions. Indeed, fuel switching from fossil fuels to renewable energy sources – or what may be more aptly called ***"technology switching"*** – represents an even more effective measure when it is appropriate and feasible for a given application. Fuel switching (coal or oil to natural gas) and the greater use of nuclear and renewable energy, taken together, represent an important means of mitigating CO_2 emissions over time from the energy sector.

Refer to: ➔ Annex II Chart 14 : Efficiencies
➔ Annex II Chart 15 : CHP Options
➔ Annex II Chart 16 : Fuel Requirements

C.3 Social and Economic Issues of Power Generation

Energy planning takes place today against a background of strong growth in world power markets. Since 1970, worldwide electricity generation has more than doubled. In 1990, about 60 percent of electricity was generated in developed countries, 18 percent in Eastern Europe and the former Soviet Union, and only 22 percent in developing countries. Between 1990 and 2010, overall world demand for electricity is expected to double, while within developing countries total demand will more than triple. The rapid growth of electricity generation capacity in developing countries to meet rising demand has already begun. Electricity generation in developing countries has more than doubled in the past decade, although supply remains largely limited to densely populated urban areas. Most governments in developing countries have initiated programs to expand electricity grids to rural areas where roughly 60 percent of the population is based; however, some 2.5 billion people in developing countries remain without access to electricity today. These people most often meet their energy needs through biomass burning (wood fires for the home and small-scale industries). Thus in addition to bolstering supply in growing urban and industrial areas, much of the growth in electricity generation in developing countries over the next decade is expected to be in rural areas.

The most obvious benefit that power generation provides is social development. Social welfare is usually enhanced when electricity is provided to homes, schools, hospitals, and commercial and industrial establishments. When continuous and abundant electricity is available to a population, living standards in the home rise considerably; services in education, health, sanitation and communication are improved; and economic activity increases. Over the past century this has been the experience recorded in developed countries as they electrified their societies. Currently, in developing countries, newly available electricity relieves households from satisfying energy needs on their own through traditional methods such as biomass burning. In the home, as time consuming wood collection and fire-based cooking and heating practices are eliminated, more time becomes available for individuals – often women and children – to pursue more productive activities, and health problems associated with exhaust smoke from home fires are eliminated. In the wider electrified community, poverty and hunger rates decline and employment opportunities within local markets materialize. Overall, enhanced social development permitted by electrification is accompanied by economic development. For this reason, a population's access to electricity is often viewed as the key to modern social and economic development. While it is clear that electricity provides benefits to society that are immediate, substantial, and far-reaching, the issue of maximizing these benefits by selecting the most attractive means of generating electricity remains.

Integrated resource planning provides an opportunity for planners to consider social, economic, and environmental sustainability criteria into the decisionmaking process. The IRP diagram presented in Section C1 indicated that social, economic, and environmental indirect costs and benefits should be considered in the energy planning process. It is desirable that power generation technologies having high indirect benefits and low indirect costs be used in meeting electricity demand. Each of the technologies that can be employed to generate electricity for a given service area has different development implications. From one technology to another, for example, associated levels of local employment, national research activity, natural resource utilization, and environmental degradation vary. By evaluating technologies based on their development implications, power generation options providing the most added value to a population's development needs can be identified.

In many countries, planning for social and economic development is conducted within the framework of a periodic (typically five-year) national development plan. Energy planning is typically an integral part of national development planning. Often, many of the screening criteria applied in evaluations of technology options in the IRP process are ones that ensure national development objectives are met.

Because economic growth (e.g., increased production and consumption) is most often the primary goal of national planning, environmental sustainability objectives may not figure highly in national plans. The important role that these latter objectives play in ensuring long-term social welfare, and economic health across all sectors of the economy, suggests that they should be explicitly included in energy planning, even when they are not explicitly elaborated in national plans.

C.3.1 Satisfying Electricity Market Needs

Taken together, social and economic needs form a set of ***market needs*** to be addressed within the IRP planning framework. In examining how well each technology option analyzed satisfies these needs, it should be emphasized that there is no unique technology which is superior to all others. Usually, no single technology can best meet *all* needs. For example, while planners may favor the integration of renewable options into energy supply on environmental grounds, conventional nonrenewable options are often more cost-effective in short-term, and thus both could play roles in electricity supply to a particular market. In integrated resource planning it becomes necessary to either make trade-offs or identify a mix of technologies, taking into full account each option's comparative advantages and disadvantages in meeting market needs.

A potential set of market needs to be met by technology options may include some of the following social and economic needs:

Social Needs:

- social acceptance of the technology
- level and quality of service provided meeting end-user expectations
- availability of continuous power supply
- relatively low access cost to end-users
- relatively low adoption cost to end-users
- ease of adoption
- minimizing local/regional health and environmental hazards
- minimizing local/regional environmental degradation
- encouraging local entrepreneurship
- providing a role for local residents in implementation and management of power facilities

Economic Needs:

- local employment opportunities for operations and maintenance
- providing flexibility to meet changing economic conditions:
    - the potential to upgrade a facility's generating capacity in the future
    - to co-fire or switch fuels in a plant
    - to support cogenerated heat and power applications
    - to support both stand-alone and grid applications
- land requirements that can be met without conflict with competing applications
- water requirements that can be met without conflict with competing applications
- making the best use of, while not exhausting, local/national energy resources
- commercializable within the service area with full recovery of direct costs
- minimized distribution costs for generated electricity
- minimized transport costs for fuels and wastes
- ease of financial and engineering implementation

- ease of installation replication for future projects
- promoting local technology research, development and production as national experience with the technology matures
- where appropriate:
    - encouraging technology transfer in introduction phase of the product/service cycle
    - having plant installation and (future) production within local absorptive capacity, so that sustainable employment opportunities are created in a vertically integrated national power sector
    - creating local ownership and income for domestic independent power producers
    - attracting sufficient foreign investments when plants are financed through project financing schemes

While this list is not exhaustive, it indicates a wide range of potential needs. Some of the above needs have relevance only for certain technologies. Other needs may be identified during actual planning for a particular service area and local/national context. A full treatment of issues related to each of the social and economic needs presented above is beyond the scope of this Guide. However, a technology's labor requirements, flexibility, and land and water needs can be determined by information provided in the Annexes of this Guide.

Labor Requirements:

When the complete energy cycle of a technology option is considered, most power generation systems are associated with high labor requirements. In fulfilling these requirements, employment opportunities are created in a vast number of areas:

- technology production
- power plant construction
- primary resource extraction, processing and transport
- power plant operation
- power plant maintenance
- solid waste processing, transport and disposal
- electricity transmission and distribution
- electricity marketing
- consumer hook-up and monitoring
- development, production, distribution and maintenance of end-use applications

Within the service area and the national economy, power generation activity can broadly stimulate economic development and result in substantial job creation. In most cases, planners seek to identify power generation options which maximize employment opportunities for local and national population groups in all of the above areas. The level of job creation associated with power generation is sensitive to:

- the level of local/national sourcing used in technology production
- the level of local/national sourcing used in plant construction
- the type of technology deployed
- the type of primary energy resource, either national or foreign
- the level of power generated
- the geographical extent to which electricity is distributed

In economies where job creation is a major criteria for decisionmaking, sensitivity analysis of technology options to job creation throughout the full energy cycle should be performed, at least on a rough comparative basis, during the IRP process. Narrowing the focus from the full energy cycle to electricity generation, this Guide provides information on labor requirements and skill levels for operations and maintenance activity of technology options at the plant.

Refer to: ➔ Annex II Chart 17 : Labor Requirements
➔ Annex III Factsheets : Labor Skill Level Requirements

Flexibility:

When a power plant becomes operational, it has a certain rated capacity. The possibility of augmenting that capacity and the ease of doing so is one measure of the plant's flexibility. As social and economic development evolves in a service area, so do requirements for additional power. Planners should seek to identify technology options that permit capacity upgrades at lower incremental costs and shorter upgrade times than the construction of entirely new facilities. Such option can help ensure that power investments today continue to provide utility in the future even as service area demand increases. They can also provide for increased power delivery with minimal disruption to existing end-users.

Technologies based on a modular structure are the most flexible, since their capacities can be increased incrementally by simply adding additional modules to the plant. Photovoltaic and wind based power plants are the best examples of flexible power generation. In these plants, additional photovoltaic collector plates or additional wind turbine units can be added to the plant's generation circuit to increase output levels. Fossil fuel plants comprised of diesel engine or turbine units are also modular in nature, and with additional units capacity is correspondingly increased. Hydropower plants also permit this flexibility, with the provisio that adequate water flow is available to feed additional turbines. For plants based on a steam cycle, such as nuclear and coal-fired steam technologies, capacity extensions are not possible since the entire plant configuration (furnace, boiler, cooling tower, etc.) is designed to cycle limited fluxes of combustion heat and steam.

Other measures of flexibility are:

- For fossil fuel technologies, whether or not they permit fuel switching without substantial system modification. Here combustion turbines and diesel engines provide great versatility, as both can be run on natural gas, landfill gas, gasified coal or petroleum fuel. Steam cycle plants do not permit fuel switching, although in some cases they can be ***co-fired***; run on a mixture of fuels, solar energy and natural gas for instance.

- Whether a technology can run in multiple duty cycles. Often it is necessary to run a plant in various duty cycles responding to changing load patterns and capacity availability.
- Whether a technology supports not only stand-alone applications for low-load sites but grid-connected applications as well.
- Whether a plant can be used in combined heat and power (CHP) generation modes.

For each of the technologies assessed in this Guide, indications of flexibility with respect to the above criteria are provided.

Refer to: ➔ Annex II Chart 18 : Modular Upgrade Capability
➔ Annex II Chart 16 : Fuel Requirements
➔ Annex II Chart 4 : Duty Cycles
➔ Annex II Chart 15 : CHP Options

Land Requirements:

An important aspect of the site selection process for power plants is the land required for the installation of the plant and its auxiliary facilities such as fuel and waste storage and processing areas. In order to reduce power losses during transmission, power plants are often situated well within the area they serve. Since land in a service area usually has high economic and/or social value, such land may have many current and future competing uses (e.g., industrial, commercial, agricultural, residential, recreational, etc.). In such cases, technologies with low land requirements will be preferred.

By the very nature of their fuel needs and/or modes of functioning, different technologies have very different requirements. Coal-fired plants have high land requirements due to the need to store and process coal and to store wastes. At a 150 MW pulverized coal-fired steam cycle plant, 2,000 tonnes of lignite coal are needed each day for full capacity operation. Land requirements (as well as facilities and equipment) for fuel-offloading, storing, cleaning, pulverizing, waste fly ash and sludge processing and storage are all in addition to land needed for the central power generating facility. Total land required is on the order of 50-100 hectares. In contrast, a natural gas fired turbine power plant of the same 150 MW capacity that is served by a gas pipeline does not need fuel and waste processing or storage space, and thus requires only about 3-5 hectares of land. Solar and wind powered plants have high land requirements due to the relatively low energy flux of their primary energy resources. A 100 MW flat plate photovoltaic plant would require on the order of 300 hectares of land, while a 100 MW wind farm would require over 1000 hectares.

Refer to: ➔ Annex II Chart 19 : Land Requirements

Water Requirements:

As populations in any given region grow, so too does the need for an expanded fresh water supply and/or more efficient use of water. Some power generation have high water requirements that could potentially stress the water budget in areas with limited water supply relative to demand.

Fossil fuel, nuclear and certain renewable power plants use water in the process of generating electricity. In fossil fuel, nuclear, biomass, and solar thermal plants water is used to generate steam in a plant's primary steam circuit that turns a turbine. In hydroelectric and geothermal plants, water and steam respectively are tapped directly from the environment to turn turbines. In all cases, water is used in the primary steam circuit, *rather than consumed,* as power is generated. A net consumption of water may, however, occur in power plants when steam in the primary steam circuit must be cooled in a condenser. This cooling is effected by a secondary cooling water circuit. Cooling water systems which circulate water through a (wet) cooling tower result in net water consumption, as water evaporation in the cooling tower must be continually replaced from external sources. In many cases water consumption rates can be considerable, and planning must assess the availability of sufficient water resources when such plants are evaluated. For sites where water is in short supply more costly cooling system options (increasing total plant costs by 10-40 percent) which require little or no water are available. These options use either dry cooling towers or air cooling systems.

Alternatively, for power plants situated near the ocean or a large river, direct cooling water systems can be used. In these systems, water from a river or ocean source passes through the plant's condenser, thereby cooling steam in the plant's primary steam circuit before being returned to its source. Direct cooling is the lowest cost cooling option for power plants with cooling requirements. However, water returned to its river or ocean source is heated, often posing problems to local water ecosystems.

As the level of water for power plant cooling is extremely site-dependent, the fact sheets for technologies with cooling requirements covered in this Guide, assume the least common denominator; i.e., that condenser cooling is performed using wet cooling towers having net water consumption. Water requirements are then evaluated as high, medium or low.

Refer to: ➔ Annex II Chart 20 : Water Requirements

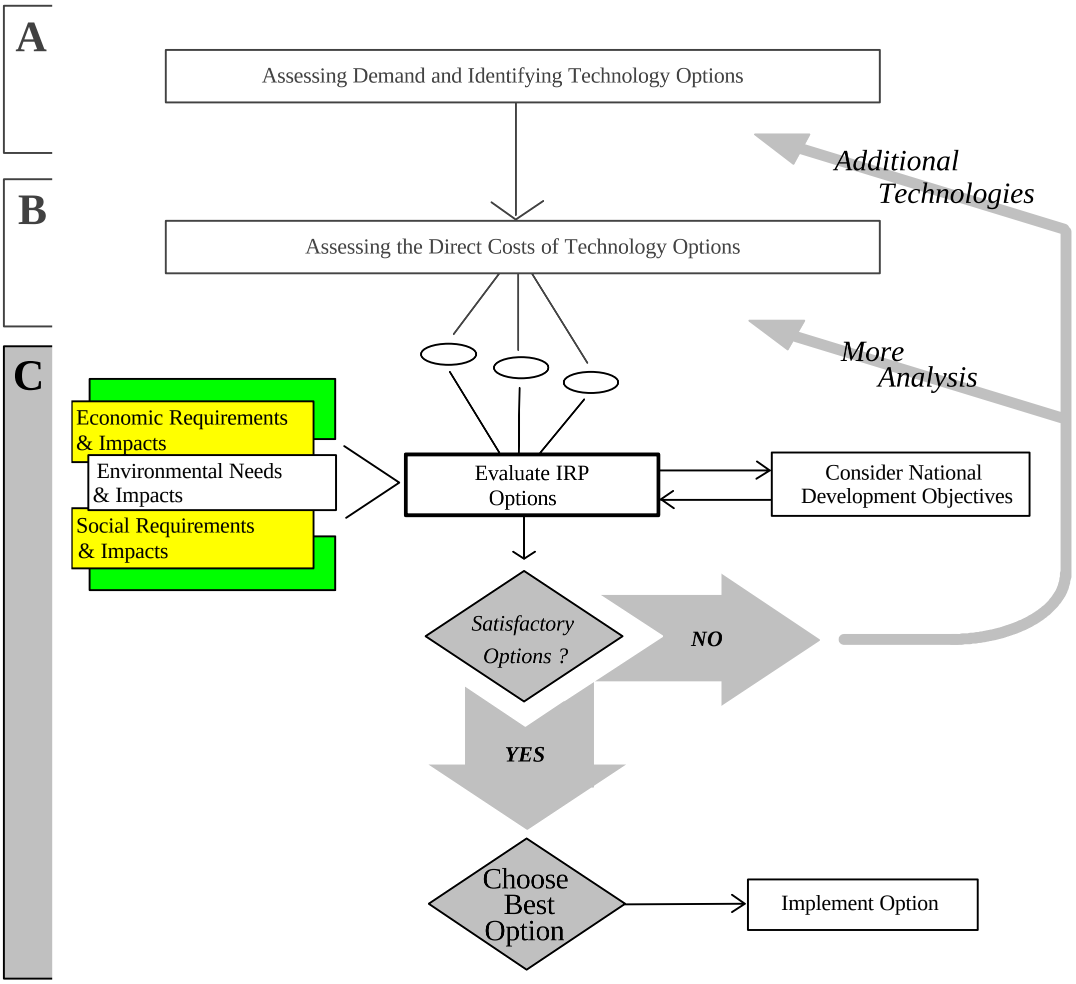
C.4 Completing the Energy Planning Cycle

As indicated in the previous sections, power generation involves substantial interactions with natural and human resource systems throughout the energy cycle. Through integrated resource planning, the indirect costs and benefits of a wide range of technology options are evaluated from integrated social, economic, and environmental perspectives. Given a set of technology options satisfying physical and direct cost criteria and based on a knowledge of each option's interaction with natural and human resource systems, the IRP process, in principle, permits the best technology-resource combination for a specific application to be identified and selected for implementation. In practice, however, an efficient IRP process remains difficult to achieve as it is hindered by various practical difficulties. Some of these include:

- environmental concerns are often ignored or understated due to decisionmakers' preoccupation with financial considerations or due to their lack of knowledge or concern about the environment
- uncertainties in predicting the level of environmental impacts throughout the fuel cycle for a wide range of technologies
- the complexity of relating environmental impacts to social and economic systems
- lack of direct experience with certain technologies leading to inaccurate assessments of how effectively they will support or conflict with social and economic needs of the service area and national economy
- agreement on the screening criteria applied in evaluations of technology options may be hard to achieve, as differences in opinion arise over what issues and impacts of power generation are important, and what timeframe should be used in evaluations

Although it is unrealistic to expect that such practical difficulties can be completely overcome in an actual planning process, they need to be recognized and addressed. A multidisciplinary team or committee of energy planners could be established so that expert advice is available on specialized issues. Planners should be given sufficient time to conduct research and perform studies on interactions between various technologies and environmental, social and economic systems. Consultations with various technology experts may be required. A number of special interest groups in the service area could be involved in the planning process so that varied perspectives can be integrated into an evaluation process that responds to stakeholders' needs. Lastly, in view of the multiple variables and varied technologies involved in IRP, a formal and objective operational method of evaluation should be adopted. Many such methods are available, including: cost-benefit analysis, cost effectiveness analysis, marginal cost analysis and multi-variate decision analysis. All of these methods will lead to a ranking of a how well evaluated technology options satisfy the wide range of objectives and needs defined by policy makers and/or energy planners, and potentially, various interest groups in the service area. Rankings will be dependent on decision criteria reflecting the relative weighting assigned to defined objectives and needs.

In most cases, the integrated resource planning yields option rankings that are satisfactory to decisionmakers. The highest ranking, or *'best'*, option is then selected for implementation and the energy planning cycle is completed.



In some cases, however, IRP may yield option rankings that are not satisfactory to decisionmakers. Conflicting objectives and undesirable trade-offs associated make choices difficult. In such cases, one might consider the next highest ranking option, a mix of two or more options, or another iteration of the IRP process using different decision criteria. Alternatively, if decisionmakers find that indirect costs are too high for all of the technologies evaluated in the IRP process (Step C of the energy planning cycle) planners may:

- revisit the least cost planning process (in Step B) making a new analysis of options with, in addition to direct costs, internalized indirect costs; or,
- assess the feasibility of additional technologies, that were not included in the first round of planning, in meeting demand levels (Step A).

Eventually, following one or more iterations of a planning cycle with modified inputs, a preferred option can be selected and implemented.

Section C Reference Sources :
3, 5, 7, 10, 11, 12, 13, 14, 19, 20, 25, 26, 29, 37, 38, 41, 42

Annex I : Technology Tables

Tables in this annex present data on performance, direct costs, and resource implications for each of the 20 technologies assessed by this Guide.

For information on how the technology data were complied and prepared, see Annex IV: *Technical and Economic Assumptions.*

	technology reference sources	lower capacity	upper capacity	availability
fossil fuel based technologies:				
coal fired steam turbine	1, 41	150	1000	85
diesel engine	36, 41	0.01	10	95
combustion turbine	6, 36, 41	0.5	250	95
gas turbine combined cycle (GTCC)	1, 18, 36, 41	50	350	90
atmospheric fluidized bed combustion (AFBC)	36, 41	100	400	85
integrated coal gasification combined cycle (IGCC)	1, 34, 41	50	350	85
nuclear fuel based technologies:				
pressurized water reactor (PWR)	41	150	1000	80
renewable energy source technologies:				
biomass gasifier - diesel engine	22, 23, 41	0.01	10	90
biomass gasifier - combustion turbine	22, 23, 42	0.5	50	90
biomass gasifier - combined cycle (BIG/CC)	22, 23, 43	10	50	85
solar photovoltaic	31, 45, 46	0.0001	1	100
solar thermal - parabolic dish	31, 45	0.005	0.025	95
solar thermal - parabolic troughs	31, 45	1	100	95
solar thermal - central receiver	31, 45	1	50	90
horizontal axis wind turbine (HAWT)	9, 41, 45	0.25	0.5	95
large-scale hydropower (dam and reservoir)	9, 20, 41	100	1000	95
small-scale hydropower turbine (run-of-river)	9, 20, 41	0.1	100	95
geothermal - dry steam plant	20, 41, 45	20	120	90
geothermal - single flash plant	31, 41	10	50	90
geothermal - binary plant	31, 41	1	10	90
UNITS		MW	MW	%
reference source(s)		4, 30	4, 30	28
see Annex II technology comparison chart N°		1,2	1,2	3
		lower capacity	upper capacity	availability

duty cycle	other duty cycles	capacity factor	capital costs / kWe	capital costs / KWh	O & M costs / kWh	fuel costs / kWh	total costs / kWh
B	I	70	1500	20	10	20	50
I	P	40	1000	23	8	35	66
P	I	15	400	25	9	39	73
B	I	70	600	8	5	32	45
B	I	70	1700	22	13	20	55
B		70	1650	22	12	18	52
B		70	2000	25	14	8	47
I	P	40	1300	30	10	24	64
P	I	15	700	50	12	33	95
B		70	1300	21	36	20	77
M		40	6000	368	7	0	375
M		40	1500			0	50
M		40	3000	69	15	0	84
M		40	3000	69	20	0	89
M		25	1000	50	14	0	64
I	B	40	2000	42	8	0	50
I	B	50	2000	42	8	0	50
B	I,P	70	1900	25	15		40
B		70	2000	26	20		46
B	I,P	70	2000	26	20		46
see Ann. IV	*see Ann. IV*	%	mills	mills	mills	mills	mills
4, 30	4, 30	*see Ann. IV*	30	30	30	30	*see Ann. IV*
4	4		5	6,7,8	6,7,8	6,7,8	6,7,8
duty cycle	other duty cycles	capacity factor	capital costs / kWe	capital costs / KWh	O & M costs / kWh	fuel costs / kWh	total costs / kWh

	technology reference sources	lifetime	leadtime	NOx output	SO2 output
fossil fuel based technologies:					
coal fired steam turbine	1, 41	30	3	3-10	1-25
diesel engine	36, 41	30	0.5	1-15	0-2
combustion turbine	6, 36, 41	30	1.5	1-2	0-1.2
gas turbine combined cycle (GTCC)	1, 18, 36, 41	30	3	0.5-1.5	0
atmospheric fluidized bed combustion (AFBC)	36, 41	30	3	1.1.5	1-8
integrated coal gasification combined cycle (IGCC)	1, 34, 41	30	5	1-2.5	0.5-3
nuclear fuel based technologies:					
pressurized water reactor (PWR)	41	30	5	0	0
renewable energy source technologies:					
biomass gasifier - diesel engine	22, 23, 41	30	1	0.5-6	0
biomass gasifier - combustion turbine	22, 23, 42	30	1.5	0.5-6	0
biomass gasifier - combined cycle (BIG/CC)	22, 23, 43	30	2.5	0.5-6	0
solar photovoltaic	31, 45, 46	30	2	0	0
solar thermal - parabolic dish	31, 45		0.5	0	0
solar thermal - parabolic troughs	31, 45	30	2	0	0
solar thermal - central receiver	31, 45	30	5	0	0
horizontal axis wind turbine (HAWT)	9, 41, 45	15	0.5	0	0
large-scale hydropower (dam and reservoir)	9, 20, 41	45	5	0	0
small-scale hydropower turbine (run-of-river)	9, 20, 41	45	2.5	0	0
geothermal - dry steam plant	20, 41, 45	30	1.5	0	0
geothermal - single flash plant	31, 41	30	1.5	0	0
geothermal - binary plant	31, 41	30	3	0	0
UNITS		yrs	yrs	kg/MWh	kg/MWh
reference source(s)		30	*see Ann. IV*	15	15
see Annex II technology comparison chart N°		9	10	11	12
		lifetime	leadtime	NO2 output	SO2 output

CO2 output	efficiency	CHP options	fuel type	other fuels	labor requirements	upgradability	land requirements	water requirements
720-1210	34	Y	C		H	N	M	M
570-880	42	Y	G	O	L	Y	L	L
700-1150	26	Y	G	O	L	Y	L	L
400-470	55	Y	G	O	H	Y	L	M
780-930	34	Y	C		H	Y	M	M
750-880	42	Y	C		H	Y	M	M
0		Y	U		H	N	L	M
0	30	Y	BM	O	M	Y	H	H
0	22	Y	BM	G	M	Y	H	H
0	35	Y	BM		M	Y	H	H
0	15	N	S		L	Y	M	L
0	25	N	S		L	Y	M	L
0	15	Y	S	G	H	N	M	M
0	23	Y	S	G	H	N	M	M
0		N	W		M	Y	M	L
0	85	N	H		M	N	H	L
0	75	N	H		L	N	M	L
38-75	60	Y	T		M	Y	L	M
38-75	40	Y	T		M	Y	L	M
0	40	Y	T		M	Y	L	M
kg/MWh	%	Y/N	*see notes*	*see notes*	H-M-L	Y/N	hectare /MWe	H-M-L
15, 29	30	*see Ann. IV*	*see Ann. IV*	*see Ann. IV*	15	*see Ann. IV*	31	30
13	14	15	16	16	17	18	19	20
CO2 output	efficiency	CHP options	fuel type	other fuels	labor requirements	upgradability	land requirements	water requirements

Annex II : Technology Comparison Charts

Charts in this annex permit technology comparisons to be made for each technology characteristic examined in the energy planning cycle. All charts are prepared using the data from tables in Annex I and references sources cited therein.

For information on how the technology data were complied and prepared, see Annex IV: *Technical and Economic Assumptions.*

Chart 1 : kW Capacity Ranges

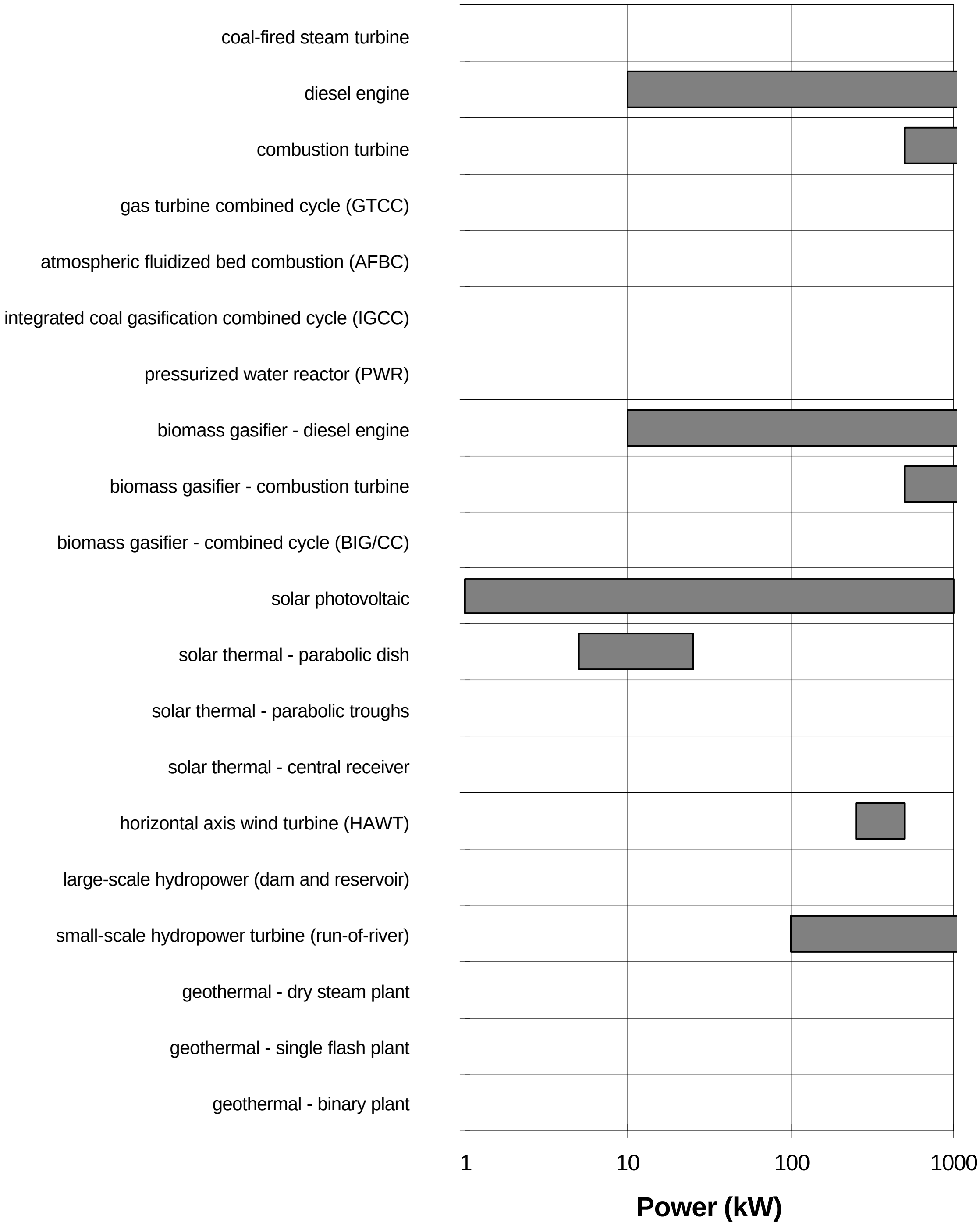


Chart 2 : MW Capacity Ranges

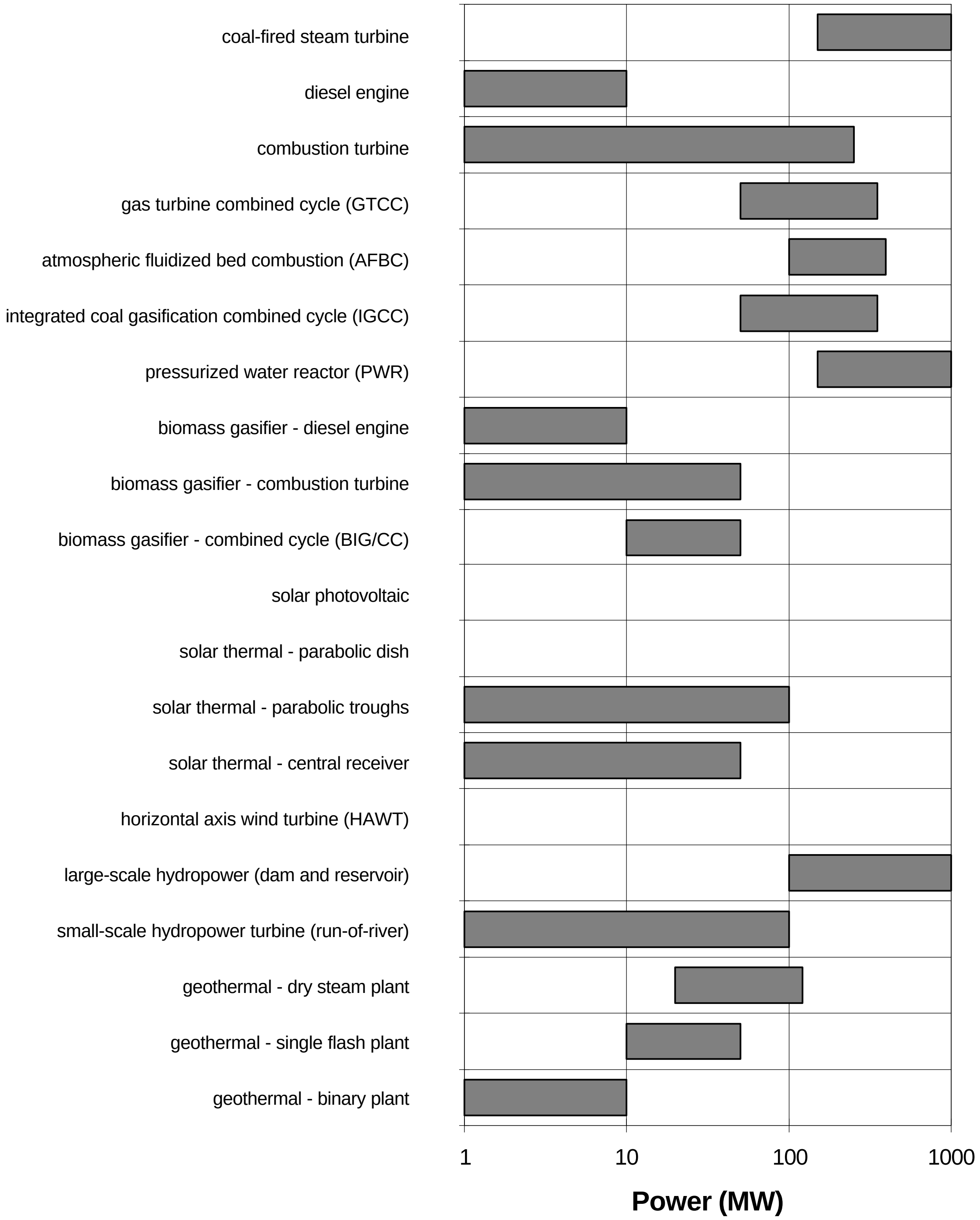


Chart 3 : Operating Availability

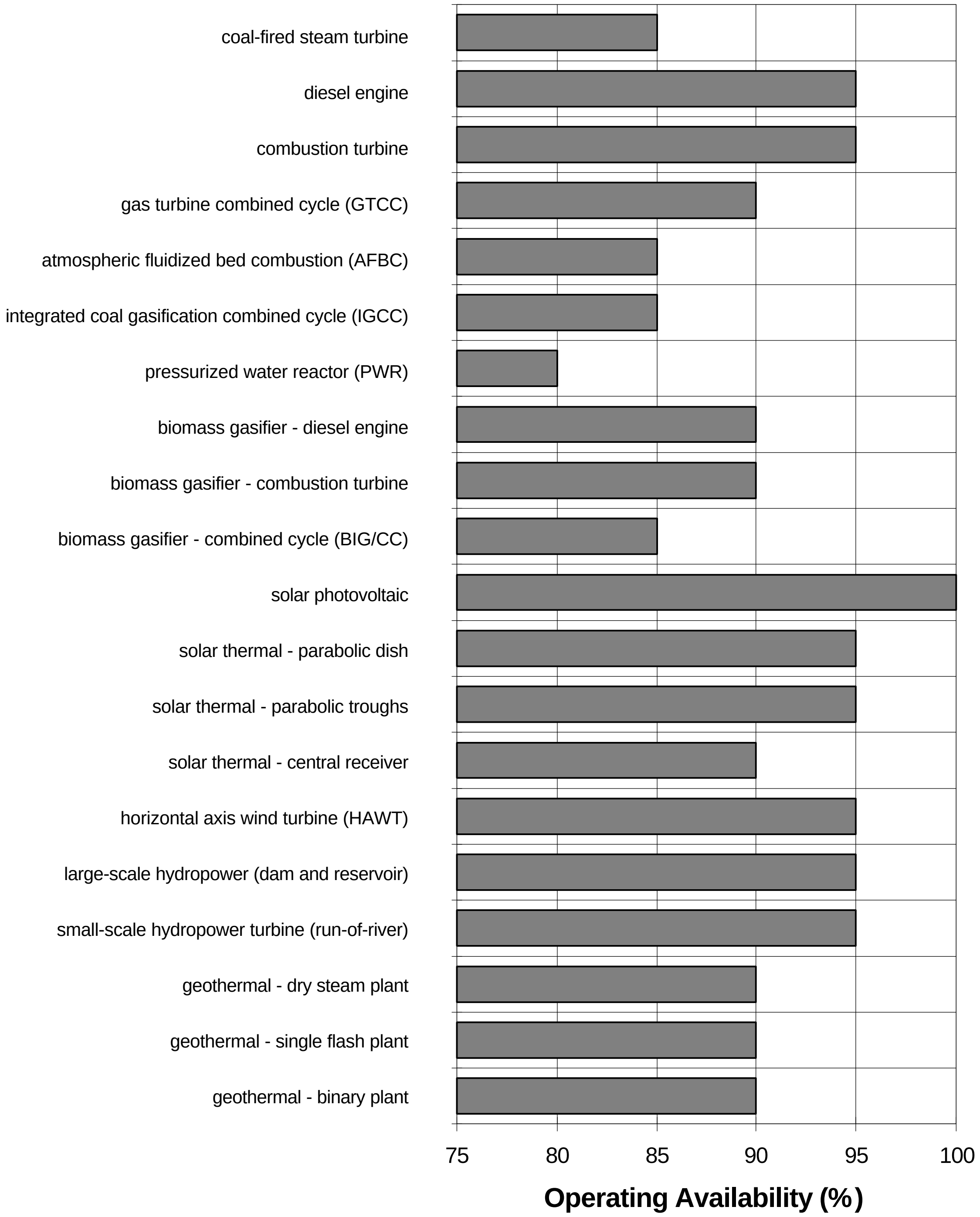
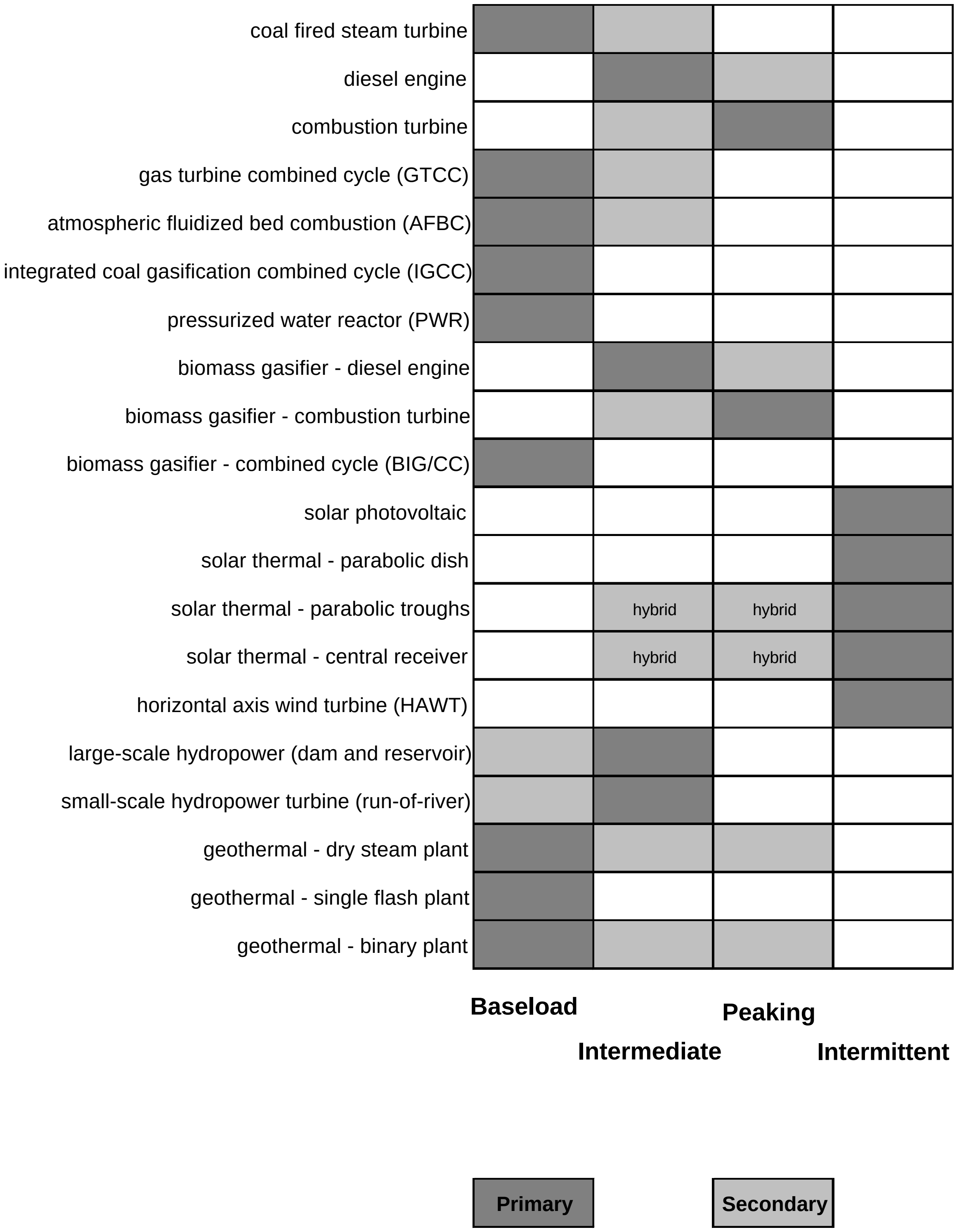


Chart 4 : Duty Cycles



	Baseload	Intermediate	Peaking	Intermittent
coal fired steam turbine	▓	░		
diesel engine		▓	░	
combustion turbine		░	▓	
gas turbine combined cycle (GTCC)	▓	░		
atmospheric fluidized bed combustion (AFBC)	▓	░		
integrated coal gasification combined cycle (IGCC)	▓			
pressurized water reactor (PWR)	▓			
biomass gasifier - diesel engine		▓	░	
biomass gasifier - combustion turbine		░	▓	
biomass gasifier - combined cycle (BIG/CC)	▓			
solar photovoltaic				▓
solar thermal - parabolic dish				▓
solar thermal - parabolic troughs		░ hybrid	░ hybrid	▓
solar thermal - central receiver		░ hybrid	░ hybrid	▓
horizontal axis wind turbine (HAWT)				▓
large-scale hydropower (dam and reservoir)	░	▓		
small-scale hydropower turbine (run-of-river)	░	▓		
geothermal - dry steam plant	▓	░	░	
geothermal - single flash plant	▓			
geothermal - binary plant	▓	░	░	

▓ **Primary**

░ **Secondary**

Chart 5 : Capital Costs per kWe

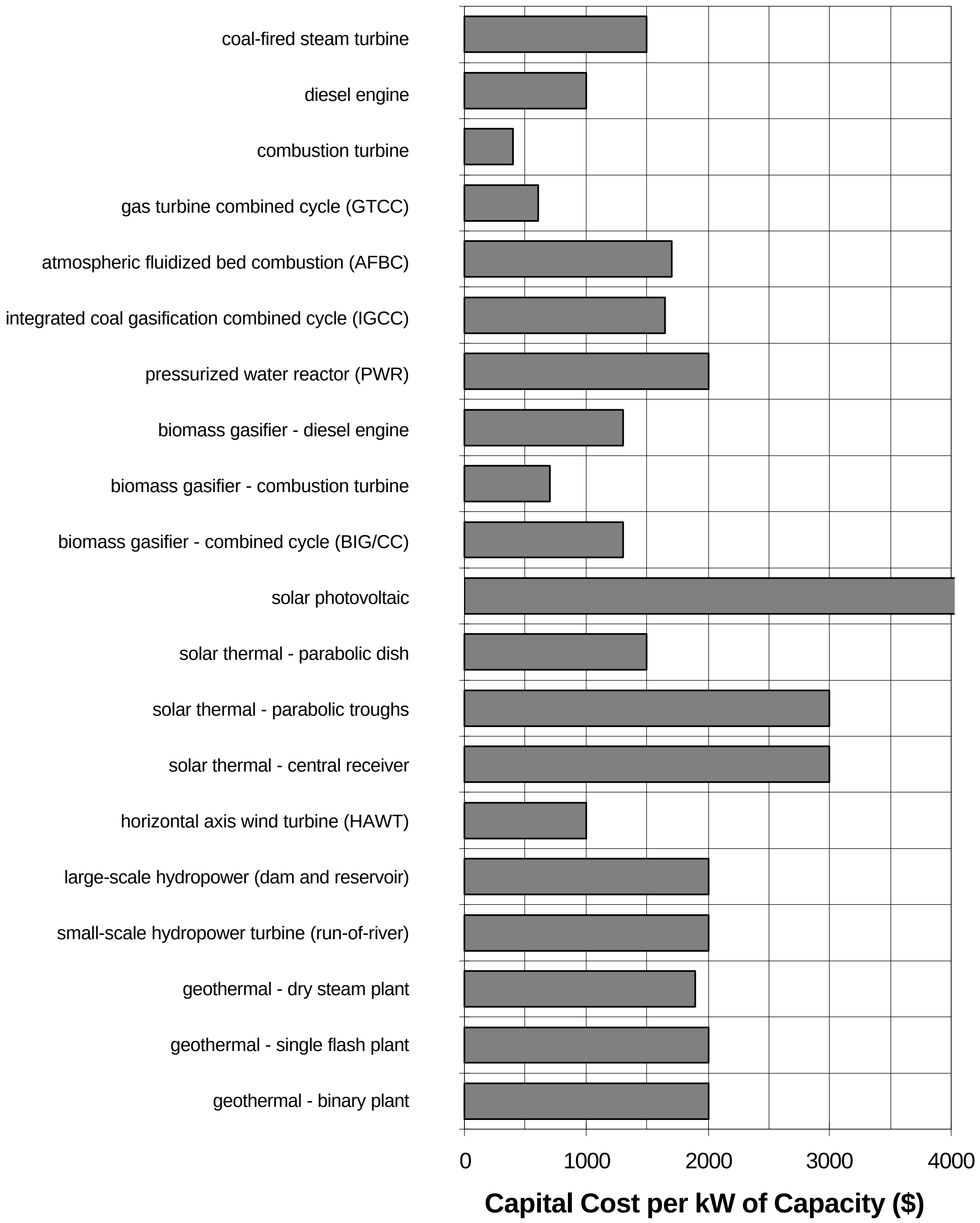


Chart 6 : Levelized Total Direct Costs

5% discount rate

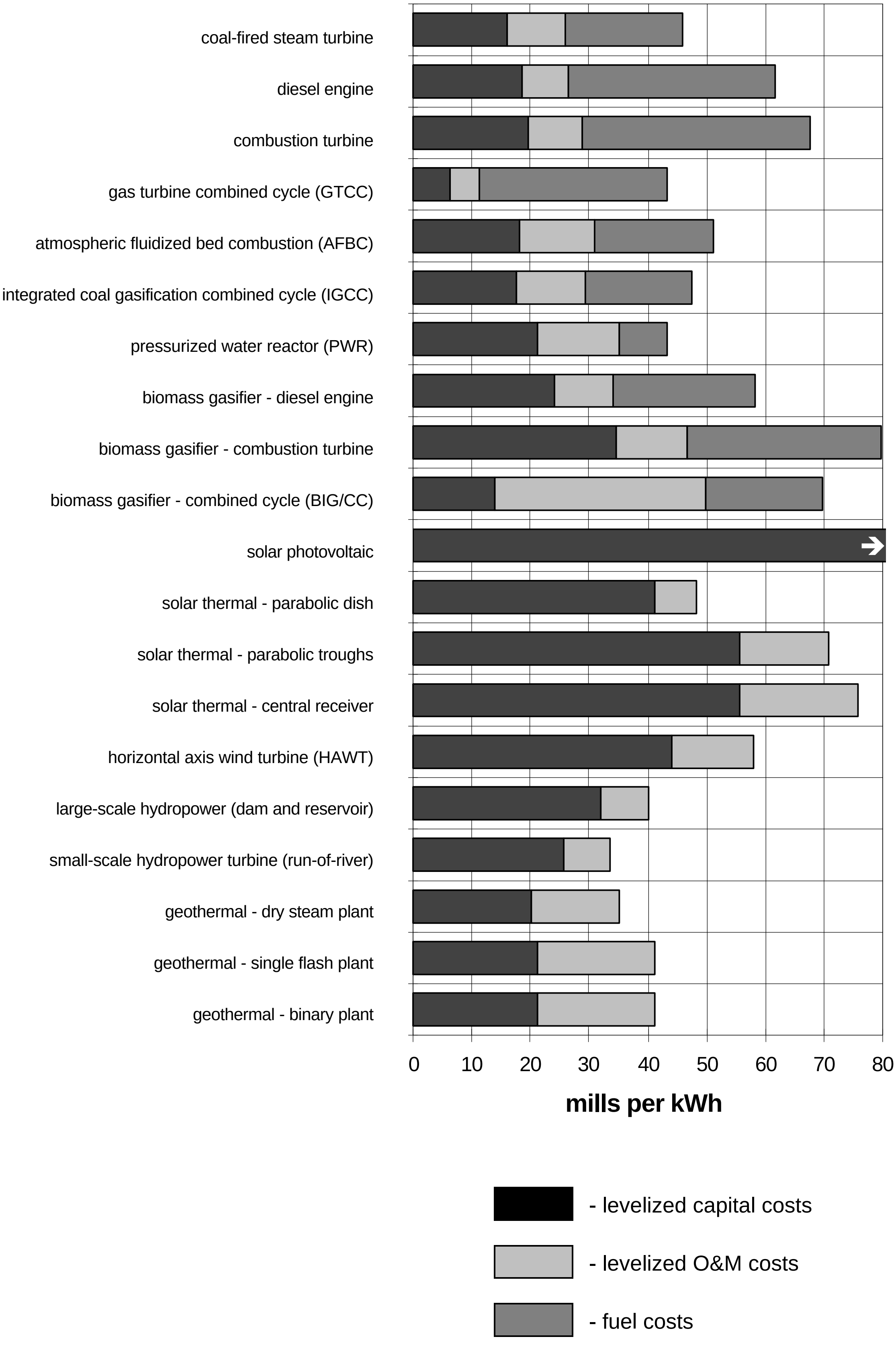


Chart 7 : Levelized Total Direct Costs

7% discount rate

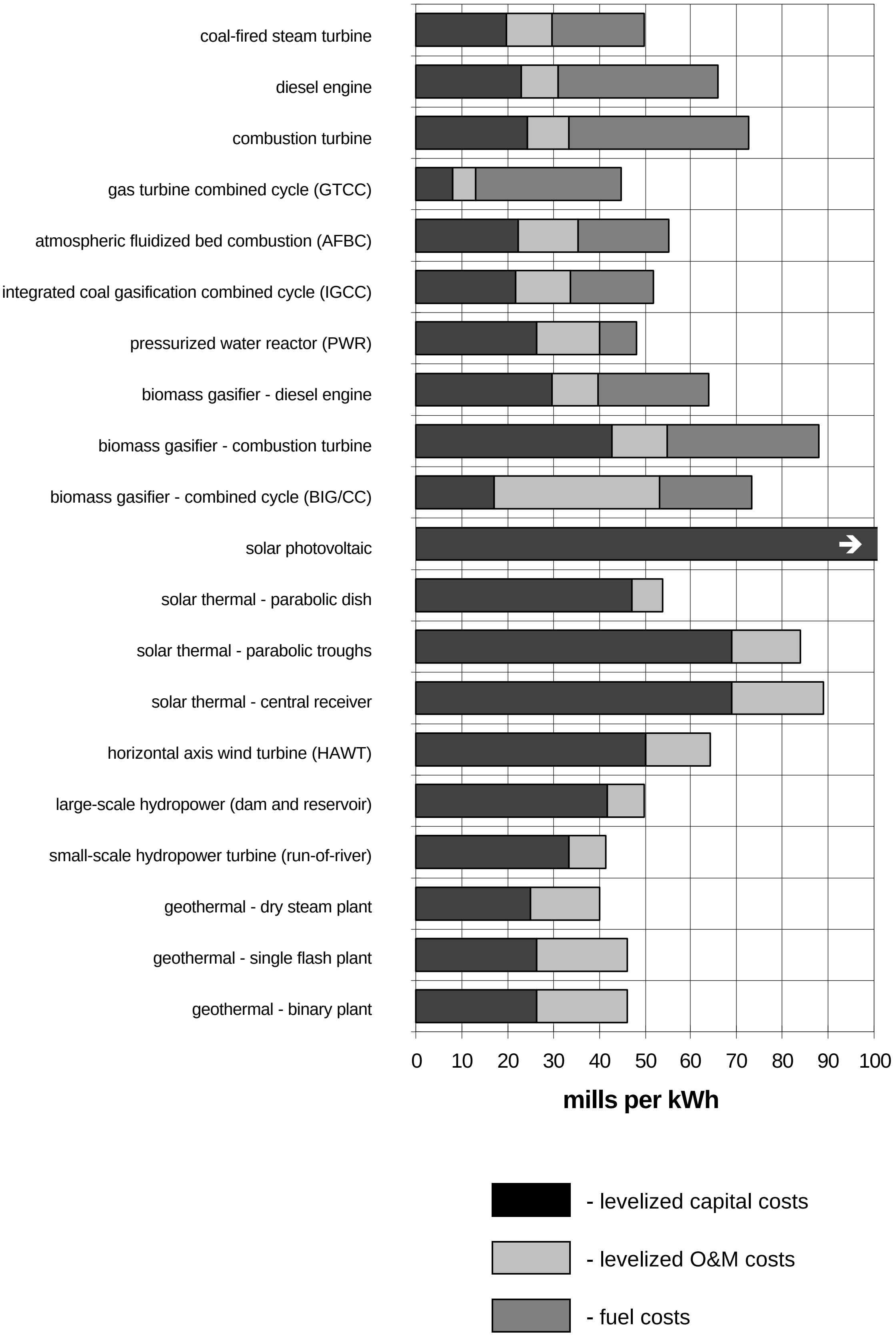


Chart 8 : Levelized Total Direct Costs

10% discount rate

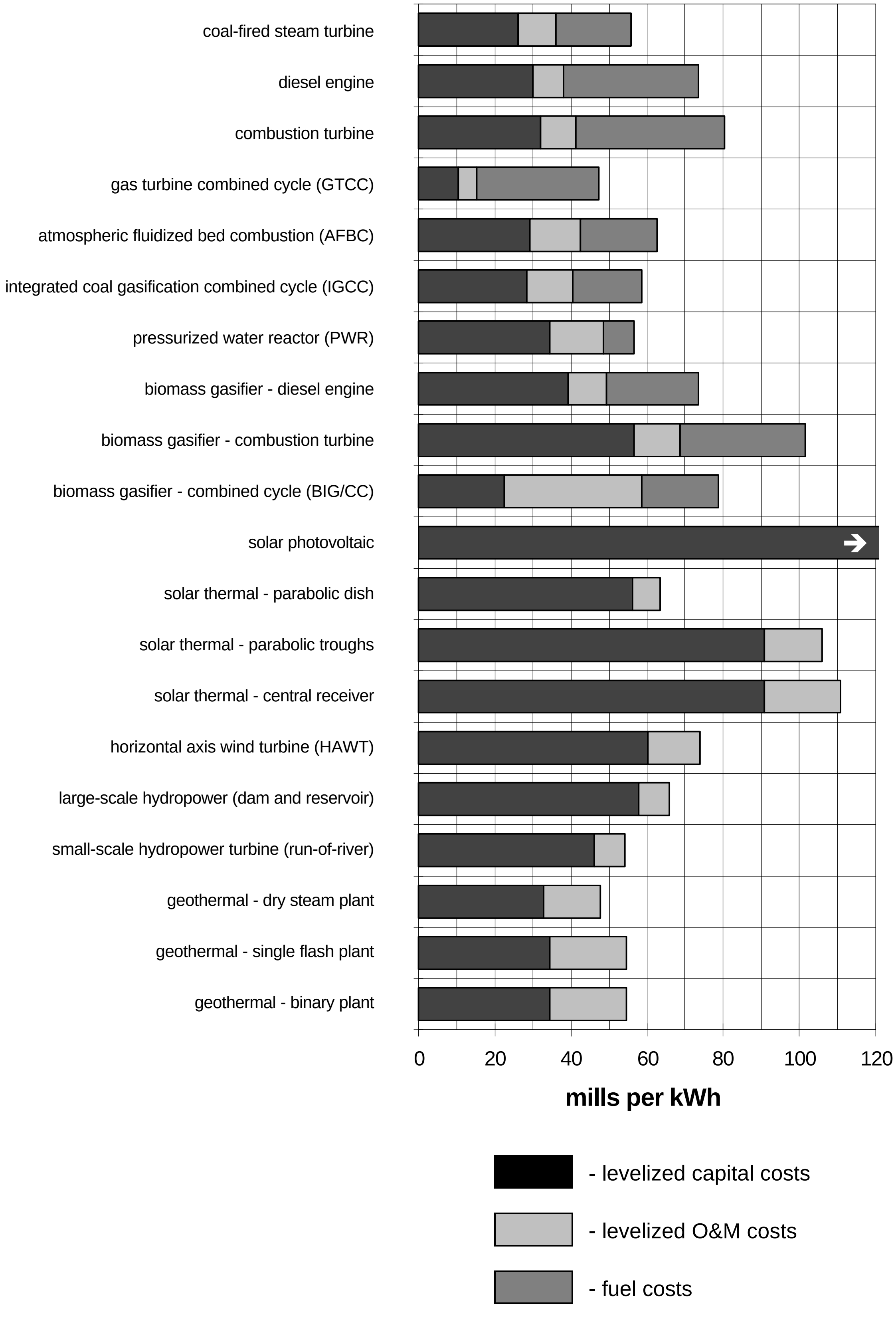


Chart 9 : Power Plant Lifetimes

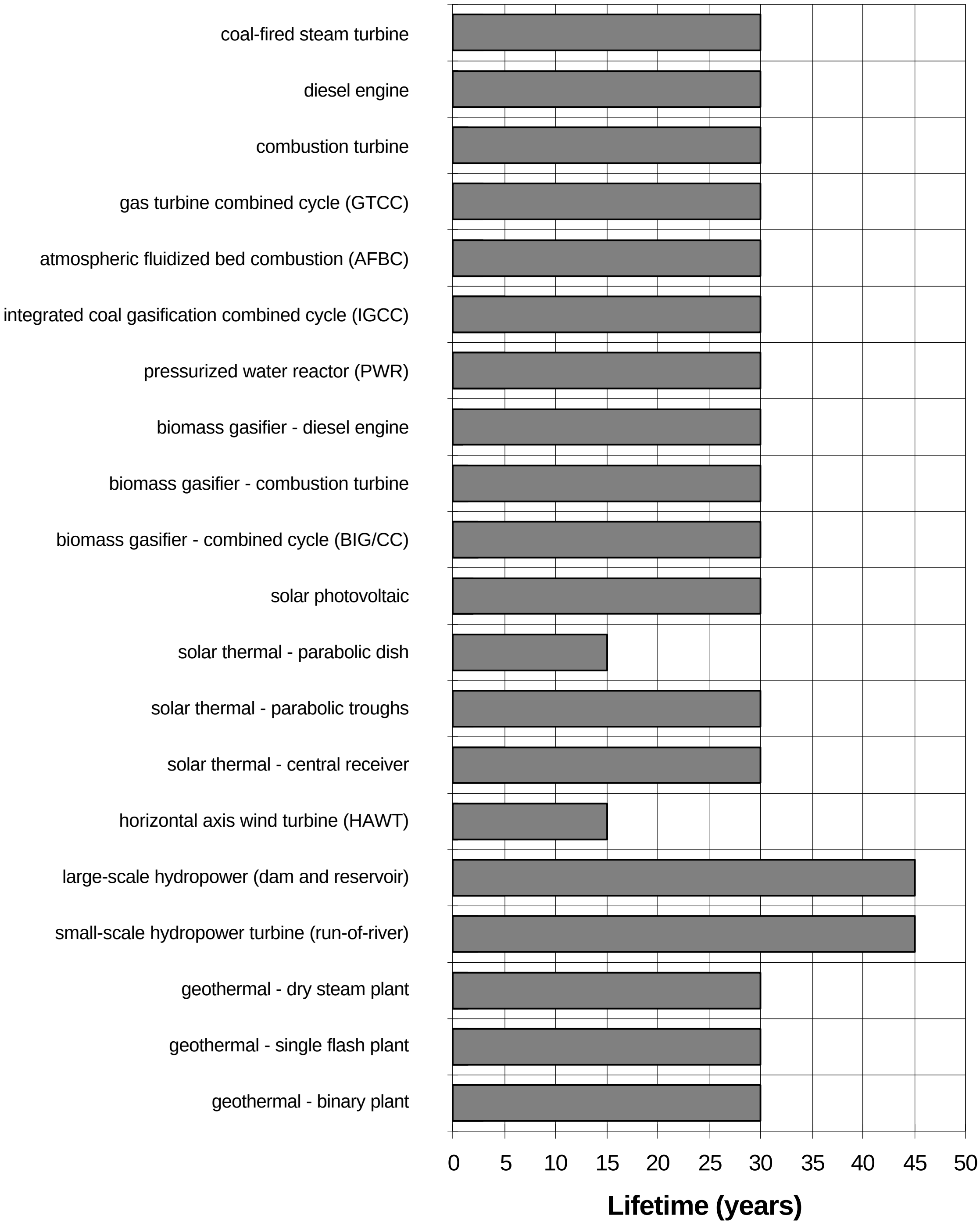


Chart 10 : Power Plant Lead-times

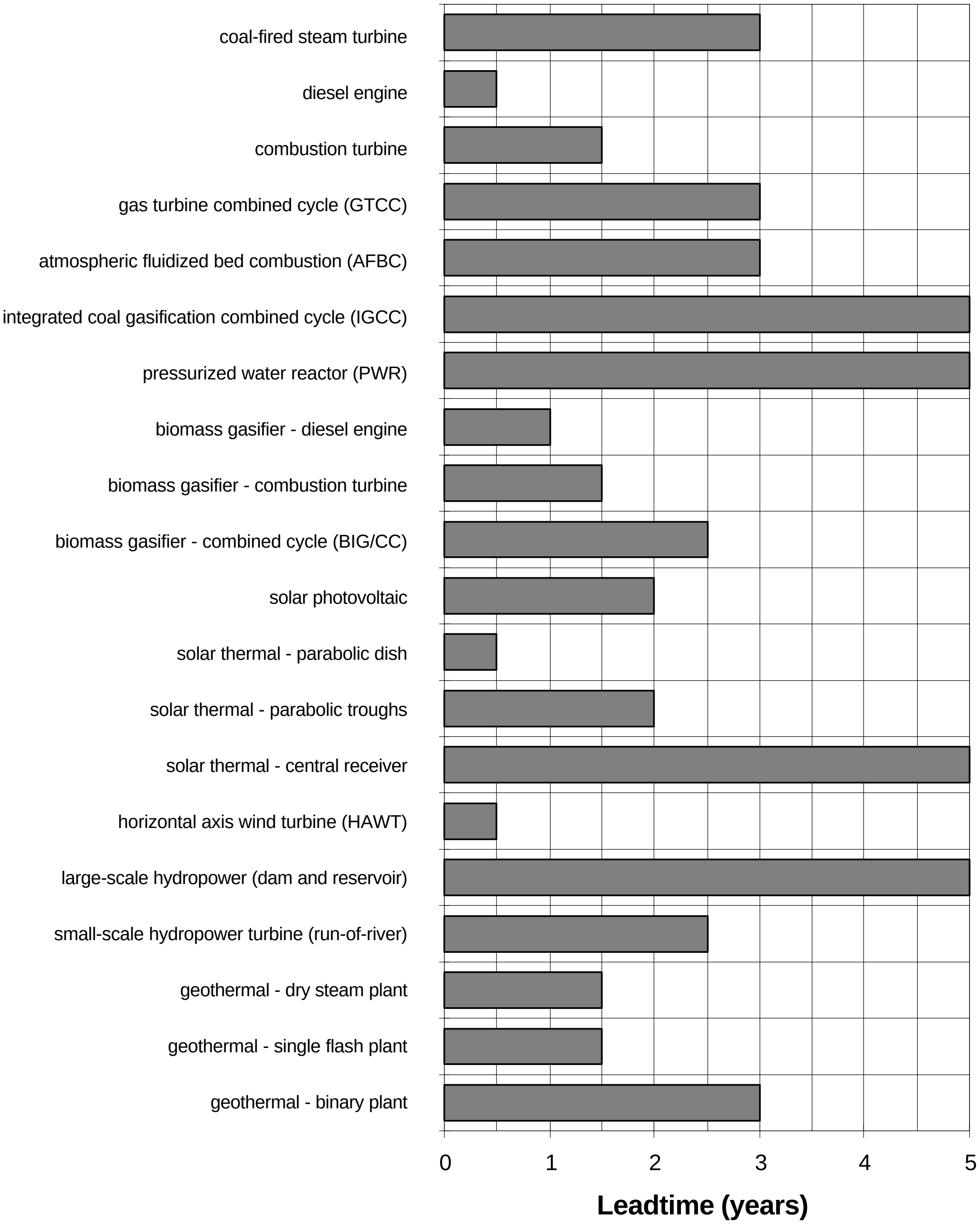


Chart 11 : NO_X Emission Ranges

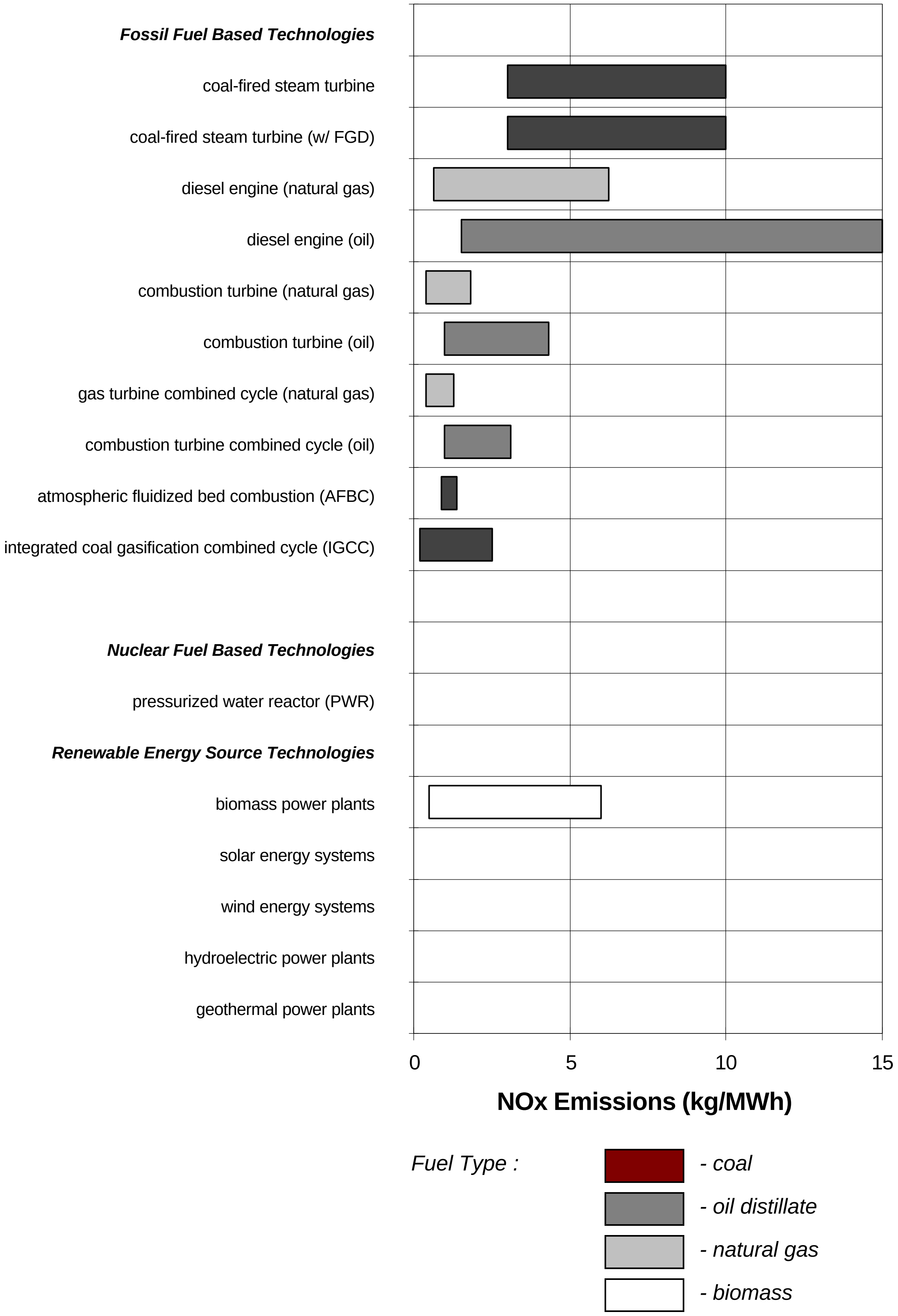


Chart 12 : SO_2 Emission Ranges

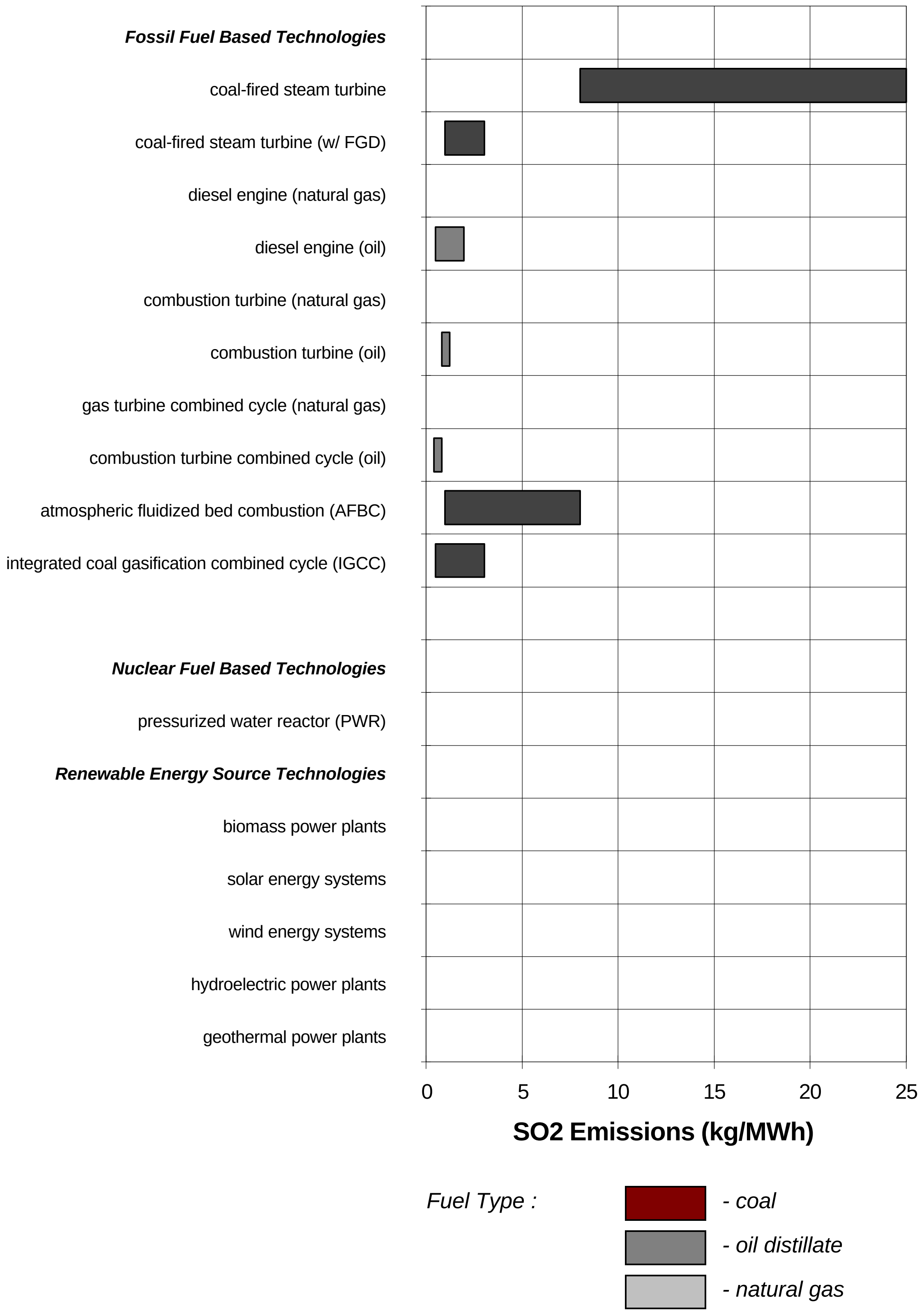


Chart 13 : CO_2 Emission Ranges

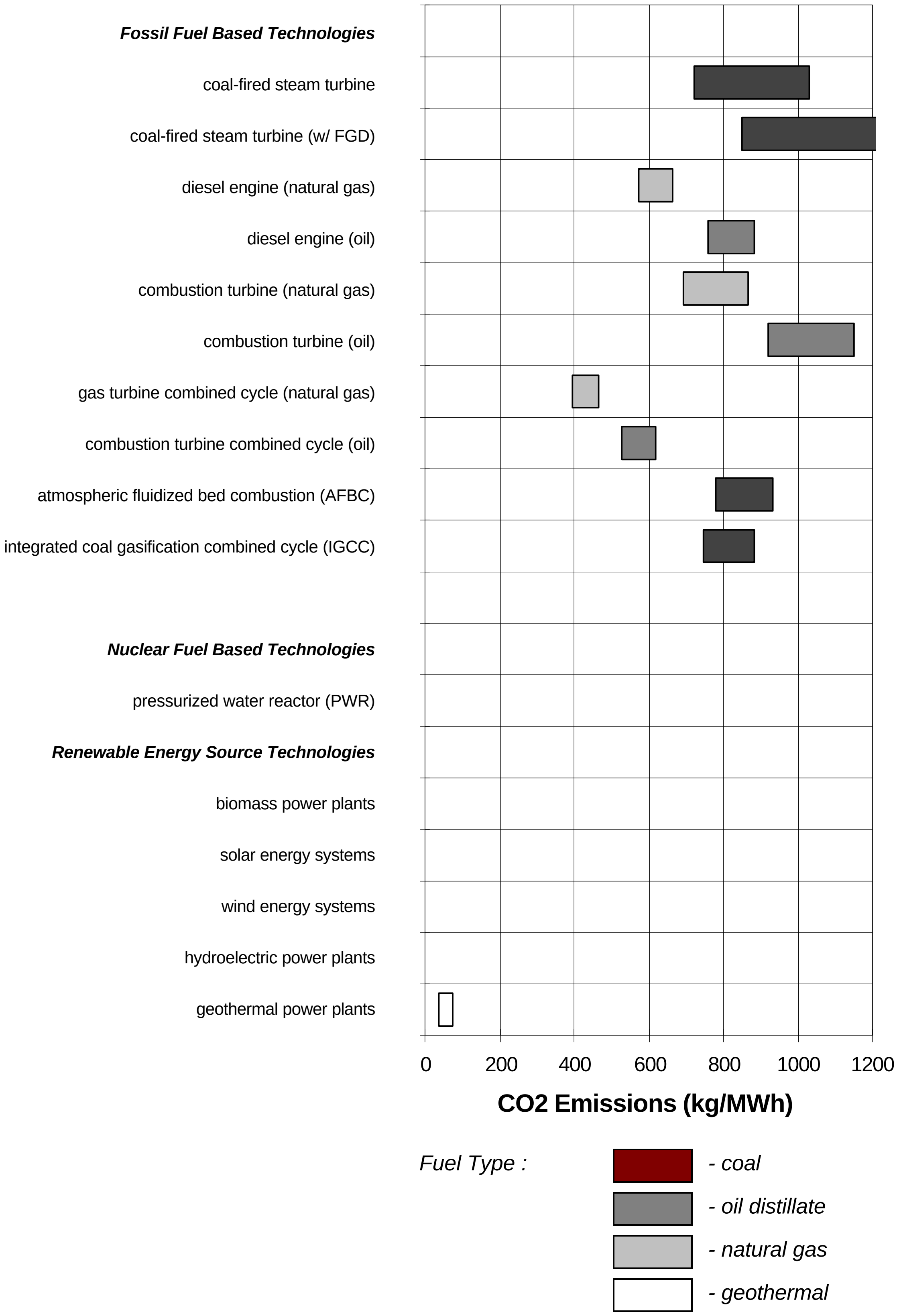


Chart 14 : Efficiencies

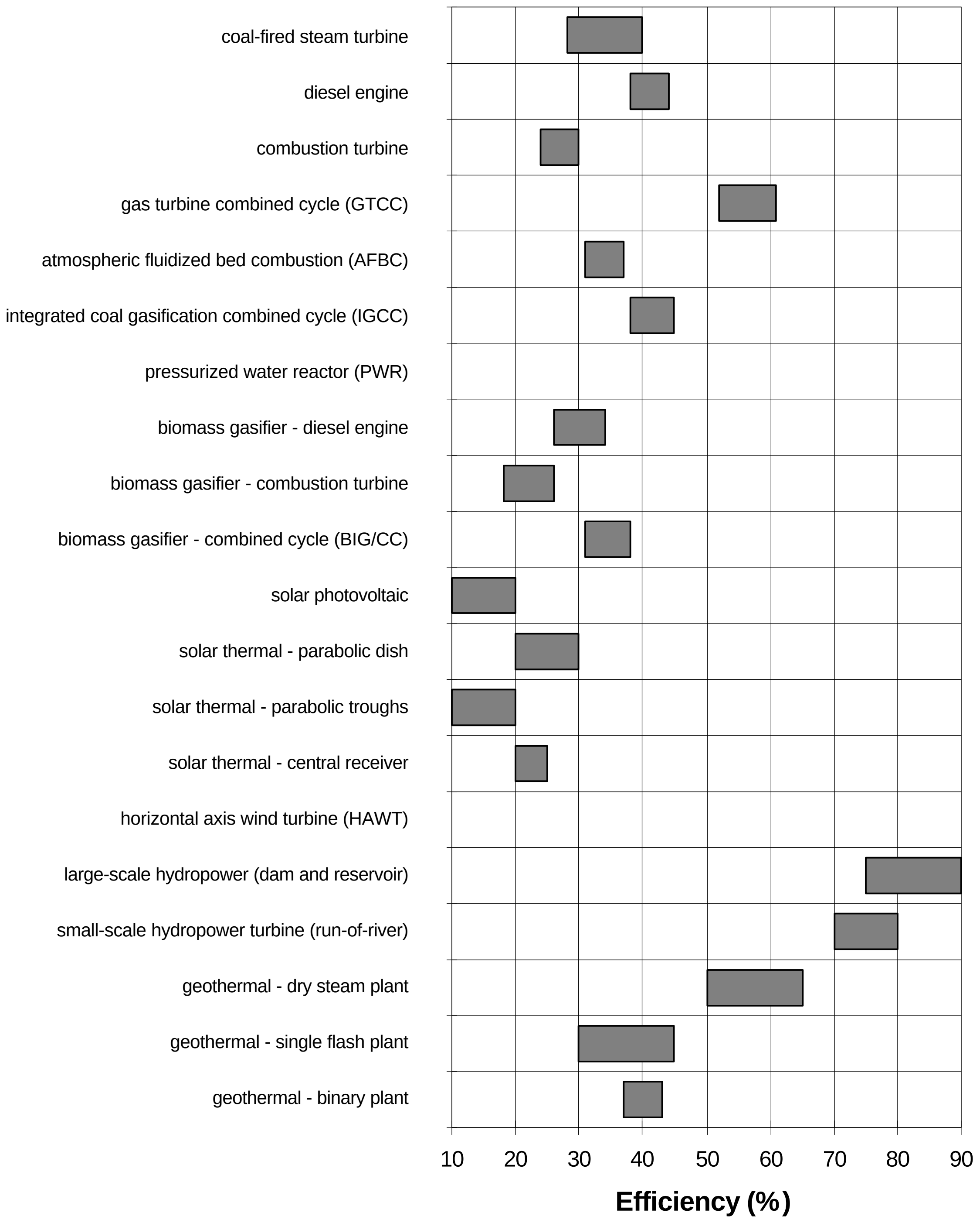
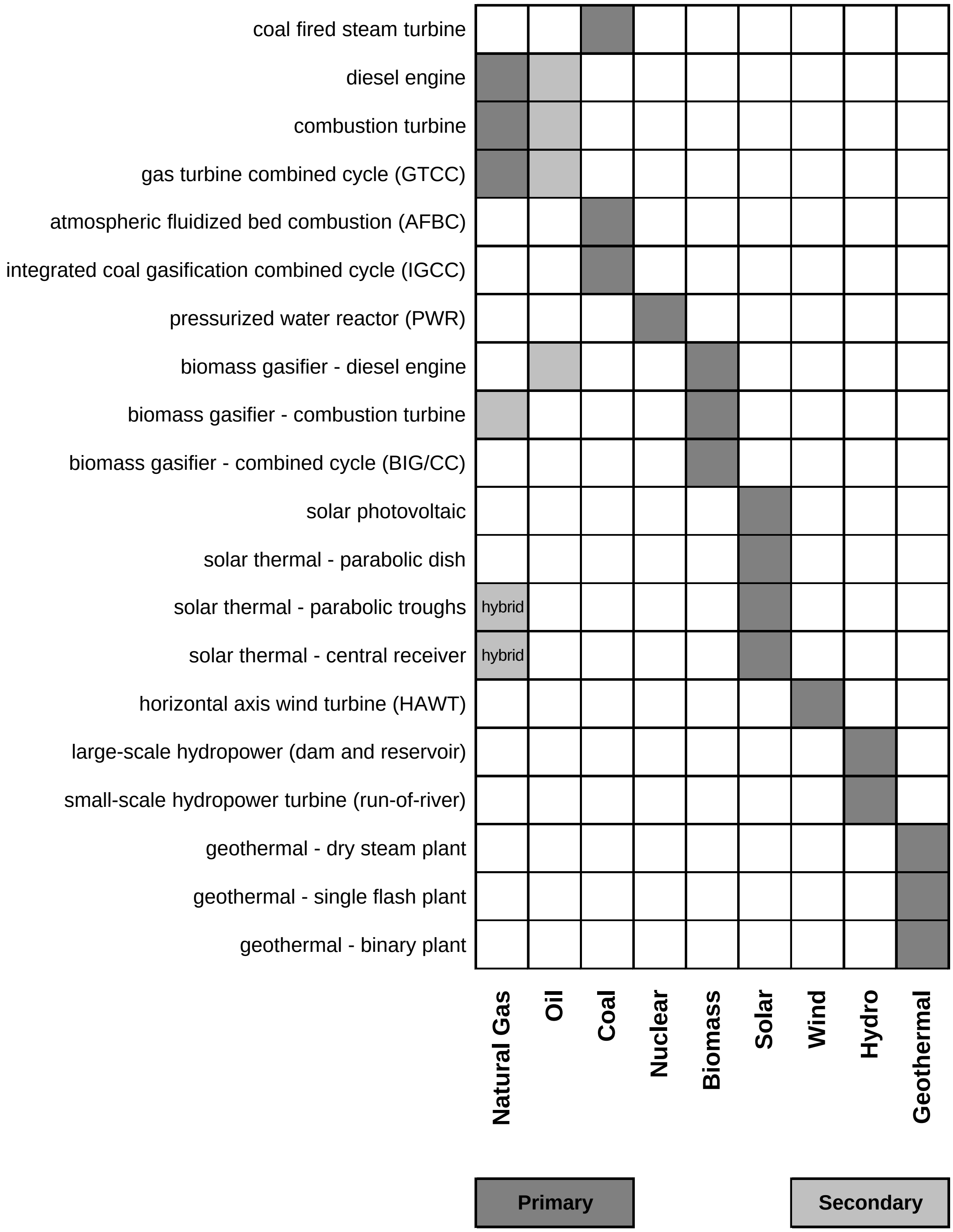


Chart 15 : CHP Options

coal-fired steam turbine	X
diesel engine	X
combustion turbine	X
gas turbine combined cycle (GTCC)	X
atmospheric fluidized bed combustion (AFBC)	X
integrated coal gasification combined cycle (IGCC)	X
pressurized water reactor (PWR)	X
biomass gasifier - diesel engine	X
biomass gasifier - combustion turbine	X
biomass gasifier - combined cycle (BIG/CC)	X
solar photovoltaic	
solar thermal - parabolic dish	
solar thermal - parabolic troughs	X
solar thermal - central receiver	X
horizontal axis wind turbine (HAWT)	
large-scale hydropower (dam and reservoir)	
small-scale hydropower turbine (run-of-river)	
geothermal - dry steam plant	X
geothermal - single flash plant	X
geothermal - binary plant	X

Chart 16 : Fuel Requirements



	Natural Gas	Oil	Coal	Nuclear	Biomass	Solar	Wind	Hydro	Geothermal
coal fired steam turbine			▓						
diesel engine	▓	░							
combustion turbine	▓	░							
gas turbine combined cycle (GTCC)	▓	░							
atmospheric fluidized bed combustion (AFBC)			▓						
integrated coal gasification combined cycle (IGCC)			▓						
pressurized water reactor (PWR)				▓					
biomass gasifier - diesel engine		░			▓				
biomass gasifier - combustion turbine	░				▓				
biomass gasifier - combined cycle (BIG/CC)					▓				
solar photovoltaic						▓			
solar thermal - parabolic dish						▓			
solar thermal - parabolic troughs	░ hybrid					▓			
solar thermal - central receiver	░ hybrid					▓			
horizontal axis wind turbine (HAWT)							▓		
large-scale hydropower (dam and reservoir)								▓	
small-scale hydropower turbine (run-of-river)								▓	
geothermal - dry steam plant									▓
geothermal - single flash plant									▓
geothermal - binary plant									▓

▓ **Primary**

░ **Secondary**

Chart 17 : Labor Requirements

	plant size MWe	**Number of personnel for O&M**		
		< 10	**10 - 30**	**> 30**
coal fired steam turbine	*100*	▓		░
diesel engine	*10*	░		
combustion turbine	*100*	░		
gas turbine combined cycle (GTCC)	*100*	▓	░	
atmospheric fluidized bed combustion (AFBC)	*100*	▓		░
integrated coal gasification combined cycle (IGCC)	*100*	▓		░
pressurized water reactor (PWR)	*150*		▓	░
biomass gasifier - diesel engine	*10*		░	
biomass gasifier - combustion turbine	*10*		░	
biomass gasifier - combined cycle (BIG/CC)	*10*	▓	░	
solar photovoltaic	*1*	░		
solar thermal - parabolic dish	*1*	░		
solar thermal - parabolic troughs	*50*	▓		░
solar thermal - central receiver	*100*		▓	░
horizontal axis wind turbine (HAWT)	*10*	▓	░	
large-scale hydropower (dam and reservoir)	*100*	▓	░	
small-scale hydropower turbine (run-of-river)	*50*	░		
geothermal - dry steam plant	*20*	▓	░	
geothermal - single flash plant	*20*	▓	░	
geothermal - binary plant	*20*	▓	░	

Skill Level : ░ **LOW** ▓ **HIGH**

Chart 18 : Modular Upgrade Capability

coal-fired steam turbine	
diesel engine	X
combustion turbine	X
gas turbine combined cycle (GTCC)	X
atmospheric fluidized bed combustion (AFBC)	X
integrated coal gasification combined cycle (IGCC)	X
pressurized water reactor (PWR)	
biomass gasifier - diesel engine	X
biomass gasifier - combustion turbine	X
biomass gasifier - combined cycle (BIG/CC)	X
solar photovoltaic	X
solar thermal - parabolic dish	X
solar thermal - parabolic troughs	
solar thermal - central receiver	
horizontal axis wind turbine (HAWT)	X
large-scale hydropower (dam and reservoir)	
small-scale hydropower turbine (run-of-river)	
geothermal - dry steam plant	X
geothermal - single flash plant	X
geothermal - binary plant	X

Chart 19 : Land Requirements

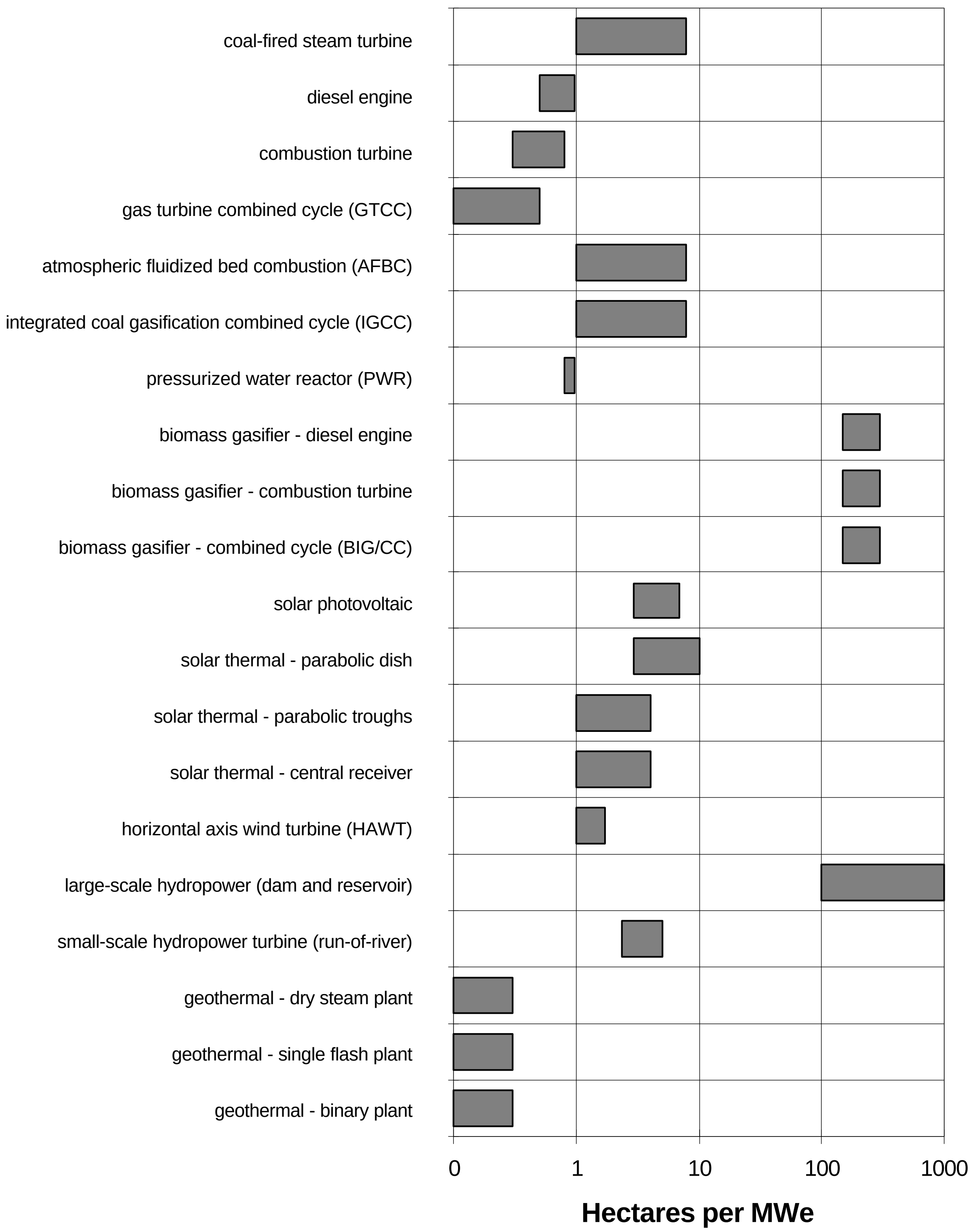


Chart 20 : Water Requirements

Water consumption (volume/MWh) :	**Low**	**Medium**	**High**
coal fired steam turbine		▨	
diesel engine	▨		
combustion turbine	▨		
gas turbine combined cycle (GTCC)		▨	
atmospheric fluidized bed combustion (AFBC)		▨	
integrated coal gasification combined cycle (IGCC)		▨	
pressurized water reactor (PWR)		▨	
biomass gasifier - diesel engine			▨
biomass gasifier - combustion turbine			▨
biomass gasifier - combined cycle (BIG/CC)			▨
solar photovoltaic	*none*		
solar thermal - parabolic dish	*none*		
solar thermal - parabolic troughs		▨	
solar thermal - central receiver		▨	
horizontal axis wind turbine (HAWT)	*none*		
large-scale hydropower (dam and reservoir)	▨		
small-scale hydropower turbine (run-of-river)	▨		
geothermal - dry steam plant		▨	
geothermal - single flash plant		▨	
geothermal - binary plant		▨	

Annex III : Technology Fact Sheets

The two-page fact sheets in this annex contain more detailed information on each of the technologies. All fact sheets are prepared using the data from tables in Annex I and references sources cited therein.

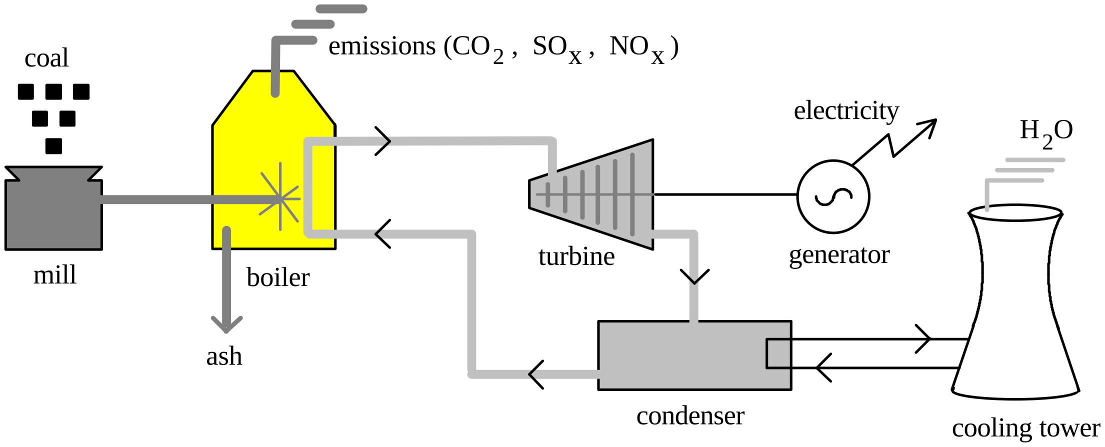
For information on how the technology data were complied and prepared, see Annex IV: *Technical and Economic Assumptions.*

Technology : coal-fired steam turbine

Fuel Type : pulverized coal (all grades)

Functioning :

Coal first enters a mill where it is pulverized into a fine powder (≤ 100µ diameter) to increase its surface area for efficient burning. The powdered coal is then injected as a suspension into the boiler combustion zone (furnace) where it is burned (at ≈ 1400 °C). The high temperatures convert feed water, in tubes in the boiler wall, into a high pressure steam. The steam is injected into a staged turbine unit thereby turning the generator to produce electricity. Low pressure steam leaving the turbine passes through the condenser (cooled by the cooling water system). Steam condensate from the condenser is the processed (deaerated and demineralized) and returned into the boiler as feed water. Emissions from the boiler stack are released into the atmosphere.



Performance

Capacity Range : 75 - 1000 MW

Furnace volumes as well as capacities for fuel and ash handling equipment are significantly higher in plants using low grade coals.

➔ Capacity of plant for which parameters are quoted : 300 MW

Operating Availability : 85%

The quoted figure is typical for plants in their first 20 years of plant life, but decreases in later years due to forced outages.

Duty Cycle : baseload

These plants are almost always run in a baseload duty cycle, an intermediate duty cycle is also possible but involves higher O&M costs and results in decreased plant life. Older plants are often run in intermediate duty cycles.

Capacity Factor : 70% (for baseload duty cycle)

Usually 40-60% in first two years of operation and typically 70% thereafter. Capacity factors may decrease significantly in later years of plant life (≥ 20 yrs) due to decreased plant efficiencies and forced outages.

Efficiency : 34%

This technology has efficiencies of scale; in larger capacity plants higher temperatures and larger furnace volumes permit slight gains in combustion efficiencies. This permits, for example, 500 MW plant efficiencies approaching 38%.

CO_2 output : 850 kg/MWh

This figure varies according to the plant's heat transfer efficiencies (furnace to boiler) and the grade of coal used. The quoted figure assumes no emissions scrubbing, cf. note 1.

Lead-time : 3 years

Lifetime : 30 years (average value)

Flexibility :

- capacity upgrades not possible
- duty cycle switches are possible (baseload and/or intermediate)
- emissions scrubbing to remove SO_X emissions from high sulphur content coals can be added (flue gas desulphurization, FGD)[1]

Direct Costs *@ 7% DCF*

	mills per KWh	*$ per KW of Capacity*
Capital	20	1,500
O&M	10	
Fuel	20	
Total	50	

Resource Implications

Major Inputs

- national coal supply and transport facilities
- high land requirements for plant site: 40 - 80 hectares
- labor pool with moderate technical skills

Major Outputs & Impacts

\+
- cheap, reliable, high-capacity power to fuel economies with access to coal
- high potential for job creation throughout the energy cycle

–
- high SO_X and NO_X emission levels causing local health hazards and acid rain
- high CO_2 emissions
- ash collection and disposal, sludge from feed water processing
- potential land degradation due to strip mining

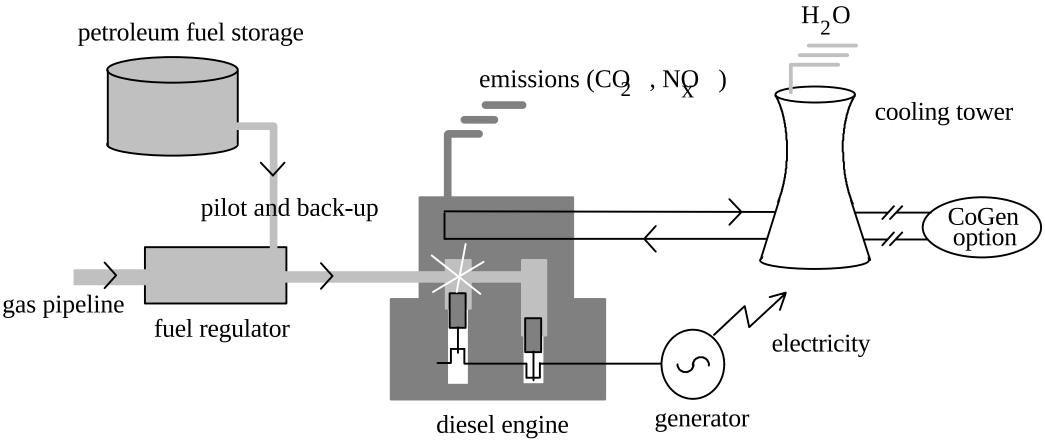
Notes: 1) capital and O&M costs rise with FGD, and plant efficiencies decline by about 20%. Accordingly, with FGD CO_2 output rises to about 1,000 kg/MWh

Technology : diesel engine

Fuel Type : natural gas *(can also be run on oil)*

Functioning :

Diesel engines are started on petroleum fuel (grade 2 or 3) from a pilot supply, and switched over to natural gas after start-up. Natural gas supplied from a pipeline enters the fuel regulator where its pressure is reduced to the level required for fuel injection into the engines cylinders. The regulator also controls the flow rate of gas so the engine runs at a desired power level. The combustion process drives pistons in the engine to turn a crankshaft. The rotating crankshaft is coupled to a generator for electricity production. Cooling water for the engine is recycled in a small cooling tower, or alternatively in a heat power cogeneration application supplying heat to nearby buildings (CoGen option in diagram). As an option petroleum fuel storage can be maintained at a high level for contingency operation during interruptions in gas supplied from the pipeline.



Performance

Capacity Range : 10 kW - 10 MW

➔ Capacity of plant for which parameters are quoted : 10 MW

Operating Availability : 95%

The quoted figure is typical for plants in their first 15 years of plant life, but decreases in later years due to forced outages.

Duty Cycle : intermediate or peaking

New diesel plants are usually run in an intermediate duty cycle. Older plants are often kept on stand-by providing on-demand power in a peaking duty cycle.

Capacity Factor : 40% (for intermediate duty cycle)

Full power operation is available immediately after installation.

Efficiency : 42%

When the option of cogeneration of heat and power is selected, overall efficiencies can approach 70%. Diesel engines can be run in a combined cycle mode coupled to a steam turbine, although this option results in only slightly higher efficiencies (≈ 45%).

CO_2 output [1] : 600 kg/MWh

Lead-time : 1/2 year

Lifetime : 30 years (in intermediate duty cycle)

Flexibility :

- engine runs on various grades of fuel permitting fuel switching (gas ⇔ oil)
- current technology permits biogas operation
- capacity upgrades are possible since design is modular
- two engines in tandem can provide baseload duty cycle coverage in remote application
- available option of cogeneration of heat and power
- duty cycle switches are possible (intermediate and/or peaking)

Direct Costs *@ 7% DCF*

	mills per KWh	*$ per KW of Capacity*
Capital	23	1,000
O&M	8	
Fuel	35	
Total	66	

Resource Implications

Major Inputs

- natural gas pipeline
- moderate land requirements for plant site: 5 hectares
- labor pool with minimal technical skills

Major Outputs & Impacts

\+
- ease and rapidity of installation
- well suited for distributed low load applications
- permits distributed job creation

–
- moderate CO_2 and NO_x emissions

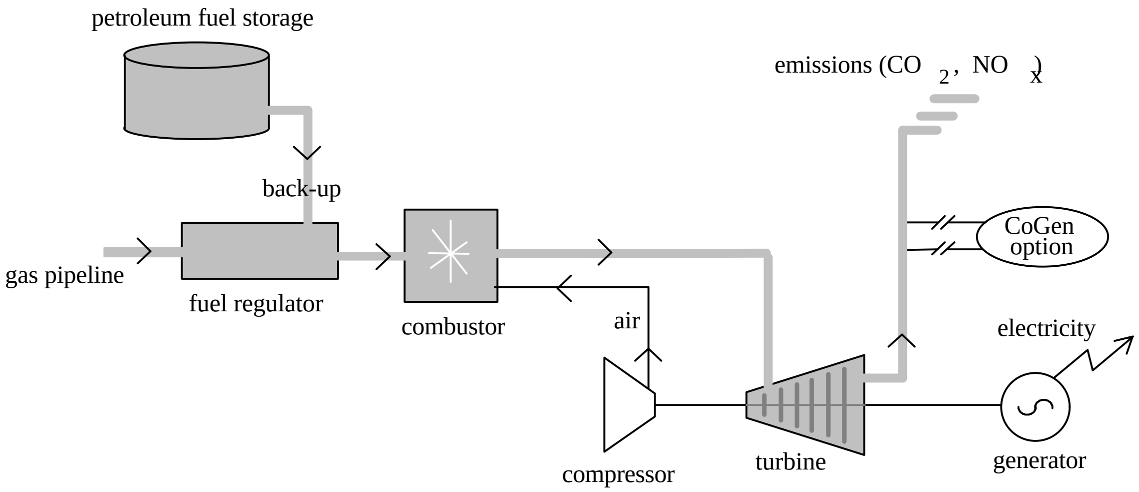
Notes: 1) The quoted figure is for a gas fueled plant. For a plant running on petroleum fuel the figure is 800 kg/MWh

Technology : combustion turbine (simple cycle)

Fuel Type : natural gas *(can also be run on oil)*

Functioning :

Natural gas supplied from a pipeline enters the fuel regulator where its pressure is reduced to the level required for fuel injection into the combustor. The regulator also controls the flow rate of gas so the turbine runs at a desired power level. Hot, high pressure gas from the combustor is injected into a staged turbine unit thereby turning the generator to produce electricity. The turbine also drives a compressor which provides high pressure gas to the combustor. As an option petroleum fuel storage can be maintained at a high level for contingency operation during interruptions in gas supplied from the pipeline.



Performance

Capacity Range : 500 kW - 250 MW

➔ Capacity of plant for which parameters are quoted : 100 MW

Operating Availability : 95%

The quoted figure is typical for plants in their first 20 years of plant life, but decreases in later years due to forced outages.

Duty Cycle : peaking

New simple cycle plants are usually run in a peaking duty cycle. Optionally they are sometimes run in an intermediate duty cycle.

Capacity Factor : 15% (for peaking duty cycle)

Full power operation is available immediately after installation.

Efficiency : 26%

Combustion turbines can be run in a combined cycle mode coupled to a steam turbine, this option results in substantially higher efficiencies (≈ 55%).

CO_2 output [1] : 800 kg/MWh

Lead-time : 1½ years

Lifetime : 30 years (in peaking duty cycle)

Flexibility :

- engine runs on various grades of fuel permitting fuel switching (gas ⇔ oil)
- current technology permits biogas operation
- capacity upgrades are possible since design is modular
- two turbines in tandem can provide baseload duty cycle coverage in remote application
- available option of cogeneration of heat and power
- duty cycle switches are possible (intermediate and/or peaking)

Direct Costs *@ 7% DCF*

	mills per KWh	*$ per KW of Capacity*
Capital	25	400
O&M	9	
Fuel	39	
Total	73	

Resource Implications

Major Inputs

- natural gas pipeline
- minimal land requirements for plant site: 2 hectares
- moderately skilled labor pool

Major Outputs & Impacts

\+
- ease and rapidity of installation
- minimal land-use impact due to compact plant design
- well suited for distributed applications
- permits distributed job creation

–
- relatively high CO_2 and NO_X emissions due to low efficiency

Notes:

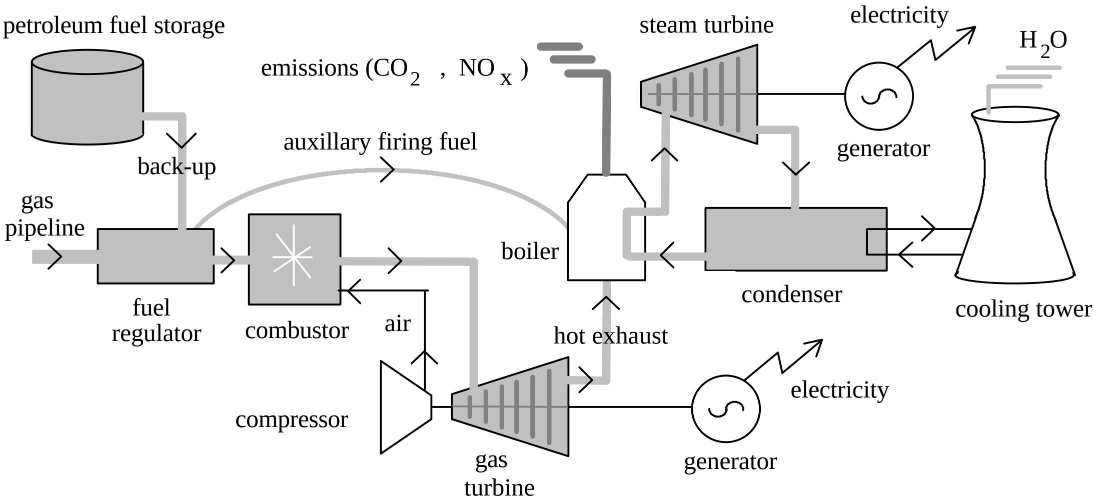
1) The quoted figure is for a gas fueled plant. For a plant running on petroleum fuel the figure is 1050 kg/MWh

Technology : gas turbine combined cycle (GTCC)

Fuel Type : natural gas *(can also be run on oil)*

Functioning : Gas and steam turbines running in series

Natural gas supplied from a pipeline enters the fuel regulator where its pressure is reduced to the level required for fuel injection into the combustor. The regulator also controls the flow rate of gas so the turbine runs at a desired power level. Hot, high pressure gas from the combustor is injected into a staged turbine unit thereby turning the generator to produce electricity. The turbine also drives a compressor which provides high pressure gas to the combustor. The hot exhaust gas from the combustion turbine passes through the boiler where its heat is used to generate steam. The steam is injected into a steam turbine unit thereby turning a second generator to produce electricity. Low pressure steam leaving the turbine passes through the condenser (cooled by the cooling water system). Steam condensate from the condenser is the processed (deaerated and demineralized) and returned into the boiler as feed water. Emissions from the boiler stack are released into the atmosphere. As an option petroleum fuel storage can be maintained at a high level for contingency operation during interruptions in gas supplied from the pipeline, and as an auxiliary firing fuel for the steam turbine boiler.



Performance

Capacity Range : 50 - 350 MW

➔ Capacity of plant for which parameters are quoted : 150 MW

Operating Availability : 90%

This figure is for full combined cycle operation. The figure for simple cycle operation of either the gas or steam turbines separately is higher (~ 98%)

Duty Cycle : baseload or intermediate

Combined cycle plants are usually run in a baseload duty cycle.

Capacity Factor : 70% (for baseload duty cycle)

Full power operation is available immediately after installation.

Efficiency : 55 %

Some plants report 58% efficiencies.

CO_2 output [1] : 440 kg/MWh

Lead-time : 3 years

Lifetime : 30 years (in baseload duty cycle)

Flexibility :

- plant runs on various grades of fuel permitting fuel switching (gas ⇔ oil)
- capacity upgrades are possible since design is modular
- duty cycle switches are possible (baseload and/or intermediate)

Direct Costs *@ 7% DCF*

	mills per KWh	*$ per KW of Capacity*
Capital	8	600
O&M	5	
Fuel	32	
Total	45	

Resource Implications

Major Inputs

- natural gas pipeline
- moderate land requirements for plant site: 5 hectares
- highly skilled labor pool

Major Outputs & Impacts

\+
- low CO_2 and NO_x emissions due to high efficiency
- minimal land-use impact due to compact plant design
- modularity is well suited for applications with service area growth
- provides low-cost baseload power

–
- as a state-of-the-art technology, GTCC systems require advanced technical support

Notes:

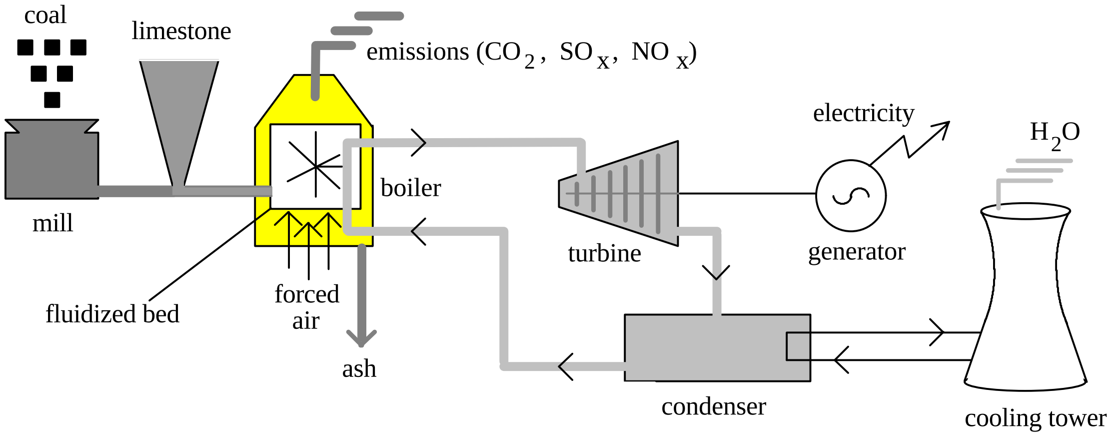
1) The quoted figure is for a gas fueled plant. For a plant running on petroleum fuel the figure is 590 kg/MWh

Technology : atmospheric fluidized bed combustion (AFBC)

Fuel Type : pulverized coal (all grades)

Functioning :

Coal first enters a mill where it is pulverized into a fine powder (≤ 100µ diameter) to increase its surface area for efficient burning, and then mixed with a limestone powder. The powder mixture is injected into the boiler where it comes in direct contact with preheated forced air from the boiler bottom forming a 'bed'. Subsequent burning in the boiler furnace is slightly more efficient than conventional coal-fired steam plants due to the presence of the heated limestone particles, and more uniform, due to the well-mixed fluidlike properties of the bed. This results in lowered SO_X and NO_X during combustion. The high boiler temperatures convert feed water, in tubes in the boiler wall, into a high pressure steam. The steam is injected into a staged turbine unit thereby turning the generator to produce electricity. Low pressure steam leaving the turbine passes through the condenser (cooled by the cooling water system). Steam condensate from the condenser is the processed (deaerated and demineralized) and returned into the boiler as feed water. Emissions from the boiler stack are released into the atmosphere.



Performance

Capacity Range : 100 - 400 MW

➔ Capacity of plant for which parameters are quoted : 100 MW

Operating Availability : 85%

The quoted figure is typical for plants in their first 20 years of plant life, but decreases in later years due to forced outages.

Duty Cycle : baseload

These plants are almost always run in a baseload duty cycle, an intermediate duty cycle is also possible but involves higher O&M costs and results in decreased plant life.

Capacity Factor : 70% (for baseload duty cycle)

Usually 40-60% in first two years of operation and typically 70% thereafter. Capacity factors may decrease significantly in later years of plant life (≥ 20 yrs) due to decreased plant efficiencies and forced outages.

Efficiency : 34%

Similar to conventional coal-fired steam plants without emissions scrubbing.

CO_2 output : 850 kg/MWh

Highly fuel dependent. Quoted figure assumes bituminous coal.

Lead-time : 3 years

Lifetime : 30 years (average value)

Flexibility :

- operates burning a wide variety of coals
- capacity upgrades are possible
- duty cycle switches are possible (baseload and/or intermediate)

Direct Costs *@ 7% DCF*

	mills per KWh	*$ per KW of Capacity*
Capital	22	1,700
O&M	13	
Fuel	20	
Total	55	

Resource Implications

Major Inputs

- national coal supply and transport facilities
- high land requirements for plant site: 40 - 80 hectares
- labor pool with moderate technical skills

Major Outputs & Impacts

\+
- emissions scrubbing (flue gas desulphurization, FGD) is not required[1]
- low SO_X and NO_X emission levels reducing local health hazards and acid rain
- cheap, reliable, high-capacity power to fuel economies with access to coal
- high potential for job creation throughout the energy cycle

–
- high CO_2 emissions
- collection and disposal of carbon fly ash from flue and calcium-sulphur ash from bed, sludge from feed water processing
- potential land degradation due to strip mining

Notes:

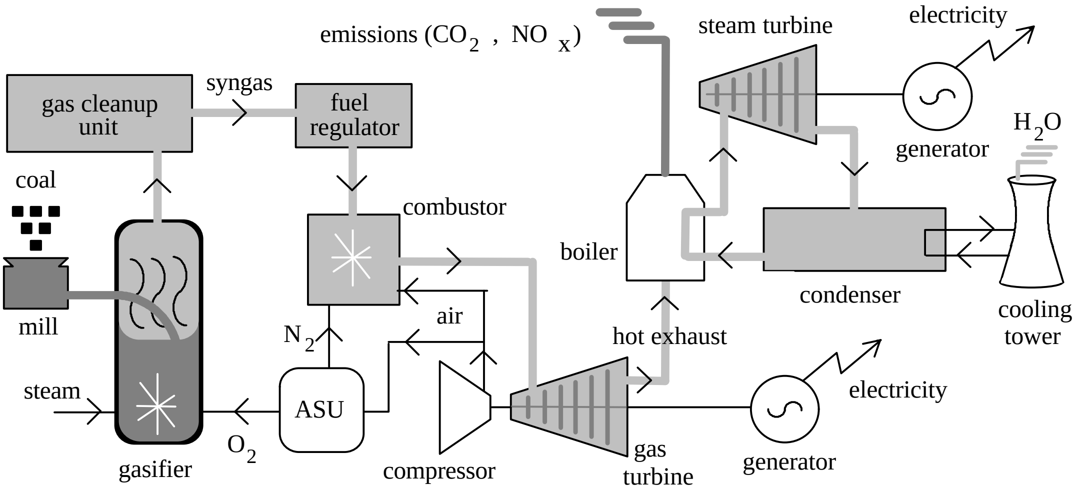
1) Relative to conventional coal-fired steam plants, AFBC plants have lowered emissions of SO_X and NO_X , therefore, emissions scrubbing is not required.

Technology : integrated gasification combined cycle (IGCC)

Fuel Type : coal

Functioning : Gas and steam turbines running in series

Coal, pulverized and dried in the mill, is passed under pressure to the gasifier. along with pressurized oxygen, prepared in the air separation unit (ASU). In the gasifier coal comes in contact with steam and oxygen prompting thermochemical reactions that produce a fuel gas. In the gas cleanup unit, solid particulates and sulphur are removed from the gas to produce a clean 'syngas'. From the fuel regulator the syngas is injected into the combustor along with nitrogen (for NO_X emission control) from the ASU. Hot, high pressure gas from the combustor is injected into a gas turbine unit therby turning the generator to produce electricity. The turbine also drives a compressor providing high pressure air to the combustor and ASU. The hot exhaust gas from the combustion turbine passes through the boiler where its heat is used to generate steam. The steam is injected into a steam turbine unit thereby turning a second generator to produce electricity. Low pressure steam leaving the turbine passes through the condenser (cooled by the cooling water system). Steam condensate from the condenser is the processed (deaerated and demineralized) and returned into the boiler as feed water. Emissions from the boiler stack are released into the atmosphere.



Performance

Capacity Range : 50 - 350 MW

➔ Capacity of plant for which parameters are quoted : 100 MW

Operating Availability : 85%

Duty Cycle : baseload

Intensive start-up and shut-down procedures preclude intermediate duty cycle operation.

Capacity Factor : 70% (for baseload duty cycle)

Full power operation is available immediately after installation.

Efficiency : 42 %

technological advances should permit 50% efficiencies within the next 10 years.

CO_2 output : 800 kg/MWh

Lead-time [1] : 4-6 years

Lifetime : 30 years (in baseload duty cycle)

Flexibility :

- gasification process accepts a wide variety of coals
- capacity upgrades are possible since design is modular

Direct Costs *@ 7% DCF*

	mills per KWh	*$ per KW of Capacity*
Capital	22	1,650
O&M	12	
Fuel	18	
Total	52	

Resource Implications

Major Inputs

- national coal supply and transport facilities
- high land requirements for plant site: 40 - 80 hectares
- labor pool with moderate technical skills

Major Outputs & Impacts

\+
- emissions scrubbing (flue gas desulphurization, FGD) is not required
- negligible emission levels of SO_X and NO_X (avoidance of local health hazards and acid rain); the best performing coal technology in this regard
- clean high-capacity power to fuel economies with access to coal
- high potential for job creation throughout the energy cycle

–
- high CO_2 emissions
- collection and disposal of carbon ash, sulphur, and tar residues from the gasifier and gas cleanup unit; sludge from feed water processing
- potential land degradation due to strip mining
- as a state-of-the-art technology, GTCC systems require advanced technical support

Notes:

1) Lead times are long, and somewhat uncertain, as this technology has only just become commercial.

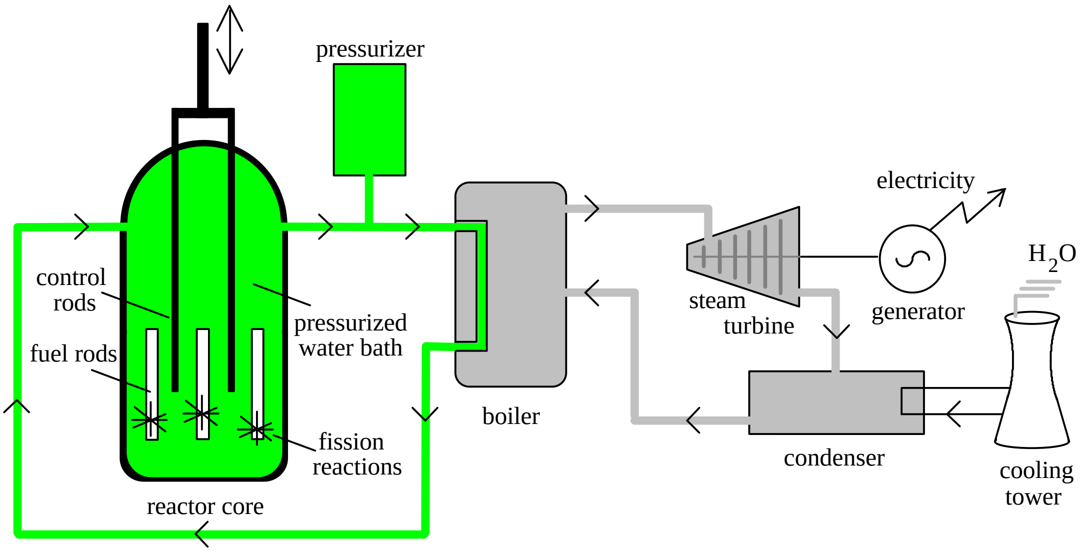
Technology : pressurized water reactor (PWR)

Fuel Type : enriched uranium dioxide (UO_2)

Functioning :

Enriched UO_2 fuel rods are placed in a pressurized water bath within the reactor core. Unstable uranium atoms (U_{235} isotopes) in the fuel readily undergo radioactive decay emitting energetic neutrons that leave the fuel rod and enter the water bath. The water bath (moderator) acts to slow down the neutrons so that they more effectively prompt a nuclear reaction, called fission, when they collide with uranium atoms in nearby fuel cells. During fission, uranium atoms are transformed into other radioactive elements as they emit energetic neutrons and heat energy. The neutrons emitted contribute to sustained fission in the reactor core. Within the core, control rods that absorb neutrons, can be raised and lowered to control levels of fission activity.

The released heat energy from fission generates high temperatures in the circulating water bath, which remains in a liquid state due to its high pressure. In the boiler, this heated water generates steam in an independent steam circuit. After transferring its heat to the steam circuit, the water is returned to the reactor core. Steam from the boiler is injected into a staged turbine unit therby turning the generator to produce electricity. Low pressure steam leaving the turbine passes through the condenser (cooled by the cooling water system). Steam condensate from the condenser is the processed (deaerated and demineralized) and returned into as feed water for the steam circuit. Wastes from the plant include condenser sludge, emissions of low-level radioactive gas, and radioactive spent fuel rods that must be stored or reprocessed.



Performance

Capacity Range : 150 - 1000 MW

➔ Capacity of plant for which parameters are quoted : 300 MW

Operating Availability : 80%

Duty Cycle : baseload

Capacity Factor : 70%

Efficiency : N/A

CO_2 output [1] : None

Lead-time : 5 years

Lifetime : 30 years (average value)

Flexibility :

- capacity upgrades not possible
- spent fuel rods can be reprocessed
- power cogeneration is possible using steam circuit

Direct Costs *@ 7% DCF*

	mills per KWh	*$ per KW of Capacity*
Capital	25	2,000
O&M	14	
Fuel	8	
Total	47	

Resource Implications

Major Inputs

- enriched uranium dioxide fuel
- moderate land requirements for plant site: 5-10 hectares
- labor pool with extremely high technical skills

Major Outputs & Impacts

\+
- cheap, reliable, high-capacity power to fuel economies without low-cost access to fossil fuels and without availability of hydropower or other renewable resources
- steam circuit for power generation is not in direct contact with reactor core
- no CO_2, SO_x or NO_x emissions

–
- not suited for regions prone to flooding, seismic and/or volcanic activity
- disposal problem for highly radioactive spent fuel rods
- major plant accident can have serious and widespread consequences

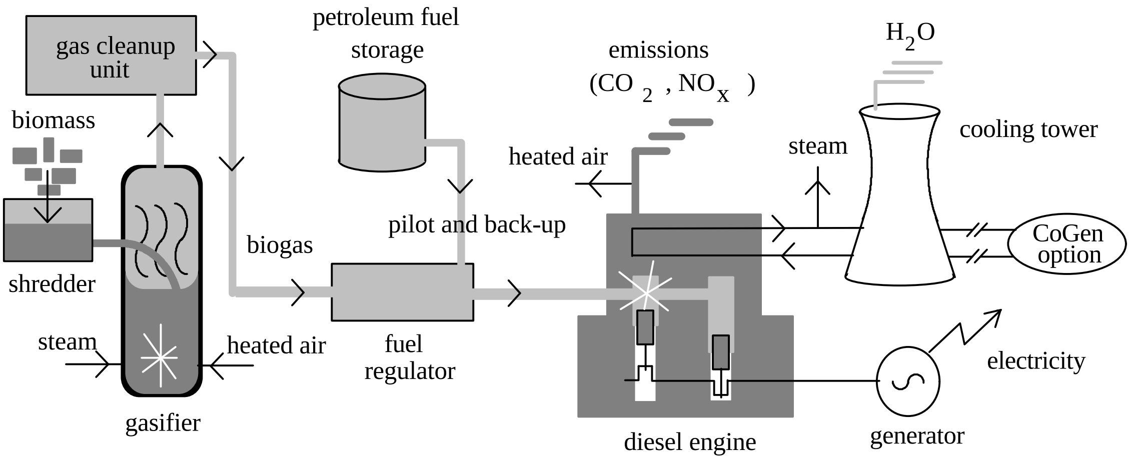
Notes: 1) During normal operation no CO_2 is emitted by the plant. Some emissions are present during start-up procedures if a fossil fuel fired heater is used to initially pressurize the reactor bath water (electric heaters are most often used).

Technology : biomass gasifier / diesel engine

Fuel Type : biomass (wood, agricultural waste, landfill gas)

Functioning :

Biomass (wood and agrowaste) is fed into a shredder to reduce particle size distribution to a level acceptable by the gasifier (usually 1-10 millimeter size particles). In the gasifier biomass particles come in contact with steam and preheated process air prompting thermochemical reactions that produce a biogas (in landfill gas applications, biogas is directly tapped from the landfill site). In the gas cleanup unit, solid particulates and tar residues are removed from the gas. This clean biogas enters the fuel regulator where its pressure is reduced to the level required for fuel injection into the engines cylinders. The regulator also controls the flow rate of gas so the engine runs at a desired power level. The combustion process drives pistons in the engine to turn a crankshaft. The rotating crankshaft is coupled to a generator for electricity production. Cooling water for the engine is recycled in a small cooling tower, or alternatively in a heat power cogeneration application supplying heat to nearby buildings (CoGen option in diagram). Diesel engines are started on petroleum fuel from a pilot supply and switched over to natural gas after start-up, thus, as an option, petroleum fuel storage can be maintained at a high level for contingency operation during interruptions in biogas supply.



Performance

Capacity Range : 10 kW - 10 MW

Capacities are limited by the rate at which biogas can be produced by the gasifier.

➔ Capacity of plant for which parameters are quoted : 1 MW

Operating Availability : 90%

Duty Cycle : intermediate or peaking

New diesel plants are usually run in an intermediate duty cycle. Older plants are often kept on stand-by providing on-demand power in a peaking duty cycle.

Capacity Factor : 40% (for intermediate duty cycle)

Full power operation is available immediately after installation.

Efficiency : 30%

Efficiencies are low relative to natural gas fired diesel operation, due to the lower energy and higher moisture content of biogas. When the option of cogeneration of heat and power is selected, overall efficiencies can approach 50%.

CO_2 output [1] : 0 kg/MWh

Lead-time : 1 year

Lifetime : 30 years (in intermediate duty cycle)

Flexibility :

- gasifier digests various biomass sources
- capacity upgrades are possible since design is modular; both gasifiers and engines can be added to a plant for enhanced capacity
- two engines in tandem can provide baseload duty cycle coverage in remote application
- available option of cogeneration of heat and power
- duty cycle switches are possible (intermediate and/or peaking)

Direct Costs *@ 7% DCF*

	mills per KWh	*$ per KW of Capacity*
Capital	30	1,300
O&M	10	
Fuel	24	(assumes biomass cost of 2$ / GJ)
Total	64	

Resource Implications

Major Inputs

- sufficient biomass supply within 100 km radius for economical transport
- high land requirements for plant and biomass source sites: ~ 200 hectares/MW
- labor pool with minimal technical skills

Major Outputs & Impacts

\+
- ease and rapidity of installation
- well suited for distributed low load applications (remote, off-grid)
- permits distributed job creation
- no net CO_2 emissions
- minimal SO_X emissions

–
- moderate NO_X emissions
- improper land management can lead to deforestation, desertification

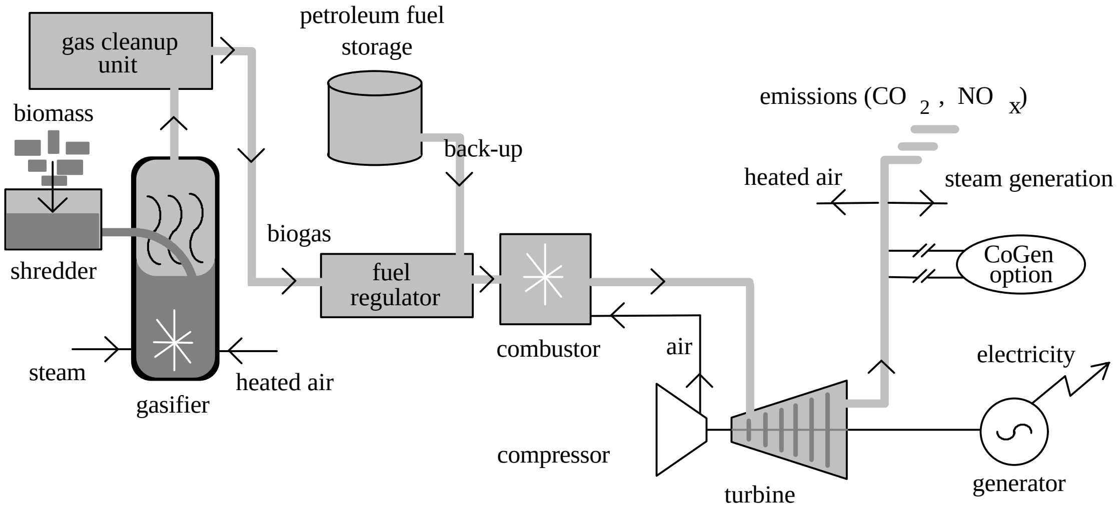
Notes: 1) When run in a sustainable manner; i.e., full regeneration of the biomass source occurs, biomass burning produces zero net CO_2 emissions. The emission figure for the case where no regeneration occurs is about 800 kg/MWh

Technology : combustion turbine (simple cycle)

Fuel Type : biomass (wood, agrowaste, landfill gas)

Functioning :

Biomass (wood and agrowaste) is fed into a shredder to reduce particle size distribution to a level acceptable by the gasifier (usually 1-10 millimeter size particles). In the gasifier biomass particles come in contact with steam and preheated process air prompting thermochemical reactions that produce a biogas (in landfill gas applications, biogas is directly tapped from the landfill site). In the gas cleanup unit, solid particulates and tar residues are removed from the gas. This clean biogas enters the fuel regulator where its pressure is raised to the level required for fuel injection into the combustor. The regulator also controls the flow rate of gas so the turbine runs at a desired power level. Hot, high pressure gas from the combustor is injected into a staged turbine unit therby turning the generator to produce electricity. The turbine also drives a compressor which provides high pressure air to the combustor. As an option petroleum fuel or natural gas can be used for contingency operation during interruptions in biogas supply.



Performance

Capacity Range : 500 kW - 100 MW

Capacities are limited by the rate at which biogas can be produced by the gasifier.

➔ Capacity of plant for which parameters are quoted : 10 MW

Operating Availability : 90%

The quoted figure is typical for plants in their first 20 years of plant life, but decreases in later years due to forced outages.

Duty Cycle : peaking

New simple cycle plants are usually run in a peaking duty cycle. Optionally they are sometimes run in an intermediate duty cycle.

Capacity Factor : 15% (for peaking duty cycle)

Full power operation is available immediately after installation.

Efficiency : 22%

Efficiencies are low relative to natural gas fired turbine operation, due to the lower energy and higher moisture content of biogas. When the option of cogeneration of heat and power is selected, overall efficiencies can approach 60%. Combustion turbines can also be run in a combined cycle mode coupled to a steam turbine, this option results in substantially higher efficiencies (≈ 45%).

CO_2 output [1] : 0 kg/MWh

Lead-time : 1½ years

Lifetime : 30 years (in peaking duty cycle)

Flexibility :

- gasifier digests various biomass sources
- capacity upgrades are possible since design is modular; both gasifiers and turbines can be added to a plant for enhanced capacity
- two turbines in tandem can provide baseload duty cycle coverage in remote application
- available option of cogeneration of heat and power
- duty cycle switches are possible (intermediate and/or peaking)

Direct Costs *@ 7% DCF*

	mills per KWh	*$ per KW of Capacity*
Capital	50	700
O&M	12	
Fuel	33	(assumes biomass cost of 2$ / GJ)
Total	95	

Resource Implications

Major Inputs

- sufficient biomass supply within 100 km radius for economical transport
- high land requirements for plant and biomass source sites: ~ 200 hectares/MW
- labor pool with minimal technical skills

Major Outputs & Impacts

\+
- ease and rapidity of installation
- well suited for distributed low load applications (remote, off-grid)
- permits distributed job creation
- no net CO_2 emissions
- minimal SO_x emissions

–
- moderate NO_x emissions
- improper land management can lead to deforestation, desertification

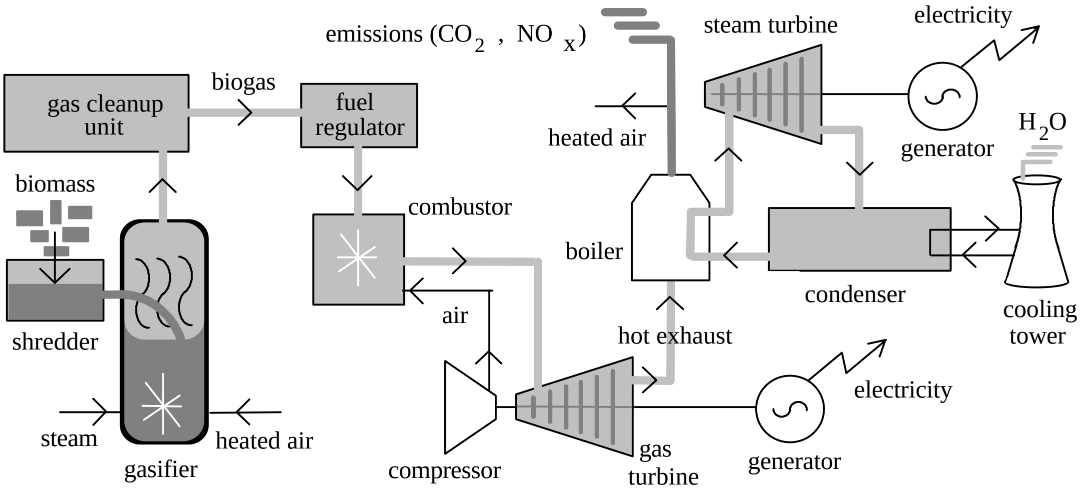
Notes: 1) When run in a sustainable manner; i.e., full regeneration of the biomass source occurs, biomass burning produces zero net CO_2 emissions. The emission figure for the case where no regeneration occurs is about kg/MWh

Technology : biomass gasifier/combined cycle (BIG/CC)

Fuel Type : biomass (wood, agrowaste, landfill gas)

Functioning : Gas and steam turbines running in series

Biomass (wood and agrowaste) is fed into a shredder to reduce particle size distribution to a level acceptable by the gasifier (usually 1-10 millimeter size particles). In the gasifier biomass particles come in contact with steam and preheated process air prompting thermochemical reactions that produce a biogas (in landfill gas applications, biogas is directly tapped from the landfill site). In the gas cleanup unit, solid particulates and tar residues are removed from the gas. This clean biogas enters the fuel regulator where its pressure is raised to the level required for fuel injection into the combustor. The regulator also controls the flow rate of gas so the turbine runs at a desired power level. From the fuel regulator the biogas is injected into the combustor along with pressurized air from the compressor. Hot, high pressure gas from the combustor is injected into a gas turbine unit therby turning the generator to produce electricity. The hot exhaust gas from the combustion turbine passes through the boiler where its heat is used to generate steam. The steam is injected into a steam turbine unit thereby turning a second generator to produce electricity. Low pressure steam leaving the turbine passes through the condenser (cooled by the cooling water system). Steam condensate from the condenser is the processed (deaerated and demineralized) and returned into the boiler as feed water. Emissions from the boiler stack are released into the atmosphere. As an option petroleum fuel or natural gas can be used for contingency operation during interruptions in biogas supply.



Performance

Capacity Range : 10 - 50 MW

Capacities are limited by the rate at which biogas can be produced by the gasifier.

➔ Capacity of plant for which parameters are quoted : 25 MW

Operating Availability : 85%

Duty Cycle : baseload

Capacity Factor : 70%

Efficiency : 35 %

technological advances should permit 45 % efficiencies within the next 10 years.

CO_2 output [1] : 0 kg/MWh

Lead-time : 2-3 years

Lifetime : 30 years

Flexibility :

- gasifier digests various biomass sources
- capacity upgrades are possible since design is modular; both gasifiers and turbines can be added to a plant for enhanced capacity

Direct Costs *@ 7% DCF*

	mills per KWh	*$ per KW of Capacity*
Capital	21	1,300
O&M	36	
Fuel	20	(assumes biomass cost of 2$ / GJ)
Total	77	

Resource Implications

Major Inputs

- sufficient biomass supply within 100 km radius for economical transport
- high land requirements for plant and biomass source sites: ~ 200 hectares/MW
- highly skilled labor pool

Major Outputs & Impacts

\+
- permits distributed job creation
- no net CO_2 emissions
- minimal SO_X emissions

–
- moderate NO_X emissions
- improper land management can lead to deforestation, desertification
- as a state-of-the-art technology, GTCC systems require advanced technical support

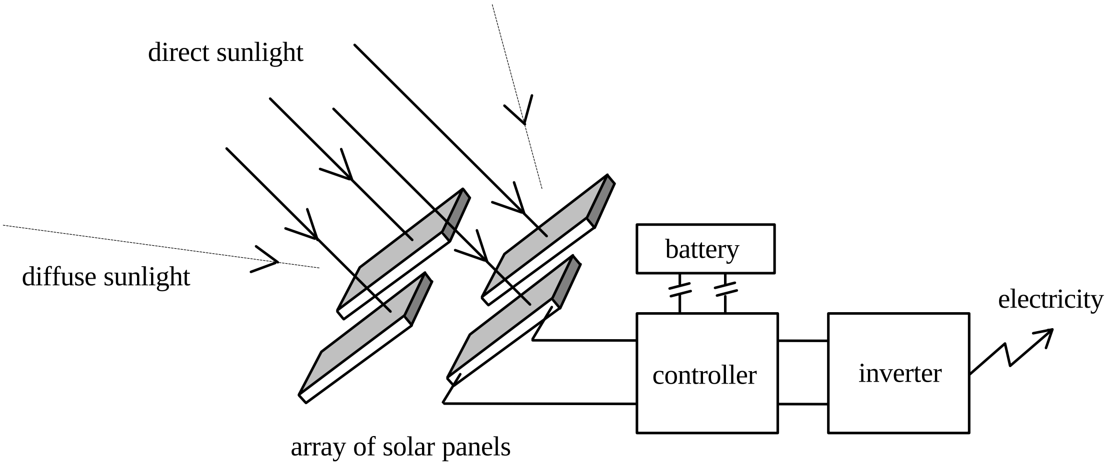
Notes: 1) When run in a sustainable manner; i.e., full regeneration of the biomass source occurs, biomass burning produces zero net CO_2 emissions. The emission figure for the case where no regeneration occurs is about 700 kg/MWh

Technology : solar photovoltaic (PV)

Fuel Type : solar radiation

Functioning :

Direct and diffuse solar radiation in the optical spectrum (sunlight) is absorbed by the semiconductor surface of flat plate solar photovoltaic (PV) cells (~ 10 cm dia.). Cells are mounted in series on flat panels oriented towards the mid-day position of the sun. These solar panels are arranged in a multi-panel array. Depending on the semiconductor material employed in the cell, 10-30% of the energy in incident sunlight is converted into electrical energy. Electricity thus produced flows in a direct current circuit to an inverter which converts it to alternating current (90% efficient) for output to the user or to the grid. Alternatively, a battery can be installed within the direct current circuit for storage, with conversion to alternating current at a later time.



Performance

Capacity Range : 100 W - 1 MW

Although in principle, there is no upper limit to plant size, the current high cost of solar cells limits and their inherent intermittency of power output, limits sizes to niche application needs (remote off-grid low power applications). Typical yields from solar panels are on the order of ***0.6 to 1.2 kWh/m^2 per day*** for high- to low-latitude sites respectively.

➔ Capacity of plant for which parameters are quoted : 1 MW

Operating Availability : 100%

Without any moving parts or maintenance needs (except for battery), solar PV plants have a full 100% operating availability.

Duty Cycle : intermittent

These plants run whenever sunlight is present. Battery storage permits power delivery at other times of the day. Intermediate and peaking duty cycles are possible.

Capacity Factor : 40%

On average, for PV plants in optimal locations.

Efficiency : 10-20%

Here efficiency is the amount of energy produced by the plant relative to the flux of solar energy received by the array. Cells based on some semiconductor materials do experience efficiency degradation over time. This technology has no efficiencies of scale.

CO_2 output : 0 kg/MWh

Lead-time : 2 years (for a 1 MW plant)

Lifetime : 30 years (most cells degrade with age)

Flexibility :

- capacity upgrades possible by adding solar panels to array
- duty cycle switches are possible (intermediate and/or peaking)
- battery storage option permits continuous power supply in some applications

Direct Costs *@ 7% DCF*

	mills per KWh	*$ per KW of Capacity*
Capital	184	8,000
O&M	7	
Fuel	0	
Total	191	

Resource Implications

Major Inputs

- high land requirements for plant site: 3-7 hectares per MW
- labor pool with moderate technical skills

Major Outputs & Impacts

\+
- emissions free power with zero cost, easily accessible primary energy source
- provides job creation for production and installation (high), and operations & maintenance (low)

–
- high capital costs and intermittency prohibit use as a primary baseload option
- high adoption costs for remote communities
- generating costs are high compared to fossil fuel power generation

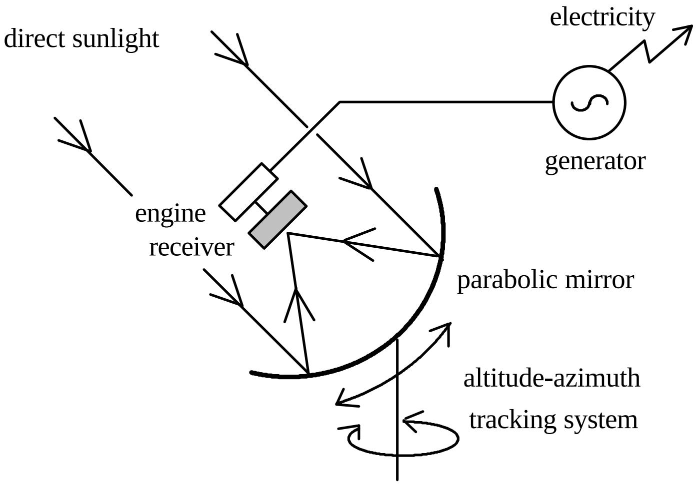
Notes:

Technology : solar thermal - parabolic dish

Fuel Type : solar radiation

Functioning :

Direct solar radiation in the optical spectrum (sunlight) is focused by a circular parabolic mirror to a central receiver. Solar radiation absorbed by the receiver causes it to heat. This heat energy is transmitted to a stirling engine.[1] The engine works with a closed volume of air in a dual piston arrangement. Shaft energy from the engine is converted to electricity by a generator. A two-axis tracking system (altitude and azimuth) is employed to keep the parabolic mirror pointed directly at the sun during the course of the day. As an option, a rectifier/battery/inverter storage unit can be combined with the system.



Performance

Capacity Range : 5 - 25 kW

Stated capacity range is for single units. Application is expected to be single dish operation in stand-alone remote sites. It is possible to install an array of dishes to create a *'dish farm'* power plant.

➔ Capacity of unit for which parameters are quoted : 5 kW

Operating Availability : 95%

Duty Cycle : intermittent

Dish units run whenever sufficient sunlight is present. Optional rectifier/battery/inverter storage units permit power delivery at other times of the day. Intermediate and peaking duty cycles are possible.

Capacity Factor : 40%

On average, for dish units in optimal locations.

Efficiency : 20 - 30%

Here efficiency is the amount of energy produced by the plant relative to the flux of solar energy received by the dish. There are no efficiencies of scale for multi-dish operation.

CO_2 output : 0 kg/MWh

Lead-time : ½ year

Off-the-shelf units are just becoming commercial.

Lifetime : N/A

Sterling engines last about 10 years, and are maintenance free.

Flexibility :

- capacity upgrades possible by adding dishes to create an array
- duty cycle switches are possible (intermediate and/or peaking)
- battery storage option permits continuous power supply in some applications

Direct Costs *@ 7% DCF*

	mills per KWh	*$ per KW of Capacity*
Capital	47	1,500
O&M	7	
Fuel	0	
Total	54	est: Solar Energy Research Institute

Resource Implications

Major Inputs

- site with good insolation
- moderate land requirements for plant site: 2-4 hectares per MW
- labor pool with moderate technical skills

Major Outputs & Impacts

\+
- emissions free power with zero cost & easily accessible primary energy source
- provides job creation for production and installation (high), and operations & maintenance (low)
- low capital costs
- generating costs are compare well with those for fossil fuel power generation

–
- intermittency of power supply
- may not be well suited to large-scale array based power generation, field tests will indicate feasibility

Notes:

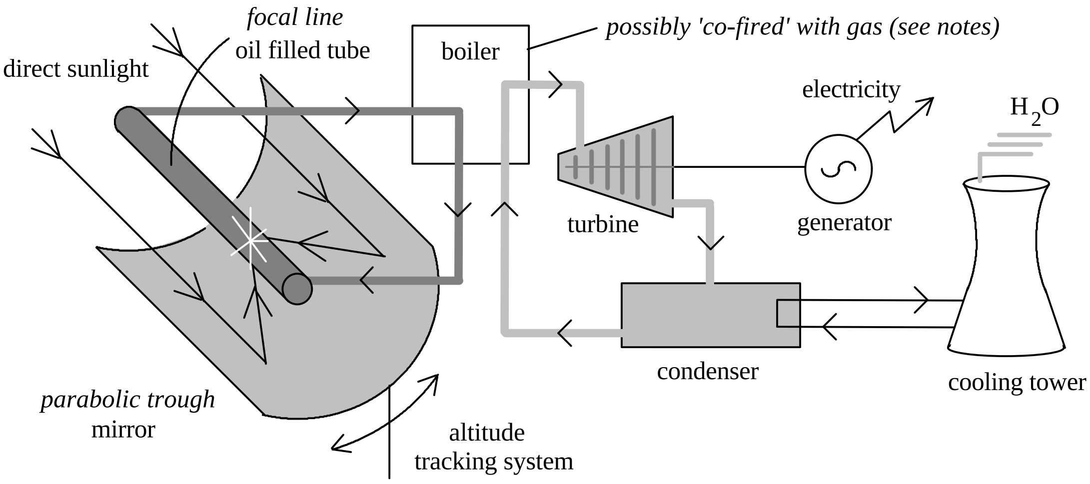
1) Alternatively, a working fluid can be heated at the receiver to run a steam turbine as is done for parabolic trough technologies, and with high efficiency since dish units can generate steam temperatures of 800 - 1,500 °C.

Technology : solar thermal - parabolic troughs

Fuel Type : solar radiation

Functioning :

Solar radiation in the optical spectrum (sunlight) is focused by a series of linear parabolic mirrors to their common central focal line, where a working fluid passes. Oil, which retains heat very well, is usually used as the working fluid. The oil passes along the focal line in a tube. Solar radiation absorbed by the tube causes the oil to heat. After passing along the length of the trough (~ 100 meters in length), continually heating along the way, the working fluid enters a boiler unit where its heat energy is transmitted to water to generate steam.[1] The steam is injected into a staged turbine unit therby turning the generator to produce electricity. Low pressure steam leaving the turbine passes through the condenser (cooled by the cooling water system). Steam condensate from the condenser is the processed (deaerated and demineralized) and returned into the boiler as feed water. Plants can employ several troughs for increased capacity. A single-axis tracking system (altitude) is employed to keep the parabolic mirror pointed at the solar inclination angle during the course of the day.



Performance

Capacity Range : 1 - 100 MW

➔ Capacity of plant for which parameters are quoted : 80 MW

Operating Availability : 95%

Duty Cycle : intermittent

These plants run whenever sufficient sunlight is present. Optional high capacity rectifier/battery/inverter storage units can permit power delivery at other times of the day. Intermediate and peaking duty cycles are possible.

Capacity Factor : 40%

On average, for plants in optimal locations.

Efficiency : 10 - 20%

Here efficiency is the amount of energy produced by the plant relative to the flux of solar energy received by the trough. Low efficiencies result from low temperatures of product steam (400-800 °C) relative to temperatures required for optimal turbine efficiency (1,400 °C). There are no efficiencies of scale for multi-trough operation.

CO_2 output [2] : 0 kg/MWh (assuming no gas co-firing)

Lead-time : 2 years

Lifetime : 30 years

Flexibility :

- duty cycle switches are possible (intermediate and/or peaking)

Direct Costs *@ 7% DCF*

	mills per KWh	*$ per KW of Capacity*
Capital	69	3,000
O&M	15	
Fuel[3]	0	
Total	84	

Resource Implications

Major Inputs

- site with good insolation
- moderate land requirements for plant site: 2-4 hectares per MW
- labor pool with moderate technical skills

Major Outputs & Impacts

\+
- emissions free power with zero cost & easily accessible primary energy source
- provides high job creation for production, installation and operation & maintenance
- low capital costs

–
- intermittency of power supply
- can supply electricity directly to the grid
- generating costs are high compared to fossil fuel power generation

Notes:

1) A gas fired superheater is often used supplementally, during normal operation, to raise steam temperatures for increased turbine efficiency; this is called gas co-firing.

2) For a hybrid plant with gas fired superheaters, CO_2 emissions will be significant.

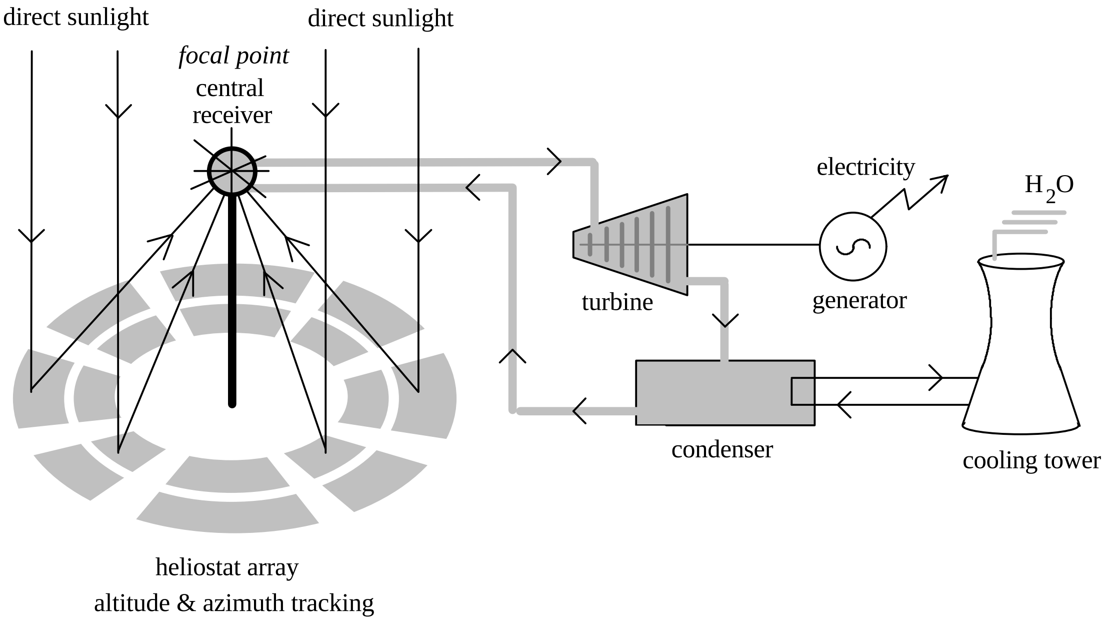
3) For a hybrid plant with gas fired superheaters, fuel costs per kWh are 9 mills bringing total generation cost to 93 mills per kWh.

Technology : solar thermal - central receiver (or tower plant)

Fuel Type : solar radiation

Functioning :

Solar radiation in the optical spectrum (sunlight) is focused by a large concentric array of mirrors, known as heliostats, to a common central focal point where a receiver is situated. Each heliostat independently tracks the sun with a two-axis (altitude and azimuth) tracking system. A working fluid, usually water, passes through the receiver. Solar radiation absorbed by the water at the receiver generates steam. The steam is injected into a staged turbine unit therby turning the generator to produce electricity. Low pressure steam leaving the turbine passes through the condenser (cooled by the cooling water system). Steam condensate from the condenser is the processed (deaerated and demineralized) and returned into the receiver as feed water.



Performance

Capacity Range : 1 - 100 MW

➔ Capacity of plant for which parameters are quoted : 80 MW

Operating Availability : 90 - 95%

Duty Cycle : intermittent

These plants run whenever sufficient sunlight is present. Optional high capacity rectifier/battery/inverter storage units can permit power delivery at other times of the day. Intermediate and peaking duty cycles are possible.

Capacity Factor : 40%

On average, for plants in optimal locations.

Efficiency : 20 - 25%

Here efficiency is the amount of energy produced by the plant relative to the flux of solar energy received by the trough. Moderate efficiencies result from lower temperatures of product steam (650-1,200 °C) relative to temperatures required for optimal turbine efficiency (1,400 °C). There are efficiencies of scale for larger heliostat array sizes.

CO_2 output [2] : 0 kg/MWh (assuming no gas co-firing)

Lead-time : 5 years

Lifetime : 30 years

Although plastic membrane heliostat mirrors have a lifetime of only 10 years, after which time they need to be replaced.

Flexibility :

- duty cycle switches are possible (intermediate and/or peaking)

Direct Costs *@ 7% DCF*

	mills per KWh	*$ per KW of Capacity*
Capital	69	3,000
O&M	20	
Fuel[3]	0	
Total	79	

Resource Implications

Major Inputs

- site with good insolation
- moderate land requirements for plant site: 2-4 hectares per MW
- labor pool with moderate technical skills

Major Outputs & Impacts

\+
- emissions free power with zero cost & easily accessible primary energy source
- provides high job creation for production, installation and operation & maintenance
- low capital costs

–
- intermittency of power supply
- can supply electricity directly to the grid
- generating costs are high compared to fossil fuel power generation

Notes:

1) Gas fired superheaters can be used to generate electricity during times of low insolation, although gas co-firing is not needed during normal operation.

2) For a hybrid plant with gas fired superheaters, CO_2 emissions may be significant.

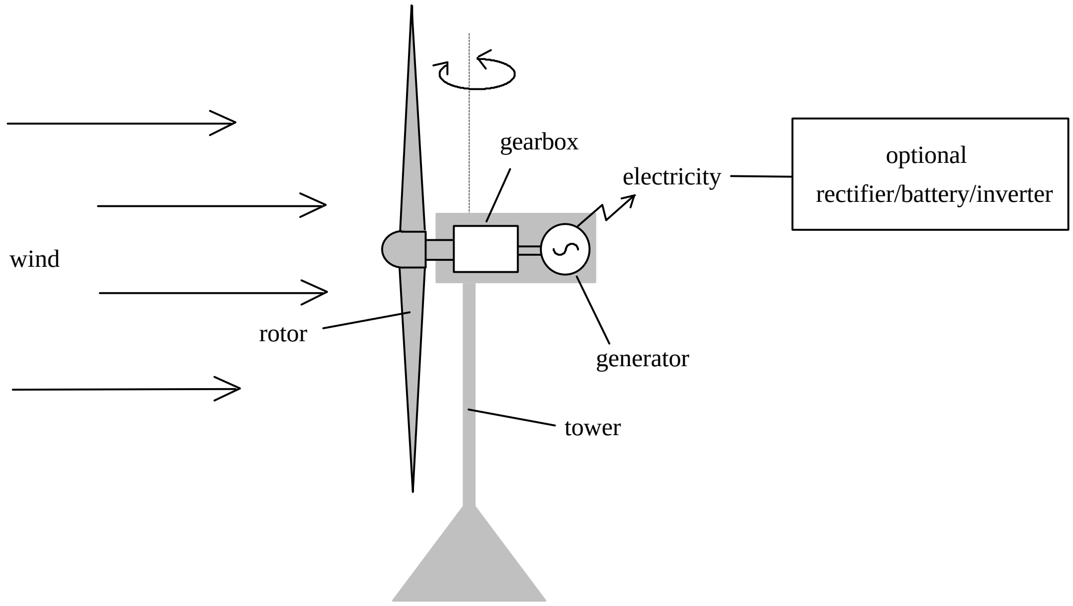
3) For a hybrid plant with gas fired superheaters, fuel costs must be considered.

Technology : horizontal axis wind turbine (HAWT)

Fuel Type : wind energy

Functioning :

A parcel of air moving through the atmosphere possesses kinetic energy. A wind turbine captures this energy and converts it into electricity. Wind turns the turbine rotor (having 2 or 3 blades of 10-30 m in length) and thus the turbine shaft rotates. As wind speed and direction are constantly varying quantities, the rotor is continually oriented in a direction with respect to the wind such that it rotates at a constant speed (30-50 rev/min). The turbine shaft is coupled to the generator shaft through a gearbox. The gearbox increases the generator shaft's rotational speed to the level required for 220V 50 cycles/sec (or 110V 60 cycles/sec) AC power generation. Electricity from the generator is output to the user or grid. As an option, a rectifier/battery/inverter storage unit can be combined with the system for electricity supply during times when wind speeds are below the operating threshold of the turbine.



Performance

Capacity Range [1] : 250 - 500 kW

Stated capacity range is for single units. Applications are single unit operation in stand-alone remote sites or high capacity generation (using an array of turbines) for grid connection. An array of turbines operated collectively is known as a *'wind farm'* power plant. Typical wind farms contain 10-100 turbines.

➔ Capacity of unit for which parameters are quoted : 250 kW

Operating Availability : 95%

Duty Cycle : intermittent

Wind turbines run whenever sufficient wind is present. Optional rectifier/battery/inverter storage units permit power delivery at other times.

Capacity Factor : 25 %

Depends on wind conditions of site, can approach 40% in certain locations.

Efficiency : N/A

CO_2 output : 0 kg/MWh

Lead-time : 0.5 years for single unit, 2 years for a wind farm

Off-the-shelf units are just becoming commercial.

Lifetime : 15 years

Flexibility :

- capacity upgrades possible by adding turbines to create an array
- battery storage option permits continuous power supply in some applications

Direct Costs *@ 7% DCF*

	mills per KWh	*$ per KW of Capacity*
Capital	50	1,000
O&M	14	
Fuel	0	
Total	64	

Resource Implications

Major Inputs

- site with good wind regime; 5m/s < wind velocities < 20m/s over 25% of the time[2]
- low land requirements for plant site: 1-2 hectares per MW
- labor pool with low technical skills

Major Outputs & Impacts

\+
- emissions free power with zero cost & easily accessible primary energy source
- provides high job creation for production, installation and operation & maintenance
- low to moderate capital costs
- generating costs are compare well with those for fossil fuel power generation

–
- intermittency of power supply
- capital equipment has relatively short lifetime (15 years vs. 30 years for most other technologies)
- can disturb ecosystems (noise), present a hazard to birds, and be unsightly

Notes:

1) The cited capacity range is for larger commercial turbines, units of lower (1-50 kW) capacity are also available.

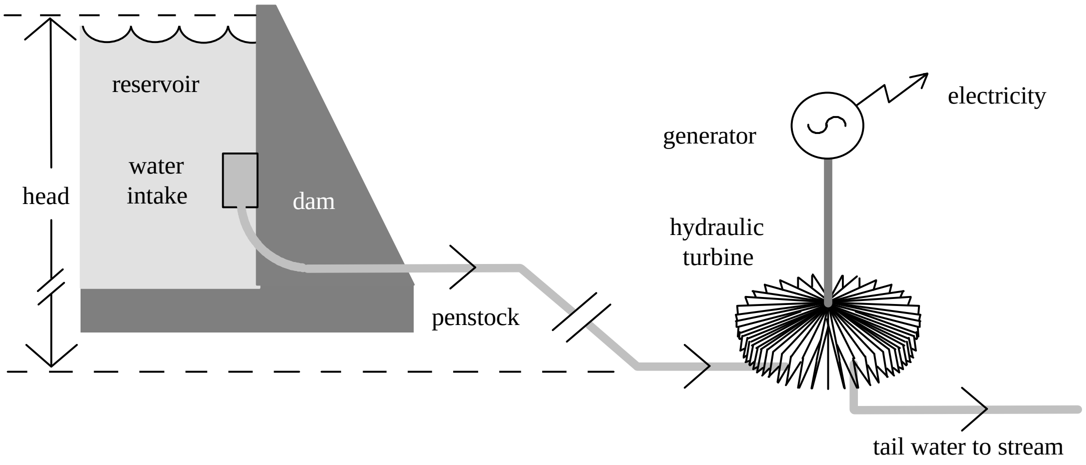
2) At the height of the rotor hub (~ 30-50 meters). Due to wind shear wind velocities are some 25% higher at a height of 50m than they are at ground level.

Technology : large-scale hydropower

Fuel Type : kinetic energy of water

Functioning :

Large quantities of water stored in a reservoir can be tapped by a hydroelectric turbine at lower elevation to generate electricity. As water passes through a vertical distance, called the *'head'*, its gravitational potential energy is converted to kinetic energy at the head's bottom. The level of power that can be produced is directly proportional to: the magnitude of the head; the flux of water passing through the turbine; and the turbine's efficiency. A dam is constructed to establish a reservoir. Reservoir water enters the water intake and flows down a conduit called the penstock. The vertical distance between the reservoir surface and the terminating point of the penstock defines the head (generally 100m or more). This distance is often much greater than the height of the dam. At the lower end of the penstock water is distributed to (one or more) hydraulic turbines. Water at high pressure (or equivalently, high ejection velocity) at the lower elevation drives the turbines which are coupled to a generator to produce electricity. High head plants operate with relatively small volumes of water at high pressure and use small diameter (0.6 - 3.5 m), high-speed (water injection at 140 m/s) Pelton turbines.



Performance

Capacity Range : 100 - 1000 MW

Capacities have no strict upper limit. This technology has economies of scale.

➔ Capacity of plant for which parameters are quoted : 300 MW

Operating Availability : 95%

The technology has high availability assuming adequate reservoir water levels are maintained.

Duty Cycle : intermediate

A baseload duty cycle is possible provided the reservoir is sufficiently fed.

Capacity Factor : 40%

This is the average capacity factor for plants in the USA.

Efficiency : 85%

Newer hydraulic turbines of the Pelton type have high efficiencies (80-90% range).

CO_2 output [1] : 0

Lead-time : 5 years

Highly variable and site specific; depends on the level of construction needed for plant.

Lifetime : 45 years

As an energy conversion technology free of combustion and heat processes, hydroplants have a long lifetime.

Flexibility :

- duty cycle switches are possible (baseload, intermediate, and/or peaking)
- plant can store energy from the grid by using it to pump water in reverse from a lower reservoir to the dammed reservoir and exploiting it at a later time (***pumped storage***)

Direct Costs *@ 7% DCF*

	mills per KWh	*$ per KW of Capacity*
Capital	42	2,000 [2]
O&M	8	
Fuel	0	
Total	50	

Resource Implications

Major Inputs

- exploitable water supply and appropriate geography in proximity to service area
- high land requirements for reservoir if needed: 1,000 hectares per MW
- labor pool with moderate technical skills

Major Outputs & Impacts

\+
- reliable, cost-effective, high-capacity power to fuel economies with indigenous hydro resources
- high potential for job creation in the construction sector

–
- seasonal precipitation fluctuations may limit plant output
- establishing a reservoir may displace humans, agriculture and destroy ecosystems
- potential downstream damages: changes in sedimentation and watershed
- adverse changes to aquatic ecosystems

Notes:

1) Excludes emissions emanating from dam construction and associated cement production.

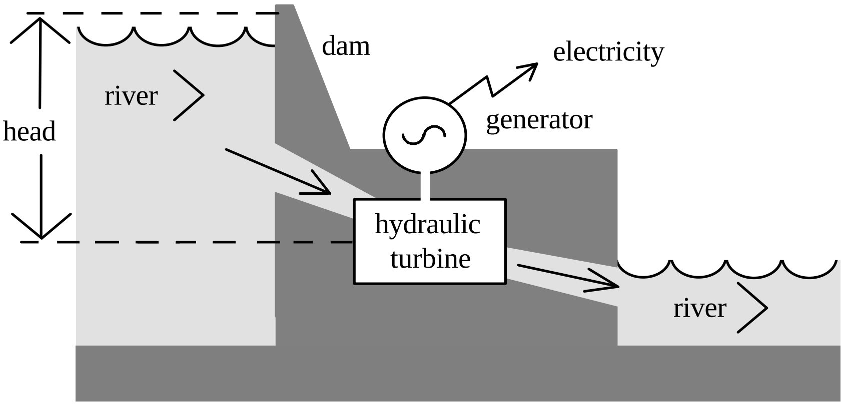
2) Capital costs are highly variable and site specific. Quoted figure is average for USA.

Technology : small-scale hydropower

Fuel Type : kinetic energy of water

Functioning :

Run of river water can be tapped by a hydroelectric turbine in a small dam structure to generate electricity. As water passes through a vertical distance, called the *'head'*, its gravitational potential energy is converted to kinetic energy at the head's bottom. The level of power that can be produced is directly proportional to: the magnitude of the head; the flux of water passing through the turbine; and the turbine's efficiency. A small-scale dam is constructed to establish low head in the water flow. River water flows through a short conduit at the dam which delivers water to hydraulic turbines (one or several turbines may be present). The vertical distance between the pre-dam river surface and the turbines defines the head (generally 20m or less). Water at moderate pressure (or equivalently, moderate ejection velocity) drives the turbines which are coupled to a generator to produce electricity. Low head plants operate with relatively large fluxes of water at moderate pressure and use large diameter (1-10 m), low-speed Kaplan turbines.



Performance

Capacity Range : 100 kW - 100 MW

Upper limit may vary. Kaplan turbine capacities can reach 25 MW. This technology has economies of scale. Run-of-river plants with low power capacity (< 1 MW) are often called mini-hydropower plants.

➔ Capacity of plant for which parameters are quoted : 100 MW

Operating Availability : 95%

The technology has high availability assuming adequate river flux is maintained.

Duty Cycle : intermediate

A baseload duty cycle is possible throughout most of the year in some locations.

Capacity Factor : 50%

This is an average value for run-of-river plants. Plants may be generating electricity on a continuous basis at variable output levels to result in this average capacity value figure. Specific values depend on season of the year and whether the year is low, average or high precipitation.

Efficiency : 75%

Newer hydraulic turbines of the Kaplan type have high efficiencies (70-80% range)

CO_2 output [1] : 0

Lead-time : 2-3 years

Highly variable and site specific; depends on the level of construction needed for plant.

Lifetime : 45 years

As an energy conversion technology free of combustion and heat processes, hydroplants have a long lifetime.

Flexibility :

- duty cycle switches are possible (baseload, intermediate, and/or peaking)

Direct Costs *@ 7% DCF*

	mills per KWh	*$ per KW of Capacity*
Capital	42	2,000 [2]
O&M	8	
Fuel	0	
Total	50	

Resource Implications

Major Inputs

- exploitable water supply and appropriate geography in proximity to service area
- low land requirements for plant <1 hectare per MW
- labor pool with moderate technical skills

Major Outputs & Impacts

\+
- reliable, cost-effective, high-capacity power to fuel economies with indigenous hydro resources
- high potential for job creation in the construction sector

–
- seasonal precipitation fluctuations may limit plant output
- potential downstream damages due to changes in sedimentation
- adverse changes to aquatic ecosystems

Notes:

1) Excludes emissions emanating from dam construction and associated cement production

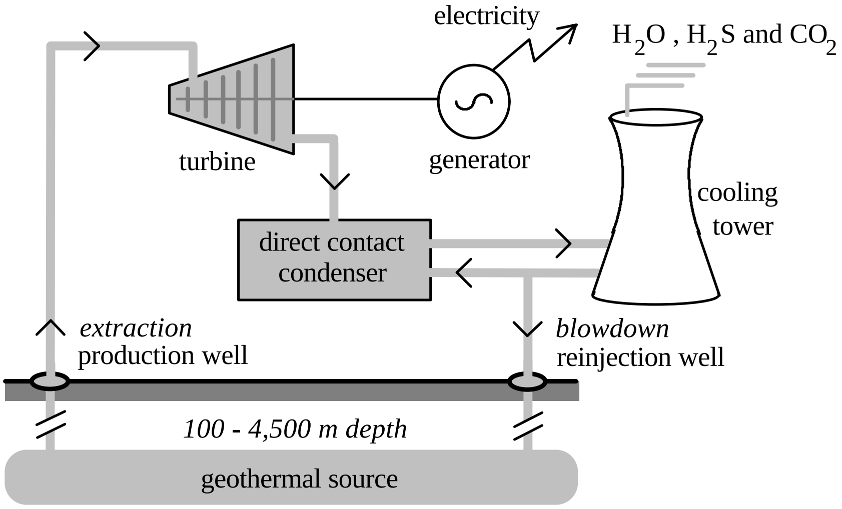
2) Capital costs are highly variable and site specific. Quoted figure is average for USA.

Technology : geothermal - dry steam plant

Fuel Type : vapor dominated geothermal well yielding dry steam

Functioning :

Dry steam (>200 °C) from the geothermal well (at a depth of 100 - 4,500 m) is extracted. This steam is injected into a staged turbine unit thereby turning the generator to produce electricity. Low pressure steam leaving the turbine passes through the direct contact condenser (cooled by direct contact with water in the cooling water system). Steam condensate mixed with heated cooling water leaving the condenser is processed (deaerated and demineralized) and then cooled in the cooling tower. To maintain a constant total quantity of water in the condenser-cooling tower cycle, some water from the cooling tower is re-injected into the well through a process called blowdown.[1] This reinjection permits reservoir recharge with eventual re-heating and re-extraction of injected water. As steam pressures in the well are usually below hydrostatic pressures at their depth, blowdown generally does not require pumping, and gravity alone returns water to the geothermal source.



Performance

Capacity Range : 20 - 120 MW

Trend is towards installations of modular capacity units of 15-20 MW above a productive well. This allows progressive well development based on confirming sustainable resource yields in a upwards stepwise fashion.

➔ Capacity of plant for which parameters are quoted : 20 MW

Operating Availability : 90%

The quoted figure is typical for plants in their first 20 years of plant life.

Duty Cycle : baseload

Other duty cycles may be possible for dry steam plants.[2]

Capacity Factor : 70% (for baseload duty cycle)

Capacity factors may decrease over time if the well becomes less productive.

Efficiency : 60%

Modern plants convert 50-70% of the steam's thermodynamic energy into electricity.

CO_2 output : 50 kg/MWh

This is an typical value; the figure varies slightly according to well characteristics.

Lead-time : 1-2 years

Lifetime : 30 years (average value)

Flexibility :

- capacity upgrades possible
- duty cycle switches (baseload, intermediate and/or peaking) may be possible[2]

Direct Costs *@ 7% DCF*

	mills per KWh	*$ per KW of Capacity*
Capital[3]	25	1,900
O&M	15	fuel costs may be levied by the geothermal resource owner less cost of resource, if present
Fuel	N/A	
Total	40	

Resource Implications

Major Inputs

- national geothermal resources
- low land requirements for plant site: 0.1 - 0.3 hectares per MW
- labor pool with moderate technical skills

Major Outputs & Impacts

+

- cheap, reliable, high-capacity power using indigenous resources
- high potential for job creation throughout the energy cycle
- low CO_2 emissions

–

- non-negligible emission levels of hydrogen sulphide (H_2S) that can cause local health hazards
- spent geothermal fluids collection and disposal, sludge from feed water processing

Notes:

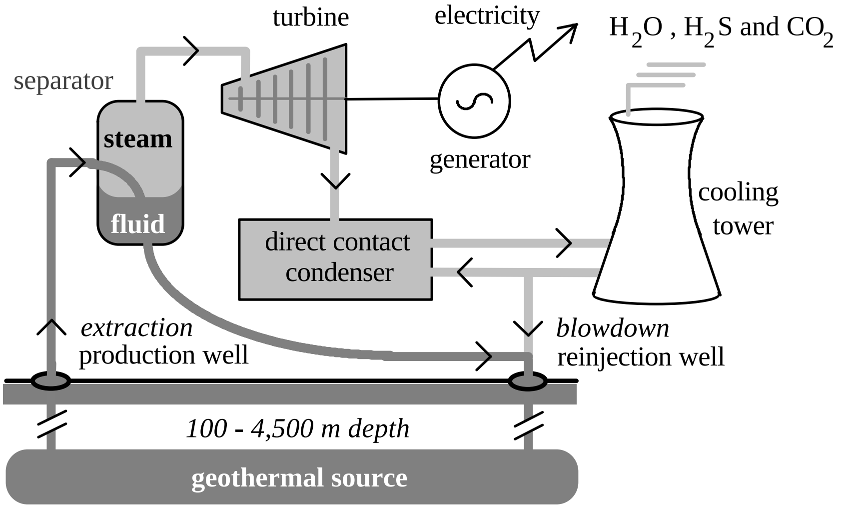
1) Reinjection must be done carefully to avoid source cooling and damaging well quality.
2) Variations in well output can damage long-term well yields in some cases.
3) Capital costs are highly variable, this estimate includes 1,500 $/KW facilities costs and 400 $/KW well drilling costs.

Technology : geothermal - single flash steam plant

Fuel Type : fluid dominated geothermal well yielding fluid-vapor

Functioning :

The hot (150 - 200 °C), two-phase (fluid-vapor) mixture from the geothermal well (at a depth of 100 - 4,500 m) is extracted. This mixture enters the separator at wellhead pressure, where it separates (flashes) due to pressure and gravity gradients into fluid and vapor states. The separator is accompanied by a check valve to prevent the passage of fluids towards the turbine. Vapor state steam from the separator is injected into a staged turbine unit thereby turning the generator to produce electricity. Low pressure steam leaving the turbine passes through the direct contact condenser (cooled by direct contact with water in the cooling water system). Steam condensate mixed with heated cooling water leaving the condenser is processed (deaerated and demineralized) and then cooled in the cooling tower. To maintain a constant total quantity of water in the condenser-cooling tower cycle, some water from the cooling tower is reinjected into the well through a process called blowdown.[1] This reinjection permits reservoir recharge with eventual re-heating and re-extraction of injected water. Since wells containing two-phase mixtures are at hydrostatic pressures at their depth, blowdown generally requires pumping.



Performance

Capacity Range : 10 - 50 MW

Trend is towards installations of modular capacity units of 10-20 MW above a productive well. This allows progressive well development based on confirming sustainable resource yields in a upwards stepwise fashion.

➔ Capacity of plant for which parameters are quoted : 20 MW

Operating Availability : 90%

The quoted figure is typical for plants in their first 20 years of plant life.

Duty Cycle : baseload

Other duty cycles are not possible for flash steam plants.[2]

Capacity Factor : 70% (for baseload duty cycle)

Capacity factors may decrease over time if the well becomes less productive.

Efficiency : 30-50%

Highly variable depending on steam/fluid yield ratios from extracted geothermal two-phase mixture. Flash steam plants are less efficient than dry steam plants as incoming fluid energy is not exploited. Multiple flash plants, using additional lowered pressure separators, increase efficiency by extracting additional process steam from the fluid.

CO_2 output : 50 kg/MWh

This is an typical value; the figure varies slightly according to well characteristics.

Lead-time : 1-2 years

Lifetime : 30 years (average value)

Flexibility :

- capacity upgrades possible

Direct Costs *@ 7% DCF*

	mills per KWh	*$ per KW of Capacity*
Capital	26	2,000
O&M	20	
Fuel	N/A	fuel costs may be levied by the geothermal resource owner
Total	46	less cost of resource, if present

Resource Implications

Major Inputs

- national geothermal resources
- low land requirements for plant site: 0.1 - 0.3 hectares per MW
- labor pool with moderate technical skills

Major Outputs & Impacts

\+
- cheap, reliable, high-capacity power using indigenous resources
- high potential for job creation throughout the energy cycle
- low CO_2 emissions

–
- non-negligible emission levels of hydrogen sulphide (H_2S) that can cause local health hazards
- spent geothermal fluids collection and disposal, sludge from feed water processing

Notes:

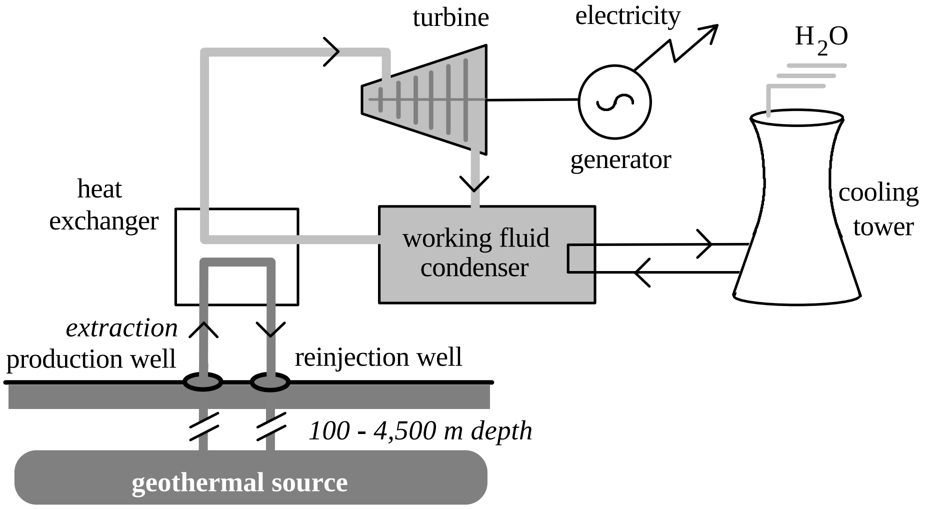
1) Reinjection must be done carefully to avoid source cooling and damaging well quality.
2) Scaling and corrosion damage to facility results from frequent plant shutdowns.
3) Capital costs are highly variable, this estimate includes 1,600 $/KW facilities costs and 400 $/KW well drilling costs.

Technology : geothermal - binary plant

Fuel Type : fluid dominated geothermal well yielding fluid-vapor

Functioning :

This system is employed when well yields have a high saline brine content (or low temperatures 120 - 150 °C) and flashing is not possible due to problems with corrosion (or ineffective flashing). The *'binary'* system employs two separate cycles; one for the geofluid and another for the working fluid that drives the turbine. The two-phase (fluid-vapor) mixture from the geothermal well (at a depth of 100 - 4,500 m) is extracted and maintained a high pressure. The mixture passes through a heat exchanger and is then discharged to the reinjection well. This reinjection permits reservoir recharge with eventual re-heating and re-extraction of injected fluid. In the heat exchanger, heat is transferred to from the geothermal fluid to the working fluid (e.g., butane, propane or ammonia) which is injected into a turbine unit thereby turning the generator to produce electricity. Low pressure working fluid vapor leaving the turbine passes through the working fluid condenser (cooled by the cooling water system). Working fluid condensate leaving the condenser is passed to the heat exchanger to repeat its working cycle. As the geofluid never enters the working fluid or cooling water circuits, the process is free of geogas emissions. All geofluids and geogases are reinjected into the well.



Performance

Capacity Range : 1 - 10 MW

Trend is towards installations of modular capacity units of 1-3 MW above a productive well. This allows progressive well development based on confirming sustainable resource yields in a upwards stepwise fashion.

➔ Capacity of plant for which parameters are quoted : 2 MW

Operating Availability : 90%

The quoted figure is typical for plants in their first 20 years of plant life.

Duty Cycle : baseload

Other duty cycles possible for binary plants[2].

Capacity Factor : 70% (for baseload duty cycle)

Capacity factors may decrease over time if the well becomes less productive.

Efficiency : 30-50%

Highly variable depending on steam/fluid yield ratios from extracted geothermal two-phase mixture. Flash steam plants are less efficient than dry steam plants as incoming fluid energy is not exploited. Multiple flash plants, using additional lowered pressure separators, increase efficiency by extracting additional process steam from the fluid.

CO_2 output : 50 kg/MWh

This is an typical value; the figure varies slightly according to well characteristics.

Lead-time : 1-2 years

Lifetime : 30 years (average value)

Flexibility :

- capacity upgrades possible

Direct Costs *@ 7% DCF*

	mills per KWh	*$ per KW of Capacity*
Capital	26	2,000
O&M	20	
Fuel	N/A	fuel costs may be levied by the geothermal resource owner
Total	46	less cost of resource, if present

Resource Implications

Major Inputs

- national geothermal resources
- low land requirements for plant site: 0.1 - 0.3 hectares per MW
- labor pool with moderate technical skills

Major Outputs & Impacts

\+
- cheap, reliable, high-capacity power using indigenous resources
- high potential for job creation throughout the energy cycle
- low CO_2 emissions

–
- non-negligible emission levels of hydrogen sulphide (H_2S) that can cause local health hazards
- spent geothermal fluids collection and disposal, sludge from feed water processing

Notes:

1) Reinjection must be done carefully to avoid source cooling and damaging well quality.
2) Scaling and corrosion damage to facility results from frequent plant shutdowns.
3) Capital costs are highly variable, this estimate includes 1,600 $/KW facilities costs and 400 $/KW well drilling costs.

Annex IV : Technical and Economic Assumptions

Technical and economic assumptions made in preparing the data are as follows:

1) Direct costs

- All direct costs are 1990 US costs.
- Capital cost estimates are from references 4 and 30, O&M costs from reference 30, and fuel costs are from reference 4.
- Levelized capital costs are calculated using the formula and assumptions given in Box 5 of this Guide.
- Levelized total direct costs are calculated using the formula given in Box 8 of this Guide.

2) All estimates of generation costs and technology performance assume the capacity factor specified in the tables. These values are estimates based on the assumed duty cycle shown for each technology; i.e., the duty cycle in which the technology is customarily engaged in. Duty cycles and capacity factors used in any given plant may be different from the representative values assumed here, particularly in capacity constrained applications wherein technologies are *'pushed'* to higher performance levels. In such cases, levelized capital costs are lowered, levelized O&M costs are raised, and resulting levelized total direct costs may vary significantly (higher or lower) from the values presented herein.

3) CO_2 emission ranges are compiled from references 15 and 29.

4) All NO_x and SO_2 emission ranges are from reference 15.

5) The capacity ranges shown are estimates compiled from references 4, 15, and 30. The range of capacity ratings for commercially available technologies from vendors is constantly changing, hence, capacity ranges may be slightly larger than indicated.

6) Labor requirements are estimated from data in reference 15.

7) Land requirements are from reference 31.

8) Water requirements indicate the relative quantity of water needed for plant operation. Estimates are from reference 30.

9) Some additional references are indicated in the tables of Annex I.

10) A more complete discussion of technical and economic assumptions will be provided in a ***revised edition*** of this guide.

All data from the Annex I tables are also presented in Annex III two-page fact sheets for individual technologies. Additional relevant information relating to characterizations is provided in the fact sheets.

Glossary

Anthropogenic: referring to an activity or process of human origin.

Baseload: The minimum level of the daily (or seasonal) load. *See Section A.1.1.*

Btu: A unit of measurement for heat energy.

Capacity factor: The ratio of power actually generated by a power plant in a specified amount of time (usually 1 year) to the amount of power that could be generated over the same time period if the plant had been operated continuously at its full capacity rating. *See Section A.2.4 and Box 4.*

Capacity range: The range of electric power which can be generated by a class of technologies. Capacities are measured in kilowatts (kW) or megawatts (MW). *See Section A.2.1.*

Capacity rating: The maximum power output of a technology. Often specified by the manufacturer. *See Section A.2.1.*

Cash flow: The sum of yearly revenues or costs associated with an investment project. *See Section B.3.*

Centralized power plant: A relatively high-capacity, grid connected power plant serving a large service area.

CHP: *Combined heat and power* or *cogeneration of heat and power.* Any application which can make productive use of thermal energy losses from a power plant is known as a CHP application. Any technology with thermal heat losses that can easily be tapped are able to support CHP applications. *See Section C.2.2.3.*

Climate friendly technology: A term commonly used to refer to technologies with relatively low levels of CO_2 emission, or indeed, zero emissions.

Co-firing: The practice of using mixture of primary energy sources as *'fuel'* input to a technology. For example, many solar thermal plants are co-fired, generating electricity from steam produced from two *'fuel'* sources; solar energy and natural gas.

Combined cycle: The generation of electricity by a technology in two sequential processes: 1) burning fuel in a primary circuit to drive a primary gas turbine, and 2) generating steam from the thermal losses in the primary circuit to drive secondary steam turbine. Both turbines drive generators to produce electricity.

DCF: *Discounted cash flow.* Future cash flows of a project are discounted to their value at the time an investment is made. A discount factor is assumed in all such calculations.

Demand-side management: Demand-side options implemented to reduce demand through the utilization of administrative and pricing mechanisms in electricity markets.

Direct costs: Those costs directly related to power plant construction and subsequent operation. These include capital, operations and maintenance, and fuel charges (when present). See Section B.1.

Discount rate: The expected rate of a return on low risk investments made in local markets. These rates vary from one region to another. In many cases, the discount rate in a country is assumed to be the current yield of long-term (e.g., 10 year) government bonds.

Distributed power plant: A relatively low capacity power plant, often without grid connection, serving a remote small population center.

Duty cycle: The level of engagement of a technology in supplying electricity to a service area. At any given time a technology performs one of various duty cycles: *baseload, intermediate, peaking, or intermittent.* Some technologies can be engaged in various duty cycles, while others can only be engaged in one duty cycle. *See Section A.2.3.*

Efficiency: The efficiency of a technology is the ratio of electrical energy output to the primary energy input needed to generate it. *See Section C.2.2.3.*

End-use efficiency: The utilization of electricity – by end-users from all sectors in a service area – using machines, devices, and appliances that are energy efficient *vis. à vis.* state-of-the-art standards.

Energy conversion: A process by which energy in one form is converted into energy of another form. Power generation technologies are used to perform energy conversion from an available form in natural resources (**primary energy** or **initial energy**) to end-use form such as electricity (**final energy**). *See Introduction and Summary.*

Energy cycle: The aggregate set of all processes and activities which must be undertaken to produce final energy (electricity) from initial energy (extracted from a primary energy resource). Energy cycles for power generation vary according to the primary energy resource and technology used for energy conversion. *See Section C.1 and Figure 4.*

Energy planning cycle: A sequence of analytical steps performed by energy planners which allows them to identify attractive supply and demand-side options which can be implemented to meet demand-side needs for energy. This guide focuses on a simplified energy planning cycle that can be used to identify new power generation technology options on the supply-side. *See Introduction and Summary and Figure 1.*

Energy: A physical quantity which is needed to perform any activity. Energy exists in various different forms. *See Box 2.*

FGD: *Flue gas desulphurization.* The process used to remove sulphur dioxide from the exhaust gas of coal-fired (and sometimes oil-fired) power plants. Depending on the nature of fuel used, the flue gas of coal (and sometimes oil) fired power plants often has high sulphur dioxide concentrations. *See Section C.2.1.1.*

Fossil fuel: An organic substance of fossil origin which can be burned to produce thermal energy. Fossil fuels include coal, oil, and natural gas. *See Box 15.*

Fuel switching: Changing the type of fuel used by a technology to generate power. Most often the term is used to denote a switch from a higher carbon fuel source (e.g., oil) to a lower carbon fuel source (e.g., natural gas). *See Section C.2.2.3.*

Generator, or electricity generator: A device which converts the rotational energy of a turbine into electrical energy.

Geothermal energy: Heat energy of geological steam or water originating from the internal thermal energy of the earth.

GHG: abbreviation for greenhouse gas.

Greenhouse gas: Gases of natural and anthropogenic origin that cause (positive) radiative forcing in the earth's atmosphere. *See Box 12.*

Grid: A network of electrical lines used to transmit and distribute electricity from a centralized power plant.

Indirect benefits: Benefits indirectly associated with power plant operation. These include benefits gained throughout the full energy cycle, including benefits such as increased employment, economic growth, and improved urban air quality. As with indirect costs, indirect benefits are often difficult to quantify. *See Section C.1 and Box 11.*

Indirect costs: Those costs indirectly associated with power plant operation. These include incurred costs throughout the full energy cycle, including costs of negative environmental and health impacts. Unlike direct costs, indirect costs are often difficult to quantify. *See Section C.1 and Box 11.*

IRP: *Integrated Resource Planning.* A planning process which takes into account considerations of the full range of resource implications associated with a power plant throughout its full energy cycle, and not simply those directly associated with power generation at the plant. *Usage of this term is variable; some consider it to implicitly include least cost planning and demand-side management. See Section C.1*

IRR: *Internal Rate of Return.* A type of mathematical analysis that indicates what the rate of return on an investment is likely to be. *See Box 9.*

Lead-time: The (minimal) amount of time in years and/or months needed for the complete construction of a power plant. *See Section B.2.2.*

Least cost planning: A planning process that identifies technology options for power generation that have relatively low direct costs. *Usage of this term is variable; some consider it to implicitly include integrated resource planning and demand-side management.*

Levelized costs: The direct financial costs of power generation distributed over the amount of electric energy they result in. Levelized costs, expressed in mills per kW, can be calculated for direct cost components of electricity generation – capital, O&M, and fuel – or for aggregate total direct costs. *See Section B.1 and Boxes 5, 6, 7, and 8.*

Lifetime: A technology's (*working*) lifetime is the amount of time in years over which a technology can be productively employed to generate electricity. *Economic* lifetimes are estimates of working lifetimes used for financial and accounting purposes. *See Section B.2.1*

Line losses: Due to electrical resistance in power lines, electrical energy is lost during transmission and distribution.

Load: The (varying) level of demand for electricity in a service area.

mills: The unit of measurement for financial costs of power generation activities. 1 mill is equivalent to 1/1000 (or 0.001) $US.

NPV: *Net Present Value.* A type of mathematical analysis that indicates whether an investment is financially attractive. *See Box 9.*

Nuclear fuel: Uranium dioxide which can be made to undergo nuclear fission with an associated release of thermal energy.

O&M: Operations and maintenance. O&M activity is required for the normal functioning of a power plant. *See Section B.1.3.*

Operating availability: The percentage of time a technology can be productively engaged to generate power. *See Section A.2.2 and Box 3.*

Peak load: The maximum level of the daily (or seasonal) load. *See Section A.1.1.*

Project financing: In the power sector, referring to a scheme wherein loans for the financing of a power plant are repaid using future revenues generated by the sale of electricity from the plant.

Service area: A geographical area to which electricity is supplied by one or more power plants.

Simple cycle: The generation of electricity by a technology in a single process: burning fuel to drive a primary gas or steam turbine. *Compare with combined cycle.*

Solar energy: Energy in the form of radiation from the sun that arrives at the earth's atmosphere. As it is naturally present in the earth environment, this Guide considers solar energy as a natural resource of the earth.

Sources (**sinks**) of greenhouse gases: Processes and/or activities that release (absorb) greenhouse gases into (from) the earth's atmosphere. *See Box 14.*

Technology: In the context of this Guide, when not otherwise stated, the general term *technology* is used to refer to *power generation technology* or *energy conversion technology*. *See Introduction and Summary and Box 1.*

Thermal losses: Heat energy loss from technologies during the energy conversion process. *See Section C.2.2.3.*

Turbine: A device which converts thermal energy (in steam or heated gas) or kinetic energy (of water or wind) into rotational (mechanical) energy.

Upgradability: An indicator of whether a power plant's capacity can be readily increased. Many technologies are modular. In the absence of resource constraints, power plants based on modular technologies are upgradable. *See Section C.3.1.*

Watt-hour: The unit of measurement for electrical energy; abbreviated as Wh. Electrical energy is often expressed in units of 1,000 Watt-hours (kWh) or 1,000,000 Watt-hours (MWh). *See Box 2.*

Watt: The unit of measurement for electrical power; abbreviated as W. Power is often expressed in units of 1,000 Watts (kW) or 1,000,000 Watts (MW). *See Box 2.*

Wind energy: The collective kinetic energy of a parcel of air in the earth's atmosphere. It originates primarily from differential heating (by solar radiation) of the earth's surface. It may also derive from temperature gradients and storm activity in the earth's lower atmosphere.

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